A study of wellbore stability in shales including poroelastic, chemical, and thermal effects

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Abstract

This paper presents the development of a model for determining wellbore stability for oil and gas drilling operations. The effects of mechanical forces and poroelasticity on shale behavior are included, as well as chemical and thermal effects.

Chemical effects are caused by the imbalance between the water activity in the drilling mud and the shale water activity. The magnitude of this contribution depends on the effectiveness of the mud/shale system to perform as a semipermeable membrane. Experimental results show that osmotic pressures develop inside shales when they are exposed to different drilling fluids. This osmotic pressure is treated as an equivalent hydraulic potential, and is then added to the hydraulic wellbore and pore pressure as time progresses.

Thermal diffusion inside the drilled formation induces additional pore pressure and rock stress changes and consequently affects shale stability. Thermal effects are important because thermal diffusion into shale formations occurs more quickly than hydraulic diffusion and thereby dominates pore pressure changes during early time.

Rock temperature and pore pressure are coupled for most porous media studies; however, we have found that they can be partially decoupled for shale formations by assuming that convective heat transfer is negligible. The partially decoupled temperature and pore pressure effects can therefore be solved analytically under appropriate initial and boundary conditions. Experimental data for shale strength alteration, which occurs when shales are exposed to different fluids, are also included for the determination of cohesion strength decay.

Pore pressure, collapse stress, and critical mud weights are variables investigated for determining poroelastic, chemical, and thermal effects on shale stability. The most important factors, which affect wellbore stability, are clearly identified.

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1. Introduction

Wellbore instability is a serious drilling problem that costs the oil industry over US$500–1000 million each year. It is also reported that shales account for 75% of all formations drilled by the oil and gas industry, and 90% of wellbore stability problems occur in shale formations. Boreholes can experience hole enlargement, hole reduction, drilling fluid loss to the formation, poor hole cleaning, and well control problems. Most of the above problems result in higher drilling costs. Shale failure is primarily caused by the redistribution of in situ stress which subsequently exceeds the shear or tensile strength of the rock.
The elastic stress distribution around a wellbore has been presented by Bradley (1979a, b). Poroelastic effects, pore pressure, and rock stress changes are discussed herein under undrained and drained conditions (Rice and Cleary, 1976; Detournay and Cheng, 1988). For a low-permeable formation, such as shale, an undrained condition exists for short exposure times. The formation will then “feel” the boundary, i.e., the wellbore mud pressure, and a transient penetration will occur between the formation and the wellbore. The transient pore pressure solution is obtained in this study so as to evaluate the wellbore failure status and determine the critical mud density.

In addition to the poroelastic effects, osmotic pressure is also found to be an important factor affecting wellbore stability (Mody and Hale, 1993; Chenevert and Pernot, 1998). Swelling pressure can be observed when the shale samples are exposed to different drilling fluids. In addition, the shale strength changes with exposure time as hydration or dehydration progresses.

It has been shown that osmotic pressure can be treated as a hydraulic potential that drives water into or out of shale formations (Chenevert, 1970). Exposure of the drilling fluid to the wellbore surface results in the contacted formation being exposed to both the hydraulic and osmotic potentials. Solute diffusion is not considered here and is discussed in detail by Yu et al. (in press).

For a low-permeable medium like shale, heat conduction dominates the heat transfer process. This has been confirmed by Wang and Papamichos (1994). Heat convection can be neglected because of the extremely low fluid flow velocity in such rocks.

Rock stresses are also affected by thermal diffusion between the drilling mud and the formation (Charlez, 1997). Thermal effects cannot be neglected but are seldom considered as an alternative approach to maintain wellbore stability since neither the drilling fluid temperature nor the rock temperature is easily manageable.

A powerful wellbore stability model is presented herein which includes poroelastic, chemical, and thermal effects. Results using this model are presented by varying values of pore pressure, rock failure status, and critical mud density.

