Analysis of time-dependent wellbore instability with a porochemothermoelastic coupling model in tight gas reservoirs

Lichun Jia
Drilling & Production Technology Research Institute of CNPC Chuanqing Drilling Engineering Company Limited, Guanghan, PR China

Dengyun Lu
Drilling & Production Technology Research Institute of CNPC Chuanqing Drilling Engineering Company Limited, Guanghan, PR China

Gui Tang
Drilling & Production Technology Research Institute of CNPC Chuanqing Drilling Engineering Company Limited, Guanghan, PR China

Changhong Zhou
Drilling & Production Technology Research Institute of CNPC Chuanqing Drilling Engineering Company Limited, Guanghan, PR China

ABSTRACT: Maintaining wellbore stability is a significant task during drilling. This study investigates time-dependent wellbore stability of a tight gas reservoir in central Sichuan Basin of China with a porochemothermoelastic model. The results show that breakout regions gradually enlarge and equivalent collapse pressure increases with exposure time. The breakout enlarge drastically in the first 5d and following a slowly enlargement from 5d to 10d and 30d. And the equivalent collapse pressure is higher than the mud density 1.45g/cm^3 at inclination 46° to 80° for t=0d and at inclination 33° to 90° for exposure time 5d, 10d and 30d. Consequently, the mud density 1.65 g/cm^3 of borehole inclination above 33° is recommended to stabilize the borehole.

Keywords: porochemothermoelastic, wellbore stability, tight gas reservoirs, time-dependent.

1 INTRODUCTION

During drilling operation, the borehole instability is a very common phenomenon, which may lead to complicated states or could cause costly operational problems in some cases, such as borehole collapse, sidetracks, and pipe sticking (Cheng et al. 2019). This problem of wellbore instability is usually because of a combination of mechanical and chemical instabilities (Ma and Chen 2015). In addition, the temperature gradient between the drilling fluids and formation will lead to not only induced thermal stresses but also transient thermo-induced pore pressure (Li and Roegiers 1998 & Chen et al. 2003). Consequently, the coupling of mechanical, chemical, and thermal effects induces time dependent instability of wellbore (Zhai et al. 2009, Gao et al. 2017, Ghasemia et al. 2018, Cheng et al. 2019 & Aslannezhad et al. 2020 and 2021).

In predicting appropriately mud weight for borehole stability, a proper rock failure criterion should be selected (Aslannezhad et al. 2020 and 2021). The commonly rock strength criteria used in borehole stability are Mohr-Coulomb criterion, Mogi-Coulomb criterion, Modified lade criterion, 3D Hoek-Brown criterion, Modified Wiebols-Cook criterion and Drucker-Prager criterion. Among these above strength criteria, the collapse pressure calculated from the Mohr-Coulomb criterion is too conservative, while those results from the modified Wiebols-Cook and Drucker-Prager criteria are too low (Aslannezhad et al. 2020 and 2021). In contrast, the Mogi-Coulomb criteria could predict an optimum mud density to stabilize borehole for safely drilling (Al-Ajmi and Zimmerman, 2009).

In this paper, the goal is to analyze the time-dependent wellbore instability of a tight gas reservoir of Jurassic Shaximiao Formation in central Sichuan Basin of China. In the drilling of this formation, serious wellbore instability occurred in the build-up section of horizontal well, which increases the costs and time of drilling. To reduce the non-productive time of drilling, the porochemothermoelastic model coupling of mechanical, chemical and thermal effects are considered to get more accurate wellbore breakout and dynamic collapse pressure in a field case of this tight gas reservoir.

