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INNOVATIVE TECHNOLOGIES OF OIL AND GAS

SIMULATION ANALYSIS OF WELLBORE INSTABILITY CONSIDERING THE INFLUENCE OF HYDRATION EFFECT ON THE PHYSICAL PROPERTIES OF BRITTLE SHALE

Zhu Luo ✉, Donglei Jiang, Chuanhua Ma, Kai Liu, Xin Yu

Shale gas, as an important unconventional oil and gas resource, its efficient development can alleviate the current severe energy demand situation. However, the water absorption and expansion characteristics and hydration effects of shale pose a great threat to the drilling safety of shale, mainly wellbore stability. Therefore, based on mechanical property experiments, the influence of hydration expansion on the mechanical property parameters of brittle shale was analyzed, and an evolution model of the mechanical property parameters of shale with hydration expansion was constructed. In addition, a finite element model for numerical simulation of wellbore stability in shale formations was established, and the effects of factors such as the addition of hydration inhibitors in drilling fluid on wellbore collapse were analyzed. Research has shown that the hydration and expansion of shale can reduce its elastic modulus and cohesive force, but the effect of hydration and expansion on Poisson's ratio and internal friction angle shows the opposite pattern. After being immersed in drilling fluid for 12 hours, the elastic modulus of shale decreased from 5.3 GPa to 3.9 GPa, and the cohesion decreased from 4.6 MPa to 3.0 MPa. In addition, wellbore collapse and instability in shale mainly occur in the early stages of drilling operations, while wellbore collapse will significantly slow down in the later stages. The wellbore enlargement rate increased to 40% within the first three hours of drilling operations. Moreover, the addition of hydration inhibitors in drilling fluids will prevent further collapse of the wellbore by inhibiting the invasion of water. When the hydration inhibitor in the drilling fluid was increased from 0 to 45 g/m3, the wellbore enlargement rate decreased from 66.2% to 27.8%. This study can provide theoretical reference for maintaining wellbore stability and drilling safety during shale drilling.

Keywords: brittle shale, hydration expansion, wellbore instability, numerical simulation.

1. Introduction

Although the development of new energy technologies such as electricity and hydrogen has made significant progress, fossil fuels such as oil and natural gas remain important strategic resources for the future [1, 2]. With the continuous surge in global demand for oil and gas, shale gas (as an important unconventional oil and gas resource) has gradually become a substitute resource for conventional oil and gas resources [3, 4]. In 2022, the global shale gas production reached $2.54 \cdot 10^{12}$ m^3 (approximately 1.084 billion tons of crude oil equivalent) accounts for 46.7% of the total natural gas production [5-7]. However, in addition to the characteristics of low permeability and development of microcracks, shale reservoirs are often prone to water absorption

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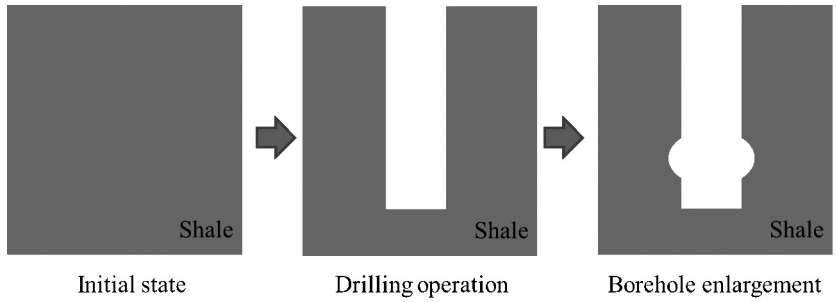

Fig. 1. Wellbore instability during drilling in brittle shale reservoirs

and swelling, which is another important characteristic that affects drilling safety [8-10]. **Figure 1** shows a schematic diagram of the wellbore instability process during drilling in shale reservoirs. As shown in Figure 1, after drilling the wellbore in shale, the filtration and invasion of drilling fluid into the surrounding rocks are inevitable. Under the long-term immersion of drilling fluid, the rocks around the wellbore will absorb water and expand, leading to collapse and wellbore enlargement [11]. Therefore, conducting research related to efficient shale gas development and drilling and completion safety control technology has strong strategic significance and value.