2. Theory

Kurashige (1989) incorporated heat transport into Biot’s poroelastic theory and developed a thermoporoelastic theory for fluid-filled porous materials. Wang and Papamichos (1994) presented solutions for partially decoupled equations for temperature and pore pressure. A similar approach is used in this paper when developing the chemical–thermal–poroelastic equations. Both the coupled and partially decoupled equations are solved in this paper to determine temperature and pore pressure distributions.

Equations which describe the temperature and pore pressure in a cylindrical coordinate system can be expressed as,

\[
\frac{\partial T}{\partial t} = c_0 \left( \frac{\partial^2 T}{\partial r^2} + \frac{1}{r} \frac{\partial T}{\partial r} \right) + c_0' \left( \frac{\partial T}{\partial r} \frac{1}{r} \frac{\partial p}{\partial r} + T \left( \frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} \right) \right)
\]

\[
\frac{\partial p}{\partial t} = c \left( \frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} \right) + c' \frac{\partial T}{\partial t}
\]

where \( c \) is hydraulic fluid diffusivity; \( c_0 \) is thermal diffusivity of the porous medium; \( c' \) and \( c_0' \) are coupling coefficients. The definition of the two coupling coefficients are (Wang and Papamichos, 1994),

\[
c' = \frac{c}{\kappa} \left[ \frac{2 \alpha_m (v_u - \nu)}{B(1 + v_u)(1 - \nu)} + \phi (\alpha_f - \alpha_m) \right]
\]

\[
c_0' = \frac{\kappa}{\phi}
\]

where the permeability coefficient \( \kappa \) is the permeability divided by pore fluid viscosity; \( B \) is the Skepmtton coefficient; \( v \) and \( v_u \) are drained and undrained Poisson’s ratios, respectively; \( \phi \) is rock porosity; and \( \alpha_f \) and \( \alpha_m \) are volumetric thermal expansions for the pore fluid and rock matrix, respectively. \( c_0' \) is primarily controlled by rock permeability; therefore, it could be quite small for a low-permeability shale. The coefficient \( c' \) is a function of the thermal expansion difference between the pore fluid and the rock matrix and is also related to some other rock properties. The relative magnitude of these coefficients for different rocks, as provided by
Charlez (1991) and Wang and Papamichos (1994), are listed in Table 1.

For shale, the coupling coefficient $c_0'$ is significantly less than $c_0$ thus the pressure term in the temperature equation can be neglected. The finite-difference solution of temperature distribution for Eq. (1) (Chen, 2001) also indicates that the $c_0'$ term can be ignored for shales, by observing the agreement between the finite difference solution to Eq. (1) and the analytical solution to Eq. (3). For the second equation in Eq. (1), if $c \ll c'$, one may suggest ignoring the hydraulic effect on pore pressure distribution and the pore pressure will be a steady-state function of temperature changes for specific radial distances. This simplified approach only applies for large distance and long time, under which temperature reaches a pseudo-steady-state distribution. Hence, the problem in Eq. (1) can be partially decoupled in this manner and the second part of Eq. (1) vanishes,

\[
\frac{\partial T}{\partial t} = c_0 \left( \frac{\partial^2 T}{\partial r^2} + \frac{1}{r} \frac{\partial T}{\partial r} \right)
\]

where the gas constant $R = 8.314 \text{ m}^2 \text{s}^{-2} \text{ g} \text{ mol}^{-1} \text{ K}^{-1}$; $T = \text{temperature, K}$; $V = 1.8 \times 10^{-5} \text{ m}^3 / \text{g mol}$, partial molar volume of the water; $a_{wm} = \text{mud water activity}$; $a_{wsh} = \text{shale water activity}$; and $I_m = \text{membrane efficiency}$. Water activity and membrane efficiency are dimensionless and range from 0 to 1. As shown by Eq. (5), the osmotic pressure can be adjusted by modifying the drilling fluid chemistry so that the drilling fluid satisfies a given wellbore stability requirement.