2 POROCHEMOTHERMOELASTIC MODELOF WELLBORE STABILITY

2.1 Stresses around the wellbore

The overall stresses around a borehole can be calculated by coupling of induced stresses with Kirsch equations. The following expressions including the mechanical (in-situ), hydraulic and thermal induced stresses demonstrate the total amount of stresses around a borehole (Aslannezhad et al. 2020):

$$\begin{aligned}\sigma_r = \frac{R^2}{r^2}p_w + \frac{\sigma_{xx}+\sigma_{yy}}{2}\left(1-\frac{R^2}{r^2}\right) + \frac{\sigma_{xx}-\sigma_{yy}}{2}\left(1-4\frac{R^2}{r^2}+3\frac{R^4}{r^4}\right)\cos 2\theta \\ + \tau_{xy}\left(1-4\frac{R^2}{r^2}+3\frac{R^4}{r^4}\right)\sin 2\theta + \frac{\alpha(1-2\nu)}{1-\nu}\frac{1}{r^2}\int_R^r p^f(r,t)rdr \\ + \frac{E\alpha_m}{3(1-\nu)}\frac{1}{r^2}\int_R^r T^f(r,t)rdr\end{aligned} \tag{1}$$

$$\begin{aligned}\sigma_\theta = \frac{\sigma_{xx}+\sigma_{yy}}{2}\left(1+\frac{R^2}{r^2}\right) - \frac{\sigma_{xx}-\sigma_{yy}}{2}\left(1+3\frac{R^4}{r^4}\right)\cos 2\theta - \tau_{xy}\left(1+3\frac{R^4}{r^4}\right)\sin 2\theta \\ - \frac{\alpha(1-2\nu)}{1-\nu}\left[\frac{1}{r^2}\int_R^r p^f(r,t)rdr - p^f(r,t)\right] \\ + \frac{E\alpha_m}{3(1-\nu)}\left[\frac{1}{r^2}\int_R^r T^f(r,t)rdr - T^f(r,t)\right] - \frac{R^2}{r^2}p_w\end{aligned} \tag{2}$$

$$\begin{aligned}\sigma_z = \sigma_{zz} - 2\nu(\sigma_{xx}-\sigma_{yy})\frac{R^2}{r^2}\cos 2\theta - 4\nu\tau_{xy}\frac{R^2}{r^2}\sin 2\theta + \frac{\alpha(1-2\nu)}{1-\nu}p^f(r,t) \\ + \frac{E\alpha_m}{3(1-\nu)}T^f(r,t)\end{aligned} \tag{3}$$

$$\tau_{r\theta} = -\frac{\sigma_{xx}-\sigma_{yy}}{2}\left(1+2\frac{R^2}{r^2}-3\frac{R^4}{r^4}\right)\sin 2\theta + \tau_{xy}\left(1+2\frac{R^2}{r^2}-3\frac{R^4}{r^4}\right)\cos 2\theta \tag{4}$$

$$\tau_{rz} = \tau_{xz}\left(1-\frac{R^2}{r^2}\right)\cos\theta + \tau_{yz}\left(1-\frac{R^2}{r^2}\right)\sin\theta \tag{5}$$

$$\tau_{\theta z} = \tau_{yz}\left(1+\frac{R^2}{r^2}\right)\cos\theta - \tau_{xz}\left(1+\frac{R^2}{r^2}\right)\sin\theta \tag{6}$$

where, σ_r, σ_θ, σ_z are the radial stress, hoop stress and axial stress, respectively, MPa; $\tau_{r\theta}$, τ_{rz}, $\tau_{\theta z}$ are three components of the shear stress, MPa; σ_{xx}, σ_{yy}, σ_{zz}, τ_{xy}, τ_{xz}, τ_{yz} are the stress components of the local wellbore coordinates, MPa; R is the radius of the wellbore, r is the distance from the centre of the wellbore, ν is the Poisson's ratio, α is Biot's coefficient, E is Young's modulus, α_m is the thermal expansion coefficient of rock matrix, p_w is the internal wellbore pressure, and θ is the circumference angle. $p^f(r,t)$ and $T^f(r,t)$ are the fluctuations of pore pressure and temperature at time zero and time t with radius r, $p^f(r,t)= p(r,t)-p_0$ and $T^f(r,t)= T(r,t)- T_0$, p_0 and T_0 are initial pore pressure and initial temperature of formation, respectively.