So far, some experts have conducted extensive academic research on the hydration and expansion characteristics of shale and the resulting wellbore instability. And significant progress has been made. Lyu et al. [12] conducted a study on the water absorption and expansion characteristics of shale samples with different initial water contents under drilling fluid immersion conditions based on previous research. Research has found that the expansion rate of shale samples increases with the increase of initial water content, and the water absorption and expansion of shale occur most severely when the initial water content is about 14%. Murtaza et al. [13] evaluated the potential and role of adding 1-ethyl-1-methylpyrrolidine bromide to water-based drilling fluids in inhibiting the hydration expansion of shale through experiments. Research has found that 0.3wt% of this inhibitor in drilling fluid can reduce shale expansion behavior by 20%. Moreover, this inhibitor can mainly achieve the goal of inhibiting shale hydration and expansion by reducing the water absorption capacity of clay components in shale. Ahmad et al. [14] evaluated the shale swelling inhibition properties of three additives, namely decyltrimethylammonium bromide, octyltrimethylammonium bromide, and hexyltrimethylammonium bromide, through linear expansion rate measurements. Research has shown that the surfactant decyltrimethylammonium bromide has superior properties in enhancing the rheological properties and shale inhibition performance of drilling fluids. Liu et al. [15] evaluated and analyzed the wellbore stability of the Longmaxi Formation shale under drilling, fracturing, and completion conditions by constructing a theoretical model. Research has found that the Longmaxi Formation shale is a typical hard and brittle shale with weak hydration and expansion ability, and the wellbore stability during drilling is relatively ideal. It is undeniable that the above studies are very helpful for understanding the mechanism of water absorption and expansion of shale and its impact on wellbore stability. However, these studies still have two shortcomings or deficiencies that urgently need to be improved. Firstly, current research has not conducted in-depth analysis on the evolution law of mechanical properties parameters of shale with hydration and expansion, let alone model construction. Therefore, research related to the hydration and expansion of shale cannot provide a theoretical basis for numerical simulation of wellbore stability. Secondly, most numerical simulations of wellbore stability in shale reservoirs are conducted for the safe mud density window, and there is little analysis on the collapse law.

This study first analyzed the influence of hydration expansion on the mechanical properties parameters of brittle shale based on mechanical property experiments. Meanwhile, based on the experimental results, an evolution model of the mechanical properties parameters of shale with hydration expansion was constructed. Finally, considering the evolution of mechanical properties parameters of shale with hydration expansion, a numerical simulation model for wellbore stability of shale formation was constructed. And the influence of engineering factors such as soaking time on wellbore collapse was analyzed. In order to provide a theoretical basis for proposing ways to reduce/avoid wellbore instability during shale drilling through this study.

2. Experimental methods and results

Experimental system and methods. Figure 2 shows an experimental system for analyzing the mechanical properties of shale. The system mainly consists of a confining pressure loading system, an axial pressure loading system, a pore pressure loading system, a servo control system, and a data acquisition system. Among them, the confining pressure loading system is mainly composed of two servo control pumps, which can load in-situ stress components in various directions on shale cores. The servo control pump is pressurized using silicone oil hydraulic technology, with a maximum confining pressure of 30 MPa and a rated flow rate of 0.15 L/min. In addition, the main component of the axial compression loading system is the axial piston, which is pushed by hydraulic silicone oil to achieve axial stress loading. During the experiment, constant footage or constant load can be chosen to achieve axial stress loading, with a loading limit of 120 MPa. Meanwhile, the equipment is also equipped with a pore pressure loading experimental system to restore the underground rock state, but this function is not used in the experiment. During the experiment, the rock core was made into 10cm×10cm×10cm cubic blocks, and axial stress and two confining pressures were loaded onto the adjacent three faces of the cube. The key component of this experimental system is the high-pressure vessel for placing rock samples. The inner side of the high-pressure vessel is made of rubber, which is used to compress rocks under hydraulic pressure and apply confining pressure.

Before the experiment begins, it is necessary to prepare cubic rock samples of shale with a length, width, and height of 10 cm, 10 cm, and 10 cm respectively. Then, soak the prepared rock sample in drilling fluid for 12 hours, remove it and place it in a high-pressure vessel. At the same time, turn on the confining pressure pump to load the confining pressure to 20 MPa. After the confining pressure stabilizes, turn on the axial pressure pump and gradually apply axial stress. However, it should be noted that the maximum displacement of the axial piston needs to be controlled at 10 mm. During the experiment, collect and store relevant data obtained through pressure sensors, strain sensors, and pressure gauges at a frequency of 1 minute each time. **Table 1** presents the relevant characteristic parameters of 5 sets of shale samples.

