Fault reactivation potential as a critical factor during reservoir stimulation

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Abstract
Hydraulic stimulation is frequently used to enhance reservoir productivity. The aim of hydraulic stimulation is to increase the formation pressure by fluid injection to create artificial fractures that act as additional fluid pathways. But large-scale fluid injection as applied in hydrocarbon and geothermal reservoirs can also induce seismicity and fault reactivation depending on the reservoir geomechanics and stress regime. Recent case studies in stimulation of geothermal reservoirs have shown induced seismicity as an undesirable side effect which needs to be understood prior to massive fluid injection. Slip tendency analysis has been successfully used to characterize fault slip likelihood and fault slip directions in any stress regime. In our study, we applied slip tendency analysis to assess the reactivation potential of shear and dilational fractures in a deep geothermal reservoir in the North-East German Basin, based on the notion that slip on faults is controlled by the ratio of shear to normal effective stress acting on the plane of weakness. The results from slip tendency analysis are supported by the spatial distribution of recorded microseismicity, which indicates slip rather than extension along a presumed NE-striking failure plane.

Introduction
Permeability enhancement of a reservoir rocks is commonly linked with hydraulic stimulation of the reservoir to increase fluid flow by generating additional fracture systems and dilating natural fractures. The orientation of artificially induced fractures depends on the in situ stress field, which is defined by the principal stresses $\sigma_1$, $\sigma_2$ and $\sigma_3$, where compressive stresses are positive and $\sigma_1 > \sigma_2 > \sigma_3$ (Zoback and Haimson, 1983). Knowledge of horizontal stress directions is particularly important for planning deviated wells that are to be hydraulically stimulated. Hydraulically induced fractures are generally oriented perpendicular to the minimum principal stress, $\sigma_3$. Thus, inclined or horizontal stimulation wells should be deviated along the direction of $\sigma_3$ to maximize production rates from multiple hydraulic fractures (Zimmermann et al., 2009). Conventional hydraulic fracturing, in which propagated fractures are kept open by proppants, is relatively inefficient in tight gas and geothermal reservoirs (Hossain et al., 2002). An alternative technology for naturally fractured reservoirs is shear dilation stimulation, which is also known as low-proppant, no-proppant, proppant-free, or waterfrac treatment (Hossein et al., 2002). The shear component causes slip motion along failure planes, and asperities on the rough fracture surfaces resist reversal of slip when stimulation ceases. Moreover, stimulation through fluid injection means a local increase of the pore pressure in the reservoir, exerting a significant impact on the initial in situ stress state. The normal effective stress acting perpendicularly to a fault surface is reduced by additional pore pressure, possibly leading to fault reactivation.

Fault reactivation through shear displacement can be measured by recording microseismicity during stimulation treatments. Fluid injection, if not adjusted to the in situ stress field and rock strength conditions, can lead to undesirable seismicity (Deichmann and Giardini, 2009), especially in earthquake-prone areas. Therefore, the effects of stress field changes on fault kinematic behaviour need to be addressed, and fault reactivation potential should be estimated before any stimulation treatments.

This study highlights the assessment of fault reactivation potential of an enhanced geothermal system by using the slip tendency method based on frictional constraints. We compare the results of the slip tendency analysis with microseismic events recorded during massive water stimulation of volcanic rocks at ~4200 m depth, and test whether slip tendency analysis is a useful method to characterize fault systems in subsurface reservoirs. Moreover, we present an alternative method to determine the stress field from borehole breakouts using fracture mechanics numerical modelling.

