Research Journal of Applied Sciences, Engineering and Technology 5(19): 4775-4779, 2013
ISSN: 2040-7459; e-ISSN: 2040-7467

Submitted: December 31, 2012 Accepted: January 17, 2013 Published: May 10, 2013

# Fracturing Pressure in Oil and Gas Well Drilling

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**Abstract:** During oil and gas well drilling, when the drilling fluid density is too high, not only tensile fracturing but also shear fracturing may occur on the wellbore. The possible fracturing modes and corresponding calculation formulas of fracturing pressure were present. Moreover, the influence of the magnitude and non-uniformity of in-situ stress, the pore pressure and the formation strength on fracturing mode was quantitatively analyzed. The results showed that: the risk of shear fracturing was higher with small non-uniformity of in-situ stress; when the horizontal stress was small, shear fracturing and tensile fracturing both probably happened and a higher in-situ stress leaded to less probability of tensile fracturing; the potential of tensile fracturing increased with the increasing of formation strength and pore pressure.

**Keywords:** Drilling, fracturing pressure, shear failure, tensile failure, wellbore stability

## INTRODUCTION

Petroleum is one of the most important energy sources in the world. Wellbore instability while drilling is a common but important problem that has puzzled the petroleum industry for long. The economic losses caused by wellbore instability reach more than one billion dollar every year (Mohammad, 2012). The aim of wellbore stability research is to determine the range of drilling fluid density that can maintain the wellbore stable (McLean and Addis, 1990). Proper mud density should satisfy following rules: the mud column pressure should be higher than the collapsing pressure and less than the fracturing pressure. Previous wellbore stability research mostly focused on collapsing pressure and revealed wellbore collapsing mechanism from different aspects such as mechanics and chemistry *et al* (Bradley, 1979; Aadnoy *et al*., 1987; Qiu *et al*., 2007; Roshan and Fahad, 2012). Research on the fracturing pressure was comparably less, though some achievement was presented (Eaton, 1969; Huang, 1984; Guo and Chang, 2004; Wang and Xu, 2005; Zhang *et al*., 2008; Roshan and Fahad, 2012), the theoretical foundation was derived from the hydraulic fracturing theory (Hubbert and Willis, 1972) and only took the tensile fracturing into consideration with overlooking of the shear fracturing which may occur when tangential stress is the minimum principal stress. The experiment results revealed that shear failure may happen when wellbore pressure is high (Liu and Li, 1986). The aim of hydraulic fracturing is to establish a big and open tensile fracture to inject huge volume of the fracturing fluid and proppant. So shear fracturing has little effect on hydraulic fracturing (Liu and Li, 1986; Liu *et al*., 2003), however, it is significantly important for wellbore stability because the wellbore will collapse when shear fracturing happens. In this study, potential failure modes of the wellbore when the mud density is high were analyzed and presented the fracturing pressure calculation formula.

## STRESS DISTRIBUTION ON THE WELLBORE WALL

Before drilling, the formation is under the subject of in-situ stress. When the wellbore established, the drilling fluid replaces the drilled rock and supports the wellbore, which definitely leads to stress concentration (Geertsma, 1985). Assuming the formation as poroelastic medium and the stress distribution can be gained with the following model: an infinite plane with a circular hole which is subjected to uniform inner pressure is forced by two horizontal stresses and the overburden pressure in the vertical direction. Because the maximum stress appears on the wellbore wall (Geertsma, 1985), this study just presents the stress distribution at the wellbore wall. The effective stress on the wellbore wall of a vertical wellbore is given by following (Fjær *et al*., 2008):

$$\begin{cases} \sigma'_r = P_{wf} - \alpha P_p \\ \sigma'_\theta = -P_{wf} + (1-2\cos 2\theta)\sigma_H + (1+2\cos 2\theta)\sigma_h - \alpha P_p \\ \sigma'_z = \sigma_V - 2\mu(\sigma_H - \sigma_h)\cos 2\theta - \alpha P_p \end{cases} \quad (1)$$

