



Local variations in stress magnitude and S_{Hmax} orientation in the Eastern Bavarian Molasse Basin: an integrated case study using legacy well data, stress measurements, and geomechanical analysis

Thomas Niederhuber¹ · Birgit I. R. Müller¹ · Annette Lenze² · Roman Przyrowski²

Received: 23 January 2026 / Accepted: 12 September 2026
© The Author(s) 2026

Abstract

The Eastern Bavarian Molasse Basin is used for geothermal energy, natural gas, and hydrogen storage, making constraints on the present-day stress field essential for assessing borehole stability and fault integrity. We integrate borehole breakout (BO) observations from 70 wells with formation integrity tests (FITs), an extended leak-off test (XLOT), drilling-mud pressures, RACOS[®] measurements, and geomechanical constraints to characterize stress orientation and magnitude. Oriented four-arm caliper data from 20 wells reveal BOs in 19 wells. The results confirm a regional N–S-oriented maximum horizontal stress (S_{Hmax}) but also document local stress rotations of up to 70–90° within the Aquitanian and Chattian. These rotations are associated with fault displacement, structural geometry, and the juxtaposition of mechanically contrasting units, indicating that mechanical heterogeneity can be as important as fault-related effects for local stress orientations. The XLOT at 1484 m TVD constrains S_{Hmin} to approximately 28.2 MPa (~19 MPa/km), while S_V is 33.7 MPa. Depending on pore pressure and XLOT uncertainties, S_{Hmax} ranges from 34.1–42.9 MPa, consistent with an independent frictional-limit estimate of 32.4–44.8 MPa, resulting in a strike-slip regime close to normal-faulting with relatively low differential stresses. BO formation at approximately 400 m, is facilitated by low strength. The value of integrating heterogeneous legacy datasets within a consistent geomechanical framework, providing a transferable workflow for stress characterization in mature hydrocarbon fields is demonstrated. The suggested low differential stresses in the uppermost 1.5 km provide favorable conditions for subsurface utilization of Eastern Bavarian Molasse Basin with a low likelihood of inducing significant seismicity.

Keywords Stress state · Borehole breakouts · Eastern Bavarian Molasse Basin · Material properties · Leak-off test

Abbreviations

BO	Borehole breakouts
DITFs	Drilling induced tensile fractures
P_0	Pore pressure
P_B	Fracture breakdown pressure
P_{clo}	Fracture closure pressure
P_m	Mud pressure
P_{prop}	Fracture propagation pressure
P_R	Fracture re-opening pressure
P_{SI}	Shut-in pressure

S_{Hmin}	Minimum horizontal stress
S_{Hmax}	Maximum horizontal stress
S_V	Vertical stress
Q_i	Injection rate
V_i	Injected volume
XLOT	Extended leak off test

Introduction

The Bavarian Molasse Basin has been extensively explored for hydrocarbons and hosts the largest oil and gas reserves in Bavaria. Exploration activity peaked between the 1950s and 1980s and declined markedly thereafter (StMWi 2021). In recent years, however, the basin has become one of the most important regions for geothermal energy development in Germany, with numerous projects in operation, under construction, or in advanced stages of planning (Schölderle et al. 2025). In addition, the basin hosts several underground

✉ Thomas Niederhuber
thomas.niederhuber@kit.edu

¹ Division of Technical Petrophysics, Institute of Applied Geosciences, Karlsruhe Institute of Technology, Karlsruhe, Germany

² Competence Center Geology and Geophysics, Uniper Energy Storage GmbH, Düsseldorf, Germany

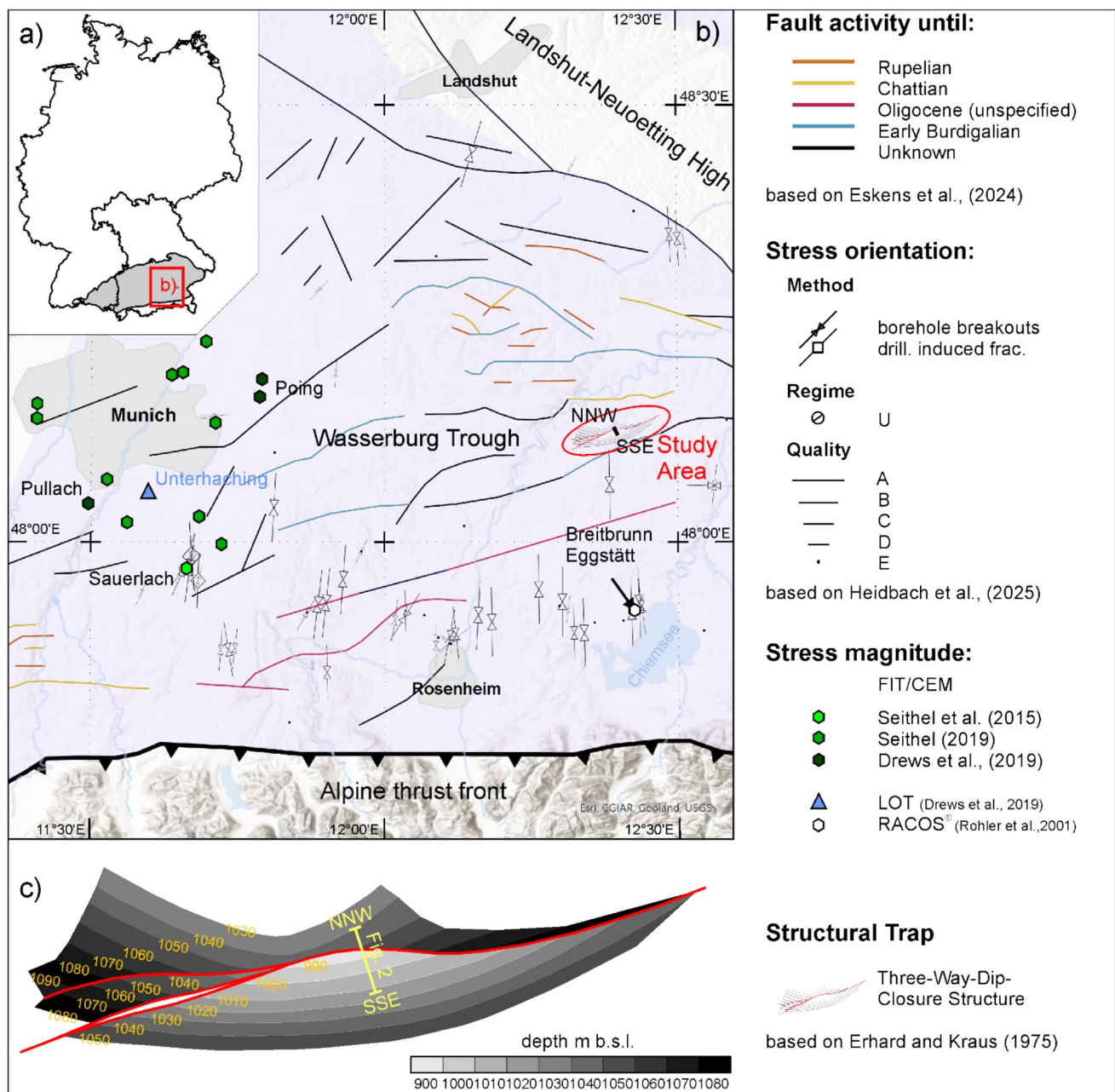


Fig. 1 **a** Overview map of Germany including the Molasse Basin (gray) based on Reinecker et al. (2010) and the extent of **b**. **b** Detailed map showing the S_{Hmax} orientation based on the World Stress Map (Heidbach et al. 2025), along with fault traces and their periods of

activity, redrawn from Eskens et al. (2024) within the Wasserburg Trough. Red ellipse highlights the study area with the analyzed three-way-dip closure. **c** Schematic of the three-way-dip closure structure along with the NNW-SSE profile of Fig. 2

natural gas storage facilities (Erhardt and Kraus 1975) and serves as a test site for the development of technologies for large-scale hydrogen storage (Strobel et al. 2023).

Knowledge of the present-day stress state is essential for assessing fault stability, borehole integrity, and the safe operation of subsurface energy systems. Despite the increasing utilization of the Bavarian Molasse Basin, its regional stress field remains incompletely characterized. The orientation

of the maximum horizontal stress (S_{Hmax}) is commonly assumed to be laterally and vertically consistent within sedimentary basins (e.g., Zoback et al. 1989). Consistent with this assumption, 75 S_{Hmax} orientations of variable quality are currently available in the World Stress Map (WSM) database for the eastern Bavarian Molasse Basin between Rosenheim, Landshut, and Munich (Heidbach et al. 2025), indicating a predominantly N–S-oriented stress field (Fig. 1b). This

is also supported by regional numerical stress models e.g., Gölke and Coblenz (1996) or Ahlers et al. (2022). However, locally deviating stress orientations have been reported (Reinecker et al. 2010; Seithel et al. 2015), suggesting that stress perturbations may occur at smaller spatial scales.

Information on stress magnitudes is considerably more limited. While the vertical stress (S_V) is comparatively well constrained from density data (Obermeier et al. 2025), the horizontal stress magnitudes remain poorly resolved.

Estimates of the minimum horizontal stress (S_{hmin}) are sparse and are primarily derived from eight formation integrity tests (FITs) of varying quality, which represent a lower bound for S_{hmin} and two leak-off tests (Fig. 1b; Morawietz et al. 2020). Additional information on stress magnitudes is provided by laboratory measurements on core samples from the Breitbrunn/Eggstätt field (Fig. 1b; Rohler et al. 2001). Estimates of S_{Hmax} are typically derived from borehole failure observations and frictional constraints on pre-existing faults (Seithel et al. 2015; Budach et al. 2018), one-dimensional mechanical earth models (Zain-UI-Abedin and Henk 2020), or numerical FE models on regional scale (Ziegler et al. 2016) or supra-regional scale (Ahlers et al. 2022). However, owing to their coarse vertical resolution and simplified rheological parameterizations, these models are generally unable to adequately resolve the uppermost kilometers of the crust. Consequently, they often predict elevated fault slip tendencies (Röckel et al. 2022) that are inconsistent with the low level of background seismicity observed in the Bavarian Molasse Basin (Megies and Wassermann 2014).

Modeled stresses and observations provide an ambiguous picture of the present-day stress regime. The occurrence of BOs suggests that one or both horizontal stress magnitudes are relatively high, potentially indicating a thrust faulting regime (Reinecker et al. 2010). In contrast, Seithel et al. (2015, 2019), Ziegler et al. (2016), and Megies and Wassermann (2014) have suggested a predominantly strike-slip regime, whereas Drews et al. (2019) have argued for a normal-faulting regime with low horizontal stress magnitudes. In addition, local rotations of S_{Hmax} orientation are usually interpreted as an indicator for low horizontal stress anisotropy, which appears to contradict the occurrence of BOs, particularly in the uppermost kilometers (Reinecker et al. 2010).

The aim of this study is to improve constraints on the contemporary stress state within the shallow to intermediate depth range of the Eastern Bavarian Molasse Basin, which is relevant for underground gas storage, thermal energy storage, and medium-depth geothermal development (Jeßberger et al. 2025), and to explain the widespread occurrence of borehole breakouts (BOs) and their apparent variability in orientation at depths shallower than 1500 m. We therefore analyze previously unpublished legacy data from 70 wells to determine S_{Hmax} orientation from BOs. Particular emphasis

is placed on improving the utilization of legacy log data by developing a workflow for BO interpretation and a quality-ranking scheme for inclined wells compatible with the World Stress Map (WSM) database. In contrast to previous studies, we analyze BO azimuths and widths as a function of depth and stratigraphy, and their suitability as indicators of the far-field stress orientation.

To constrain stress magnitudes and pore pressure (P_0), we analyze mud-weight records from 61 wells and an unpublished extended leak-off test (XLOT), which provides an estimate of S_{hmin} . These data are complemented by 10 formation integrity tests (FITs) from five wells. In addition, two unpublished RACOS[®] (Rock Anisotropy Characterization On Samples) tests provide independent constraints on the full stress tensor. These newly compiled data are integrated with stress information from the World Stress Map (WSM), pore pressure data reported by Drews et al. (2019) and published (Seithel et al. 2015; Seithel 2019) and previously published FIT results to obtain an improved characterization of the present-day stress field. Finally, we evaluate the relationship between depth-dependent mechanical strength and BO width and discuss its implications for stress-field characterization. Particular attention is given to their potential role in generating local rotations of apparent S_{Hmax} orientations and deviations from the regional stress field.

Geology of the study area

During the Alpine orogeny, the Molasse forearc Basin developed with asymmetric deepening. This resulted in varying sedimentary regimes led to the deposition of distinct facies. The most important reservoir units for oil and gas fields in the Eastern Molasse Basin are the Upper Oligocene Chattian and Lower Miocene Aquitanian, which form the Lower Freshwater Molasse (LFM).

During the middle Chattian (28–25 Ma), a transition from neritic to littoral conditions (Eskens et al. 2024) facilitated the deposition of permeable, porous deltaic sands, which later formed important hydrocarbon reservoir rocks (Kraus 1969). These sands were subsequently sealed by marly shales, deposited under the influence of sea-level fluctuations at the Chattian–Aquitanian transition (Sissingh 1997). The NNW-directed transgression (~25 Ma) led to the onlap of neritic deposits onto Chattian Sands, shaping the eastward-facing Bavarian Shelf. By the Aquitanian (23–20 Ma), sea-level regression stabilized the shelf (Kuhlemann and Kempf 2002), with the final Aquitanian transgression marking the end of the first megacycle (Sissingh 1997). This is succeeded by a depositional cycle comprising the Upper Marine Molasse (UMM), Upper Brackish Molasse (UBM), and Upper Freshwater Molasse (UFM) units (Bachmann and Müller 1992).

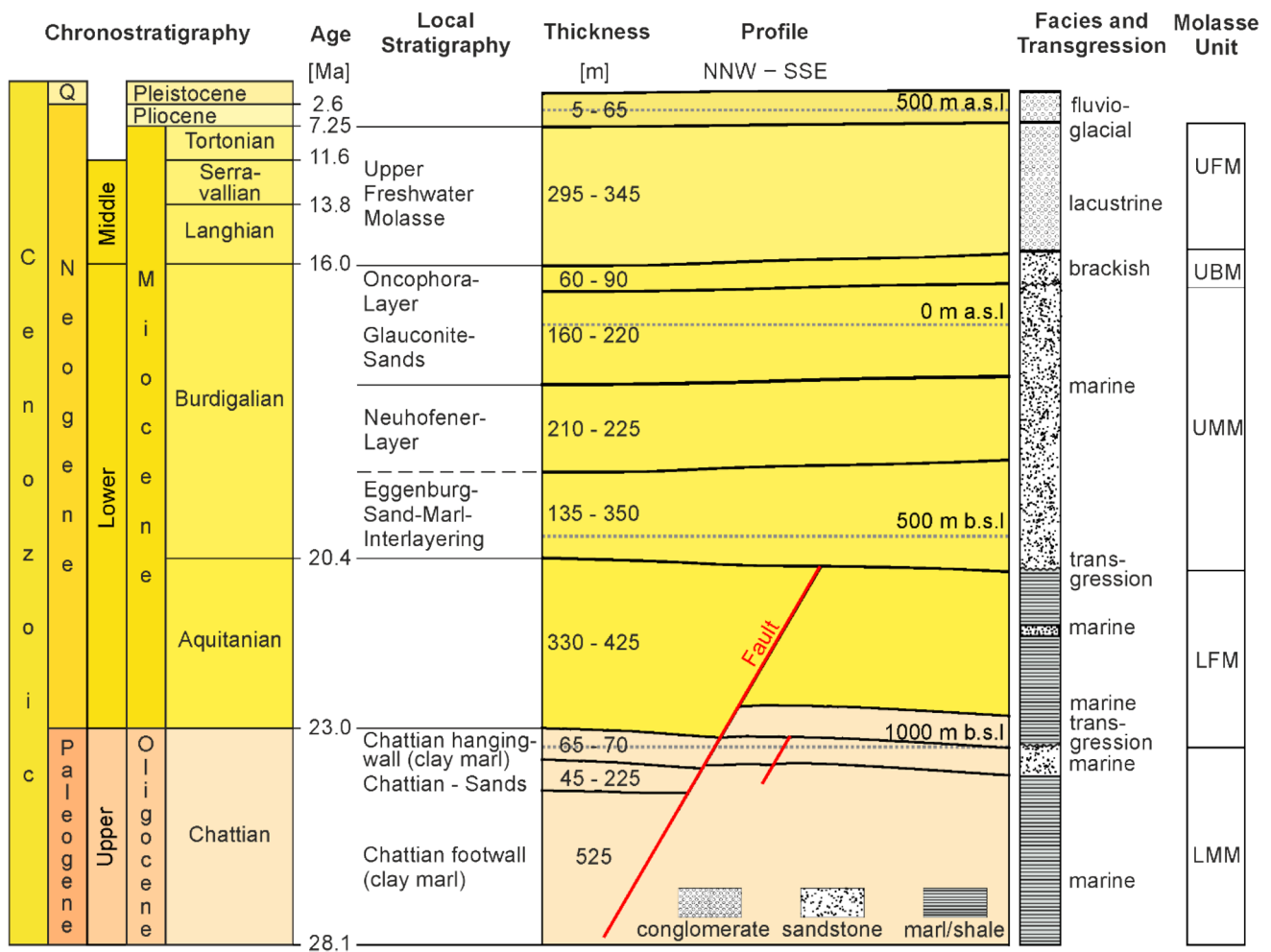


Fig. 2 Chronostratigraphic and lithological units in the study area along with a NNW-SSE profile indicated in Fig. 1, perpendicular to the main fault (red line) through the center of the three-way-dip

closure structure. Coloring and classification is based on Erhardt and Kraus (1975), Kuhleemann and Kempf (2002), DSK (2022)

The sedimentary evolution of the basin was controlled by both vertical deepening rates and lateral shortening rates, which influenced fault formation and activity. Most faults trend ENE–WSW or SW–NE, while the major alpine thrust fault is E–W, parallel to the Alps in the Molasse Basin (Seithel et al. 2019; Eskens et al. 2024). As a result of varying subsidence and shortening of the basin, the heave and throw of the faults are changing during different stages of formation of the Bavarian Molasse Basin. Generally, the fault offset increases from west to east. Fault activity in the Bavarian Molasse Basin was particularly pronounced during the Late Oligocene (Chattian) to early Lower Miocene (Aquitanian), when synsedimentary faulting and reactivation were widespread. Fault activity became negligible in late Lower Miocene (Burdigalian) sediments. Not all faults were active simultaneously, reflecting the episodic nature of deformation driven by sedimentary loading and tectonic forces (Eskens et al. 2024).