The stresses σ_{xx}, σ_{yy}, σ_{zz}, τ_{xy}, τ_{xz}, τ_{yz} for the local wellbore coordinates are given by:

$$\sigma_{xx} = \sigma_H cos^2\alpha_b cos^2\beta_b + \sigma_h cos^2\alpha_b sin^2\beta_b + \sigma_v sin^2\alpha_b \tag{7}$$

$$\sigma_{yy} = \sigma_H sin^2\beta_b + \sigma_h cos^2\beta_b \tag{8}$$

$$\sigma_{zz} = \sigma_H sin^2\alpha_b cos^2\beta_b + \sigma_h sin^2\alpha_b sin^2\beta_b + \sigma_v cos^2\alpha_b \tag{9}$$

$$\tau_{xy} = -\sigma_H \cos\alpha_b \cos\beta_b \sin\beta_b + \sigma_h \cos\alpha_b \cos\beta_b \sin\beta_b \tag{10}$$

$$\tau_{yz} = -\sigma_H \sin\alpha_b \cos\beta_b \sin\beta_b + \sigma_h \sin\alpha_b \cos\beta_b \sin\beta_b \tag{11}$$

$$\tau_{xz} = \sigma_H \cos\alpha_b \sin\alpha_b cos^2\beta_b + \sigma_h \cos\alpha_b \sin\alpha_b sin^2\beta_b - \sigma_v \cos\alpha_b \sin\alpha_b \tag{12}$$

where, σ_H, σ_h, σ_v are the maximum horizontal stress, minimum horizontal stress and vertical stress, respectively, MPa; α_b and β_b are the inclination and azimuth angle of the borehole, respectively.

2.2 Rock failure criteria

The Mogi-Coulomb failure criteria which include the effect of the average principal stress satisfactorily complies with tri-axial laboratory results for many rock samples (Al-Ajmi and Zimmerman, 2009). Analysis of wellbore stability based on Mogi criterion leads to much less conservative predictions of safe mud stress than other criteria (Aslannezhad et al. 2020 and 2021). The Mogi-Coulomb failure criterion can be expressed as (Al-Ajmi and Zimmerman, 2009):

$$\tau_{oct} = \frac{2\sqrt{2}}{3} C \cos\varphi + \frac{2\sqrt{2}}{3} \sin\varphi\, \sigma_{m,2} \tag{13}$$

$$\sigma_{m,2} = \frac{\sigma_1 + \sigma_3}{2} \tag{14}$$

$$\tau_{oct} = \frac{1}{3}\sqrt{(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2} \tag{15}$$

where, $\sigma_{m,2}$ is the effective normal stress and τ_{oct} is the octahedral shear stress; C is the cohesive strength, φ is the internal friction angle; σ_1, σ_2, σ_3 are the major, intermediate and minor principal stresses, respectively.

3 A FIELD CASE OF WELLBORE STABILITY IN TIGHT GAS RESERVOIRS

3.1 Basic parameters

The tight gas reservoir of Jurassic Shaximiao Formation in central Sichuan Basin of China has an estimated reserves of 100 billion cubic meters, which is the main target for increasing natural gas production in this area. The thickness of this formation is 1000 to 1500m, which is divided into two sub formation, S-1 and S-2. The main lithologies of this reservoir are argillaceous siltstone and muddy quartz sandstone with porosity of 8.0% to 16.0% and permeability of 0.01mD to 1mD. In the drilling of this formation, serious wellbore instability occurred in the build-up section of horizontal well. Here, the caliper, well inclination, acoustic logging, elastic parameter and in-situ stresses of a horizontal well (YT-H1) are shown in Figure 1.

It can be seen from Figure 1 that the wellbore enlargement rate of 1941～2263m is extremely severe, having an average enlargement rate of 10.77% and maximum value 42.64%, where the well inclination is 31.8° to 73.4°, especially in the section with a inclination exceeding 54.3°. The serious wellbore breakouts could increase the potential for pipe sticking and the difficulty of casing.

It is widely recognized that the cohesive strength could alter with time when rock is exposed to drilling fluids after the borehole is drilled (Chen et al. 2003, Ma and Chen 2015 & Aslannezhad et al. 2020 and 2021). In this study, the alteration of cohesive strength and internal friction angle with time of oil-based mud (OBM) are illustrated in Figure 2. The results show that the cohesion decreases sharply with exposure time, while the internal friction angle alters slightly. Based on the experimental data, the evolution equations of sandstone obtained from Shaximiao Formation are fitted by a nonlinear curve fitting method and are listed in Figure 2.