As an example, consider a shale which has a 0.915 water activity in contact with a water-based fluid which has a 0.78 water activity and a membrane efficiency of 0.1. Assuming the rock temperature is 375.7 K, the osmotic pressure can be estimated as,

\[
p_z = -0.1 \frac{8.314 \times 375.7}{1.8 \times 10^{-5}} \ln \frac{0.78}{0.915} = 2.77 \text{ MPa}
\]

This would mean that there is a driving osmotic potential of 2.77 MPa trying to drive the water out of the shale.

### 2.1. Temperature

The wellbore wall temperature can be considered to be equal to the temperature of the drilling fluid in the annulus. The drilling fluid temperature can be calculated using a steady-state method (Holmes and Swift, 1970) or a transient approach (Kabir et al., 1996). For constant temperature at the wellbore wall

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Table 1

<table>
<thead>
<tr>
<th>Rock</th>
<th>Hydraulic diffusivity $c$, m$^2$/s</th>
<th>Thermal diffusivity $c_0$, m$^2$/s</th>
<th>Coupling coefficient $c_0'$, MPa</th>
<th>Coupling coefficient $c'$, MPa/K</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weber sandstone</td>
<td>2.07e-2</td>
<td>1.64e-6</td>
<td>5.92e-3</td>
<td>0.4</td>
</tr>
<tr>
<td>Tennessee marble</td>
<td>1.3e-5</td>
<td>1.78e-6</td>
<td>3.29e-7</td>
<td>0.5</td>
</tr>
<tr>
<td>Shale (abyssal clay)</td>
<td>3.41e-10</td>
<td>9.54e-7</td>
<td>7.05e-10</td>
<td>0.01</td>
</tr>
</tbody>
</table>
and the far-field formation boundary, the closed-form solution is (Carslaw and Jaeger, 1959),

$$T(r, t) = T_0 + (T_w - T_0)L^{-1}\left\{ \frac{1}{s} \frac{K_0(r\sqrt{s/c_0})}{K_0(r_w\sqrt{s/c_0})} \right\}$$  (7)

If the wellbore wall temperature is transient, the formation temperature has to be calculated using the superposition approach.

2.2. Pore pressure

For the partially decoupled temperature/pore pressure problem, under initial and boundary conditions as given in Eq. (4), the closed-form pore pressure solution can be written as

$$p(r, t) = p_0 + \left( (p_{tw} - p_0) - \frac{\epsilon'(T_w - T_0)}{1 - c/c_0} \right)$$

$$\times L^{-1}\left\{ \frac{1}{s} \frac{K_0(r\sqrt{s/c})}{K_0(r_w\sqrt{s/c})} \right\} + \frac{\epsilon'(T_w - T_0)}{1 - c/c_0}$$

$$\times L^{-1}\left\{ \frac{1}{s} \frac{K_0(r\sqrt{s/c_0})}{K_0(r_w\sqrt{s/c_0})} \right\}$$  (8)

When the undrained response of the wellbore is neglected, the poroelastic coefficient does not contribute to the transient pore pressure solution, as shown in Eq. (8). However, its effect on stress alteration cannot be neglected, as shown in Section 2.4.

2.3. Finite-difference solution

The finite-difference method can be used to solve the coupled problem (Eq. (1)). Using the coefficients shown in Table 1, the contribution of temperature changes to pore pressure alterations for the Weber sandstone is found to be negligible. However, thermally induced pore pressure changes for shale formations are significant and, therefore, cannot be neglected, as discussed later in this paper.

Temperature and pore pressure solutions for shale also indicate that the analytical solution to the partially decoupled problem matches the solution to the coupled problem (Chen, 2001). Therefore, the partially decoupled problem can reflect the coupling behavior of shales and can be used to analyze the effect of temperature and pore pressure changes on shale stability.