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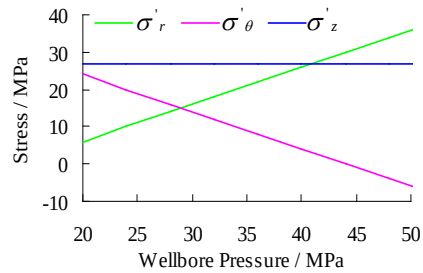


Fig. 1: Variation of principal stress with wellbore pressure at maximum horizontal stress direction

where, $\sigma_r'$, $\sigma_\theta'$, $\sigma_z'$, are the radial, tangential and axial stress, $P_{wf}$ is the wellbore pressure, $P_p$ is the pore pressure, $\alpha$ is the Biot's coefficient, $\sigma_V$ is the overburden pressure, $\sigma_H$ and $\sigma_h$ are the maximum and minimum horizontal in-situ stress, θ is the angle from the direction of the maximum horizontal stress to the radial line of the point on the wellbore.

## CALCULATION MODEL OF FRACTURING PRESSURE

In traditional wellbore stability analysis, fracturing pressure was determined by tensile failure (Eaton, 1969; Huang, 1984; Guo and Chang, 2004; Wang and Xu, 2005; Zhang *et al*., 2008; Fjær *et al*., 2008; Roshan and Fahad, 2012). What is ignored is that shear failure may also take place when the drilling fluid density is too high and the tangential stress is the minimum principal stress (Liu and Li, 1986; Liu *et al*., 2003).

The minimum tangential stress appears at the direction of maximum horizontal stress ($\theta$ = 0° or $\theta$ = 180°) (Fjær *et al*., 2008). At this direction the values of ($\sigma_r'$ - $\sigma_\theta'$) and ($\sigma_z'$ - $\sigma_\theta'$) all reach the maximum. Figure 1 shows the variation of effective stress with wellbore pressure when $\theta$ = 0° or $\theta$ 180°. The tangential stress decreases with the increasing of wellbore pressure. When the wellbore pressure is higher than 29 MPa, the tangential stress becomes the minimum stress. The axial stress maintains constant. The radial stress increases with the increasing of wellbore pressure. If ($\sigma_r'$-$\sigma_\theta'$) or ($\sigma_z'$-$\sigma_\theta'$) exceeds the formation shear strength before tangential stress reaches the tensile strength, shear fracturing will occur.

We label the shear fracturing when $\sigma_r'$ the maximum stress as shear fracturing is I and the shear fracturing when $\sigma_z'$ is the maximum stress as shear fracturing II.

When the drilling fluid density is too high, the fracture is most likely to occur when θ = 0° or θ = 180°, the effective stresses at the two points are as following:

$$\begin{cases} \sigma_r' = P_{wf} - \alpha P_p \\ \sigma_\theta' = -P_{wf} - \sigma_H + 3\sigma_h - \alpha P_p \\ \sigma_z' = \sigma_V - 2\mu(\sigma_H - \sigma_h) - \alpha P_p \end{cases} \quad (2)$$

It is assumed that the formation followed Mohr-Coulomb strength criterion (Fjær *et al*., 2008):

$$\sigma_1 = \sigma_3 \tan^2\left(\frac{\pi}{4} + \frac{\varphi}{2}\right) + 2C\tan\left(\frac{\pi}{4} + \frac{\varphi}{2}\right) \quad (3)$$

where,

$\sigma_1$, $\sigma_3$ = The maximum and minimum effective principal stress respectively
φ = The internal friction angle of the formation
C = The cohesion

When radial stress is the maximum stress and the tangential stress is the minimum stress, the stress state on the wellbore wall is:

$$\begin{cases} \sigma_1 = \sigma'_r \\ \sigma_3 = \sigma'_\theta \end{cases} \quad (4)$$

Inserting Eq. (4) into Eq. (3), fracturing pressure of shear fracturing I can be got:

$$P_I = \frac{K^2(3\sigma_h - \sigma_H) + (1 - K^2)\alpha P_P + 2CK}{1 + K^2} \quad (5)$$

where,

$$K = \tan\left(\frac{\pi}{4} + \frac{\varphi}{2}\right) \quad (6)$$

When axial stress is the maximum stress and the tangential stress is the minimum stress, the stress state on the wellbore wall is:

$$\begin{cases} \sigma_1 = \sigma'_z \\ \sigma_3 = \sigma'_\theta \end{cases} \quad (7)$$