In addition to the in-situ stresses, Young's modulus and Poisson's ratio, the rest of the parameters for analysis of borehole instability obtained from laboratory or filed are listed in Table 1.

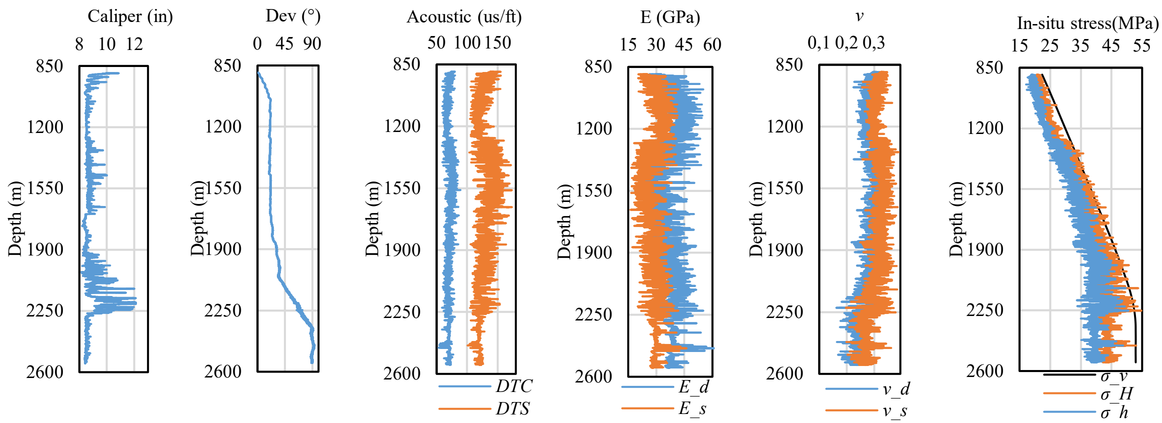


Figure 1. The caliper, deviation, acoustic logging, elastic parameter and in-situ stresses of a horizontal well YT-H1 (*DTC* and *DTS* are *P*- and *S*-wave slowness, respectively; suffix *d* and *s* are dynamic and static values, while suffix *v*, *H* and *h* represent vertical, horizontal maximum and minimum stress respectively).

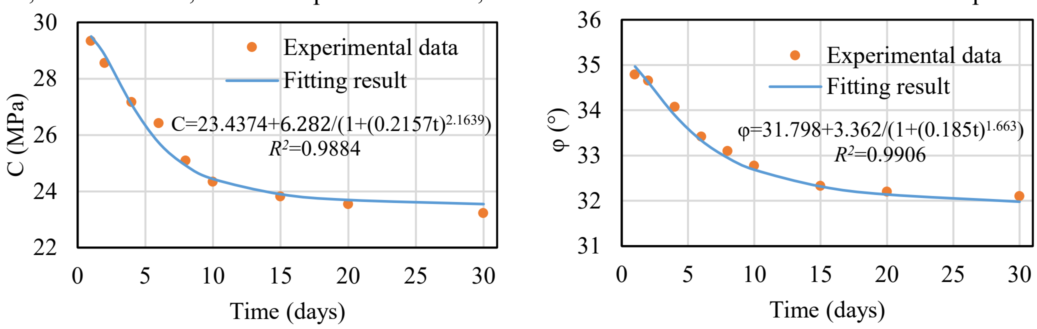


Figure 2. The alteration of cohesive strength (C) and internal friction angle (φ) with time (t).

Table 1. The basic parameters for analysis of borehole instability ([a] Provided by Chen et al. 2003).