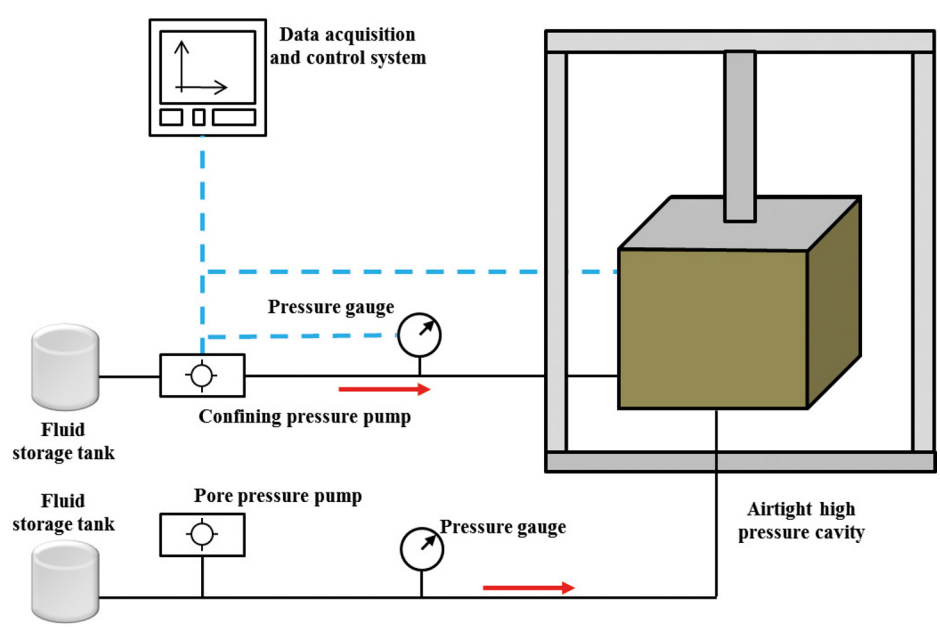

Fig. 2. Experimental system for triaxial mechanical properties of shale

Table 1. Characteristic parameters and experimental conditions of shale samples

No.	Soaking time (h)	Length (cm)	Width (cm)	Heigh (cm)	Mineral composition (%)	Experimental condition
1	0	10.2	10.1	10.2	Quartz: 10.1 Feldspar: 38.3 Clay mineral: 47.2 Others: 4.4	Confining pressure: 20 MPa Axial load: 25 MPa
2	3	10.1	9.9	10.1		
3	6	9.8	9.7	9.8		
4	9	9.9	10.3	10.1		
5	12	10.1	10.2	9.9		

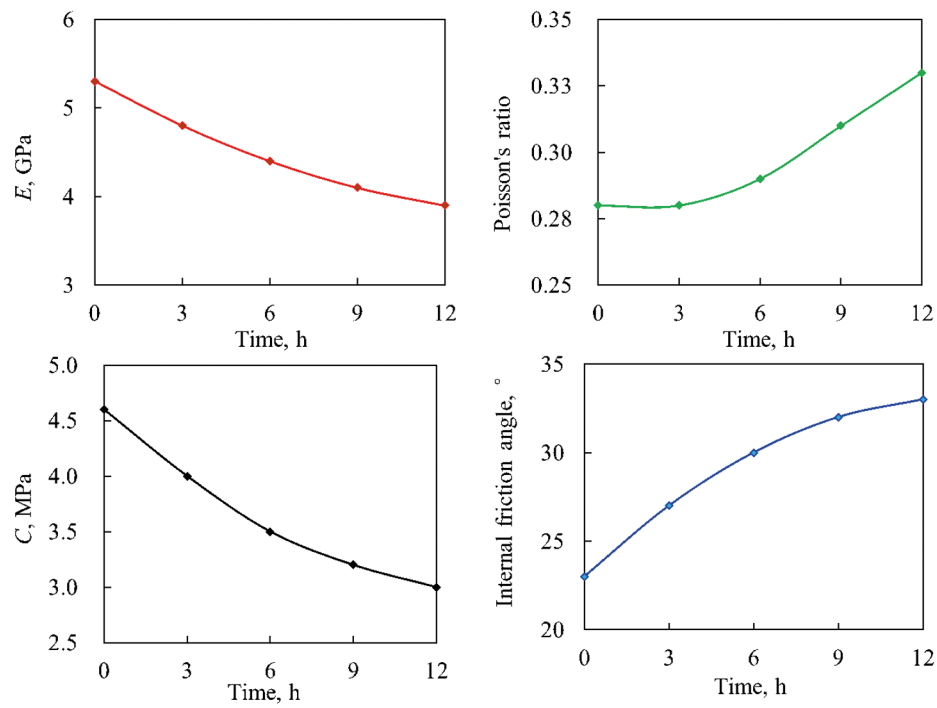

Fig. 3. Influence of hydration and expansion of shale on its mechanical properties parameters