Inserting Eq. (7) into Eq. (3), fracturing pressure of shear fracturing II can be got:

$$P_{II} = \frac{K^2(3\sigma_h - \sigma_H) + (1 - K^2)\alpha P_P - \sigma_V + 2\mu(\sigma_H - \sigma_h) + 2CK}{K^2} \quad (8)$$

Tensile fracturing takes place when the tangential stress reaches the tensile strength of the formation:

$$\sigma'_\theta = -S_t \quad (9)$$

Introducing Eq. (2) into Eq. (9), fracturing pressure of tensile fracturing is as following (Fjær *et al*., 2008):

$$P_t = 3\sigma_h - \sigma_H - \alpha P_P + S_t \quad (10)$$

The fracturing pressure ($P_f$) in drilling process is the minimum value of $P_{\mathrm{I}}$, $P_{\mathrm{II}}$ and $P_t$, to prevent any kind of failure taking place:

$$P_f = \min(P_{\mathrm{I}}, P_{\mathrm{II}}, P_t) \tag{11}$$

## INFLUENCING FACTORS OF FRACTURING MODES

The calculation parameters are as follows: $\sigma_v$ = 46MP$\alpha$, $\sigma_H$ = 44MP$\alpha$, $\sigma_h$ = 34MP$\alpha$, $P_P$ 20.6MP$\alpha$, $\alpha$ = 0.7 μ = 0.25 $C$ = 10MP$\alpha$ $\varphi$ = 30°, $S_t$ = 2.9MP$\alpha$.

**The influence of in-situ stress magnitude:** Figure 2 shows the variation of three kinds of fracturing pressure with the maximum horizontal stress when the in-situ stress non-uniform coefficient $M$ = 1.5 ($M = \sigma_H / \sigma_h$). With the increasing of $\sigma_H$, three kind of fracturing pressure increases approximately linearly, which means the greater the horizontal stress is, the wellbore is more difficult to fracture. He increasing rate of $P_{\mathrm{II}}$ is the fastest and the increasing rate of $P_{\mathrm{I}}$ is the slowest. When $\sigma_H$ is smaller than 52 MPa, $P_t$ is the minimum, tensile fracturing occurs first. When $\sigma_H$ is higher than 52 MPa, $P_{\mathrm{I}}$ is the minimum, shear fracturing I occurs first. In this non-uniform stress coefficient, it is less likely to occur tensile fracturing when the in-situ stress is great and the greater the in-situ stress is, the greater the possibility of shear fracturing I is.

**The influence of non-uniformity of in-situ stress:** Keep $\sigma_h$ = 34MP$\alpha$, only M changed, variation of the three kind of fracturing pressure is shown in Fig. 3. As the value of M increases, three kind of fracturing pressure all reduced linearly, the possibility of wellbore fracturing increases with the increasing of in-situ stress non-uniformity. The decreasing rate of $P_t$ is the fastest and that of $P_{\mathrm{I}}$ is the slowest. Shear fracturing I occurs first when $M$ is smaller than 1.5. When M is bigger than 1.5, tensile fracturing occurs first. In some areas with little tectonic movement, the in-situ stress non-uniformity is small; the possibility of shear fracturing can not be ignored.

**The influence of pore pressure:** Figure 4 shows the variation of fracturing pressure with pore pressure. When pore pressure increases from 10 MPa to 40 MPa, fracturing pressure increases linearly, but he growth rate of $P_t$ is far less than $P_{\mathrm{I}}$ and $P_{\mathrm{II}}$. When the pore pressure is less than 30 MPa, shear fracturing I occurs first; when the pore pressure is higher than 30 MPa, tensile fracturing occurs first. The greater the pore pressure is, tensile fracturing is more easily to occur.