The field is developed within a structural trap (three-way dip closure) oriented SW–NE, and bounded by a parallel, 50–60° northwards dipping fault to the north (Erhardt and Kraus 1975), typically for Cenozoic reservoirs in this area. Reservoir formation in this region is primarily controlled by variations in subsidence rates and lateral compression within the Molasse Basin, which lead to flexural deformation and the development of basin-parallel synthetic and antithetic fault systems. Among these, north-dipping antithetic normal faults serve as the main structural traps for hydrocarbon accumulation (Bachmann et al. 1987; Bachmann and Koch 1983).

Data basis for stress analysis

The dataset comprises information from 70 boreholes. The majority of which target depths between 1000 and 1200 m b.s.l. (Fig. 3a). A substantial fraction of the data

was originally acquired in analog format during the 1970s and 1980s. These legacy logs have been subsequently scanned and digitized.

Borehole geometry is constrained using a combination of caliper and borehole imaging data. Microcaliper (MCal) measurements are available for 11 boreholes, unoriented four-arm caliper (FAC) data for 27 boreholes, oriented FAC data for 20 boreholes, and six-arm caliper (SAC) data for 8 boreholes. In addition, Formation MicroScanner (FMS) and Formation MicroImager (FMI) logs are available for three boreholes (Fig. 3). No caliper data are available for five boreholes. Only oriented measurements may provide information on S_{Hmax} orientation, limiting the analysis to 20 wells. As a consequence, the cumulative length of usable logging intervals is reduced from approximately 75–17 km.

Depth-dependent drilling mud density data are available for 61 of the 70 wells (Fig. 3b). FITs are available from four boreholes, and an XLOT was conducted in well W1 in the Aquitanian formation at 1484 m TVD, around 4 km SW of the main structural trap (Fig. 3a). Additionally, results from an unpublished report providing estimates of stress magnitudes derived using the RACOS[®] technique (see Appendix A1 for methodological details) are incorporated. These measurements have been performed on core samples from both the caprock (Aquitanian) and the reservoir (Chattian Sandstone) of a nearby depleted gas field. For both units, rock mechanical tests have been conducted. In the Aquitanian the angle of friction (ϕ) is 16° corresponding to a coefficient of friction (μ) of about 0.3. The unconfined uniaxial stress (UCS) therein is 23.6 MPa and the tensile strength (σ_t) is 2.8–3.2 MPa. The Young's Modulus (E) of Aquitanian is 30.6 GPa, whereas it is 45 GPa in the Chattian Sands. Porosity (ϕ) and permeability (k) was measured on 116 samples. Within the Aquitanian and Chattian marls the mean $\phi = 0.02$ (0.01–0.03) with $k = 1.6$ mD (0.1–6.0). The Chattian sands are characterized $\phi = 0.25$ (0.11–0.33) with $k = 604$ mD (16–2680).

Methods

The stress state is commonly described by the Cauchy stress tensor, a symmetric second-order tensor, with six independent components. Assuming an Andersonian state of stress, where the S_V is a principal stress (Anderson 1905) shear components can be neglected, and the stress state can be fully characterized by a reduced stress tensor (Angelier 1984) comprising the three principal stresses (S_V , S_{Hmax} and S_{hmin}), and the orientation of S_{Hmax} (e.g., Zoback 2007).

Stresses around boreholes and borehole wall failure for determination of S_{Hmax} orientation

In the vicinity of a borehole, stresses redistribute and are described in cylindrical coordinates with radial (rr) and tangential ($\theta\theta$) components. For a vertical borehole, the effective radial σ_{rr} and tangential $\sigma_{\theta\theta}$ stresses acting at the borehole wall can be calculated by Eq. 1 after Moos and Zoback (1990):

$$\begin{aligned}\sigma_{rr} &= \Delta P = P_m - P_0, \\ \sigma_{\theta\theta} &= S_{hmin} + S_{Hmax} - 2(S_{Hmax} - S_{hmin}) \cdot \cos 2\theta - \Delta P - 2P_0 + \sigma^{\Delta T},\end{aligned}\quad (1)$$

where P_m is the mud pressure, $\sigma^{\Delta T}$ is the thermal stress at the borehole wall, which is positive for heating and negative for cooling.

The most common and reliable indicators to determine stress orientations from boreholes is the analysis of BOs and drilling-induced tensile fractures (DITFs). The mechanism of BO formation is dependent on rock strength, depth of BO occurrence, and the state of stress (Plumb 1989). BOs can form by tensile spalling at the borehole or tunnel wall, as described e.g., by Hoek (1965), Lee and Haimson 1993, Diederichs (2003), Barton and Shen (2017), Hoek (2023), but at greater depth they are generally interpreted as a consequence of shear failure at the borehole wall (Bell and Gough 1982; Plumb and Hickman 1985). BOs lead to an elongation of the borehole cross section and are aligned with S_{hmin} . According to Zoback et al. (1985) and Barton et al. (1988) BO formation by shear failure requires that the tangential stress at edge of the BO θ_b to exceed the rock strength (e.g., unconfined compressive strength UCS). Therefore Eq. 1 can be rewritten to Eq. 2:

$$\begin{aligned}\sigma_{\theta\theta} &= (S_{Hmax} + S_{hmin} - 2P_0) - 2(S_{Hmax} - S_{hmin}) \\ &\quad \cos(2\theta_b) - P_m + P_0 + \sigma^{\Delta T} \geq \text{UCS}.\end{aligned}\quad (2)$$

DITFs form in direction of S_{Hmax} , perpendicular to S_{hmin} if σ_t is exceeded at the borehole wall (Eq. 3 based on Eq. 1):

$$\begin{aligned}\sigma_{\theta\theta} &= (S_{Hmax} + S_{hmin} - 2P_0) - 2(S_{Hmax} - S_{hmin})\cos(2\theta_b) \\ &\quad - P_m + P_0 + \sigma^{\Delta T} \leq \sigma_t.\end{aligned}\quad (3)$$

In inclined boreholes, the concept of the reduced stress tensor is violated because the borehole axis is no longer aligned with a principal stress direction. Consequently, stress orientation inferred from BOs and DITFs may be significantly rotated relative to the far-field orientation, depending on the Andersonian tectonic regime (Mastin 1988; Peška and Zoback 1995). Mastin (1988) showed that in strike-slip regimes, BO orientations are relatively insensitive to borehole deviation, remaining within $\sim 10^\circ$ of S_{Hmax} for borehole inclinations up to $\sim 30^\circ$. In contrast, in normal and thrust faulting regimes, subequal horizontal stresses can lead to

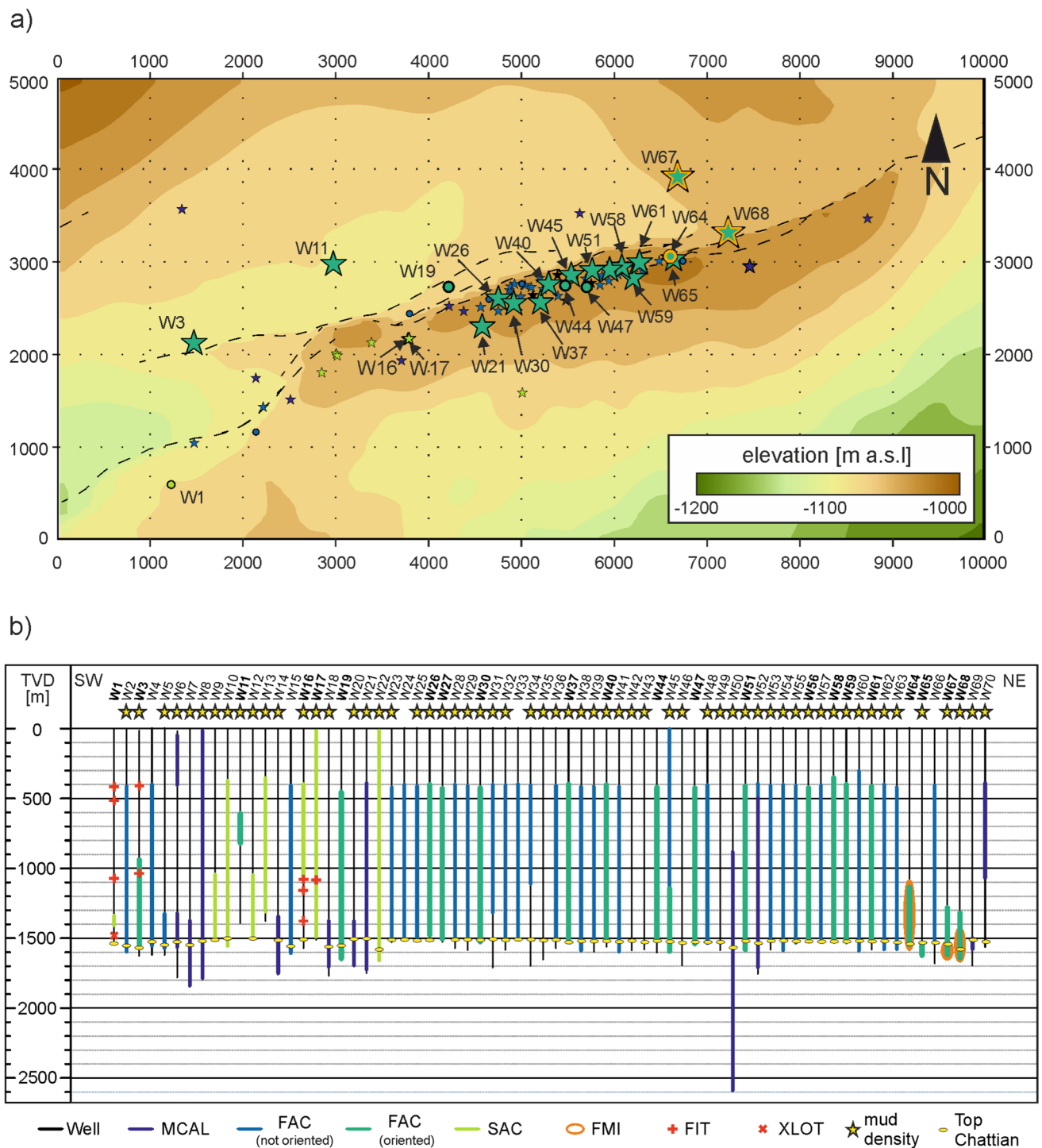


Fig. 3 **a** Overview map of the 70 analyzed boreholes. Stars indicate boreholes with available drilling mud density data, whereas circles denote boreholes lacking such information. Colors represent the type of logging performed. Boreholes used for S_{Hmax} orientation analysis is highlighted by larger symbols. **b** Overview of depth distribution of logging and testing. Black lines show the total depth. Logged bore-

hole sections are colored according to the performed logging type. FMI intervals are shown as orange ellipses, while yellow ellipses indicate the top of the Chattian. Red markers denote the locations of FIT/LOT measurements. Yellow stars mark wells for which drilling mud density data are available

substantial BO rotation even for borehole deviations of less than $\sim 10^\circ$.

BOs can exhibit quite wide openings, locally exceeding 90° , as observed in Tyrnyauz well (Hickman 2015). In contrast, DITFs are narrow, discrete tensional cracks and can only be resolved with high-azimuthal-resolution imaging tools like FMS and FMI. BOs can be captured with mechanical caliper tools (FAC, SAC).

Most data in this study originate from FAC tools. To analyze these data, we developed a custom software solution in MATLAB® (FAC-Tool V1.0) (Niederhuber 2025) and Python (Niederhuber 2026a). In contrast to previous versions or other available software, this software enables the detection and correction of digitalization-related errors, allowing a reliable identification and analysis of BOs. The software requires several input parameters and thresholds, including Bit-size, SCD-range (Difference of smaller Caliper to Bitsize), caliper difference limit (minimum difference between the smaller and larger Caliper), RB (relative bearing) limit, key seat deviation limit (difference to borehole azimuth) and maximum deviation (DEVI). Based on these parameters, the caliper data are automatically preprocessed, and depth intervals containing potential BOs are suggested to the user, which then can be manually picked (more details on the workflow in Appendix A2). While SAC data need to be centralized before they can be analyzed (e.g., with SAC Tool; Niederhuber 2026b) the centralization of FAC is not required due to the caliper sonde where the tool is automatically centralized by the configuration of two dependent caliper arms opposite each other. However, the Pad1 Azimuth ($P1Az$) must be corrected for wells with high inclination (Fuchs and Clauss 1988). Without correction, azimuths rotate systematically toward hole azimuth ($HAZI$).

$$P1Az = HAZI + \arctan \frac{\tan(RB)}{\cos(DEVI)}. \quad (4)$$

Criteria for identifying BOs from FAC data were originally introduced by Plumb and Hickman (1985) and have since been further refined. A comprehensive overview is given in Reinecker et al. (2003). Once picked, BO data (depth, length, azimuth, opening angle) are stored in a database and can be analyzed in two methods (e.g., with SFRV, Niederhuber 2026c):

- Length-weighted: here the data is normalized by the cumulative BO length
- Number weighted: here the data is normalized by the cumulative BO number

For both approaches, mean BO azimuth and standard deviations are calculated using the circular statistics of Mardia (1972). The implementation follows the workflow

suggested in the World Stress Map, treating values between 180° and 360° as equivalent to 0° – 180° (Reinecker et al. 2003).

In this study, we use length-weighted BO azimuths. Length weighting reduces sampling bias by accounting for the proportional contribution of individual BOs along the borehole, whereas number weighting treats short and long BOs equally. The latter may bias stress orientations when numerous short BOs contribute little to the overall borehole coverage.

Where BO length information is available, length-weighting therefore provides a more representative estimate of the stress-induced azimuth. The software-processing input parameters follow the recommendations of the WSM (Reinecker et al. 2003). The caliper difference limit is set to 10% and the key-seat deviation limit to 5° , and the maximum deviation threshold to 30° . To account for orientation uncertainties associated with high borehole inclination and the breakdown of the reduced stress–tensor assumption, the data are further corrected according to the prevailing Andersonian stress regime, using critical inclinations given by Mastin (1988). In normal- and thrust faulting, all data with an inclination $> 10^\circ$ must be excluded. For strike-slip regime, additional standard deviation of 10° must be considered when the analyzed borehole section is inclined with more than 10° but less than 30° . All sections with an inclination $> 30^\circ$ are excluded by the deviation limit.

Depth-dependent BO analyses, including feature counts per depth and depth dependent S_{Hmax} orientations, are performed with *SPUDS* (Niederhuber 2026d). Thereby a moving window counts and averages the observed BO orientations using the statistics of Mardia (1972). The corresponding average BO opening width is determined with *SFBO* (Niederhuber 2026e).