Parameters	Value	Parameters	Value
Borehole radius R	0.108mm	Biot's coefficient α	0.8
Borehole azimuth β_b	30°	Initial cohesive strength C_0	29.342 MPa
Borehole inclination α_b	0°~90°	Initial internal friction angle φ_0	34.788°
Initial pore pressure p_0	8.72~12.16MPa	Cohesive strength after 30d C'_0	23.219 MPa
Geothermal gradient G_g	3.88℃/100m	Internal friction angle after 30d φ'_0	32.102°
Shale activity a_{wsh}	0.915[a]	Wellbore wall temperature T_w	65.8~69.2℃
Mud activity a_{wm}	0.78[a]	Rock initial temperature T_0	76.6~81.3℃
Membrane efficiency I_m	0.1[a]	Coupling coefficient c'	0.124 MPa/K[a]
Drilling time t	0~30d	Mud weight ρ_w	1.43~1.50g/cm^3
Fluid hydraulic diffusivity c	3.41×10^{-10} m^2/s[a]	Thermal diffusivity of rock c_0	9.54×10^{-7} m^2/s[a]
Volumetric thermal expansion coefficient of fluid α_f	5×10^{-4} K^{-1}[a]	Volumetric thermal expansion coefficient of rock α_m	2.59×10^{-5} K^{-1}[a]

3.2 Wellbore stability analysis

Firstly, the evolution of wellbore breakout with time is analyzed from the porochemothermoelastic coupling model. Here, the borehole section at depth of 2204.75m (vertical depth 2061.81m, inclination 63.43°) with a mud density of 1.45g/cm^3 is taken as an example for investigating the wellbore enlargement with time and the results are depicted in Figure 3. The observation shows that breakout failure regions around wellbore gradually enlarge with time. The breakout enlarge drastically in the first 5d exposure time following with a slowly enlargement from 5d to 10d and 30d. This is mainly caused by the strength weakening of Shaximiao sandstone. As shown in Figure 2, the strength parameters decreases drastically with time in the first 5d, after that, the strength parameters decreases slowly. In addition, the maximum wellbore enlargement rate is 43.62%, which is very close to the result from the caliper logging 42.35%.