Setting
The test site is a deep geothermal reservoir at Gross Schönebeck in the North-East German Basin, where a well doublet consists of injector and producer (Figure 1). The well now used as the

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Determination of stress regime and magnitudes from geological constraints

The regional orientation of the maximum horizontal stress, $\sigma_{H}$, in the Lower Permian subsalt successions of the North-East German Basin ranges from N to NE (Röckel and Lempp, 2003). The 3D geological model of the geothermal aquifer in the Gross Schönebeck area of the basin, obtained by analysis of well and 2D seismic data (Moeck et al., 2009), displays fault throw characteristics that are only compatible with stress regimes ranging from normal to strike-slip faulting, including the transitional type between these two regimes (Figure 1). The in situ stress is estimated by a combined use of frictional-failure theory (Peška and Zoback, 1995, and references therein) with observations from hydraulic fracturing in the geothermal well (Legarth et al., 2005). For the case study reported here, the orientation of $\sigma_{H}$ is $18.5^\circ \pm 3.7^\circ$ (Holl et al., 2005). The vertical stress, $\sigma_{v}$, is estimated as 105 MPa from a compilation of density data collected for rocks in the North-East German Basin (Moeck et al., 2009).

The reservoir fault pattern consists of major faults striking $130^\circ$ and minor faults striking $030^\circ$ and $170^\circ$ (Figure 1) (Moeck et al., 2008). The minimum horizontal stress, $\sigma_{h}$, was determined to be $\leq 54$ MPa and the pore pressure, $P_p$, is $\sim 43.5$ MPa from a hydraulic stimulation campaign (Legarth et al., 2005; Zimmermann et al., 2009). Analysis of the well history revealed that a casing lift test for productivity determination was the cause of breakouts, estimated from FMI images as about $145^\circ$ (Figure 2c) (Backers, 2006). During this casing lift test, the mud pressure was decreased from the formation pore pressure of 43.5 MPa to 3.7 MPa.

**Figure 1** 3D geological model of the geothermal reservoir at Gross Schönebeck, located in the Barnim Low in the NE German Basin. The red box in the map refers to the area of the geological reservoir model. The reservoir consists of siliciclastic and volcanic rocks at 4000–4250 m depth. The red and blue tubes represent the well doublet installed at Gross Schönebeck.
The range of possible in situ stress regimes can be conveniently shown diagrammatically by stress polygons (Zoback, 2007) on a plot of maximum horizontal stress, $\sigma_h$, normalized by the vertical stress (Figure 3). The stress polygon in Figure 3 represents the potential stress states and respective stress ratios for the geothermal reservoir rock at 4100 m depth in Lower Permian successions, where $\sigma_v = 105$ MPa. In these plots, it is assumed that one principal stress is vertical. At critical stress states for faulting, on the lines labelled with Roman numerals, the ratio of principal effective stresses is given by Jaeger et al. (2007) as

$$\frac{(\sigma_1 - P_o)}{(\sigma_3 - P_o)} = (\mu^2 + 1 + \mu)^2,$$  \hspace{1cm} (1)

where $\mu$ is the coefficient of frictional sliding on pre-existing planes of weakness. Byerlee (1978) has shown that for fractures subject to moderate values of normal stress over the range 5–100 MPa, which includes the normal stress values at the studied reservoir depth, $\mu = 0.85$ better defines the onset of failure than the widely used value of 0.6. Assuming $\mu = 0.85$ and approximately hydrostatic pore pressure conditions ($P_o = 0.43 \sigma_v$), Equation (1) yields the following limiting values for the horizontal principal stresses (Figure 3): $\sigma_h \leq 3.10 \sigma_v$, and $\sigma_h \geq 0.55 \sigma_v$. For higher pore pressures, lower coefficients of friction and a smaller range of differential stress values may apply, resulting in smaller stress polygons (Moos and Zoback, 1990, 1993; Peška and Zoback, 1995).

**Figure 2** (a) Well path geometry, schematic illustration of the hydraulically induced fractures, and geological units of the well doublet at Gross Schönebeck. (b) Detailed lithological description of the reservoir units. (c) Section of borehole breakouts observed in well EGrSk3/90.

**Determination of the maximum horizontal stress**

The maximum horizontal stress is determined by an innovative numerical method based on rock fracture mechanics, using the fracid2D software. In this method, the generation and propagation of fractures in the rock mass are explicitly simulated and the interaction of fractures leads to distinct fracture networks governing the mechanical and hydraulic behaviour (Backers, 2010). fracid2D is a 2D boundary...
element method code that is capable of handling the initiation of fractures due to a Mohr-Coulomb criterion and the propagation of fractures by a mixed mode, stress intensity-based criterion (Rinne, 2008). The known information about the rock and in situ stress field as well as conditions during drilling and well testing are employed in the numerical analysis of observed borehole breakouts. The input data and boundary conditions are summarized in Table 1. The boundary stress conditions and breakout geometry are summarized in the previous section.