2.4. Normal stresses induced by pore pressure and temperature changes

For a cylindrical system, the stresses induced by hydraulic and thermal diffusion can be solved using an axisymmetric approach. Only normal stresses (not the shear stresses) are modified:

$$\sigma_{rr} = \frac{\alpha(1 - 2\nu)}{1 - \nu} \frac{1}{r^2} \int_{r_w}^r p^f(r, t) r dr + \frac{E\alpha_m}{3(1 - \nu)}$$

$$\times \frac{1}{r^2} \int_{r_w}^r T^f(r, t) r dr + \frac{p_w}{r^2}$$  (9)

$$\sigma_{\theta\theta} = \frac{\alpha(1 - 2\nu)}{1 - \nu} \left[ \frac{1}{r^2} \int_{r_w}^r p^f(r, t) r dr - p^f(r, t) \right]$$

$$- \frac{E\alpha_m}{3(1 - \nu)} \left[ \frac{1}{r^2} \int_{r_w}^r T^f(r, t) r dr - T^f(r, t) \right] - \frac{r_w^2}{r^2} P_w$$

$$\sigma_{zz} = -\frac{\alpha(1 - 2\nu)}{1 - \nu} p^f(r, t) + \frac{E\alpha_m}{3(1 - \nu)} T^f(r, t)$$

where $p^f(r, t) = p(r, t) - p_0$ and $T^f(r, t) = T(r, t) - T_0$. It can be demonstrated that Eq. (9) is identical to the Laplace-domain solutions (Cui et al., 1997; Li et al., 1998; Chen and Ewy, 2003).

The axial stress, $\sigma_{zz}$, is calculated based on a plane-strain assumption. The first term in the above equations includes flow-induced stresses and the second term is thermally induced stresses. The third term in the above equations is stresses induced by the borehole pressure. In conjunction with elastic stresses, the total stress in the formation can be computed. Therefore, near wellbore failure can be determined by comparing the formation stress state with selected failure criteria.
Stresses on the wellbore wall are important and are used in determining the critical mud density. The induced normal stresses are, 

\[ \sigma_{rr} = p_w \]

\[ \sigma_{\theta\theta} = \frac{2}{1 - \nu} (p_w - p_r - \rho_0) + \frac{E \varepsilon_m}{3(1 - \nu)} (T_w - T_0) \]

\[ \sigma_{zz} = \frac{2}{1 - \nu} (p_w - p_z - \rho_0) + \frac{E \varepsilon_m}{3(1 - \nu)} (T_w - T_0) \]  

(10)

3. Modeling results

3.1. Input data for modeling

Many important factors such as in situ stresses, borehole inclination, initial pore pressure, mud weight, and rock strength affect wellbore stability. Some parameters can be directly obtained at the wellhead. Others have to be either measured in the laboratory or in the field using appropriate techniques or calculated based on available theories or empirical correlations.

Over 30 parameters are required in our model. The input data used in this study (Table 2) were primarily obtained from Mody and Hale (1993), Kabir et al. (1996), Fonseca (1998), and Chenevert and Pernot (1998).

In this study we have selected the maximum radial distance of interest to be 1.3 times the borehole radius. All calculations include a time dependence.

3.2. Pore pressure and collapse stress

The collapse stress is defined as rock strength less rock stresses (Eq. (11)); therefore, a negative collapse stress represents shear failure. For the Drucker–Prager failure criterion, the collapse stress, \( \sigma_{cl} \), can be expressed as,

\[ \sigma_{cl} = -\sqrt{j_z} + A J_1^{ef} + B \]  

(11)

Constants \( A \) and \( B \) are defined in the following way (McLean and Addis, 1990),

\[ A = \frac{2 \sqrt{2} \sin \phi}{3 - \sin \phi}, \quad B = \frac{2 \sqrt{2} C \cos \phi}{3 - \sin \phi} \]  

(12)