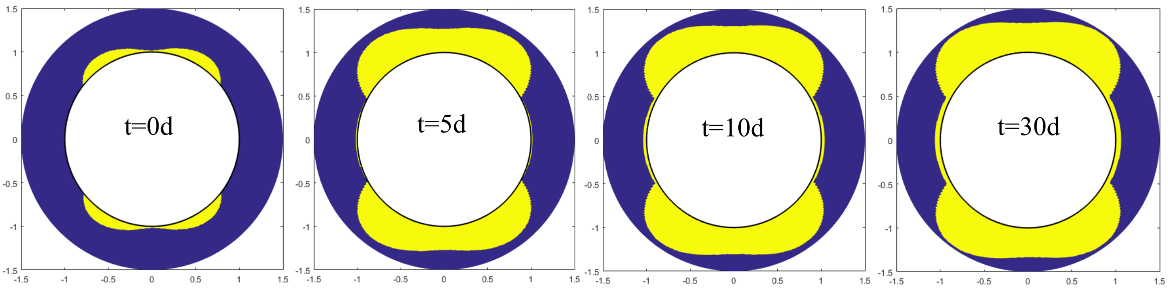
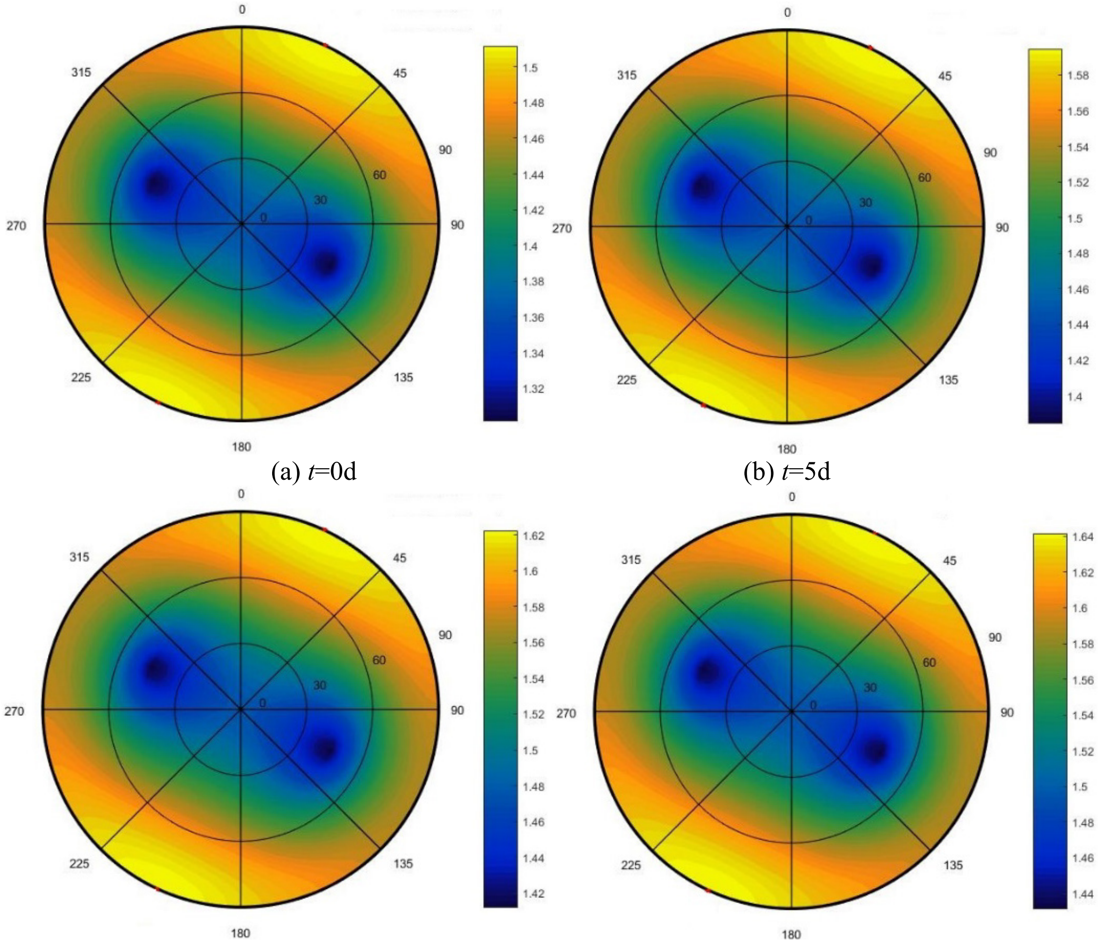


Figure 3. The evolution of wellbore breakout with time at depth of 2204.75m and inclination 63.43°.

Figure 4 shows the equivalent collapse pressure with time at depth of 2204.75m for inclination from 0° to 90°. As observed, the equivalent collapse pressure increases significantly with exposure time. This result indicates that the mud density of 1.45g/cm^3 will not stabilize wellbore at this depth 2204.75m as exposure time increases for any borehole inclination.



(a) *t*=0d (b) *t*=5d

(c) *t*=10d (d) *t*=30d

Figure 4. The equivalent collapse pressure with time at depth of 2204.75m for any inclination.

The equivalent collapse pressure with time under different borehole inclination are shown in Figure 5. It is clear that the equivalent collapse pressure increases with borehole inclination for any exposure time. The equivalent collapse pressure is higher than the real mud density 1.45g/cm^3 at inclination 46° to 80° for *t*=0 and at inclination 33° to 90° for exposure time 5d, 10d and 30d. This result manifests that there will be borehole breakout as the borehole inclination higher than 33°, which is consistent with the actual wellbore enlargement from caliper logging. To stabilize the borehole for reducing collapse risk, it is recommended to increase the mud density to 1.65 g/cm^3.

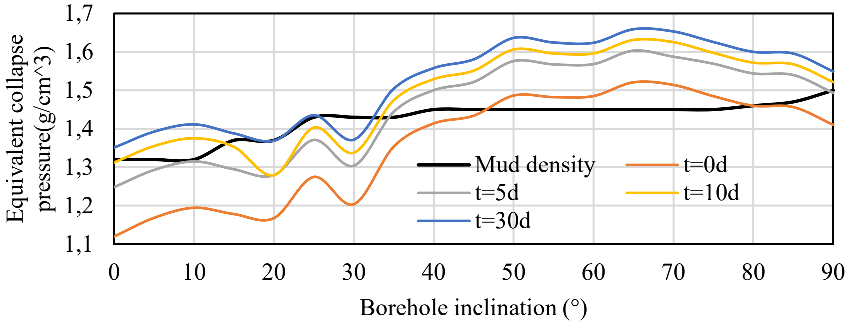


Figure 5. The equivalent collapse pressure with time under different borehole inclination.