Determination of stress magnitudes

S_V is usually obtained by integrating density data. However, due to the lack of density logs, we estimate S_V based on an empirical model for the Eastern Molasse Basin by Obermeier et al. (2025). The magnitude of minimum principal stress (S_3) is constrained by FITs and one XLOT. During a FIT a borehole interval is pressurized toward the expected S_{hmin} . However, FITs are intentionally conducted below the threshold of fracture initiation. Consequently, they provide only an upper limit of S_3 (Zoback et al. 2003). In contrast, XLOT are designed to generate new fractures. For reliable interpretations on the regional state of stress, the test must remain unaffected by operational pressure and associated stress changes, which can significantly alter the regional stress state (e.g., Altmann et al. 2010; Niederhuber et al. 2019). The XLOT analyzed in this study can be assumed to be unaffected by such perturbations because of its lateral of

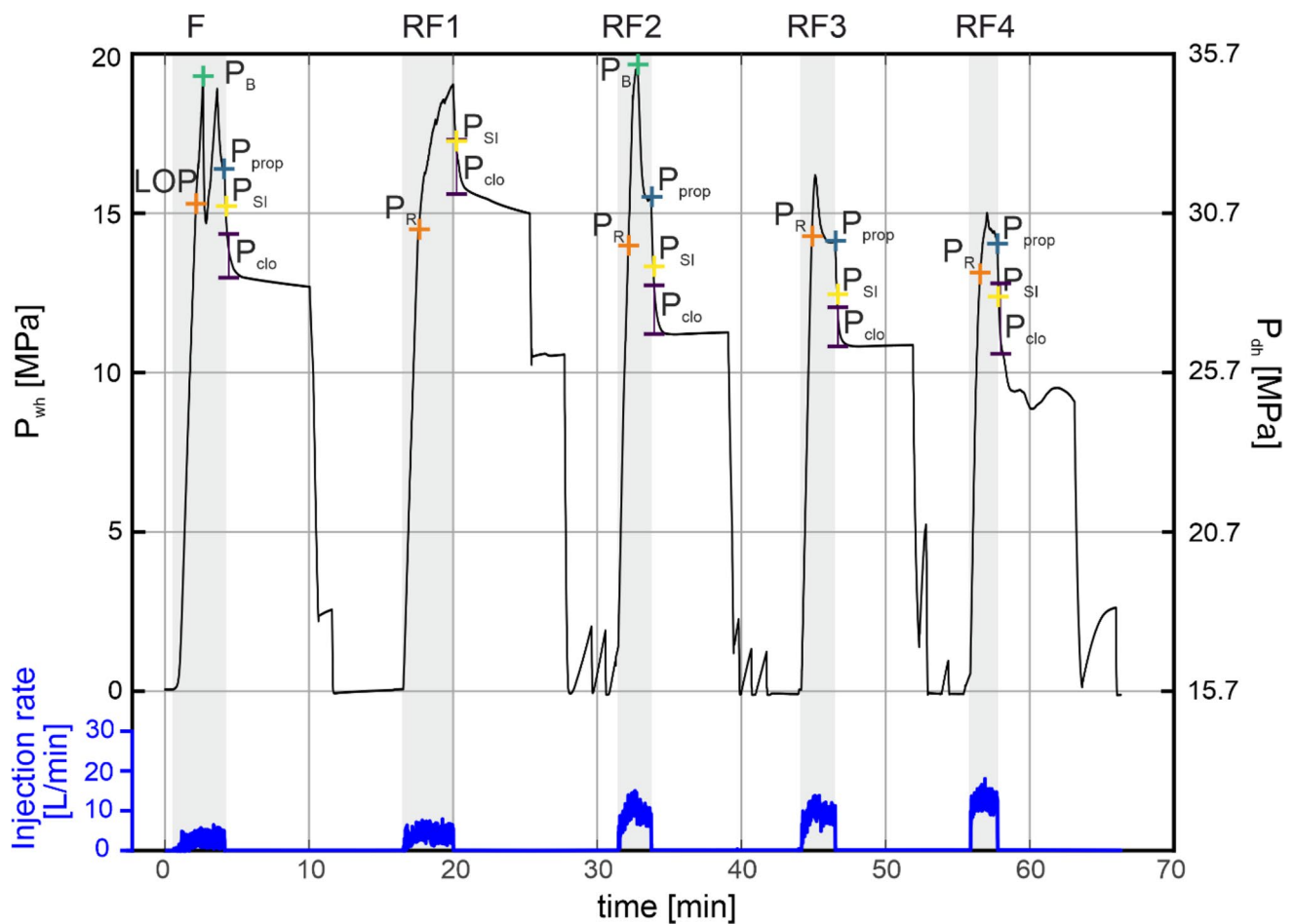


Fig. 4 Extended leak-off test conducted in the Aquitanian Formation at 1484 m TVD, comprising one frac (F) and four re-frac (RF) cycles. Injection periods are highlighted by gray shading, and the injection rate is given by the blue curve. Pressure data are shown as measured wellhead pressure P_{wh} (left y-axis) and the calculated downhole pres-

sure P_{dh} derived from Eq. 5 (right y-axis). LOP is the leak-off pressure, P_B is the breakdown pressure, P_R is the refract pressure, P_{SI} is the shut-in pressure; P_{prop} is the fracture propagation pressure, P_{clo} is the fracture closure pressure

approx. 4 km distance to the main structure (Fig. 3a). The maximum principal stress magnitude (S_1) is derived from a fracture-mechanical model after Hubbert and Willis (1957) for fracture initiation during hydraulic testing.

During the test, a 2 m interval was isolated by packers within a 5-inch borehole section. The borehole in this interval has an azimuth of N206°E and an inclination of 25°. The test was conducted using KCL-Chalk drilling mud with a density of 1080 kg/m³. It includes an initial frac cycle followed by four re-frac cycles (Fig. 4). During each cycle, the injection rate and wellhead pressure were recorded.

The wellhead pressure P_{wh} recordings are affected by viscous friction loss and system stiffness or system compliance. The latter represents how compressible the wellbore-fracture system is. It consists of both wellbore compliance and fracture compliance (Wang and Sharma 2020). The borehole compliance is dominated by the fluid compressibility, with additional contributions from the cased and open parts of the

borehole, which both in most cases can be neglected. The fracture compliance depends on the length of the fracture (Raaen et al. 2006) and is small for short fractures. For small fractures, the actual downhole pressure P_{dh} deviates from P_{wh} by P_m and the friction loss (ΔP_f) between the pumped fluid and the borehole wall (Eq. 4). Observations from Basel 1 well using high flow rates and large volumes at 4.6 km indicate a difference between 0.25 and 0.36 MPa.

$$P_{dh} = P_{wh} + P_m - \Delta P_f. \quad (5)$$

Frictional pressure losses mainly depend on the pipe length, pipe diameter, the fluid viscosity and density as well that govern the flow regime that can be expressed by the Reynolds Number. It can be calculated using the Darcy–Weisbach equation in combination with Hagen–Poiseuille equation for laminar flow ($Re < 2000$) and Swamee–Jain equation for turbulent flow ($Re \geq 4000$).

From the pressure recording during the test cycles the breakdown pressure (P_B), fracture reopening pressure (P_R), shut in pressure (P_{SI}) and fracture closure pressure (P_{clo}) are determined. P_{SI} is identified as the transition point from a rapid, linear pressure decline (immediately following shut-in) to the onset of a diffusion-dominated gradual pressure decrease. The exact transition point was determined by fitting a tangent to the linear pressure decline in a detailed P versus t plot. Hickman and Zoback (1983) and Addis et al. (1998) demonstrate that the magnitude of P_{SI} stabilizes with the number of frac cycles. The fracture closure pressure $P_{clo,T}$ is determined from the decline part of each cycle, where the decline of P deviates from the linear relationship of $\sqrt{t - t_0}$. Here t is the time of the test and t_0 the time of the shut-in of each cycle (Nolte and Economides 1989). While this method is known to overestimate the magnitude of P_{clo} , it is also determined using the G-function as described e.g., in Nolte (1979). The G-function is a specialized time function that linearizes pressure decline during shut-in, allowing fracture closure behavior to be identified independent of pumping history (Nolte 1979). Fracture closure is identified as the point where the pressure vs G-function plot departs from its initial linear trend ($P_{clo,G}$), reflecting a transition from Carter leak-off-controlled behavior to increased system stiffness (Nolte 1979). The very early time after shut-in should not be considered as it is often characterized by a sharp pressure drop, which can be related to the loss of friction within and in the vicinity of the borehole (McClure et al. 2016). In practice, this is equivalently picked at the inflection or peak in the G-function derivative (dP/dG), which marks the loss of fracture compliance and provides a more robust diagnostic than pressure–time methods (Barree et al. 2009). However, especially in low permeable rocks, it is recommended to use the fracture compliance method (McClure et al. 2014, 2016), which instead pick the initial deviation from linearity from the pressure vs G plot ($P_{clo,FC}$). If pressure estimates obtained from methods with different sensitivities to compliance effects are essentially identical, this suggests that compliance-related effects are not strongly influencing the interpreted pressures.

P_R is determined from pressure versus volume plots. Hickman and Zoback (1983) recommend using the third cycle. Until the opening of a fracture the increase in volume V is linear with pressure P . P_R is the pressure where the pressure increase deviates from linearity, similar to the leak-off test pressure in the frac cycle. In some tests, the stiffness (dP/dV) during the pressurization of the test interval was used as the stiffness trend also deviates from linearity when a fracture is opened. Increasing number of cycles and thus increasing injected fluid volume can lead

to poroelastic effects causing a progressive increase in P_R and P_{SI} (Addis et al. 1998).

Based on the pressure parameters from the XLOT S_{hmin} can be estimated. However, there is an ongoing debate regarding the most reliable proxy for S_3 , which represents S_{hmin} in normal- and strike-slip regimes. Addis et al. (1998), Gronseth and Kry (1982), Haimson and Cornet (2003), or Schmitt et al. (2012) indicate that P_{SI} is the best estimate for S_3 , particularly under conditions of low fluid viscosity and limited fracture propagation (Haimson and Fairhurst 1967; Fjaer 2008). In contrast, Economides and Nolte (2000), Zoback (2007) or Fjaer (2008) indicate, that in some cases also P_{clo} can be the most robust estimate of S_3 , particularly when a fracture is generated over the entire thickness of the gross pay interval, which requires high injection rates and large volume. Both values can vary significantly and can therefore largely influence the interpretation on the stress state and stability considerations (e.g., Bröker and Ma 2022). Schmitt and Haimson (2017) indicated that the value that best represents S_{hmin} is strongly controlled by rock permeability. For low rates and volumes, fracture dimensions are expected to be limited, and P_{clo} may not be fully representative of far-field stress conditions. Consequently, P_{SI} is a first-order approximation of S_3 (Economides and Nolte 2000).

To account for methodological uncertainty, S_{hmin} is defined as a range rather than a single value (Desroches and Kurkjian 1999). The lower and upper bounds are derived from the minimum and maximum values of P_{SI} and P_{clo} , respectively. To assess the internal consistency of the dataset, a reconciliation plot following Desroches and Kurkjian (1999) is employed. This approach is particularly relevant as the test interval is inclined with respect to the principal stress axes. However, if P_{clo} stabilizes after a few cycles and if the boreholes deviate less than $\sim 30^\circ$ from a principal stress direction, P_{clo} can still provide a reasonable estimate of the far-field stress magnitude (Desroches and Kurkjian 1999).

The determination of the S_{Hmax} is based on the classical approach by Hubbert and Willis (1957), where we account for the best fit S_{hmin} as well as the uncertainty derived from the reconciliation plot. Using the approach of Bredehoeft et al. (1976) the tensile strength σ_t of the rock can be expressed by $\sigma_t = P_B - P_R$. The Hubbert and Willis (1957) equation can be rewritten as:

$$S_{Hmax} = 3S_{hmin} - P_0 - P_R. \quad (9)$$

For the calculation of S_{Hmax} , P_0 is a crucial parameter, which can even change the determined stress regime if assigned wrong (Niederhuber et al. 2025a). As the pore pressure was not measured before the test, indirect methods are used to constrain the pore pressure. The Bavarian Molasse Basin contains overpressured regions, with overpressure reported from approximately 1500 m depth

Table 1 Summary of BO statistics by well, including cumulative breakout length, number of BO sections, maximum borehole deviation, length-weighted mean S_{Hmax} azimuth, circular standard deviation, and modified World Stress Map (WSM) quality classification

Well ID	length BO [m]	Number BO	Max. deviation [°]	S_{Hmax} —azi [°]	Std [°]	Quality
W3	290.6	53	24.0	64.5	30.7*	(C) D
W11	39.4	3	0.9	91.4	18.9	D
W26	490.8	26	28.0	151.9	28.7*	(B) D
W37	694.0	36	19.0	36.5	32.3*	(C) D
W45	59.6	21	17.2	90.4	30.0*	(C) D
W58	54.5	26	11.4	3.1	38.7*	D
W59	69.4	14	0.9	178.5	13.3	C
W68	102.0	13	28.8	171.8	14.7*	B
W67	83.9	12	20.9	158.5	14.0*	C

Mean S_{Hmax} orientations account for uncertainty associated with borehole deviation following the approach of Mastin (1988) described in the Methods section. Asterisks (*) indicate wells for which the deviation correction contributes substantially to the reported orientation uncertainty

(Dreux et al. 2018), close to the XLOT depth. Because P_m must exceed P_0 for safe drilling conditions, P_m can be used as an upper limit for the pore pressure, while a hydrostatic pore pressure P_{hydr} provide a lower bound.

In addition, S_{Hmax} is constrained by the frictional limit approach for critically stressed, optimally oriented faults. The ratio of the effective maximum σ_1' to the effective minimum stress σ_3' is a function of the coefficient of friction μ (e.g., Jaeger and Cook 1979; Townend and Zoback 2000; Zoback and Healy 1984). Thus, if either S_1 or S_3 is known, the other principal stress can be derived from Eq. 7:

$$\frac{\sigma_1'}{\sigma_3'} = \frac{S_1 - P_p}{S_3 - P_p} \leq [(\mu^2 + 1)^{\frac{1}{2}} + \mu]^2. \quad (7)$$

Furthermore S_{Hmax} can be derived by inversion of BO opening width under the assumption that BOs form by compressive shear failure of the borehole wall rather than tensile spalling. Following e.g., Zoback et al. (1985) or Barton et al. (1988), BO opening width is related to the stress concentration around the borehole and can therefore be used to estimate S_{Hmax} . Using the geometric relation $2\theta_b = \pi - w_{BO}$, Eq. (2) can be rewritten as

$$S_{Hmax} = \frac{(UCS + P_0 + P_m) - S_{hmin} \cdot (1 + 2 \cdot \cos(\pi - w_{BO}))}{1 - 2 \cdot \cos(\pi - w_{BO})}. \quad (8)$$

The inversion combines BO geometry with UCS, P_p , P_m , and S_{hmin} magnitudes. Uncertainties in these parameters are propagated using Monte Carlo simulations, resulting in a probabilistic estimate of S_{Hmax} and associated uncertainty bounds at each depth. The analysis is carried out with the software *SFBO—Stress Profiles From BO Opening Width* (Niederhuber 2026e), which generates depth-dependent S_{Hmax} profile and associated uncertainty bounds.

Results

Breakout analysis and stress orientation

We observe BOs in 19 of the 20 wells with oriented four-arm caliper (FAC) logs. Only well W65 does not exhibit identifiable BO intervals. Of the 19 wells, nine yield an overall modified WSM quality rating between B and D (Table 1). A complete list with all qualities and for all wells and separated by units is given in Appendix A3.

Within the Burdigalian succession, comprising the Oncophora Layer, Glauconite Sands, Neuhofener Layer, and Eggenburgian units, we identify 213 BO sections with a cumulative length of 2395 m, representing approximately 31% of the logged interval. The mean S_{Hmax} orientation is $N005^\circ \pm 59^\circ$. Even though the average points to the regional far-field orientation, the Burdigalian exhibits substantial variability in S_{Hmax} orientation both within and between wells. However, individual units of the Burdigalian achieve moderate to good qualities. Even if borehole deviation is considered, quality B is observed in two wells, and quality C is observed in seven wells (Table 1), whereas the combined Burdigalian dataset exhibits considerable scatter and only well W59 shows a modified quality C.

Within the Aquitanian, we identify 389 BO sections with a cumulative BO length of 2143 m, representing approximately 35% of the logged interval. The mean S_{Hmax} orientation is $N175^\circ \pm 46^\circ$. The Aquitanian generally yields higher modified WSM quality classes (four of quality B and five of quality C) than the Burdigalian. Nevertheless, significant variability between wells remains present. Particularly observed in wells W3, W45, and W51, where stress orientations nearly perpendicular to the far field orientation are observed.

Within the Chattian, we identify 32 BOs with a cumulative length of 184 m, representing approximately 31% of the logged interval. The mean S_{Hmax} orientation is $N088^\circ \pm 82^\circ$.