Hydration expansion characteristics. Clarifying the influence of hydration expansion on the mechanical properties of shale is a necessary prerequisite for conducting finite element analysis of wellbore stability. **Figure 3** shows the experimental results of the mechanical properties parameters of shale when the soaking time is different. Figure 3 indicates that as the soaking time of shale in drilling fluid prolongs, the elastic modulus and cohesive force will gradually decrease. When the soaking time of drilling fluid gradually increases from 0 hours to 12 hours, the elastic modulus decreases from 5.3 GPa to 3.9 GPa. Correspondingly, the cohesive force will decrease from 4.6 MPa to 3.0 MPa during this process. However, the Poisson's ratio and internal friction angle will gradually increase with the prolongation of immersion time in drilling fluid. Taking Poisson's ratio as an example, as the soaking time of drilling fluid gradually increases from 0 hours to 12 hours, its value will increase from 0.28 to 0.33, with an increase of up to 17.86%. And the hydration and expansion characteristics of shale vary at different drilling times.

From Figure 3, we can also observe that the hydration and expansion of shale mainly occur in the early stage of drilling operations (the first 6 hours). Taking the elastic modulus of shale as an example, the rate of decrease in elastic modulus within the first 6 hours is 0.15 GPa/h. However, within the last 6 hours of drilling operations, the rate of decrease in elastic modulus becomes 0.08 GPa/h. Further fitting of the experimental results resulted in the dynamic evolution characteristic equation of parameters, as shown in equations:

$$E = 0.0056t^2 - 0.1833t + 5.3, \tag{1}$$

$$\nu = 0.0004t^2 - 0.0004t + 0.2791, \tag{2}$$

$$C = 0.0079\mathrm{t}^2 - 0.2286\mathrm{t} + 4.6029 \tag{3}$$

$$\varphi = -0.0556t^2 + 1.5t + 23, \tag{4}$$

where, E is the elastic modulus, GPa; v is the Poisson's ratio, *Con.*; C is the cohesive force, Kpa; φ is the internal friction angle, °; t is the soaking time of drilling fluid, h.

Mathematical model and applicability verification. The analysis of wellbore stability involves changes in the seepage field, solid mechanics field, and chemical field, with extremely strong nonlinearity. To investigate the wellbore stability during drilling in shale reservoirs, a force chemical coupling mathematical model was constructed. Firstly, during the drilling process, the invasion of drilling fluid into the mud shale layers around the wellbore can be described using the equation [16]

$$-\nabla\left(\phi\rho_w S_w V_w\right)+m_w+q_w=\frac{\partial\left(\phi\rho_w S_w\right)}{\partial t}, \tag{5}$$

where, ϕ represents porosity, %; ρ represents density, g/cm^3; S represents flow velocity, m/s; q represents source and sink terms. In addition, the subscript w represents pore water.

The analysis of wellbore mechanics is the foundation for conducting wellbore integrity, and this article provides the basic theory of wellbore mechanics analysis. After coordinate transformation, the stress distribution around the wellbore at different wellbore angles and inclinations in polar coordinates can be represented by equation [17]

$$\begin{cases}\sigma_r=P_m\\ \sigma_\theta=\sigma_B^{xx}+\sigma_B^{yy}-2\left(\sigma_B^{xx}-\sigma_B^{yy}\right)\cos 2\theta-4\sigma_B^{xy}\sin 2\theta-P_m\\ \sigma_z=\sigma_B^{zz}-2v\left[\left(\sigma_B^{xx}-\sigma_B^{yy}\right)\cos 2\theta+2\sigma_B^{xy}\sin 2\theta\right]\\ \sigma_{\theta z}=2\left(\sigma_B^{yz}\cos\theta-\sigma_B^{xz}\sin\theta\right)\end{cases} \tag{6}$$

where, σ_r, σ_θ, σ_z and $\sigma_{\theta z}$ are the stress components in the wellbore coordinate system represented by polar coordinates respectively, MPa; σ_B^{xx}, σ_B^{yy}, σ_B^{zz}, σ_B^{xy}, σ_B^{xz} and σ_B^{yz} represent the stress components in the wellbore coordinate system represented by cartesian coordinates respectively, MPa; P_p represents the pore pressure, MPa; P_m was the drilling mud pressure, MPa; θ was the peristaltic angle, °.