The applied boundary stresses for the numerical simulation are \( \sigma_h = 54 \) MPa and the downhole mud pressure, \( P_w \), was 43.5 MPa and 3.7 MPa before and after formation of the borehole breakouts, respectively (Figure 4). The unknown maximum horizontal stress, \( \sigma_H \), is varied in the simulations indicating a strong effect on the breakout angle. Comparison of the measured breakout angle and the predicted angle from numerical modelling yields an estimate of \( \sigma_H \). The results from the numerical models are plotted in Figure 5, predicting \( \sigma_H = 95 \) MPa (Backers et al., 2006). Barton et al. (1988) suggested the following equation for estimation of the maximum horizontal stress:

\[
\sigma_H = \text{UCS} + f \left( \frac{1 + 2 \cos 2\theta}{1 - 2 \cos 2\theta} \right)
\]  

(2)

where \( f \) is a function of pore pressure, downhole mud pressure, and stress change due to temperature change, \( \text{UCS} \) is the uniaxial compressive strength, and \( \theta \) is the angle of friction. The results from the numerical models are plotted in Figure 5, predicting \( \sigma_H = 95 \) MPa (Backers et al., 2006). Barton et al. (1988) suggested the following equation for estimation of the maximum horizontal stress:

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Table 1 Geomechanical parameters used for the numerical fracture model of borehole breakouts to back calculate the maximum horizontal stress, \( \sigma_H \).
the uniaxial compressive strength, and $\theta$ is the breakout angle. The equation is derived from the Kirsch solution (Pollard and Fletcher, 2003) with the assumption that the tangential stress at the breakout is in equilibrium with the UCS. With UCS = 110 MPa (determined from point load tests) and known values of $\sigma_h$ and $\theta$, Equation (1) yields $\sigma_H = 93$ MPa, which is in agreement with the numerical predictions and geological constraints.

Summarizing, the in situ stress field in Gross Schönebeck is $\sigma_h = 54$ MPa, $\sigma_H = 95$ MPa and $\sigma_v = 105$ MPa in a stress regime that is transitional from normal to strike-slip faulting with $\sigma_H$ and $\sigma_v$ being similar in magnitude (Moeck et al., 2009).

**Slip tendency analysis and fault reactivation potential**

This technique has been used for seismic risk and fault rupture risk assessment in earthquake prone areas (e.g., Morris et al., 1996), and to understand shearing versus dilation along fault and bedding planes as part of interacting deformation (e.g., Ferrill and Morris, 2003). We test the ability of the slip tendency method to forecast rupture plane orientation and intensity of rupture induced by hydraulic stimulation of geothermal reservoirs. From that perspective, we calculate the shear and dilational stresses along mapped and suspected faults cutting the reservoir, evaluate slip and dilation potential, and compare the results with recorded and analysed microseismic events. According to Amonton’s law, stability or failure is determined by the ratio of shear stress to normal effective stress acting on the plane of weakness, which is defined as the slip tendency, $T_s$ (Morris et al., 1996):

$$T_s = \frac{\tau}{\sigma_n'},$$

where $\tau$ is the shear stress and $\sigma_n'$ is the normal effective stress acting on a surface (Morris et al., 1996). Slip is likely to occur on a surface if the slip tendency exceeds the sliding friction coefficient.

Dilation of faults and fractures is largely controlled by the normal stress acting perpendicularly to the plane of the fault or fracture. The magnitude of the normal stress can be computed for surfaces of all orientation within a given stress field. This normal stress is normalized by the differential stress, $\sigma_1 - \sigma_3$, to give the dilation tendency, $T_d$, for a surface:

$$T_d = \frac{(\sigma_1 - \sigma_3)}{(\sigma_1 - \sigma_3)}.$$  

(4)

Visual analysis of slip and dilation tendency is done with stereo plots to enable rapid assessment of stress states and related fault reactivation potential.