**The influence of formation cohesion:** Cohesion and internal friction angle are the parameters to reveal the formation strength characters in Mohr-Coulomb strength criterion. The relationship of tensile strength ($S_t$) and Uniaxial Compressive Strength (UCS) is given by the Griffith criterion (Fjær *et al*., 2008).

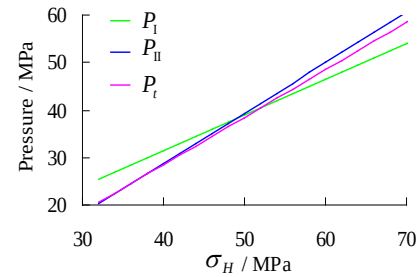


Fig. 2: The influence of in-situ stress magnitude on fracturing pressure

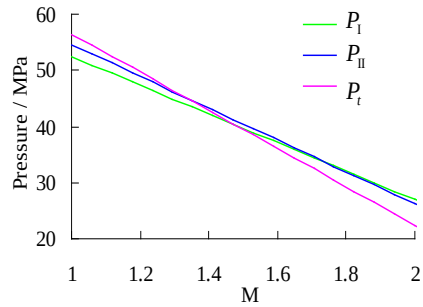


Fig. 3: The influence of in-situ stress non-uniformity on fracturing pressure

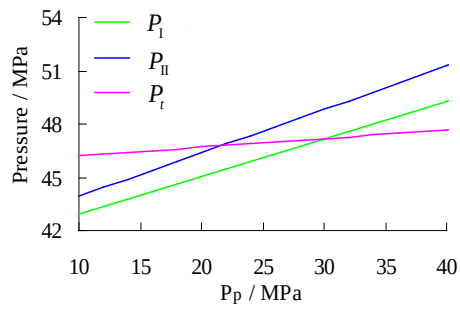


Fig. 4: The influence of pore pressure on fracturing pressure

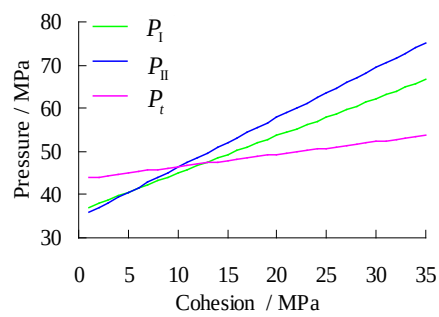


Fig. 5: The influence of cohesion on fracturing pressure

Figure 5 shows the variation of fracturing pressure with cohesion. The fracturing pressure increase linearly with the increasing of cohesion, which means the

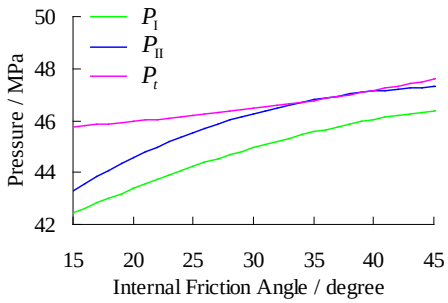


Fig. 6: The influence of internal friction angle on fracturing pressure

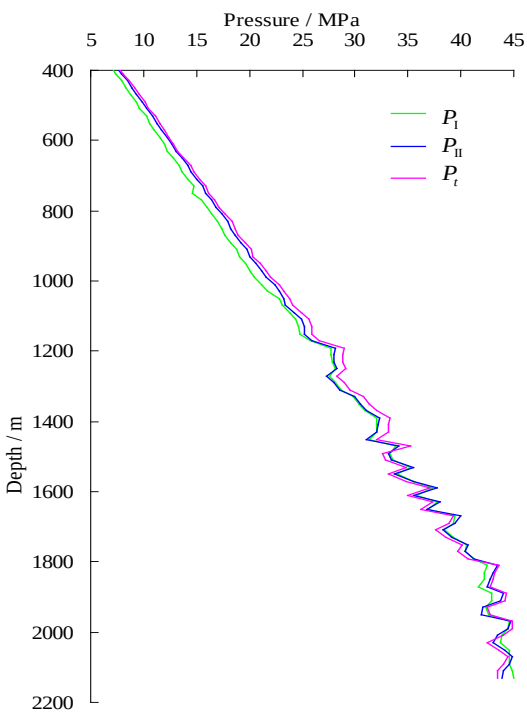


Fig. 7: Fracturing pressure of Well-A

stability of the formation increases with higher cohesion. The increasing rate of $P_{II}$ is the fastest and that of $P_t$ is the slowest; when the cohesion is less than 5 Mpa, shear fracturing II takes place first; when the cohesion is between 5 Mpa and 12 Mpa, shear fracturing I takes place first; when the cohesion is higher than 12 Mpa, tensile fracturing takes place first. When the cohesion is small, the probability of shear fracturing can not be ignored.