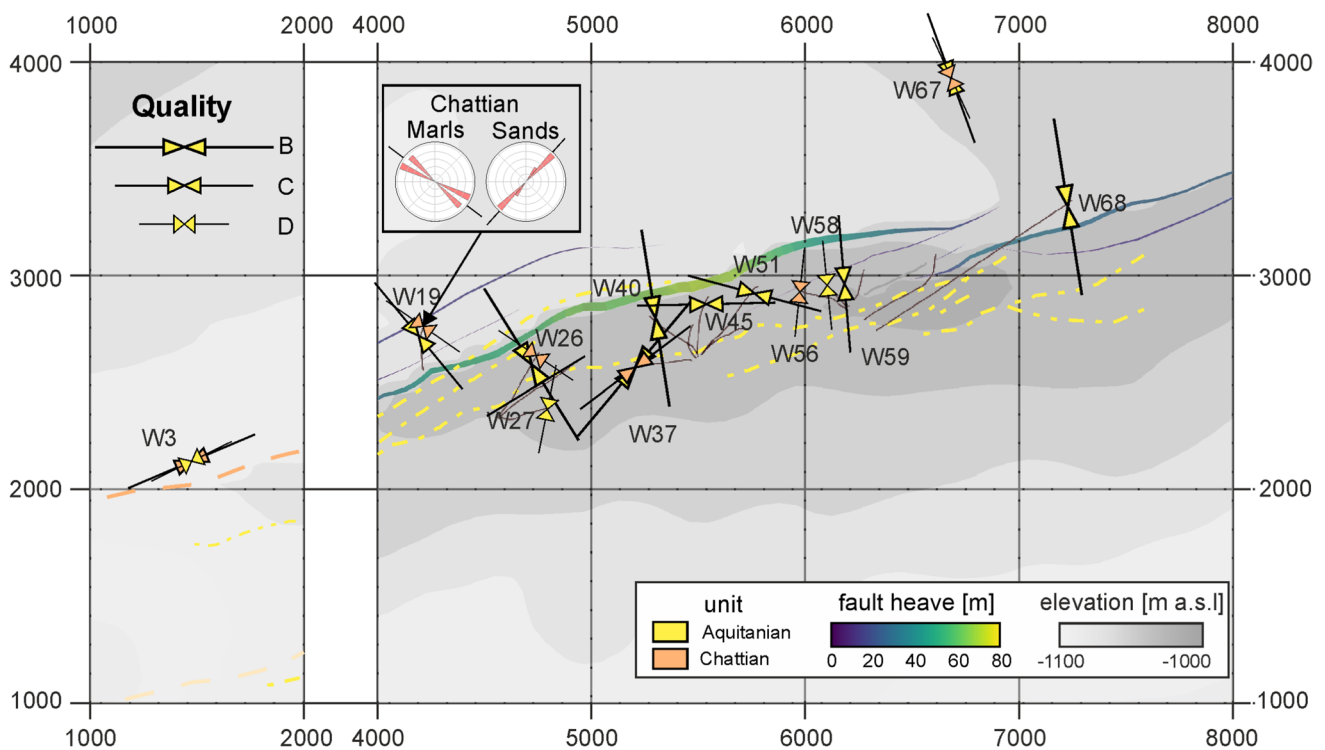


Fig. 5 Depth-projected S_{Hmax} orientations within the local coordinate system of the three-way-dip closure. The plotted wells are grouped by modified WSM quality, where symbol size shows the quality. Col-

oring indicates Aquitainian (yellow) and Chattian (orange) intervals. The main fault is color-coded by the heave ranging up to 80 m

Only wells W3 and W37 achieve a modified WSM quality ranking of C. Approximately 95% of the cumulative BO length occurs within the Chattian Marls, where BO affect 38% of the analyzed gross interval. In contrast, only 12 BO intervals, with a cumulative length of 20 m, were identified within the Chattian Sands, corresponding to approximately 9% of the gross thickness. Notably, the S_{Hmax} orientation within the sands is N016°E, which is a rotation of 85° counterclockwise compared to the Marls (Fig. 5).

Pore pressure and stress magnitudes

Pore pressure and mud pressure

No direct measurements on the undisturbed pore pressure are available for the study area. Therefore, two end-member scenarios are considered. The lower-bound scenario assumes hydrostatic conditions ($P_0 = P_{hydr}$), whereas the upper-bound scenario assumes pore pressure equal to the lowest drilling mud pressure ($P_0 = P_m$). To constrain the latter, depth-dependent drilling mud densities from 61 wells are evaluated (Fig. 6). Within the Aquitainian, where the XLOT was performed, drilling mud densities range from 1050 to 1260 kg/m³, with a mean value of 1130 kg/m³. At the XLOT depth, the minimum observed mud density corresponds to

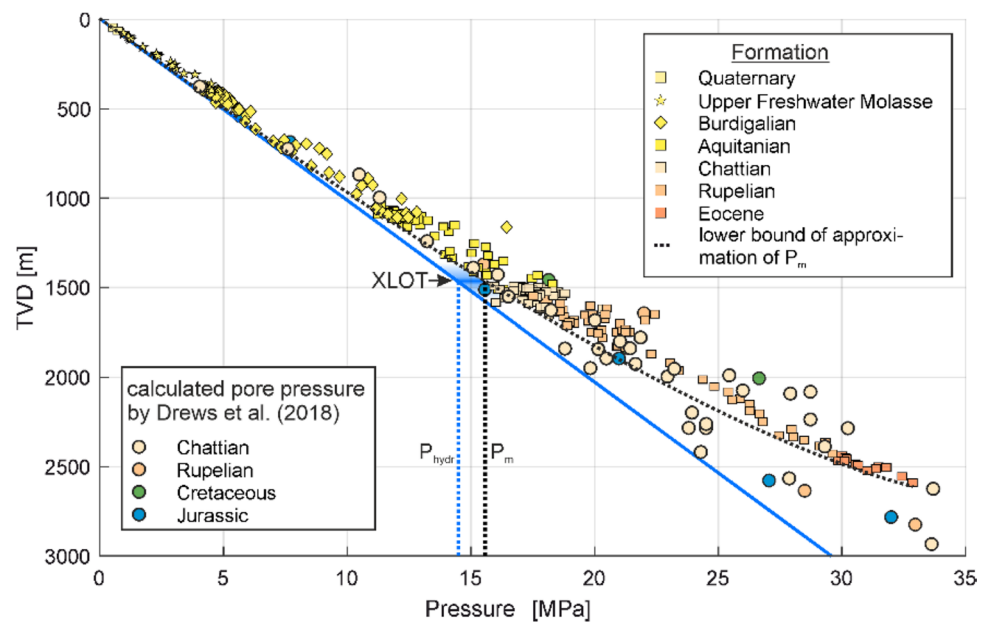
the mud pressure of $P_m = 15.7$ MPa, whereas hydrostatic conditions result in a pore pressure of $P_{hydr} = 14.6$ MPa (Fig. 6).

Implications for S_{hmin} and S_{Hmax} from XLOT test

The basis of the stress analysis is an XLOT at a depth of 1484 m TVD (Fig. 4), conducted with a fluid density of 1080 kg/m³. Therefore, an P_m of 15.7 MPa is added to the wellhead pressure readings (Eq. 4). The viscous friction loss (Appendix A4) was found to be in the order of $\Delta P_f = 0.001$ – 0.004 MPa and is neglected in subsequent analysis. The initial frac cycle does not show a clear characteristic pressure response and is therefore not used to define the stable refracturing pressures.

For the first-order approximation of the stress state, we determine P_R from RF3 at 30.1 MPa, in line with the recommendation by Hickman and Zoback (1983). P_{SI} is determined from RF3 and RF4 showing a constant value of 28.2 MPa. Because of the low rates of 18 l/min, small fluid volumes of in total less than 285 L (51.9–62.5 L each cycle), and low fluid viscosity used in the XLOT test, P_{SI} is used as a first-order approximation of S_{hmin} . The results can be treated reliably as the deviation between borehole orientation (206°) and the regional stress orientation (~N008°E)

Fig. 6 Mud densities used during drilling at the study area. Colors show the stratigraphic unit according to Fig. 2. For Neogene rock units, different markers were used for better visualization. In addition, the calculated pore pressures by Drews et al. (2018) were added as well as the pore pressures at the depth of the XLOT



is approximately 20° and P_{clo} stabilizes with fluctuations less than 4% from RF2–RF4 as required by Desroches and Kurkjian (1999). P_B was recorded at 35.1 MPa (35.5 MPa in RF2) and $P_{clo,T}$ at 26.7 MPa (more details in Appendix A5).

We calculate the S_{Hmax} magnitude of 39.9 MPa using Eq. 6 as proposed by Bredehoeft et al. (1976). Using Eq. 7 with $\mu = 0.3$ we derive a S_{Hmax} magnitude of 37.5 MPa. S_V at the test depth is 33.7 MPa based on the model introduced by Obermeier et al (2025), placing the stress regime formally within a strike-slip faulting domain (i.e., $S_{Hmax} > S_V > S_{hmin}$).

To account for uncertainty, we define upper and lower bounds based on a reconciliation plot (Fig. 7), using $P_{SI} = 29.1$ MPa from RF2 as the upper limit and $P_{clo,G} = 26.6$ MPa from RF3 as the lower limit. To calculate S_{Hmax} range (Eq. 6), we constrain P_R to 29.3–30.1 MPa based on RF2–RF4 and combine this range with uncertainties in S_{hmin} and pore pressure. We obtained an S_{Hmax} range of 34.1–42.9 MPa. The lower bound for S_{Hmax} is derived with the assuming $P_0 = P_m$ and the upper bound by assuming $P_0 = P_{hydr}$. Using the same limits for the frictional limit approach, we obtained an S_{Hmax} range of 35.2–38.7 MPa based on Eq. 6. Despite these uncertainties and the presence of pore pressure uncertainty, we classify the stress regime as strike-slip. However, the lower-bound estimate of S_{Hmax} approaches S_V , placing the stress state close to the transition to a normal-faulting regime.

Stress profile of S_{Hmax}

The S_{Hmax} profile analysis is conducted exclusively for the Aquitanian interval because an independent stress magnitude constraint from one XLOT is only available within this

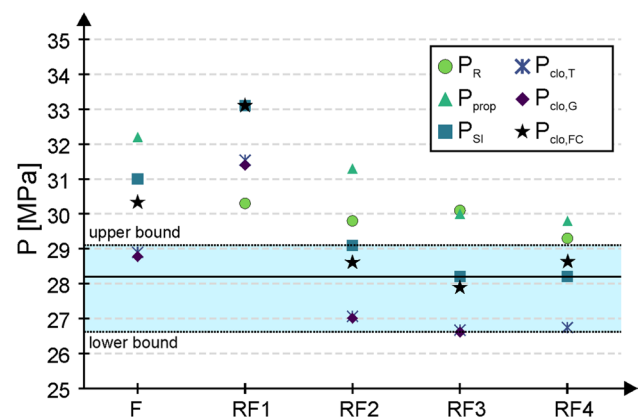


Fig. 7 Reconciliation plot of XLOT pressure indicators from the initial frac and re-frac cycles. The stable RF2–RF4 cycles show the pressure range used to constrain S_{hmin} and P_R ; the shaded region illustrates the adopted lower and upper bounds for the uncertainty analysis

unit. The three FITs performed in the Aquitanian support a linear S_{hmin} gradient within the unit. The uncertainty range of the S_{hmin} is derived from the reconciliation plot (Fig. 7). Because no direct pore pressure measurements are available, P_0 is allowed to vary between a hydrostatic lower bound and an upper bound defined by the P_m . Mud pressures are calculated from drilling mud densities ranging from 1050 to 1260 kg/m³ (Fig. 6), and the resulting P_0 and P_m gradients are propagated through the analysis as uncertainty bounds. The UCS profile is adopted from Zain-Ul-Abidin and Henk (2020). Because their study area is located farther south, where the reservoir occurs at slightly greater burial depth, the published UCS profile is adjusted to the present study area using lithostratigraphic tops as correlation markers.

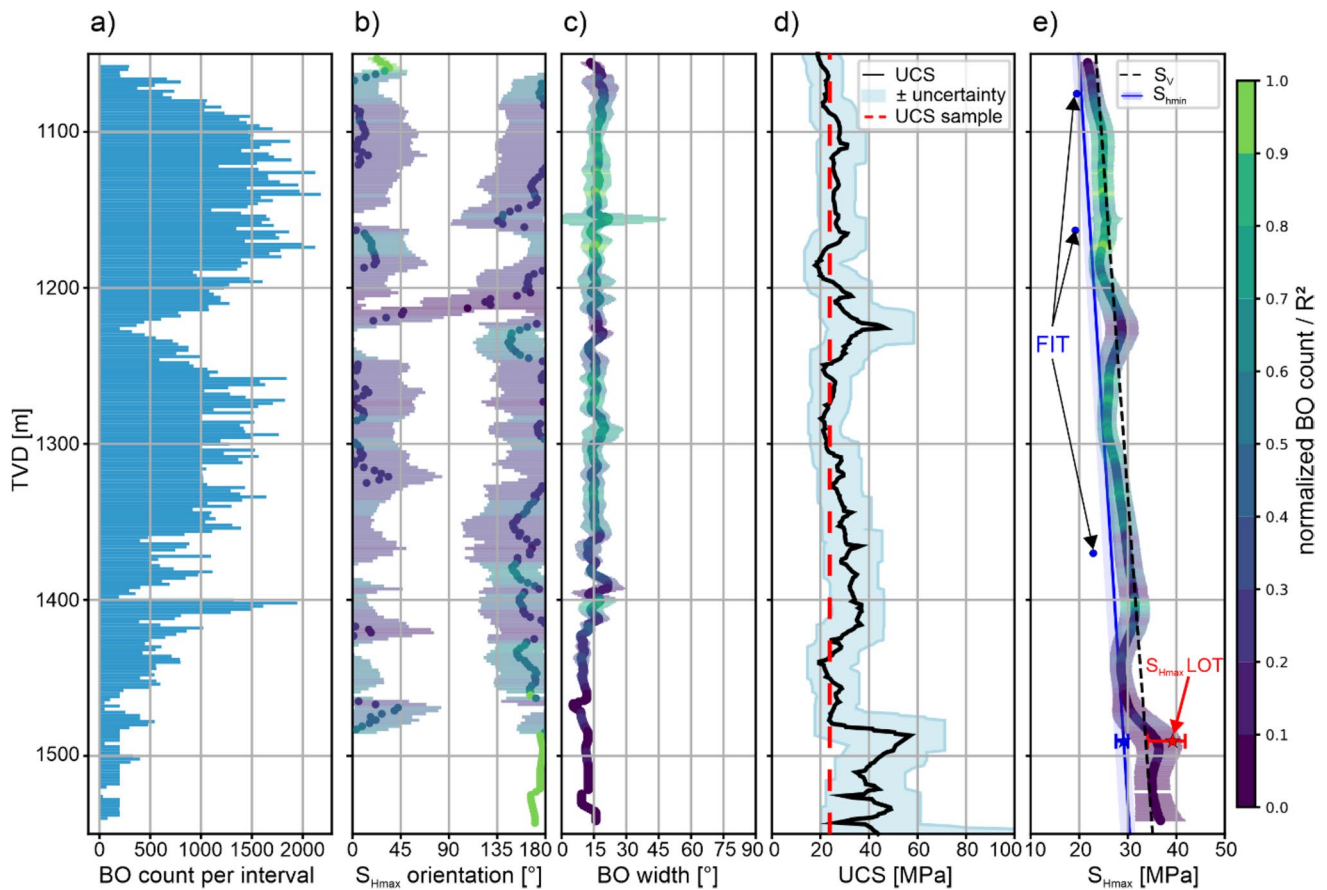


Fig. 8 Depth-dependent S_{Hmax} and BO analysis of the Aquitanian interval: **a** BO count per interval; **b** mean S_{Hmax} orientation; **c** BO opening width; **d** UCS profile with the Aquitanian sample values; and

e calculated S_{Hmax} magnitudes from BO-width inversion, including the XLOT and FIT constraints and associated uncertainties

Based on this correlation, the UCS profile from Zain-Ul-Abedin and Henk (2020) is shifted slightly upward prior to the stress magnitude calculations.