When considering the influence of pore pressure, the formula for the distribution of rock stress around the well can be expressed as equation [18]:

$$\begin{cases}\sigma_r=P_m-P_p\\ \sigma_\theta=\sigma_B^{xx}+\sigma_B^{yy}-2\left(\sigma_B^{xx}-\sigma_B^{yy}\right)\cos 2\theta-4\sigma_B^{xy}\sin 2\theta-P_m-P_p\\ \sigma_z=\sigma_B^{zz}-2v\left[\left(\sigma_B^{xx}-\sigma_B^{yy}\right)\cos 2\theta+2\sigma_B^{xy}\sin 2\theta\right]-P_p\\ \sigma_{\theta z}=2\left(\sigma_B^{yz}\cos\theta-\sigma_B^{xz}\sin\theta\right)\end{cases} \tag{7}$$

Based on the above theory, a mud shale wellbore stability analysis model was constructed as shown in **Figure 4**. It should be noted that all research is based on the ABAQUS platform. For the convenience of research, the model shown in Fig. 4a is a two-dimensional plane strain model set based on an open hole vertical well in a brittle shale rock layer. To avoid the influence of boundary effects, the side length of the model in the study is 15m and the wellbore radius is 0.15 m. After grid partitioning, the finite element model consists of 8250 CPE4P fluid structure coupling elements, and the simulation time is 24 hours. The hydration effect of shale (Equations (1) to (4)) needs to be simulated in wellbore stability using Fortran language and implemented by writing USDFLD subroutines, as shown in Figure 4c.

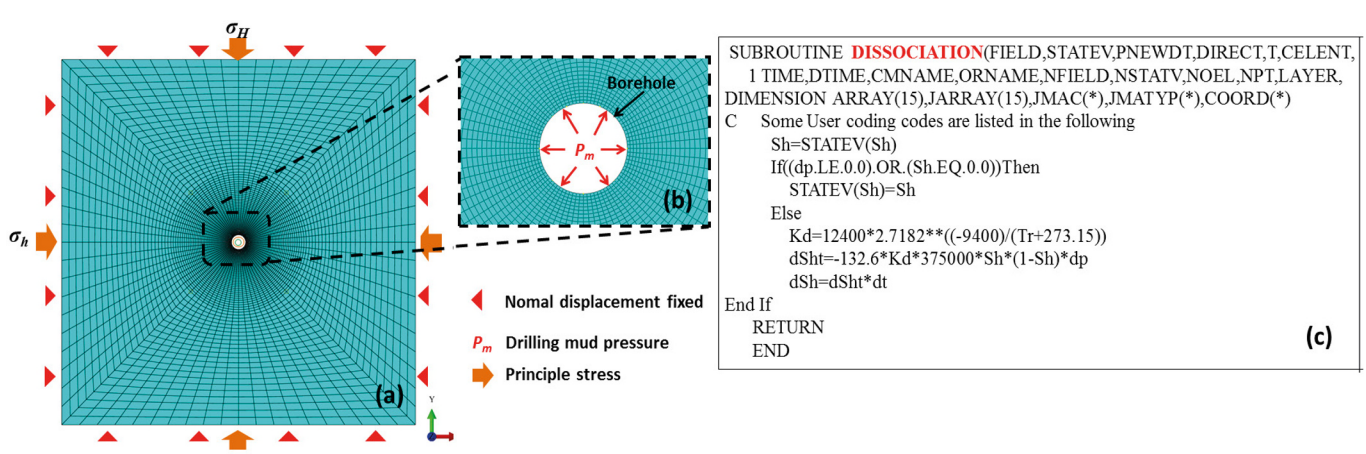

Fig. 4. Grid model and USDFLD subroutine code for shale wellbore stability analysis. a) Complete model; b) Local grid near wellbore area; c) Detailed code for USDFLD subroutine

The simulation results show that the deformation and damage of the wellbore mostly occur around the wellbore, and the size of the elements around the wellbore is much smaller than that near the outer boundary. In addition, during the simulation process, it is not only necessary to apply a load on the wellbore wall, but also to apply a pore pressure equal to the bottom hole pressure on the wellbore wall. Meanwhile, the event where the normal displacement of the outer boundary is constrained needs to run through the entire simulation process.