Table 2

<table>
<thead>
<tr>
<th>Variables</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale activity</td>
<td>( a_{wsh} )</td>
<td>0.915</td>
<td>dimensionless</td>
</tr>
<tr>
<td>Mud activity</td>
<td>( a_{wm} )</td>
<td>0.78</td>
<td>dimensionless</td>
</tr>
<tr>
<td>Membrane efficiency</td>
<td>( f_m )</td>
<td>0.1</td>
<td>dimensionless</td>
</tr>
<tr>
<td>Geothermal gradient</td>
<td>( G_0 )</td>
<td>2</td>
<td>K/100 m</td>
</tr>
<tr>
<td>Overburden gradient</td>
<td>( \sigma_v )</td>
<td>0.01945</td>
<td>MPa/m</td>
</tr>
<tr>
<td>Minimum horizontal</td>
<td>( \sigma_n )</td>
<td>0.01696</td>
<td>MPa/m</td>
</tr>
<tr>
<td>Geothermal gradient</td>
<td>( T_0 )</td>
<td>350.7</td>
<td>K</td>
</tr>
<tr>
<td>Maximal horizontal</td>
<td>( \sigma_{cl} )</td>
<td>0.1877</td>
<td>MPa/m</td>
</tr>
<tr>
<td>Negative collapse stress</td>
<td>( \sigma_{cl} )</td>
<td>0.1877</td>
<td>MPa/m</td>
</tr>
<tr>
<td>Positive collapse stress</td>
<td>( \sigma_{cl} )</td>
<td>0.1877</td>
<td>MPa/m</td>
</tr>
<tr>
<td>Initial cohesive strength</td>
<td>( C_0 )</td>
<td>8.74</td>
<td>MPa</td>
</tr>
<tr>
<td>Equilibrium cohesive strength</td>
<td>( C_e )</td>
<td>5.19</td>
<td>MPa</td>
</tr>
<tr>
<td>Cohesion alteration factor</td>
<td>( a^e )</td>
<td>0.5</td>
<td>dimensionless</td>
</tr>
<tr>
<td>Shale Young's modulus</td>
<td>( E )</td>
<td>6895</td>
<td>MPa</td>
</tr>
<tr>
<td>Friction angle</td>
<td>( \phi )</td>
<td>30</td>
<td>( ^\circ )</td>
</tr>
<tr>
<td>Time</td>
<td>( t )</td>
<td>8640, 86,400, 864,000</td>
<td>s</td>
</tr>
<tr>
<td>Pore fluid or mud hydraulic diffusivity</td>
<td>( c )</td>
<td>3.41e-10</td>
<td>m²/s</td>
</tr>
<tr>
<td>Thermal diffusivity of porous media</td>
<td>( c_0 )</td>
<td>9.54e-7</td>
<td>m²/s</td>
</tr>
<tr>
<td>Coupling coefficient</td>
<td>( c' )</td>
<td>0.124</td>
<td>MPa/K</td>
</tr>
<tr>
<td>Volumetric thermal expansion coefficient of pore fluid</td>
<td>( \varepsilon_\text{ef} )</td>
<td>5e-4</td>
<td>K⁻¹</td>
</tr>
<tr>
<td>Volumetric thermal expansion coefficient of rock matrix</td>
<td>( \varepsilon_\text{m} )</td>
<td>2.59e-5</td>
<td>K⁻¹</td>
</tr>
<tr>
<td>Wellbore wall temperature</td>
<td>( T_w )</td>
<td>350.7</td>
<td>K</td>
</tr>
<tr>
<td>Rock initial temperature</td>
<td>( T_0 )</td>
<td>375.7</td>
<td>K</td>
</tr>
</tbody>
</table>

*The cohesive strength varies with time in the following manner:

\[ C(t) = (C_0 - C_e) \exp(at) + C_e, \]  

where \( t \) has units of days. The factor \( a \) is assumed to be \( -0.5 \) based on experimental observations.