The BO depth distribution (Fig. 8a) is characterized by three distinct intervals of elevated BO abundance. The first occurs approximately 50–150 m below the top Aquitanian. BO occurrence then decreases markedly before increasing again within a second interval approximately 200 m below top Aquitanian. A third, peak in BO abundance is observed at approximately 350 m below the top Aquitanian. Toward the Aquitanian–Chattian boundary, BOs become increasingly sparse. The S_{Hmax} orientations derived from BOs indicate a generally NNW–NNE trend but exhibit considerable scatter (Fig. 8b). Orientation variability is highest in the upper part of the unit and gradually decreases with depth. In the deeper sections, S_{Hmax} becomes more consistently oriented approximately N–S, although these intervals are supported by a smaller number of BO observations and therefore provide a less robust statistical constraint than the shallower intervals. Despite these variations in BO abundance and orientations, BO opening width remains relatively uniform with depth,

averaging approximately 15° , and exhibits only a weak linear decrease downward (Fig. 8c). The UCS profile shows little variation and remains close to 23.6 MPa (Fig. 8d), consistent with the UCS measured on core samples in this study. Elevated UCS values are observed between approximately 1200 and 1250 m depth and below 1480 m depth. These intervals coincide with the highest calculated S_{Hmax} magnitudes. On average, S_{Hmax} exceeds S_v within these zones, indicating a strike-slip stress regime. Most other depth intervals indicate S_{Hmax} and S_v are of similar magnitude. Locally, S_v exceeds S_{Hmax} , suggesting normal-faulting stress conditions. Overall, the calculated stress magnitudes indicate relatively low differential stresses throughout the Aquitanian (Fig. 8e).

Discussion

The stress-orientation analysis is based on a dataset that includes numerous inclined boreholes, some with borehole deviations exceeding 30° . Mastin (1988) has shown that BO orientations in deviated wells can be sensitive to the

prevailing stress regime; however, in strike-slip settings, S_{Hmax} orientations inferred from BOs have remained comparatively robust, with uncertainties typically below $\sim 10^\circ$ for borehole inclinations up to 30° . Our results indicate a high likelihood of a strike-slip stress regime at ~ 1500 m depth (approximately the depth of the XLOT).

Our study highlights the importance of considering S_{Hmax} orientations on a unit-by-unit basis. When geological units are analyzed separately, as commonly done in previous studies (e.g., Schnaitsee C7 in Reinecker and Müller 2007; Reinecker et al. 2010; Heidbach et al. 2025; or MK-6, D-4 k, and D-1 in Jarosiński et al. 2024), stress orientations often achieve good WSM quality rankings (A–C), suggesting that they reflect the regional far-field stress regime. In contrast, analyzing an entire well as a single dataset can obscure these relationships. This is particularly evident in wells W19 and W40 (Appendix A3), where individual units yield B-quality, such as Burdigalian (N082°E) and Aquitanian (N171°E) in Well W40, yet the combined dataset returns an E-quality ranking. This demonstrates that significant stress variations between stratigraphic units may be masked when unit-specific analyses are not performed.

Controls on S_{Hmax} orientations from borehole breakouts

BOs are commonly observed in the Burdigalian, Aquitanian, and Chattian intervals, as also evident in Sauerlach (Seithel et al. 2015). The overall S_{Hmax} orientation of N178°E is consistent with the regional stress field and likely reflects the far-field tectonic stress orientation. However, substantial variability is observed within and between stratigraphic units as well as between individual wells, affecting BO orientations, frequency and width.

Within the Burdigalian succession (N005°E $\pm$ 59° 213 BOs, 2387 m BO length), S_{Hmax} orientation varies considerably between formations. The Oncophora Formation yields a mean orientation of N022°E $\pm$ 30°, based on eight BO intervals (28.5 m cumulative BO length) with an average BO opening angle of 15°. The Glauconite Horizon exhibits a mean orientation of N137°E $\pm$ 41°, derived from 72 BOs (725 m cumulative BO length) and an average opening angle of 20°. The Neuhoften Formation yields a mean orientation of N010°E $\pm$ 40° from 75 BOs (1134 m cumulative BO length) and exhibit the largest average BO opening angle (25°). The Eggenburgian interval yields a mean orientation of N068°E $\pm$ 38° based on 64 BOs (500 m cumulative BO length) with an average BO opening angle of 16°. These large rotations of S_{Hmax} orientation at relatively shallow depths of less than 1100 m, are consistent with observations from Schmidhausen A3, Inzenham-West 14, Höhenrain A5, and the uppermost section of Breitbrunn C10, Aitingen 4a, which are shallower

than 1000 m (Reinecker et al. 2010). Despite differences in mean orientation, all Burdigalian units display substantial scatter (± 30 – 41°), indicating pronounced local stress variability.

The comparatively large number of BO and high opening angles observed in the Neuhoften and Glauconite units may indicate higher stress concentrations and/or lower rock strength relative to the Oncophora and Eggenburgian intervals. Because major fault-related stress perturbations are restricted to the underlying Aquitanian and Chattian units, where faults are present, the variations between formations are interpreted as reflecting local geological and mechanical heterogeneities superimposed on an overall N–S-oriented regional stress field.

The Aquitanian interval yields a mean S_{Hmax} orientation of N175°E, based on 426 BO intervals with a cumulative length of 2329 m. Overall 40% of the Aquitanian logs exhibit BOs. Comparatively few BOs are observed within the Aquitanian sandstone, which is consistent with its higher rock strength and reduced susceptibility to BO formation compared to the surrounding marls (Hoek and Brown 1997). Also, a decreasing number is observed close to the transition to the Chattian (Figs. 8, 10), which reflects the findings of Seithel et al. (2019). Although the average value suggests that the N–S far-field stress field remains the dominant control, the large standard deviation ($\pm 46^\circ$) reveals significant local stress perturbations. These are particularly pronounced in wells W3, W45, and W51, where S_{Hmax} orientations locally deviated by almost 90° from the regional trend (Fig. 6). Besides the shallow well (< 1000 m), such rotations are also known from Illmensee 5 and 8, Mönchsrot 26, Tacherting 1b, Schnaitsee 7, Vorderriss 1, and Hindelang 3L (Reinecker et al. 2010). W3, W45, and W51 are all located adjacent to major fault segments. Wells W45 and W51 are situated close to the area of maximum fault throw of around 80 m. W3 is located near the western fault zone and S_{Hmax} orientations in both the Chattian and Aquitanian intervals are subparallel to the strike of the western fault zone. Similarly, well W30 exhibits a marked change in orientation across the fault. Above the fault, BOs indicate a near-regional orientation S_{Hmax} of N007°E $\pm$ 13° whereas within the first 70 m below the fault S_{Hmax} orientations rotate to N117°E $\pm$ 9°, approximately parallel to the fault strike. Because the perturbed interval is relatively short compared to the undisturbed interval, the overall S_{Hmax} orientation (N174°E $\pm$ 34°), remains close to the regional N–S trend, although the associated standard deviation increases. Such fault-parallel orientations are consistent with stress perturbations that have been attributed to fault displacement, fault-zone geometry, and mechanical contrasts across faults (Dart and Swolfs 1992; Barton and Zoback 1994; Yale 2003; Faulkner et al. 2006; Konstantinovskaya et al. 2012).

The influence of the fault, however, is not uniform throughout the field. No influence of the fault on the S_{Hmax} orientation is observed in wells W19, W37, W26, W59, and W68, while wells W27 and W40 exhibit only minor variations that remain within the BO scatter. All are not in the vicinity of the maximum fault heave. Even if a drilling-related bias cannot be excluded in Well 70, because the S_{Hmax} orientation below the fault closely matches the borehole azimuth, it might indicate, that the local structural control of the fault on the stress field is spatially extremely limited, and decrease with distance (Zoback 1991; Reiter et al. 2024).

The largest deviations within wells occur where fault displacement does not necessarily intersect the fault but instead generates lateral mechanical contrasts between juxtaposed lithologies. The main fault strikes approximately N070°E and reaches a maximum displacement of ~80 m within the Chattian Main Sandstone (Erhardt and Kraus 1975), locally juxtaposing competent sandstones against weaker marls and shales. Such mechanical contrasts have been shown to perturb stress trajectories and rotate S_{Hmax} orientations near lithological contacts (Bell 1996; Gudmundsson 2004; Reiter 2021; Ziegler et al. 2024). This mechanism can explain the observed rotations in wells W19 and W45. In these wells the Chattian Marl and Chattian Sands intervals are constrained by only a limited number of BOs and are therefore classified as D or E quality. In W19, S_{Hmax} orientation changes from N127°E ± 9° to N042°E ± 2°, and in W45, S_{Hmax} orientation changes from N150°E to N037°E ± 33°. In both wells the Chattian Sands exhibit orientations that are approximately parallel to fault strike. South of the fault, these competent sands ($E = 45$ GPa) are laterally juxtaposed against weaker Chattian Marls or Aquitanian ($E = 30.6$ GPa) to the north owing to fault displacement. This behavior is consistent with observations that stresses in stiffer units rotate parallel to competency contrasts, whereas stresses in weaker units rotate perpendicular to them (Bell 1996; Tingay et al. 2006; Reiter 2021). Such rotations were also observed in Tachtering 1b with rotations of 85° counterclockwise from the upper part, dominated by Aquitanian and Chattian to less competent Chattian and Rupelian clays in the bottom part. Also Schnaitsee 7 show a strong clockwise rotation by 34° between the Molasse sequence (Aquitanian to Rupelian), characterized by large sequences of Claystone and Marls and the Mesozoic strata dominated by limestones (Reinecker et al. 2010). The importance of lateral over vertical mechanical contrasts is further supported by well W67. Here, S_{Hmax} remains nearly constant between the Chattian Marls (N155°E ± 3°), and Chattian Sands (N163°E ± 14°), despite the same vertical lithological transition. In contrast to wells W19 and W45, W67 is located far from the fault zone, and no lateral juxtaposition of mechanically contrasting units occurs. The absence of significant stress rotation therefore suggests that vertical lithological differences alone do not

perturb the stress field appreciably. Rather, the observed rotations appear to require fault displacement that generates lateral competency contrasts.

In addition to juxtaposing lithological units, spatially variable fault heave has produced a gently folded structure, where S_{Hmax} orientation may rotate parallel to fold axes (Jarosiński et al. 2024). Thus, the stress tensor can locally be inclined resulting in deviations from a purely Andersonian stress state. However, the gentle dip (2–5°) of the flanks suggests that the vertical stress remains close to a principal stress. In depleted reservoirs, Yale et al. (1994), Wright and Conant (1995), Wright et al. (1994) or Wolhart et al. (2000) state that S_{Hmax} orientation aligns with the strike of the fault. In our dataset, fault-parallel S_{Hmax} orientations are observed only in wells W45 and W3. However, W3 is located laterally outside the reservoir and therefore cannot be attributed to reservoir depletion effects.

Constraints on pore pressure, stress magnitudes and tectonic regime from in-situ testing

While horizontal stress orientations can generally be constrained reliably from BOs and other wellbore-failure indicators, the magnitudes of the principal stresses, particularly S_{Hmax} , are commonly estimated using empirical relationships and geomechanical assumptions rather than direct measurements. Pore pressure is a critical parameter in these analyses (Eq. 6). Because no direct pore pressure measurements are available for the study area, we consider two scenarios: $P_0 = P_{hydr}$ and $P_0 = P_m$. The assumption of hydrostatic conditions is supported by the lowest recorded mud weight of 1050 kg/m³. However, overpressure intervals are known within the Eastern Bavarian Molasse Basin (Müller et al. 1988; Drews et al. 2018; Shatyrbayeva et al. 2023). Dynamic fluid-flow simulations by Zain-UI-Abedin and Henk (2020) indicate nearly hydrostatic conditions above the reservoir, followed by a transition to slight overpressure at greater depth. The onset of overpressure has been reported for the Chattian, which is at approximately 1500 m depth (Drews et al. , 2018);, this corresponds closely to the depth of the XLOT used to constrain S_{hmin} . The average mud weight within the Aquitanian section is approximately 1130 kg/m³, which resembles the mud weights of nearby wells drilled with 1100 and 1200 kg/m³ (Shatyrbayeva et al. 2023), and also the mud weight (1100 kg/m³) used in Drews et al. (2019) for a LOT in comparable depth (1345 m TVD) and the same stratigraphic unit. Together, these observations suggest that slightly overpressured conditions are plausible at the test depth.

To enable comparison of stress magnitudes from our study with datasets from other locations within the Eastern Molasse Basin, we calculate stress gradients. While it allows for comparison of data from different depths, this

simplification introduces uncertainty because it neglects local and depth-dependent lithological controls on stress. S_V at the test depth is estimated at 33.7 MPa based on the empirical model of Obermeier et al. (2025). The model reflects progressive compaction and increasing bulk density with depth, consistent with measurement reported in Zain-UI-Abedin and Henk (2020). From the model an average overburden density of 2310 kg/m³ (S_V gradient of 22.7 MPa/km) above the depth of the XLOT is estimated. This resembles the value of 2330 kg/m³ (S_V gradient 22.9 MPa/km) based on Drews et al. (2019) for a similar depth or 23 MPa/km reported in Seithel et al. (2015).

S_{hmin} is determined from the XLOT and is subject to several quantifiable uncertainties, including viscous friction losses, pressure-picking methodology, and the selection of the pressure representing S_{hmin} . The calculated viscous friction losses are small ($\Delta P_f = 0.001\text{--}0.004$ MPa), because of the low flow rates ($max Q_i = 26.3$ L/min) during the XLOT and are therefore not considered in the analysis. Examples from Basel with up to $Q_i = 870$ L/min demonstrate that also for high flow rates, frictional losses are moderate ($\Delta P_f = 0.26\text{--}0.36$ MPa) and have no larger impact on the derived stress magnitudes (Ortiz R et al. 2011). Pressure-picking methodology uncertainties are considered explicitly in the analysis and incorporated into the stress reconciliation plot. Within RF2–RF4, the difference between $P_{clo,FC}$ and $P_{clo,T}$ ranges from 1.2 to 1.9 MPa, while the difference between $P_{clo,FC}$ and $P_{clo,G}$ ranges from 1.2 to 2.2 MPa. In contrast, $P_{clo,FC}$ is generally within ± 0.5 MPa of P_{SI} . The observed discrepancy between the compliance-based and tangent-method estimates is comparable to the underestimation of 1–2 MPa reported by Jung et al. (2016) and McClure et al. (2016) for low-permeability formations. This interpretation is consistent with the Aquitanian interval, where permeability is typically around 1 mD and frequently lower. Consequently, besides P_{SI} , $P_{clo,FC}$ is considered as representative estimate of S_{hmin} based on closure pressures, which supports a strike-slip stress regime at the depth of the XLOT. Furthermore, the differences among the closure-pressure estimates remain largely constant across the refracturing cycles, indicating that system stiffness did not change significantly during the test.

However, uncertainty remains regarding the orientation of the induced fracture, as no borehole image logs were acquired before or after the test to exclude that an existing fracture is reopened. Fracture propagation along a plane not perpendicular to S_{hmin} would require higher injection pressures and could therefore lead to an overestimation of S_{hmin} . Although this possibility cannot be excluded completely, the FIT results from the same stratigraphic unit are consistent with the XLOT-derived S_{hmin} . Also, the difference of P_B and P_R of around 5 MPa indicates that σ_t is not zero as expected when reopening an existing fracture.

Reservoir depletion may also influence the least principal stress through pore pressure reduction, compaction, and the associated redistribution of total stresses (Teufel et al. 1991; Teufel 1996; Santarelli et al. 1998; Zoback and Zinke 2002). Field observations and geomechanical models indicate that the largest stress reductions occur within the depleted reservoir, whereas stress arching may locally increase stresses near reservoir margins. However, the XLOT location is approximately 4 km laterally offset from the depleted reservoir. We therefore consider a significant depletion-related effect on the XLOT-derived S_{hmin} unlikely.

Comparison with other sites is complicated by the fact that only two LOTs have been conducted at Unterhaching, whereas estimates of S_{hmin} at other locations are primarily based on FITs (Fig. 1). The shallower LOT at Unterhaching was performed in 825 m TVD and yielded an S_{hmin} of 12.8 MPa (15.6 MPa/km). The test was conducted in shale-dominated stratigraphic unit rather than within the Aquitanian, which may explain the comparatively lower S_{hmin} values (Drews et al. 2019). The deeper LOT was conducted at 1345 m depth, close to the depth of our XLOT and within the Aquitanian. It yielded a stress magnitude of 16.2 MPa (12.1 MPa/km), which is significantly lower than the value derived in this study. In Unterhaching S_{hmin} was estimated from P_{prop} , a method prone to overestimate S_{hmin} especially if viscous fluids are used (Zoback 2007) and therefore should represent an upper bound. However, the value shows a lower gradient as the lower bound in our study (17.9 MPa/km). Lower bounds of S_{hmin} are obtained from FITs provided by Seithel et al. (2015), Seithel (2019), Drews et al. (2019) and from the study area (Table 2).

FITs and CEMs are limit tests; therefore, the maximum value provides the constraint on the lower boundary of S_{hmin} . Except for Sauerlach data reported by Seithel et al. (2015), pressure gradients are well approximated by 18 MPa/km, closely matching the 17.9 MPa/km from the XLOT in this study. Although slightly lower gradients have been reported from Sauerlach, the data of Seithel et al. (2015) and Seithel (2019) have shown no significant difference between Lower Miocene and Upper Oligocene FIT/CEM pressure gradients, suggesting a linear S_{hmin} gradient across both units. Furthermore, the similarity between the gradients reported by Seithel (2019) and Drews et al. (2019) indicates that this linear trend has extended into the Middle Miocene.