**The influence of internal friction angle:** Figure 6 shows the variation of three kind of fracturing pressure with the internal friction angle. The pressure increases with the internal friction angle increasing. The increasing rate of the shear fracturing pressure decreases with the increasing of internal friction angle, but the increasing rate of the tensile fracturing pressure increases gradually. Shear fracturing I always occur first with the parameters this study selected.

## CASE STUDY

Fracturing pressure of Well-A in Gas Filed-M in South China Sea were calculated using the above model. The results are shown in Fig. 7. The calculation parameters such as strength parameters, in-situ stress, pore pressure, etc., are obtained by logging data (Fjær *et al*., 2008).

It can be seen from Fig. 7 that $\rho_\alpha$ is the minimum above 1200 m, shear fracturing I happens first, thus the $\rho_\alpha$ can be regarded as the fracturing pressure of this interval. Shear fracturing still appears first from 1200 m to 1500 m, but these two shear fracturing modes exist alternatively; the difference of three kinds of fracturing pressure below 1500 m are small and also exist alternatively, while there are mainly tensile fracturing. The minimum of these three kinds of fracturing pressure should be regarded as the fracturing pressure and the upper limit of safe mud density window in wellbore stability analysis.

Shear fracturing won't lead to fracturing fluid leakage in hydraulic fracturing, the leakage of fracturing fluid only happens after the fracturing opened and thus the initial opening and re-opening of shear fracturing are both on the same shear fracturing plane, so the initial opening fracturing pressure is equal to the re-opening pressure (Liu and Li, 1986). There was a leak off test at 660 m depth in Well-A, the result showed the initial opening fracturing pressure is equal to re-opening fracturing pressure, it indicated that the first fracturing was shear fracturing.

According to the statistics by Liu and Li (1986), approximately 50% of the fracturing curves showed that the initial opening fracturing pressure was equal to the re-opening fracturing pressure in Dagang oil-field of China. The hydraulic fracturing tests in San Andreas Fault showed that the formation initial fracturing pressure above 500 m was bigger than the re-opening fracturing pressure; but below 500m they were equal. The results implied that the formation above and below 500 m belonged to different fracturing modes.

The fracturing mode is affected by in-situ stress and formation strength together. Overburden pressure in San Andreas Fault is the minimum stress (Keys *et al*., 1979), while overburden pressure in Gas Filed-M is the maximum stress. In addition, the formation of San Andreas Fault is older, so the variations of fracturing modes in these two areas are different, but they both show shear fracturing is very common. Although the shear fracturing pressure cannot be applied in hydraulic fracturing, it is very important in wellbore stability analysis.

## CONCLUSION

When the mud density is too high, no only tensile fracturing but also shear fracturing may occur on the wellbore wall. There are two types of combining forms of the stress that can cause shear fracturing; shear fracturing pressure calculation formula is deduced.

When the non-uniformity of in-situ stress is constant, the possibility of shear fracturing I increases with the in-situ stress increasing; when the non-uniformity of in-situ stress is weak, shear fracturing easily appears on the wellbore wall, in addition, the potential of tensile fracturing increases with the non-uniformity of in-situ stress increasing; the higher the formation strength and pore pressure are, the shear fracturing is easier to occur.

Shear fracturing must be considered in wellbore stability analysis, take the minimum of shear fracturing pressure and tensile fracturing pressure as the upper limit of mud density.

## ACKNOWLEDGMENT

This study is supported by Science Fund for Creative Research Groups of the National Natural Science Foundation of China (Grant No. 51221003).

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