4 CONCLUSIONS

This study investigates wellbore stability with a porochemothermoelastic model of a tight gas reservoir of Jurassic Shaximiao Formation in central Sichuan Basin of China. In this model, the coupling of mechanical, chemical, and thermal effects is considered to predict the time-dependent wellbore breakout regions and dynamic collapse pressure. The results show that breakout regions gradually enlarge and equivalent collapse pressure increases with exposure time. The breakout enlarge drastically in the first 5d following a slowly enlargement from 5d to 10d and 30d. And the equivalent collapse pressure is higher than the mud density 1.45g/cm^3 at inclination 46° to 80° for t=0d and at inclination 33° to 90° for exposure time 5d, 10d and 30d. These results agree well with the observations of a field drilling situation. Finally, the mud density 1.65 g/cm^3 of inclination above 33° is recommended to stabilize the borehole.

REFERENCES

Al-Ajmi, A.M. & Zimmerman, R.W. 2009. A new well path optimization model for increased mechanical borehole stability. *Journal of Petroleum Science and Engineering* 69(1), pp.53-62.

Aslannezhad, M., Keshavarz, A. & Kalantariasl, A. 2020. Evaluation of mechanical, chemical, and thermal effects on wellbore stability using different rock failure criteria. *Journal of Natural Gas Science and Engineering* 78, 103276, from https://doi.org/10.1016/j.jngse.2020.103276.

Aslannezhad, M., Kalantariasl, A. & Keshavarz, A. 2021. Borehole stability in shale formations: Effects of Thermal- Mechanical-Chemical parameters on well design. *Journal of Natural Gas Science and Engineering* 88, 103852, from https://doi.org/10.1016/j.jngse.2021.103852.

Chen, G.Z., Chenevert, M.E., Sharma, M.M. & Yu M.J. 2003. A study of wellbore stability in shales including poroelastic, chemical, and thermal effects. *Journal of Petroleum Science and Engineering* 38, pp.167-176.

Cheng, W., Jiang, G.S., Li, X.D., Zhou, Z.D. & Wei, Z.J. 2019. A porochemothermoelastic coupling model for continental shale wellbore stability and a case analysis. *Journal of Petroleum Science and Engineering* 182, 106265, from https://doi.org/10.1016/j.petrol.2019.106265.

Gao, J.J., Deng, J.G., Lan, K., Song, Z.C., Feng, Y.T. & Chang, L. 2017. A porothermoelastic solution for the inclined borehole in a transversely isotropic medium subjected to thermal osmosis and thermal filtration effects. *Geothermics* 67, pp.114-134.

Ghasemia, M.F., Ghiasi, M.M., Mohammadi, A.H., Garavand, A. & Noorollahi, Y. 2018. Coupled Thermo-Poro-Elastic modeling of near wellbore zone with stress dependent porous material properties. *Journal of Natural Gas Science and Engineering* 52, pp.559-574.

Li, X., Cui, L. & Roegiers J.C. 1998. Thermoporoelastic analyses of inclined boreholes. In: *SPE/ISRM Rock Mechanics in Petroleum Engineering*, Trondheim, Norway, July 8-10, Paper Number: SPE-47296-MS.

Ma, T., Chen, P., 2015. A wellbore stability analysis model with chemical-mechanical coupling for shale gas reservoirs. *Journal of Natural Gas Science and Engineering* 26, pp.72-98.

Zhai, Z.Y., Zaki, K.S., Marinello, S. & Ahmed A.S. 2009. Coupled thermo-poro-mechanical effects on borehole stability. In: *SPE Annual Technical Conference and Exhibition*, New Orleans, Louisiana, October4-7, Paper Number: SPE-123427-MS.