RACOS[®] measurement on samples from a field nearby at slightly greater depth indicate a systematic increase in the S_{hmin} gradient (Fig. 9). This trend coincides with increasing mud pressure and overpressure with depth, consistent with observations by Drews et al. (2018, 2019) or Shatyrbayeva et al. (2023). As pore pressure increases, both S_{Hmax} and S_{hmin} tend to converge toward S_V (Zoback 2007). Such an effect is visible in the measurements results, with $S_{hmin} = 36.6$ MPa and $S_{Hmax} = 37.8$ MPa in 1754 m or $S_{hmin} = 36.7$ MPa and

Table 2 Compilation of minimum, average and maximum pressure gradients from FITs and cementation pressures (CEM) from this study, and from the larger Munich area digitized from Seithel et al. (2015), and reported in Seithel (2019), and Drews et al. (2019)

Strati-graphy	Unit	FIT/CEM gradients [MPa/km]															
		this study				Seithel et al. (2015)				Seithel (2019)				Drews et al. (2019)			
		min	mean	max	#	min	mean	max	#	min	mean	max	#	min	mean	max	#
Middle Miocene	All													14.7	16.3	17.9	4
Lower Miocene	All	13.1	15.3	18.1	10	11.1	13.5	16.9	11	14.0	16.2	18.0	22				
	B	13.1	14.5	17.6	7					14.0	16.2	18.0	17				
	A	16.5	17.1	18.1	3					15.4	16.2	17.0	5				
Upper Oligocene	All					12.0	14.6	16.7	9	14.6	16.4	18.0	18	14.3	16.8	19.4	3
	M									15.3	16.6	18.0	11				
	S									14.6	16.0	18.0	7				

The data is sorted by stratigraphy and unit

A Aquitanian, B Burdigalian, M Chattian Marl, S Chattian Sands

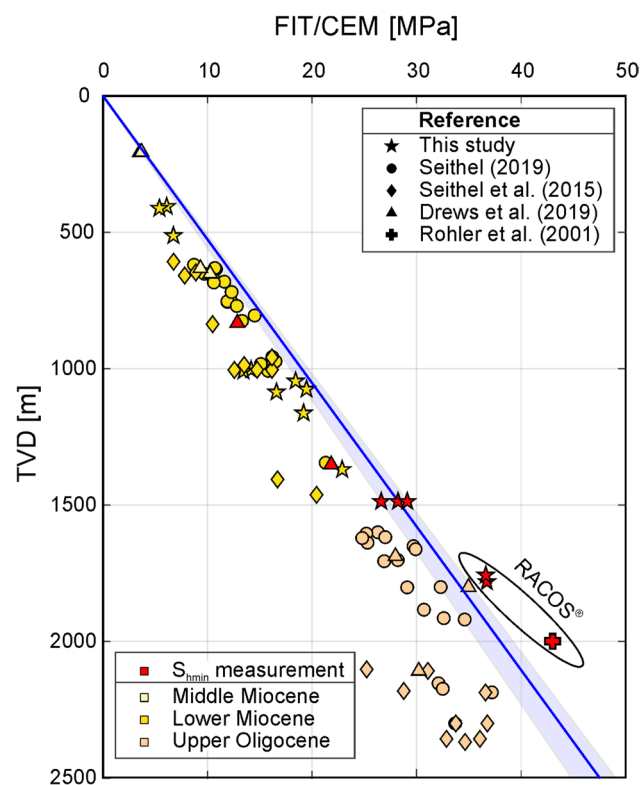


Fig. 9 Comparison of S_{hmin} values from this study (derived from XLOT and FITs) with results from RACOS[®] results, FITs and CEMs from Seithel et al. (2015), Seithel (2019), and FIT, CEM, and LOT data from Drews et al. (2019). S_v is estimated following Obermeier et al. (2025). The values are colored according to their stratigraphic unit. The blue line and polygon indicate the linear S_{hmin} gradient used for BO-inversion

$S_{Hmax} = 38.2$ MPa in 1779 m depth. The observed increase in the horizontal stress gradient with depth therefore likely reflects the progressive influence of overpressure on the stress state.

To estimate S_{Hmax} , we follow the classical approach of Bredehoeft et al. (1976), which uses P_0 , P_{SI} , and particularly P_R as key input parameters (Eq. 6). Among these, P_R is associated with the greatest uncertainty. Ito et al. (1999) showed that uncertainty arises both from limitations of the underlying model assumptions and from difficulties in accurately identifying P_R . Measured values may be overestimated because of system compliance, variable injection rates, or incomplete fracture propagation during the initial cycle, which can preserve residual tensile strength along the fracture plane and elevate P_R in subsequent cycles. Conversely, pressure diffusion and fluid infiltration into the fracture network were observed by Hickman and Zoback (1983) to reduce P_R during repeated injection cycles. Poroelastic effects were further shown by Addis et al. (1998) to influence both P_R and P_{SI} , thereby affecting the estimation of S_{Hmax} . We consider significant poroelastic effects to be unlikely in the present study. The injected volumes are small, and both P_R and P_{SI} remain highly consistent between RF2 and RF4. The observed P_R/P_{SI} ratios range from 1.04–1.07 and closely resemble the ratio of approximately 1.03 reported by Niederhuber et al. (2025b) for short-duration mini-frac tests with small injection volumes (Rummel 1986), conditions under which poroelastic effects were considered negligible. This interpretation is consistent with the observations of Rutqvist et al. (2000), who demonstrated that P_R commonly approximates P_{SI} .

Nonetheless, even if P_R is determined correctly, the classical Bredehoeft equation neglects fluid pressure acting within the fracture and may therefore overestimate S_{Hmax} . To address this limitation, Ito et al. (1999) proposed a modified formulation that accounts for this effect and yields lower estimates of S_{Hmax} . This interpretation is consistent with the findings of Schmitt et al. (2012), who likewise concluded that the classical approach tends to overestimate S_{Hmax} . The derived S_{Hmax} magnitudes range from 34.1–42.9 MPa

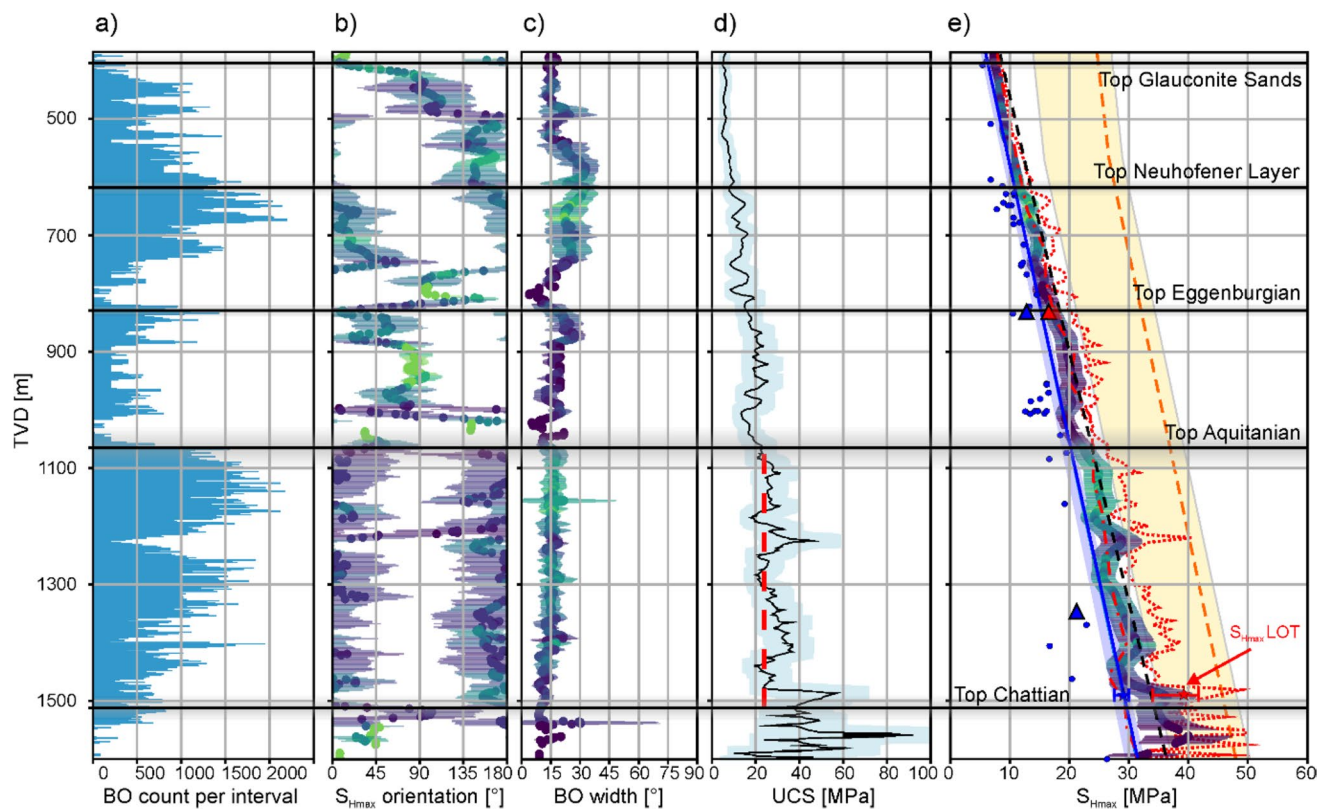


Fig. 10 Depth-dependent BOs and stress analysis. **a** BO counts per 5 m interval. Black horizontal lines mark lithostratigraphic tops, while gray shaded intervals indicate their local depth uncertainty and lateral variability; **b** average orientation of S_{Hmax} derived from BOs, with uncertainty. Colors represent R^2 ; **c** BO opening widths with uncertainty. Colors indicate normalized BO count per interval relative to the maximum number of observations, ranging from purple (few BOs) to green (many BOs); **d** UCS profile adopted from Zain-Ul-Abedin and Henk (2020); UCS values obtained from the Aquitanian samples are shown as red dashed lines; **e** Stress magnitudes derived from BO widths inversion using the UCS profile shown in **d** and a linear S_{hmin} gradient. The black line shows the S_v after Obermeier

et al. (2025). Circles denote FITs and CEMs from this study, Drews et al. (2019), Seithel et al. (2015), and Seithel et al. (2019). Stars with error bars indicate XLOT measurements from this study, and the triangle represents the LOT measurement reported by Drews et al. (2019). Blue triangle and line with shaded polygon indicate S_{hmin} and its uncertainty, and the red triangle and line S_{Hmax} . Red dashed and red dotted-dashed lines represent S_{Hmax} magnitudes from 1-D geomechanical model and the 3-D finite-element model of Zain-Ul-Abedin and Henk (2020), respectively. The yellow shaded area indicates S_{Hmax} estimates from Ziegler et al. (2016), with the corresponding best-fit trend shown as a dashed line

(gradients of 22.9–28.9 MPa/km). In contrast, application of the formulation proposed by Ito et al. (1999) yields S_{Hmax} magnitudes of only 19.7–27.7 MPa. These estimates are substantially lower than those obtained using the classical Bredehoeft approach. For most parameter combinations, the resulting S_{Hmax} values fall below S_{hmin} , contradicting the fundamental requirement that S_{Hmax} represents the maximum horizontal principal stress. Consequently, the Ito formulation is not considered applicable to the present dataset.

We further constrain S_{Hmax} in the depth of XLOT using the frictional limit approach (Eq. 7). The friction angle $\varphi = 16^\circ$, equivalent to a coefficient of friction (μ) of about 0.3, was used, based on uniaxial and triaxial compressive strength tests. This friction coefficient falls within the range ($\mu = 0.2$ – 0.4) reported for shallow, shale-rich formations in the Molasse Basin (Drews et al. 2019). Using the values

of Drews et al. (2019) as upper and lower limits of μ , the range of S_{Hmax} is 32.4–44.8 MPa (21.8–30.2 MPa/km), with 38.1 MPa (25.3 MPa/km) on average.

Similar analysis has been performed by Seithel et al. (2015), who applied $\mu = 0.6$ and reported a gradient of ~ 28 MPa/km.

As discussed, a linear S_{hmin} gradient is assumed for the Middle and Lower Miocene and the Upper Oligocene. However, as shown in Fig. 10, local deviations may occur due to lithological contrasts particularly pronounced in the Aquitanian sands, a small layer surrounded by marls or the Chattian sands within the clay-rich layers of the Chattian. BOs are first and frequently observed within the Burdigalian (Glauconite sands, Neuhofer layer, Eggenburgian), consistent with Reinecker et al. (2010) and Seithel et al. (2015). The occurrence of BOs at shallow depth (starting in around

400 m) appears at odds with the pronounced stress rotations reported from the Molasse Basin Reinecker et al. (2010). Stress rotations, as described by Sonder (1990), Bell (1996), Yale (2003), and more recently by Ziegler et al. (2024), typically indicate low horizontal differential stresses, that is, similar magnitudes of S_{Hmax} and S_{Hmin} . Such conditions generally reduce the probability of BO formation.

However, inversion of BO widths using the XLOT-derived S_{Hmin} gradient and the UCS profile of Zain-UI-Abedin and Henk (2020) yields comparatively low differential stresses throughout the well (Fig. 10e). BO width decreases almost linearly with depth, whereas UCS increases, resulting in only minor changes in $S_{Hmax} - S_{Hmin}$. This suggests that the depth-dependent reduction in BO width primarily reflects increasing rock strength rather than major changes in the stress field. BO formation at shallow depth is therefore facilitated by the low UCS of the Burdigalian sediments which only require low differential stresses implied by the observed stress rotations. This interpretation is independently supported by borehole ellipticity data (HD_{max}/HD_{min}). Increased number of elliptic borehole intervals is observed within the Neuhofener Layer and the Aquitanian, whereas lower values occur in the Eggenburgian and Glauconite Sands, and almost no ellipticity is observed within the Chattian Sands. The depth distribution of borehole ellipticity closely mirrors that of BO occurrence and BO width, suggesting that both indicators reflect the same stress-induced wellbore deformation processes rather than tool-related artifacts.

The BO-derived S_{Hmax} magnitudes agree closely with independent constraints. In particular, they are consistent with the LOT data of Drews et al. (2019) when $\sigma_t = 1.2$ MPa is assumed, which is slightly lower than values measured in this study (2.8–3.2 MPa). The 1-D geomechanical model of Zain-UI-Abedin and Henk (2020) reflects the trend of S_{Hmax} , as both are governed by the same UCS profile, but with slightly higher magnitudes than the BO inversion. The 3D FE model of Zain-UI-Abedin and Henk (2020), in contrast resembles the S_{Hmax} magnitudes derived from BO inversion and the magnitude of the LOT of Drews et al. (2019) for the Miocene, but underestimates S_{Hmax} in the Chattian. In contrast, the FE model of Ziegler et al. (2016) overestimates S_{Hmax} in the shallow section but converges toward the BO-derived estimates and XLOT near 1500 m depth. This discrepancy likely reflects the limited vertical resolution of regional-scale models, in which thin lithological units are merged into mechanically homogeneous layers and calibration is predominantly constrained by deeper data. Similar shortcomings are evident in the Germany-wide model of Ahlers et al. (2022), which tends to underestimate horizontal stress magnitudes at shallow depths. While such regional models can adequately reproduce the first-order stress field at depth, they cannot be used for shallow subsurface, where

local lithological controls become increasingly important. Assuming a homogeneous stress state therein, without considering local stress concentration is insufficient for predicting local fault stability or induced seismicity (Niederhuber et al. 2025b). Our reconstructed stress magnitudes based on FITs, XLOT und BO width inversion indicate a normal-faulting stress regime in the Burdigalian, consistent with findings of Drews et al. (2019) and geomechanical models of Zain-UI-Abedin and Henk (2020). With increasing depth, S_{Hmax} approaches S_v , indicating a gradual transition toward strike-slip faulting. Although local uncertainties result in minor variations, our analysis reveals a predominant, strike-slip regime within the Chattian, in agreement with RACOS® measurements from Breitbrunn/Eggstätt (Rohler et al. 2001). Our results and the findings in literature point to low differential stresses in the Burdigalian and Aquitanian. Together with the smaller number of faults within this units compared to deeper units (Eskens et al. 2024), this may explain the absence of natural tectonic earthquakes (Gruenthal and Bosse 1996; Megies and Wassermann 2014) and induced seismicity. The observed trend toward a strike-slip regime with depth is consistent with studies focusing on sub-Molasse Mesozoic sediments (Budach et al. 2018; Seithel et al. 2015) and the crystalline basement (Megies and Wassermann 2014).