3. Discussion

Validation of model applicability. To verify the effectiveness of the model, the simulated wellbore stability results were compared with the analytical results, as shown in **Figure 5**. In the analytical model, the hydration reaction of shale has not been taken into account. The stress distribution curve of the surrounding rock of the well was obtained by analyzing the model, and then the stress distribution curve was obtained through the finite element model in this paper. This is because the reduction in shale strength caused by hydration effect has not been considered in the analytical model. Higher rock strength will accumulate greater stress, resulting in stronger stress unloading during rock failure. On the contrary, when considering the hydration effect of shale around the well, stress concentration will be slowly released during the hydration process. In this way, the stress of shale near the wellbore is correspondingly lower. However, the interval between the two curves in Figure 5 is limited, and the maximum effective stress difference is only 0.45 MPa. All of these indicate that considering the hydration reaction of shale during drilling is extremely important for finite element analysis of complex downhole accidents such as wellbore stability.

Evolution law and mechanism of wellbore collapse. It is generally believed that the area around the wellbore where yielding occurs is the area where collapse is about to occur. At the same time, in order to facilitate quantitative research on the wellbore stability of shale, the ratio of the yield area around the wellbore in the two-dimensional model to the initial wellbore cross-sectional area is defined as the wellbore enlargement rate. Therefore, the definition for wellbore enlargement rate is as equation

$$\beta = \frac{A_{yield}}{A_{Bore}} \cdot 100\%, \tag{8}$$

where, A_{yield} and A_{bore} represent the area of the yield zone and the initial wellbore cross-sectional area respectively, m^2.

Based on this, the evolution characteristics of wellbore enlargement rate and the range of hydration reactions in the surrounding rock of the well were studied, as shown in **Figure 6**. From Figure 6, we can observe that the wellbore enlargement rate rapidly increases in the first three hours of drilling operations, and wellbore collapse is more significant. By the third hour after the drilling operation began, the wellbore enlargement rate had reached 40%. However, as drilling operations continue, wellbore collapse

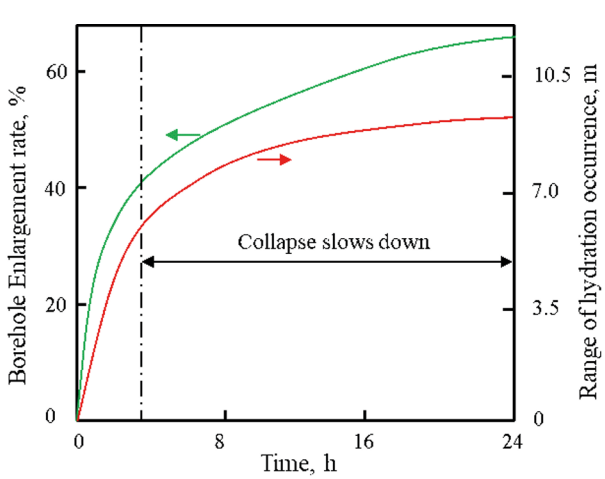

Fig. 5. Comparison of effective stress distribution around the wellbore obtained from analytical models and FEM models

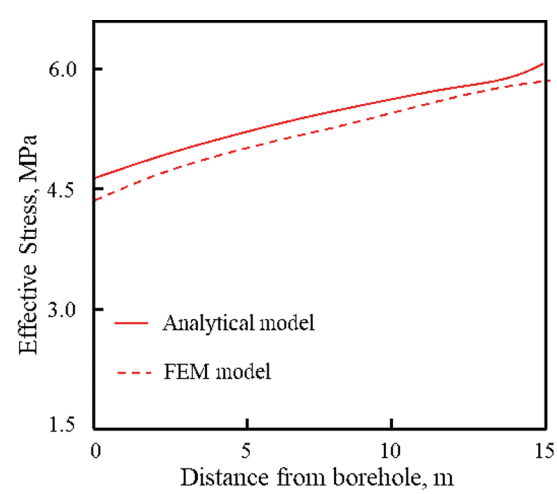

Fig. 6. Relationship between wellbore enlargement rate and range evolution of hydration reaction occurrence

will significantly slow down and the increase in wellbore enlargement rate will slow down. Within the last 21 hours of drilling operations, the wellbore enlargement rate only increased from 40% to 66.2%. Meanwhile, the changing trends of the two curves are consistent. This suggests that the collapse of the wellbore in brittle shale is mainly due to hydration reactions occurring in the shale near the wellbore. As is well known, hydration reactions can significantly reduce the strength and cementation of shale, making it difficult for the wellbore to withstand tensile damage caused by low drilling fluid density. At the end of the drilling operation, the range of hydration reactions occurring in the mud shale around the well had reached 9.24 m.