For anisotropic horizontal in situ stresses as displayed in Table 2, the collapse stress is a function of wellbore radial distances and time. The collapse stress for a specific radial distance is presented in Fig. 1a. (Note: Values used for development of Figs. 1–5 are given in Table 2.) The collapse stress decreases as the drilling operation proceeds. After 240 h of drilling, the
collapse stress is about 2.5 MPa lower than at 24 h. This difference is uniformly distributed over the entire near wellbore area because of decreasing shale strength with hydration time. The perturbation of pore pressure, as shown in Fig. 1a at \( r/r_w = 1.3 \) after 2.4 h, is induced by thermal diffusion which is much faster than hydraulic diffusion. The lowest collapse stress appears at the wellbore wall rather than inside the formation, which illustrates that, under this mud gradient (13.1 lb/gal); the wellbore wall is the point of potential collapse failure. In this example, the virgin far-field pore pressure is 67.1 MPa. The net hydraulic differential, which drives the fluid flow, happens to be the negative osmotic potential, \(-2.77 \) MPa. This negative osmotic potential immediately lowers the wellbore pore pressure from 67.1 to 64.3 MPa. The pore pressure decreases in the near wellbore area as time increases; however, the collapse stress still decreases with time due to a decrease in rock strength with time.

Pore pressure and collapse stress distributions after a 24-h hydration are shown in Figs. 2 and 3, respectively. The lowest pore pressure and highest collapse stress can be obtained when both thermal and chemical effects are taken into account.

As shown in Eq. (8), poroelastic coefficients do not appear in the transient pore pressure solutions if the undrained response of the wellbore is ignored. Significant changes in collapse stress are not observed in this study either (Fig. 3) because of the low net driving force (\(-2.77 \) MPa).

When a water-based fluid is in direct contact with shale, osmotic water movement can occur. Under the conditions given in Table 2, water flow is driven by the higher water activity (higher chemical potential) of the shale to the lower water activity of the drilling fluid.

Fig. 2. Pore pressure distribution after 24 h for thermal, chemical, and poroelastic conditions active.

Fig. 3. Collapse stress distribution after 24 h for thermal, chemical, and poroelastic conditions active.
fluid. A negative net chemical potential of $-2.77$ MPa drives a flow of water out of the shale and helps to stabilize the borehole. At the wellbore wall, the chemical potential causes a 2.77-MPa decrease in pore pressure and a 1.7-MPa increase in collapse stress (Figs. 2 and 3). An improvement of shale stability due to chemical effects can be concluded.

It is generally accepted that critical mud weights are functions of shale exposure time, as well as well orientations. This results from both the rock strength and rock stress varying with shale exposure time. In order to determine the critical mud weight, both the wellbore wall and the entire near wellbore area need to be inspected for stability as a function of time.

The effect of cooling on pore pressure can be observed from Fig. 2 in which an increased pore pressure occurs in the near wellbore area when thermal cooling is neglected. Also, Fig. 3 shows that thermal effects are able to raise the near wellbore collapse stress because of the contribution of thermal effects on pore pressure and normal stresses. For example, a 1.4-MPa increase of collapse stress is found at $r/r_w = 1.3$ if thermal effects are included.

3.3. Time-dependent mud weight window

The variation of the strength of the Speeton shale can be represented by Eq. (13), as deduced from experimental data (Chenevert and Pernot 1998),

$$C = (C_0 - C_e) \exp(at) + C_e$$

where $C_0 = 8.74$ MPa, $C_e = 5.19$ MPa, and $a = -0.5$ for the example used in this study. The cohesive strength, $C$, is given in units of MPa and the exposure time $t$ has units of days.

For a constant cohesive strength and a constant friction angle, the critical mud weight window barely changes with time. For drilling a vertical and a horizontal well, the initial mud weights of 0.98 and 1.26 specific gravity (SG), respectively, are needed to prevent wellbore collapse.

Significant alterations of the critical mud weight will take place, as shown by Fig. 4a, if the shale cohesive strength varies with time. For this example, a 0.78-water activity CaCl$_2$ fluid is used for determining critical mud weights. An apparent increase in the minimum mud weight is observed from this time-dependent mud weight plot. For instance, after 2.4 h of exposure, a water-base mud with SG = 1.0 can maintain a stable vertical well while a 1.27 SG mud is required for stabilizing a horizontal well. Drilling mud density required for stability still increases after 24-h drilling, requiring a 1.12 SG mud for a vertical well and a 1.39 SG mud for a horizontal well. At 240 h after drilling, the shale cohesive strength reaches its lowest value, and consequently the minimum mud weight needed increases to 1.32 SG to stabilize a vertical well and 1.58 SG to stabilize a horizontal well.