Conclusion

This study provides new constraints on the present-day stress state in the Eastern Bavarian Molasse Basin by integrating BO observations from 70 wells with XLOT, FIT, drilling-mud pressure, RACOS® measurements, and geomechanical constraints. The results demonstrate the value of combining diverse and partly legacy datasets, including records affected by digitization errors, incomplete documentation, and observations from deviated wells, to derive a robust characterization of the stress field. The findings show that the stress field cannot be described adequately by a laterally and vertically uniform stress orientation or by a single stress gradient. Instead, the regional stress field is superimposed by pronounced local-scale variations that are controlled by stratigraphic heterogeneities, faults, and the three-dimensional structural geometry. We conclude that the regional orientation of S_{Hmax} is broadly preserved in the overburden but is not uniformly stable with depth or stratigraphy. The 20 wells with oriented four-arm caliper data provide 19 wells with identifiable BOs, allowing stress orientation to be evaluated in detail for the Upper Oligocene and Lower Miocene units compared to previous studies. The Burdigalian shows a mean orientation close to the regional N–S direction, but with considerable scatter, indicating that the far-field orientation is present while local perturbations

occur even within the overburden. The most pronounced systematic deviations occur in the Aquitanian and Chattian successions, particularly close to the main fault and at lithological contacts. In consequence, treating all BOs from an individual well or basin as a single representative S_{Hmax} orientation can obscure important depth-dependent variations in the local stress field.

This work highlights the importance of specific geological and mechanical controls on rotation of S_{Hmax} orientation.

Local rotations of up to 70–90° are not restricted to the immediate intersection with the main fault. Two wells show rotation within the Chattian sands where the fault has displaced mechanically stronger Chattian sands against weaker Aquitanian marls. Other rotations are spatially associated with fault displacement. These observations indicate that the local stress field results from the superposition of the regional far-field stress and perturbations caused by fault geometry, fault displacement, structural morphology, and contrasts in mechanical properties. In particular, we conclude from the occurrence of rotations at lithological contacts away from the fault plane that mechanical heterogeneity can be as important as the fault itself in controlling the local stress orientation.

Our integrated stress-magnitude analysis indicates high S_{hmin} magnitudes at shallow depth and a stress regime varying from normal-faulting to strike-slip within Lower Miocene and transition to strike-slip at 1.5 km depth. The XLOT constrains S_{hmin} to approximately 28.2 MPa at the test depth corresponding to a gradient of about 19 MPa/km, while S_V is approximately 33.7 MPa. Depending on the assumed pore pressure and the uncertainty of the XLOT parameters, S_{Hmax} is constrained to approximately 34.1–42.9 MPa, with the frictional-limit analysis providing a comparable range and a mean value of approximately 37.5 MPa. Consequently, the preferred stress state is characterized by $S_{Hmax} > S_V > S_{hmin}$, indicating a strike-slip regime, but one close to the normal-faulting. Particularly important is the relatively high S_{hmin} because it hints to lower the horizontal differential stress. This is consistent with the shallow occurrence of BOs and observed stress rotations, that are commonly associated with low differential stress between S_{Hmax} and S_{hmin} , whereas BOs are often interpreted as evidence for sufficiently high differential stress to induce compressive failure. In the study area, these observations can coexist because the weak marly and clay-rich Aquitanian and Chattian formations have sufficiently low UCS for borehole failure to occur at shallow depths. Conversely, the mechanically stronger Chattian sandstones or Aquitanian Sands generally show fewer BOs and behave more consistently with the far-field stress state, except where local structural or lithological contrasts perturb the stress field. Pore pressure provides a plausible contribution to the observed low differential stresses, although the

magnitude of pore pressure remains uncertain because direct pore pressure measurements were unavailable. However, drilling-mud densities and published data indicate that slight overpressure is plausible near the XLOT depth. Increasing pore pressure therefore promotes a state in which S_{Hmax} and S_{hmin} approach S_V .

Overall, this study presents a transferable workflow for stress characterization in mature hydrocarbon fields, where data availability is commonly limited to historical well records. Our results demonstrate that legacy datasets, although frequently affected by incomplete documentation, digitization errors, and other uncertainties, can provide valuable constraints on the present-day stress field when analyzed within an integrated geomechanical framework. Given the large number of mature fields worldwide with extensive archival datasets, such approaches offer significant potential for improving stress characterization. Our study underscores that the present-day stress field in the Bavarian Molasse Basin is heterogeneous on the scale of individual stratigraphic units and geological structures. While a regional N–S S_{Hmax} orientation is preserved local stress rotations arise where this far-field stress interacts with faults, structural morphology, and strong mechanical contrasts. Consequently, stress information derived from individual boreholes should not automatically be extrapolated vertically or laterally without considering the geological and mechanical context. This is particularly relevant for subsurface applications such as gas and hydrogen storage, geothermal development, and fault-stability assessment, where pore pressure, temperature or both change effective stresses. Our results demonstrate that the differential stresses in the uppermost 1500 m are quite low, which may provide favorable stress conditions for an intensive use of the subsurface without generating seismicity of significant magnitudes.

Appendix

Appendix A1: Description of RACOS® test procedure

RACOS® is an advanced laboratory method for determining the effective three-dimensional in-situ stress state directly from core samples (Braun et al. 1999; Braun and Reinhold 2017). Upon core extraction, the natural stress field is released, leading to decompression-related damage such as fracturing and loosening. RACOS® compensates for these effects by subjecting the cores to controlled isotropic reloading while measuring the directional propagation velocities of compressional and shear ultrasonic waves.

By analyzing the stress-dependent anisotropy of wave velocities, RACOS® enables a direct, constitutive-law-independent reconstruction of the effective principal stresses

present at the time of core retrieval. Additionally, it allows for the derivation of elastic rock properties (e.g., Young's modulus, Poisson's ratio) and the total stress state, including pore pressure effects, through integration with porosity data and standard plug tests. All results are resolved in three dimensions and can be determined retrospectively, without requiring in situ testing or real-time measurements at the borehole (Braun et al. 1999; Braun and Reinhold 2017).

Appendix A3: Results of BO analysis for all 19 wells separated by units

See Table 3.

Appendix A2: Workflow used in FAC software

See Fig. 11.

Fig. 11 Integrative and coupled workflow of the FAC-Tool showing the input parameters, the preprocessing, analysis step as well as visualization of the results and the export options

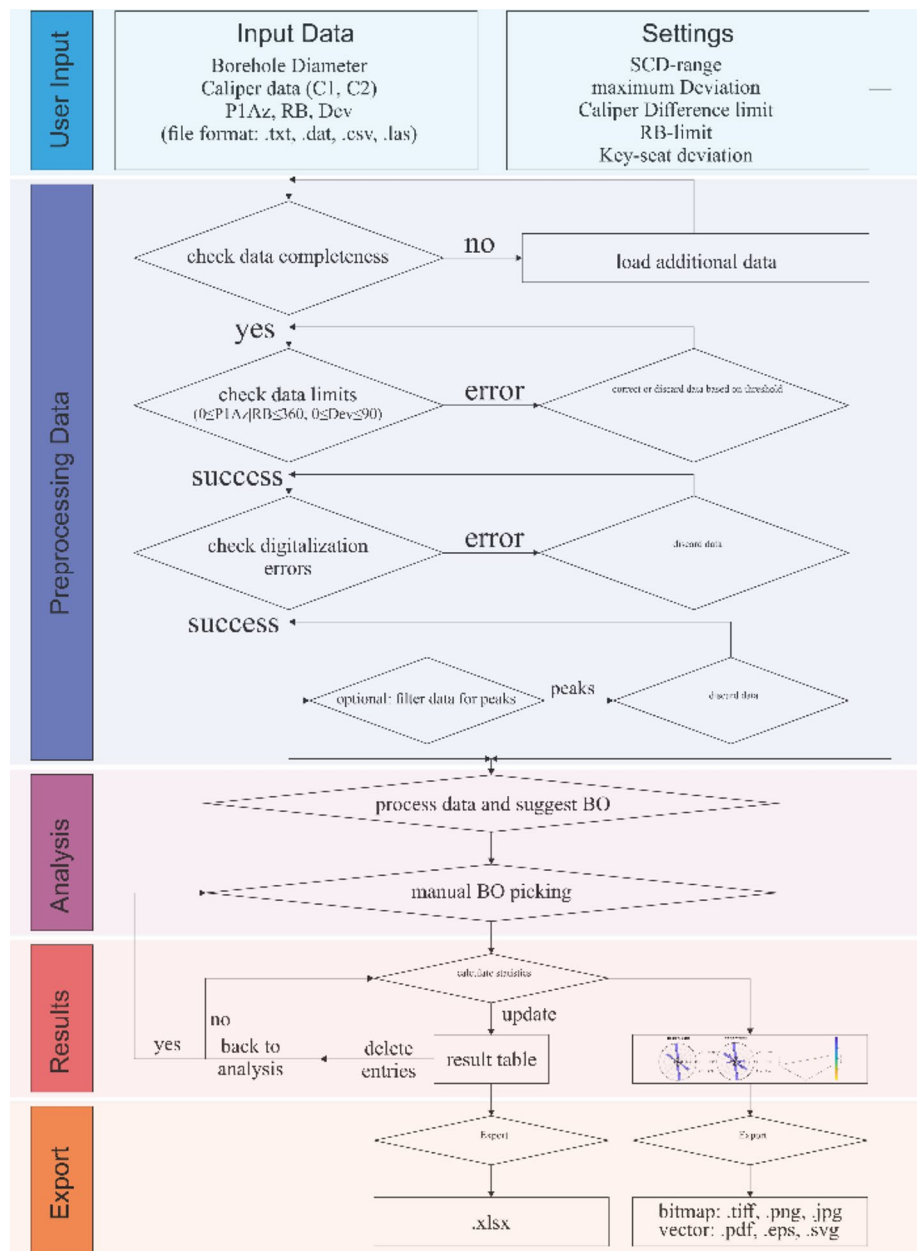


Table 3 Results of the BO analysis for all 19 wells, listed by stratigraphic unit and well

Unit	Well	log length [m]	Thickness [m]	len BO [m]	BO/Log (%)	BO count	max Devi	S _{Hmax}	std	WSM Quality	std mod	mod Quality
Burdigalian	W37	713.9	723.5	295.6	41	22	19.0	24.6	34.8	D	44.8	E
<i>Oncophora Layer</i>	W37	56.5	65.6	10.5	19	3	0.2	10.8	16.9	D	16.9	D
<i>Glauconite Sands</i>	W37	216.3	216.5	66.1	31	3	13.8	128.6	22.6	D	32.6	D
<i>Neuhofener Layer</i>	W37	208.0	208.1	126.7	61	10	19.0	16.6	16.4	B	26.4	D
<i>Eggenburgian</i>	W37	233.1	233.3	92.3	40	6	18.2	43.4	1.3	C	11.3	C
Aquitanian	W37	349.6	349.6	339.7	97	10	14.9	39.4	5.4	A	15.4	B
Chattian	W37	45.3	66.8	40.8	90	4	14.0	53.2	6.6	C	16.6	C
<i>Chattian Marls</i>	W37	45.3	66.8	40.8	90	4	14.0	53.2	6.6	C	16.6	C
SUMMARY	W37	1108.8	1531.9	694.0	63	36	19.0	36.5	22.3	C	32.3	D
Burdigalian	W26	640.8	705.4	168.6	26	13	24.3	164.9	28.4	D	38.4	D
<i>Glauconite Sands</i>	W26	177.3	211.8	103.3	58	6	13.6	152.0	9.9	B	19.9	B
<i>Neuhofener Layer</i>	W26	208.8	209.0	54.1	26	4	19.3	18.7	5.1	C	15.1	C
<i>Eggenburgian</i>	W26	222.1	222.2	11.1	5	3	24.3	102.6	20.7	D	30.7	D
Aquitanian	W26	358.9	359.0	314.5	88	11	28.0	148.1	7.4	A	17.4	B
Chattian	W26	29.4	66.1	7.7	26	2	21.2	123.8	25.2	D	35.2	D
<i>Chattian Marls</i>	W26	29.4	66.1	7.7	26	2	21.2	123.8	25.2	D	35.2	D
SUMMARY	W26	1029.1	1510.5	490.8	48	26	28.0	151.9	18.7	B	28.7	D
Burdigalian	W59	723.9	745.5	37.0	5	5	0.5	0.9	2.5	C	2.5	C
<i>Neuhofener Layer</i>	W59	208.3	208.4	37.0	18	5	0.3	0.9	2.5	C	2.5	C
Aquitanian	W59	327.6	328.7	32.4	10	9	0.9	175.1	19.4	C	19.4	C
SUMMARY	W59	1051.5	1074.2	69.4	7	14	0.9	178.5	13.3	C	13.3	C
Burdigalian	W58	739.3	746.8	33.3	5	12	11.4	94.2	19.1	C	29.1	D
<i>Oncophora Layer</i>	W58	60.6	67.8	7.6	13	2	11.4	38.5	19.5	D	29.5	D
<i>Glauconite Sands</i>	W58	212.7	212.9	1.1	1	1	10.2	167.0	0.0	E	10.0	E
<i>Neuhofener Layer</i>	W58	209.2	209.3	22.2	11	6	9.0	179.8	3.4	D	3.4	D
<i>Eggenburgian</i>	W58	256.8	256.9	2.4	1	3	6.7	163.7	4.3	E	4.3	E
Aquitanian	W58	326.3	326.5	16.2	5	10	5.7	174.2	34.5	D	34.5	D
Chattian	W58	54.1	64.3	5.0	9	4	4.2	68.5	41.0	E	41.0	E
<i>Chattian Marls</i>	W58	54.1	64.3	5.0	9	4	4.2	68.5	41.0	E	41.0	E
SUMMARY	W58	1147.1	1520.8	54.5	5	26	11.4	3.1	28.7	D	38.7	D
Burdigalian	W56	692.0	747.9	74.2	11	20	17.7	4.6	32.3	D	42.3	E
<i>Glauconite Sands</i>	W56	208.6	213.0	50.7	24	7	9.3	13.1	17.1	C	17.1	C
<i>Neuhofener Layer</i>	W56	208.7	208.8	8.3	4	5	13.4	176.5	31.3	D	41.3	E
<i>Eggenburgian</i>	W56	258.6	260.3	15.2	6	8	17.7	126.0	17.9	D	27.9	D
Aquitanian	W56	328.0	328.1	101.4	31	48	19.0	10.0	34.7	D	44.7	E
Chattian	W56	56.7	59.4	5.4	10	2	21.1	6.1	6.2	D	16.2	D

Table 3 (continued)