On the other hand, low drilling fluid density is also an important mechanism leading to wellbore collapse. The simulation results show that the wellbore enlargement rate gradually decreases with the increase of drilling fluid density. When the relative density of drilling fluid is only 0.96, the wellbore enlargement rate reaches an astonishing 66.2%. However, when the drilling fluid density increased to 1.00 and 1.04, the wellbore enlargement rate decreased to 22.1% and 0%, respectively. This is mainly because at lower drilling fluid densities, smaller static fluid column pressures are difficult to effectively support the loose wellbore wall after water absorption and expansion, leading to tensile failure. Moreover, the lower the density of drilling fluid, the more likely and severe the tensile failure of the wellbore wall [19]. To maintain the stability of the wellbore during shale drilling, it is recommended to have a drilling fluid density of at least 1.03 g/cm^3.

Effect of hydration inhibitors on wellbore instability. To avoid the occurrence of uncontrollable wellbore collapse accidents, in addition to designing the drilling fluid density reasonably, it can also be achieved by adding hydration inhibitors to the drilling fluid. **Figure 7** shows the final wellbore enlargement rate values in shale under different concentrations of hydration inhibitors. From Figure 7, it can be observed that an increase in the concentration of hydration inhibitors in drilling fluid significantly slows down the occurrence of hydration effects in shale formations, thereby weakening wellbore instability and collapse. When no hydration inhibitor is added to the drilling fluid, the wellbore enlargement rate is only 66.2%. However, when the hydration inhibitors in the drilling fluid were 15 g/m^3, 30 g/m^3, and 45 g/m^3, the wellbore enlargement rate decreased to 42.5%, 33.1%, and 27.8%, respectively.

The effect of hydration inhibitor concentration in drilling fluid on wellbore stability can be illustrated by **Figure 8**. From Figure 8, it can be observed that when the concentration of hydration inhibitors in the drilling fluid is low, a large amount of drilling fluid in the wellbore will invade the pores of the shale around the wellbore, leading to a larger range of shale hydration reactions. At this point, inhibitors will to some extent alter the wettability of shale pores [20]. In this way, the probability of water molecules meeting shale crystals is greatly reduced, making it difficult for shale to undergo intense hydration reactions again. We can also observe that the addition of hydration inhibitors in the drilling fluid cannot completely suppress the instability and collapse of the wellbore. This is mainly because the collapse of the wellbore is not solely influenced by the hydration and expansion of

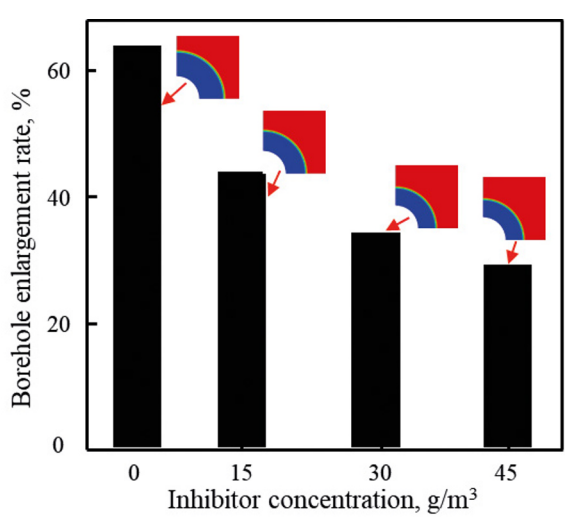

Fig. 7. Expansion rate of shale wellbore under different concentrations of hydration inhibitors

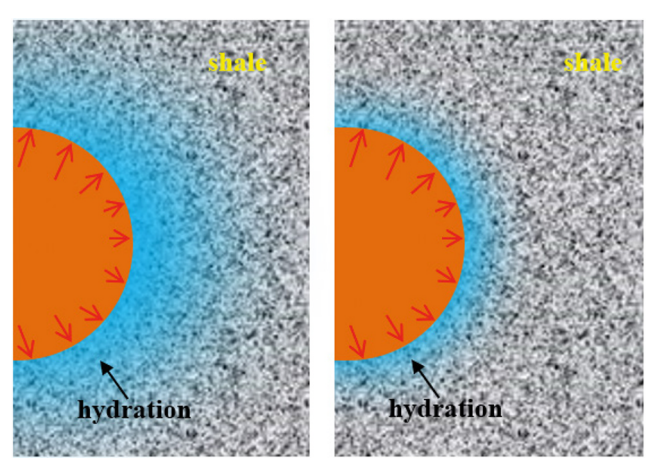

Fig. 8. The range of rock hydration around the well under different concentrations of hydration inhibitors (Left: low concentration, Right: high concentration)

Table 2. Influence of in-situ stress difference on wellbore enlargement rate

Parameters	Minimum horizontal principal stress, MPa		
	15.0	17.5	20.0
Wellbore enlargement rate, %	64.3	28.4	15.3
Maximum shear stress, MPa	35.7	25.4	22.1

shale [21]. The density of drilling fluid and the stress concentration of the surrounding rock are also important factors affecting wellbore stability.