Only the wellbore wall is examined in plots of Fig. 4a. If all the near wellbore area within $r/r_w = 1.3$
is analyzed for stability, there is a small change in minimum mud weights between different times (Fig. 4b) compared to results from the wellbore wall model. This is because the failure criterion is not first satisfied at the wellbore wall. For example, at 24 h, the critical positions, which require the maximum mud weight to stabilize a vertical and a horizontal well, occur at $r/r_w = 1.08$ and 1.05 (instead of at the wall), respectively. The critical mud weights for drilling both a stable vertical borehole and a stable horizontal borehole are listed in Table 3. The maximum mud weight needed to prevent breakdown failure for all the times is found to be equal to 1.80 SG for a vertical well and 1.62 SG for a horizontal well. In this case the tensile strength of the shale is assumed to be constant with increasing hydration time.

If pore pressure tends to decrease monotonically from the wellbore wall to far-field formations, or if it reaches the maximum at the wellbore wall, results from inspecting only the wellbore wall stability can be used as the critical mud density. However, in some cases where pore pressure reaches a maximum value inside the formation, the entire near wellbore area needs to be inspected for stability. The displacement of the critical mud weight positions from the wellbore wall into the near wellbore formation has been discussed by Detournay and Cheng (1988) and Charlez (1997). This can be induced by poroelastic effects and/or thermal effects.

3.4. Thermal cooling effect on mud weights

Charlez (1997) found that in the absence of heat convection, a mud which is colder than the formation will reduce both pore pressure and hoop stress. Consequently, a beneficial borehole stability effect can be achieved from a drilling fluid that cools the formation. As shown in Fig. 5, reduced collapse and breakdown mud weights are obtained for the condition of a drilling fluid cooling the formation by 25 ºC ($\Delta T = -25 ^\circ C$). The cooling allows for a lowered mud weight thereby preventing wellbore collapse.

For example, a reduction of the collapse mud weight by 0.4 lb/gal (0.05 SG) is obtained when the cooling effect of the drilling fluid is considered, if a vertical wellbore is drilled. Reduced breakdown mud weights are due to the cooling effect, which reduces the hoop stress and pore pressure. The change of the breakdown mud weight is greater than that of the collapse mud weight since the decrease of the hoop stress makes the rock more tensile.

A displacement of the initial failed position from the wellbore wall can also be observed when studying thermal effects. For example, in Fig. 5, the critical mud weight required for stabilizing a vertical and a horizontal well at 24 h is 11.9 and 11.69 lb/gal, which are calculated from $r/r_w = 1.08$ and 1.04, respectively.

4. Discussions and conclusions

The Drucker–Prager failure criterion, as used in many literatures, is alleged to generate an unconservative critical mud weight window by overestimating rock strength (Ewy, 1999). By taking into account the intermediate stress with appropriate manipulations,
the modified Lade failure criterion can predict the rock strength closest to test results, compared to other failure criteria such as Drucker–Prager criteria and Mohr–Coulomb criteria (Ewy, 2002). Hence, the modified Lade failure criterion may be suggested for wellbore stability studies.

The decline of rock cohesive strength is used for the time-dependent effect when rock samples are exposed to selected fluids. Time-dependent cohesion changes are interpreted from triaxial test results (Che-nevert and Pernot, 1998) with measured failure angles. An averaged constant friction angle of 30° is used for this study. As shale samples are hydrated, in most cases, other properties such as Young’s modulus, Poisson’s ratio, and Biot’s constant may also change with the stress history and the shale–fluid interaction. Due to the limited quantity of lab data, the time dependency of other rock strength properties are not investigated.