Slip tendency analysis for the Gross Schönebeck reservoir fault system was performed for both the Lower Permian (Rotliegend) red beds and volcanic rocks, using the in situ stresses from Moeck et al. (2008) for the red beds and...
from Zimmermann et al. (2009) for the volcanic rocks for the ambient stress field (Figure 6a). Slip tendency analysis indicates that the reactivation potential of any faults in the volcanic layer is very low. The maximum slip tendency is less than 0.5 and is below the value of frictional strength of a rock mass at that reservoir depth. Additional pore pressure of 24.5 MPa would be required to increase the maximum slip tendency within the volcanic interval to about 0.8. This would approach failure conditions for these rocks and would likely initiate slip along preferential fault planes. In both formations (sandstone and volcanic rock), these preferential fault planes are NNW-striking, moderately dipping normal faults and steep NW-striking and NE to ENE-striking strike-slip faults (Figure 6a).

The large increase in pore pressure (>24 MPa) required to generate slip within the volcanic rocks implies that substantial induced seismicity during stimulation is unlikely. In contrast, the sandstones are close to a critically stressed state (Figure 6a). To understand the stress distribution along faults, slip and dilation tendency are applied to the reservoir fault pattern as mapped by interpretation of 2D seismic lines and compared with results from induced seismicity.

**Discussion: slip tendency and induced seismicity**

Induced seismicity is observed during shear dilation stimulation if increased pore fluid pressure causes faulting, i.e., shear failure on fracture planes with associated release of energy. Shear failure and sliding of two rough fracture surfaces (shear slippage) to dilate an aperture normal to the fracture surface is a necessary process in shear dilation stimulation to retain fracture permeability in a growing fracture network (Hossein et al., 2002). Induced seismicity, however, can reach magnitudes that are undesirable, especially in populated and earthquake-prone areas. In Gross Schönebeck, a set of geophones was installed in well EGksk3/90 when well GTGrSk4/05 was stimulated. Kwiatek et al. (2010) have described in detail the recording, data processing, and analysis of induced seismicity at the Gross Schönebeck test site, where the magnitudes of events were surprisingly low although large volumes of water were injected. We summarize their findings here and compare their results with our stress analysis. The focus of the discussion is to give an explanation for the very low magnitude of induced seismicity from the structural geological perspective.

During the stimulation of the volcanic rocks, the maximum injection bottom-hole pressure was 86 MPa. The first pressure drop indicating fracturing occurred at a bottom-hole pressure of 63 MPa (i.e., 20 MPa of overpressure). 29 events from seismic sequences were located using polarization analysis to estimate the back azimuth and angle of incidence and hence the direction of incoming waves (Kwiatek et al., 2010). A plane surface to the location coordinates was fitted using least squares (Figure 6b and c). The strike and dip of the resulting plane was found to be 17º ± 10º and 52º ± 5º, respectively. Unfortunately, due to the limited number of stations, no fault plane solutions could be calculated.

A waveform correlation analysis and amplitude ratio comparison was performed to identify similarities between events that may suggest the similarity of their rupture process (Kwiatek et al., 2010; Moeck et al., 2009). Almost all recorded waveforms from located events are very similar. Additionally, spectral analysis performed on a subgroup of analysed clusters made it possible to calculate the ratio between S and P energy released and estimate other source characteristics, such as the static stress drop (Kwiatek et al., 2010). The average ratio of S to P energy released and estimate other source characteristics, such as the static stress drop (Kwiatek et al., 2010). The average ratio of S to P energy was ~30, which is typical for a shearing type of focal mechanism. The calculation of static stress drop resulted in values around 1 MPa, which is a typical value for mining-induced seismic events (Kwiatek et al., 2010; Moeck et al., 2009).