Influence of stress difference on wellbore instability. Stress concentration affects the stability of the wellbore by altering the distribution of rock stress around the wellbore. **Table 2** shows the wellbore enlargement rates under different in-situ stress differences. It should be noted that the maximum horizontal and vertical principal stresses under all operating conditions in Table 2 are 22.5 MPa and 30.5 MPa, respectively. The results indicate that the wellbore enlargement rate significantly decreases with the decrease of in-situ stress difference level, and the wellbore stability significantly improves. When the minimum horizontal principal stress is 15 MPa, the difference in in-situ stress is relatively high, and the wellbore enlargement rate is as high as 64.3%. However, when the minimum horizontal principal stress increases to 20 MPa, the wellbore enlargement rate decreases to 15.3%.

The reason why the difference in in-situ stress affects the stability of the wellbore can be explained by the maximum shear stress of the surrounding rock. When the level of in-situ stress difference is high, the maximum shear stress of the rock around the wellbore is higher during the drilling process. If the maximum shear stress exceeds the tensile failure strength of shale, shale will naturally collapse and yield [22]. As the difference in in-situ stress levels decreases, the maximum shear stress decreases below the tensile failure strength. At this point, the yielding instability of the shale around the well is naturally more difficult to occur.

To prevent the occurrence of uncontrollable wellbore instability during drilling in shale reservoirs, relevant engineering design can be carried out through the following three aspects:

1) Firstly, when carrying out drilling and completion operations in shale formations, oil-based drilling fluid systems can be used to fundamentally avoid the problem of shale swelling when encountering water.

2) Secondly, adding an appropriate concentration of hydration inhibitor to the drilling fluid is also an effective means to prevent collapse and expansion of shale rock sections. Moreover, considering both drilling cost and anti expansion effect, the optimal concentration of hydration inhibitor in drilling fluid is recommended to be designed as 30 g/m^3.

3) Finally, solid particles with particle sizes ranging from 1um to 2.5 μm (such as barite) are added to the drilling fluid. In this way, during the drilling process, solid particles can adhere to the wellbore wall to form mud cakes, thereby preventing the invasion of water in the drilling fluid into the shale layer.

4. Conclusions

The hydration expansion that occurs during shale drilling can significantly reduce its elastic modulus and cohesive force. Meanwhile, its Poisson's ratio and internal friction angle will increase with the occurrence of hydration reaction. Research has found that after being immersed in drilling fluid for 12 hours, the elastic modulus of shale decreases from 5.3 GPa to 3.9 GPa, and the cohesion decreases from 4.6 MPa to 3.0 MPa. Meanwhile, the Poisson's ratio increased from 0.28 to 0.33.

The collapse and instability of wellbore in shale mainly occur in the early stage of drilling operations, while the occurrence of wellbore collapse will significantly slow down in the later stage of drilling operations. The wellbore enlargement rate increased to 40% within the first 3 hours of drilling operations, and only increased from 40% to 66.2% within the next 21 hours.

A certain concentration of hydration inhibitor will prevent uncontrolled collapse of the wellbore by inhibiting the invasion of water. When the concentration of hydration inhibitor in drilling fluid increased from 0 g/m^3 to 45 g/m^3, the wellbore enlargement rate decreased from 66.2% to 27.8%. However, considering both drilling cost and wellbore stability control, it is more reasonable to design a hydration inhibitor concentration of 30 g/m^3 in the drilling fluid.

The increase in the in-situ stress difference level of shale reservoirs will significantly affect their wellbore stability. When the minimum horizontal principal stress is increased from 15 MPa to 20 MPa, the difference in in-situ stress level decreases, and the wellbore enlargement rate decreases from 64.3% to a controllable 15.3%. The level of in-situ stress difference is an artificially

uncontrollable factor, but the stability of the wellbore can be synergistically adjusted by adjusting the concentration of hydration inhibitors in the drilling fluid.

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