This study shows that pore pressure can be partially decoupled from temperature for shale formations. The partially decoupled equations can be solved analytically under appropriate initial and boundary conditions while including thermal and chemical effects.

Poroelastic effects on collapse stress may be significant if a large mud pressure/pore pressure differential is applied. In this study, we found that poroelastic effects change the collapse stress only slightly if the wellbore undrained response at early time of the fluid/shale contact is neglected.

Altering mud water activity can be considered as an alternative approach to control wellbore stability in addition to raising mud density. A lower mud water activity can help decrease pore pressure and thereby increase rock effective stress conditions and consequently increase shale stability. In addition, wellbore stability control can also be achieved by changing the membrane efficiency of the fluid/shale system (a challenging task). For example, higher membrane efficiency is beneficial when the shale water activity is greater than that of the drilling fluid. A lower membrane efficiency is preferred if the drilling fluid activity is greater.

When determining the critical mud weight window, both the wellbore wall and the entire near wellbore area need to be inspected for failure because the location of shear failure can be displaced inside the formation.

Two effects can cause the displacement of the initial collapse failure location: (1) the poroelastic effect of equalized pore pressure at the wellbore wall, and (2) the thermal diffusion between the wellbore and the formation.

Cooling the formation is found to be helpful in maintaining wellbore stability. Cooler muds can reduce pore pressure and increase collapse stress. Hotter muds can result in unstable shales and are not desirable in drilling operations. The impact of thermal effects depends on the magnitude of the coupling coefficient \( c' \) that can vary from 0.012 to 0.372 MPa/K for shales.

The following factors are found to be important when modeling wellbore stability: unequal horizontal in situ stresses, membrane efficiency, water activity ratio (between the drilling fluid and shale formation), pore pressure, rock strength, the ratio of shale hydraulic diffusivity to thermal diffusivity, the thermal coupling coefficient \( c' \), thermal expansion coefficients of shale and pore fluid, and the temperature difference between the drilling fluid and the formation.

### Nomenclature

- \( A, B \) material constants
- \( a_{wm} \) drilling mud water activity
- \( a_{wsh} \) shale water activity
- \( B \) Skempton coefficient
- \( C \) cohesive strength
- \( c \) hydraulic diffusivity
- \( c' \) coupling coefficient
- \( c_0 \) thermal diffusivity
- \( c_0' \) coupling coefficient
- \( E \) Young’s modulus
- \( I_m \) membrane efficiency
- \( J_1^{ef} \) the effective mean stress
- \( J_2^{ef} \) the shear stress
- \( K_0 \) second kind of modified Bessel function of order zero
- \( L^{-1} \) inversion of Laplace transform
- \( p \) pore pressure
- \( p_0 \) initial pore pressure
- \( p_{nw} \) near wellbore pore pressure
- \( p_w \) wellbore pressure
- \( p_{osm} \) osmotic pressure
- \( p(r,t) \) pore pressure fluctuations
- \( r \) near wellbore radial position
\( r_w \)  wellbore radius  
\( R \)  universal gas constant  
\( t \)  time  
\( T_0 \)  initial formation temperature  
\( T_w \)  wellbore wall temperature  
\( T^i(r,t) \)  temperature fluctuations  
\( V \)  partial molar volume of water  
\( \alpha \)  Biot’s constant  
\( \alpha_f \)  thermal expansion coefficient of pore fluid  
\( \alpha_m \)  thermal expansion coefficient of rock matrix  
\( \Delta T \)  mud-formation temperature  
\( \phi \)  friction angle; formation porosity  
\( \nu \)  drained Poisson’s ratio  
\( \nu_u \)  undrained Poisson’s ratio  
\( \sigma_{cl} \)  collapse failure index  
\( \sigma_{rr}, \sigma_{00}, \text{ and } \sigma_{\varphi} \)  radial, hoop, and axial stress, respectively  
\( \sigma_{t} \)  tensile strength  

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References

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