At the simplest level of explanation, fluid injection causes faulting because the normal effective stress acting perpendicularly to the fault surface decreases by an amount...
equal to the pore pressure increase, so the ratio of shear to normal effective stress increases (e.g., Cuenot et al. 2006). Considering the effect of pore pressure increase on the Mohr circle in a Mohr-Coulomb stress diagram, shear failure would appear to be the most likely mode of failure under the given differential stresses (Figure 7) during hydraulic stimulation of the volcanic rock. Zimmermann et al. (2009) described in detail the stimulation treatment of well GrGrSk4/05 and concluded that a first pressure drop indicating fracture initiation occurred at 20 MPa additional pore pressure. Analysis of stress conditions by the Mohr-Coulomb failure criterion suggests that additional pore pressure of 24 MPa is needed to reactivate existing failure planes in the reservoir (Figure 7a).

At first sight, tensile failure would seem to be less likely as a mechanism for failure along existing planes of weakness. However, pore pressure-stress coupling also affects the state of stress. If the stress state and pore pressure are laterally invariant, an increase of pore pressure in rocks that are laterally confined causes the horizontal stresses to increase as well, albeit by a lesser amount, whereas the vertical stress is unchanged (e.g., Engelder and Fischer, 1994; Hillis, 2000; Goulty, 2003). Thus the minimum horizontal effective stress decreases by a smaller amount than the increase in pore pressure. As a result, in a normal faulting stress regime as in the geothermal reservoir at Gross Schönebeck, the differential stress might decrease as pore pressure increases, possibly causing hybrid or tensile failure along existing planes of weakness. In a more sophisticated analysis considering point source injection, Altmann et al. (2010) have shown that pore pressure–stress coupling varies with distance from the injection point and can change over the lifetime of a reservoir. Whatever the level of sophistication in analysis of the pore pressure and stress distribution, it is clear that the effective stress concept explains rock failure during injection and the associated induced seismicity.

**Conclusion**

The very low seismicity (moment magnitudes of −1.0 to −1.8) interpreted from the seismic events are consistent with the low-stress state in the volcanic reservoir rocks. Additional pore pressure of 2–4.5 MPa would be necessary to increase the slip tendency from −0.5 to −0.8. The latter value is a reasonable value for the friction coefficient at the studied crustal depth of 4.2 km (Byerlee, 1978). It is, therefore, a limiting value where slip occurs, i.e., when the slip tendency equals or exceeds the sliding friction coefficient of rock. In contrast, the sandstones are less competent and highly stressed, as indicated by fault planes with high slip tendencies. We assume that the critically stressed faults can be easily reactivated by additional fluid pressure during stimulation. Low injection rates, however, were used for the stimulation of the sandstones, presumably resulting in only small fracturing and faulting events. Effectively, no significant seismicity was recorded during stimulation of the sandstones. By contrast, large volumes of injected water at high pressures were used to treat the volcanic rocks, resulting in large increases in pore pressure and the subsequent recorded microseismicity. The direct pressure response in the offset well, at 475 m distance from the stimulated well in the reservoir to the stimulated well, during stimulation suggests that fractures were reactivated for enhanced fluid flow.

Analysis of the microseismic events indicates an induced fracture plane with a strike and dip of 017°/52°. The fracture plane is consistent with an independent reinterpretation of geological data using 2D seismic profiles (Moeck et al., 2008). This investigation revealed a fault located nearby the fitted plane (fault F28 in Figure 7c) with strike and dip similar to the located planar cluster of seismicity. The recorded events possibly occurred along the existing fault plane. The fracture plane also agrees with the slip tendency plane with a strike and dip of 017°/52°. The fracture plane is consistent with an independent reinterparation of geological data using 2D seismic profiles (Moeck et al., 2008). This investigation revealed a fault located nearby the fitted plane (fault F28 in Figure 7c) with strike and dip similar to the located planar cluster of seismicity. The recorded events possibly occurred along the existing fault plane. The fracture plane also agrees with the slip tendency plane with a strike and dip of 017°/52°. The fracture plane is consistent with an independent reinterpreta-

Figure 7 (a) Mohr-Coulomb diagram illustrating the effect of fluid pressure increase on stress state and failure of cohesionless (existing) planes. Under high differential stresses, shear failure is most likely. (b) Failure modes depending on the angle between the maximum principal stress and the failure plane. The colouring of fracture planes is consistent with points of failure in (a).
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References

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