Unit	Well	log length [m]	Thickness [m]	len BO [m]	BO/Log (%)	BO count	max Devi	S _{Hmax}	std	WSM Quality	std mod	mod Quality
<i>Chattian Marls</i>	W56	56.7	59.4	5.4	10	2	21.1	6.1	6.2	D	16.2	D
SUMMARY	W56	1076.8	1520.3	181.0	17	70	21.1	7.5	33.1	D	43.1	E
<i>Burdigalian</i>	W30	632.3	706.1	213.4	34	26	24.4	129.5	30.3	D	40.3	E
<i>Glauconite Sands</i>	W30	197.8	210.7	89.7	45	8	14.5	119.2	20.9	C	30.9	D
<i>Neuhofener Layer</i>	W30	209.9	210.0	94.5	45	10	19.9	142.2	33.2	D	43.2	E
<i>Eggenburgian</i>	W30	223.2	223.4	29.2	13	8	24.4	136.7	34.2	D	44.2	E
<i>Aquitanian</i>	W30	357.8	358.0	96.6	27	19	34.0	1.8	31.8	D	–	E
SUMMARY	W30	1055.5	1509.5	310.0	29	45	34.0	142.0	39.5	D	–	E
<i>Burdigalian</i>	W27	636.9	707.3	97.5	15	15	25.0	179.2	41.2	E	51.2	E
<i>Glauconite Sands</i>	W27	201.0	211.2	44.4	22	5	7.7	163.0	16.6	C	16.6	C
<i>Neuhofener Layer</i>	W27	208.0	208.2	43.1	21	6	14.2	35.0	36.0	D	46.0	E
<i>Eggenburgian</i>	W27	225.0	225.2	10.0	4	4	25.0	76.1	40.9	E	50.9	E
<i>Aquitanian</i>	W27	364.9	365.0	157.7	43	53	27.2	11.2	23.3	C	33.3	D
SUMMARY	W27	1049.1	1516.2	255.2	24	68	27.2	8.4	30.4	D	40.4	E
<i>Burdigalian</i>	W44	694.5	725.3	144.7	21	13	18.2	35.1	34.1	D	44.1	E
<i>Oncophora Layer</i>	W44	36.0	66.3	5.3	15	1	2.5	49.0	0.0	D	0.0	D
<i>Glauconite Sands</i>	W44	218.1	218.2	55.1	25	5	14.8	34.9	36.7	D	46.7	E
<i>Neuhofener Layer</i>	W44	209.2	209.3	84.3	40	7	18.2	33.5	33.7	D	43.7	E
<i>Aquitanian</i>	W44	342.3	342.4	3.5	1	1	8.0	180.0	0.0	E	0.0	E
SUMMARY	W44	1097.3	1525.6	148.2	14	14	18.2	33.8	34.3	D	44.3	E
<i>Burdigalian</i>	W40	677.9	723.6	193.2	28	9	17.0	82.4	16.2	B	26.2	D
<i>Oncophora Layer</i>	W40	22.6	65.3	1.6	7	1	0.8	6.0	0.0	E	0.0	E
<i>Glauconite Sands</i>	W40	209.4	212.1	35.9	17	2	11.3	62.6	6.9	D	16.9	D
<i>Neuhofener Layer</i>	W40	211.5	211.6	155.7	74	6	17.0	87.1	12.7	B	22.7	C
<i>Aquitanian</i>	W40	397.2	403.7	117.4	30	47	24.3	171.0	7.3	B	17.3	B
SUMMARY	W40	1075.1	1522.7	310.6	29	56	24.3	85.5	54.3	E	64.3	E
<i>Burdigalian</i>	W51	677.3	730.1	331.6	49	23	26.0	169.4	32.3	D	42.3	E
<i>Glauconite Sands</i>	W51	216.5	217.2	56.7	26	8	16.0	114.8	27.9	D	37.9	D
<i>Neuhofener Layer</i>	W51	206.4	206.5	193.0	94	3	26.0	176.6	7.3	D	17.3	D
<i>Eggenburgian</i>	W51	242.4	242.6	81.9	34	12	26.0	136.9	53.4	E	63.4	E
<i>Aquitanian</i>	W51	342.1	342.3	71.4	21	4	26.2	105.1	4.2	C	14.2	C
SUMMARY	W51	1082.3	1527.3	403.0	37	27	26.2	158.0	41.3	E	51.3	E
<i>Burdigalian</i>	W47	687.4	729.1	325.4	47	22	21.0	165.5	31.9	D	41.9	E
<i>Glauconite Sands</i>	W47	203.1	212.9	103.2	51	10	11.6	123.5	22.5	C	32.5	D
<i>Neuhofener Layer</i>	W47	209.8	210.0	190.5	91	2	21.0	179.9	4.8	D	14.8	D
<i>Eggenburgian</i>	W47	241.2	241.2	31.7	13	10	21.0	125.8	34.6	D	44.6	E

Table 3 (continued)

Unit	Well	log length [m]	Thickness [m]	len BO [m]	BO/Log (%)	BO count	max Devi	S_{Hmax}	std	WSM Quality	std mod	mod Quality
Aquitanian	W47	340.7	340.9	77.1	23	36	10.7	147.9	39.8	D	49.8	E
SUMMARY	W47	1091.8	1525.9	402.5	37	58	21.0	163.0	33.9	D	43.9	E
Burdigalian	W61	706.7	750.0	358.1	51	19	13.5	75.8	27.8	D	37.8	D
<i>Oncophora Layer</i>	W61	28.8	65.6	3.5	12	1	0.7	146.0	0.0	E	0.0	E
<i>Glauconite Sands</i>	W61	210.1	216.3	76.5	36	3	5.7	131.8	29.8	D	29.8	D
<i>Neuhofener Layer</i>	W61	207.4	207.5	80.4	39	8	13.3	55.4	16.8	C	26.8	D
<i>Engenburgerian</i>	W61	260.3	260.5	197.7	76	7	13.5	75.9	7.0	B	17.0	B
Aquitanian	W61	337.1	337.2	107.5	32	30	11.9	84.8	36.9	D	46.9	E
SUMMARY	W61	1083.5	1526.0	465.6	43	49	13.5	77.3	30.0	D	40.0	E
Aquitanian	W45	315.1	342.6	51.6	16	17	17.2	88.7	8.1	C	18.1	C
Chatian	W45	130.4	130.6	8.0	6	4	11.6	157.2	33.4	D	43.4	E
<i>Chatian Marls</i>	W45	64.9	65.1	5.0	8	1	10.8	149.6	0.0	D	10.0	D
<i>Chatian Sands</i>	W45	65.5	65.5	3.0	5	3	11.6	37.4	33.5	E	43.5	E
SUMMARY	W45	445.5	1590.0	59.6	13	21	17.2	90.4	20.0	C	30.0	D
Burdigalian	W19	618.2	691.4	82.7	13	11	14.1	31.2	33.4	D	43.4	E
<i>Glauconite Sands</i>	W19	205.5	213.4	48.0	23	6	13.4	37.1	51.0	E	61.0	E
<i>Engenburgerian</i>	W19	199.8	200.0	34.7	17	5	14.1	29.4	10.8	C	20.8	C
Aquitanian	W19	421.2	421.4	150.3	36	10	14.3	140.5	10.1	B	20.1	C
Chatian	W19	133.9	134.2	37.1	28	5	9.4	124.9	31.0	D	31.0	D
<i>Chatian Marls</i>	W19	63.2	63.3	29.4	47	2	8.7	126.9	8.5	D	8.5	D
<i>Chatian Sands</i>	W19	70.7	70.8	7.7	11	3	9.4	42.4	2.3	D	2.3	D
SUMMARY	W19	1173.3	1247.0	270.1	23	26	14.3	144.0	35.2	D	45.2	E
Aquitanian	W64	344.4	344.8	109.0	32	17	35.8	156.0	21.0	C	–	E
SUMMARY	W64	405.1	1547.9	109.0	27	17	35.8	156.0	21.0	C	–	E
Burdigalian	W11	210.2	666.6	39.4	19	3	0.9	91.4	18.9	D	18.9	D
<i>Neuhofener Layer</i>	W11	165.4	216.0	39.4	24	3	0.9	91.4	18.9	D	18.9	D
SUMMARY	W11	210.2	1029.6	39.4	19	3	0.9	91.4	18.9	D	18.9	D
Aquitanian	W68	253.1	411.2	102.0	40	13	28.8	171.8	4.7	B	14.7	B
SUMMARY	W68	299.3	1627.3	102.0	34	13	28.8	171.8	4.7	B	14.7	B
Aquitanian	W67	191.2	373.5	55.0	29	6	20.9	160.2	3.2	C	13.2	C
Chatian	W67	71.4	71.4	28.9	40	6	15.2	155.3	3.4	D	13.4	D
<i>Chatian Marls</i>	W67	71.4	71.4	28.9	40	6	15.2	155.3	3.4	D	13.4	D
<i>Chatian Sands</i>	W67	71.8	71.8	8.8	12	6	12.3	162.8	14.0	D	24.0	D
SUMMARY	W67	262.6	1547.2	83.9	32	12	20.9	158.5	4.0	C	14.0	C
Aquitanian	W3	445.5	445.7	239.7	54	48	24.0	63.7	23.0	C	33.0	D
Chatian	W3	74.7	80.5	50.9	68	5	22.0	67.4	3.0	C	13.0	C

Table 3 (continued)

Unit	Well	log length [m]	Thickness [m]	len BO [m]	BO/Log (%)	BO count	max Devi	S_{Hmax}	std	WSM Quality	std mod	mod Quality
------	------	----------------	---------------	------------	------------	----------	----------	------------	-----	-------------	---------	-------------

Reported parameters include length of logged interval (log length), thickness of the unit (thickness) and BO lengths (len BO), intensity of BO length per log length (BO/Log), BO frequency (BO count) and estimated S_{Hmax} orientation (S_{Hmax}), associated standard deviations (std), corresponding WSM quality classes and modified standard deviation (std mod) based on maximum deviation (max Devi) as well as modified Quality (mod Quality). Summary rows provide aggregated results for each well

Main stratigraphic units are in regular font, whereas values in italic refer to subunits

<i>Chatian Marls</i>	W3	74.7	80.5	50.9	68	5	22.0	67.4	3.0	C	13.0	C
SUMMARY	W3	621.1	1553.7	290.6	47	53	24.0	64.5	20.7	C	30.7	D

Appendix A4: Viscous friction loss

Frictional pressure losses ΔP_f mainly depend on the flow path length L , pipe diameter D , dynamic fluid viscosity μ , fluid density ρ , and flow rate Q , which controls the flow regime (e.g., Rennels and Hudson 2012). The flow regime can be expressed by the Reynolds Number Re :

$$Re = \frac{\rho v D}{\mu} \quad (9)$$

where v is the mean flow velocity. For laminar flow ($Re < 2000$), ΔP_f can be calculated using the Darcy–Weisbach equation:

$$\Delta P_f = f_D \frac{L}{D} \frac{\rho v^2}{2} \quad (10)$$

With the Darcy friction factor f_D for laminar flow given by:

$$f_D = \frac{64}{Re}, \quad (11)$$

For fully developed laminar Newtonian flow in a circular pipe, this formulation is equivalent to the Hagen–Poiseuille equation:

$$\Delta P_f = \frac{128 \mu L Q}{(\pi D^4)} \quad (12)$$

In the present test, a KCl-based drilling fluid with a density of $\rho = 1080 \text{ kg/m}^3$ was used. The dynamic viscosity of comparable drilling fluids can vary between approximately 11 and 37 cP (Elkatatny 2017; Leusheva et al. 2022). Drilling fluids of similar density commonly have viscosities on the order of 22 cP, corresponding to $\mu = 0.022 \text{ P} \cdot \text{s}$ (Elkatatny 2017). The flow path length was taken as the measured depth, $L = 1608 \text{ m}$, and the pipe diameter was $D = 127 \text{ mm}$. For each injection cycle, the maximum flow rate listed in Table 4 was used. These flow rates range from $Q = 17.4$ to 26.3 L/min . Using Eq. 9, the resulting Reynolds numbers range from approximately $Re = 85$ to 431 , indicating laminar flow conditions. Applying Eq. 10 together with Eq. 11, or equivalently Eq. 12, gives frictional pressure losses between approximately 0.001 and 0.004 MPa , depending on the assumed dynamic viscosity.

Appendix A5: Results from the extended leak-off test (XLOT) at 1484 m TVD

See Table 4.

Table 4 Test details from XLOT: injection rate (Q_i), injected volume (V_i), fracture breakdown pressure (P_B), fracture re-opening pressure (P_R), propagation pressure (P_{prop}), shut-in pressure (P_{SI}), and fractureclosure pressure (P_{clo}) determined with tangent method ($P_{clo,T}$), with g-function ($P_{clo,G}$), and fracture compliance method ($P_{clo,FC}$)

Cycle	Q_i [L/min]	V_i [L]	P_B [MPa]	P_R [MPa]	P_{prop} [MPa]	P_{SI} [MPa]	$P_{clo,T}$ [MPa]	$P_{clo,G}$ [MPa]	$P_{clo,FC}$ [MPa]
F	17.40	62.30	35.10		32.20	31.00	28.9	28.8	30.3
RF1	17.60	62.50		30.30		33.10	31.5	31.4	33.1
RF2	22.00	52.40	35.50	29.80	31.30	29.10	27.1	27.0	28.6
RF3	23.20	56.10		30.10	30.00	28.20	26.7	26.6	27.9
RF4	26.30	51.90		29.30	29.80	28.20	26.7	(26.4)	28.6

Acknowledgements This study was conducted with the generous support of data provided by Uniper Energy Storage. A special thanks to Evgenia Schauenburg for the preparation of the 3D model that was used for the construction and calculation of the fault displacements. We also acknowledge Prof. Frank Schilling (KIT) for his guidance, expertise, and supervision and Prof. Tobias Rudolph (formerly Uniper Energy Storage, now at Georg Agricola University of Applied Sciences) for his ideas and discussions. Furthermore, we want to thank the Editor-in-Chief, the Topic Editor, and the two anonymous reviewers for their helpful comments, which significantly improved the quality of the manuscript.

Author contributions Thomas Niederhuber: conceptualization, formal analysis, investigation, methodology, software, validation, visualization, writing—original draft. Birgit Müller: conceptualization, supervision, validation, writing—original draft. Annette Lenze: conceptualization, validation, data curation, writing—review and editing. Roman Przyrowski: conceptualization, validation, data curation, writing—review and editing.

Funding Open Access funding enabled and organized by Projekt DEAL.

Availability of data and materials The datasets generated and/or analyzed during the current study are not publicly available. Aggregated or anonymized data supporting the findings of this study may be available upon reasonable request from Uniper Energy Storage.

Declarations

Conflict of interest The authors declare no competing interests.

Open Access This article is licensed under a Creative Commons Attribution 4.0 International License, which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence, and indicate if changes were made. The images or other third party material in this article are included in the article's Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the article's Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. To view a copy of this licence, visit <http://creativecommons.org/licenses/by/4.0/>.

References

Addis MA, Hanssen TH, Yassir N, Willoughby DR, Enever J (1998) A comparison of leak-off test and extended leak-off test data

- for stress estimation. In: SPE/ISRM rock mechanics in petroleum engineering. SPE, Trondheim, Norway, p SPE-47235-MS. <https://doi.org/10.2118/47235-MS>
- Ahlers S, Röckel L, Hergert T, Reiter K, Heidbach O, Henk A, Müller B, Morawietz S, Scheck-Wenderoth M, Anikiev D (2022) The crustal stress field of Germany: a refined prediction. *Geotherm Energy* 10:10. <https://doi.org/10.1186/s40517-022-00222-6>
- Altmann JB, Müller TM, Müller BIR, Tingay MRP, Heidbach O (2010) Poroeleastic contribution to the reservoir stress path. *Int J Rock Mech Min Sci* 47:1104–1113. <https://doi.org/10.1016/j.ijrmms.2010.08.001>
- Anderson EM (1905) The dynamics of faulting. *TRNED* 8:387–402. <https://doi.org/10.1144/transed.8.3.387>
- Angelier J (1984) Tectonic analysis of fault slip data sets. *J Geophys Res* 89:5835–5848. <https://doi.org/10.1029/JB089iB07p05835>
- Bachmann GH, Koch K (1983) Alpine Front and Molasse Basin, Bavaria. In: Bally AW (ed) *Seismic Expression of Structural Styles*. American Association of Petroleum Geologists, pp 21–32
- Bachmann GH, Müller M (1992) Sedimentary and structural evolution of the German Molasse Basin. *Eclogae Geol Helv*. <https://doi.org/10.5169/SEALS-167019>
- Bachmann GH, Müller M, Weggen K (1987) Evolution of the Molasse Basin (Germany, Switzerland). *Tectonophysics* 137:77–92. [https://doi.org/10.1016/0040-1951\(87\)90315-5](https://doi.org/10.1016/0040-1951(87)90315-5)
- Barree RD, Barree VL, Craig DP (2009) Holistic fracture diagnostics: consistent interpretation of prefract injection tests using multiple analysis methods. *SPE Prod Oper* 24:396–406. <https://doi.org/10.2118/107877-PA>
- Barton N, Shen B (2017) Risk of shear failure and extensional failure around over-stressed excavations in brittle rock. *J Rock Mech Geotech Eng* 9:210–225. <https://doi.org/10.1016/j.jrmge.2016.11.004>
- Barton CA, Zoback MD (1994) Stress perturbations associated with active faults penetrated by boreholes: possible evidence for near-complete stress drop and a new technique for stress magnitude measurement. *J Geophys Res* 99:9373–9390. <https://doi.org/10.1029/93JB03359>
- Barton CA, Zoback MD, Burns KL (1988) In-situ stress orientation and magnitude at the Fenton Geothermal Site, New Mexico, determined from wellbore breakouts. *Geophys Res Lett* 15:467–470. <https://doi.org/10.1029/GL015i005p00467>
- Bell JS (1996) Petro Geoscience 2. In situ stresses in sedimentary rocks (part 2): applications of stress measurements. *Geoscience* 23:135–153
- Bell JS, Gough DI (1982) The use of borehole breakouts in the study of crustal stress. In: Zoback MD, Haimson BC (eds) *Workshop on hydraulic fracturing stress measurements*. Menlo Park, California, pp 539–557
- Braun R, Reinhold C (2017) Ermittlung von 3D-Gebirgsspannungszuständen für den Brenner Basistunnel. *Geotechnik* 40:250–264. <https://doi.org/10.1002/gete.201600025>

- Braun R, Jahns E, Stromeyer D (1999) Ermittlung von Gebirgsstrukturen und -belastungen. Teil 1: In-situ-Spannungen und Gesteinsanisotropie. *Erdöl Erdgas Kohle* 115:191–197
- Bredehoeft JD, Wolff RG, Keys WS, Shuter E (1976) Hydraulic fracturing to determine the regional in situ stress field, Piceance Basin, Colorado. *Geol Soc Am Bull* 87:250. [https://doi.org/10.1130/0016-7606\(1976\)87%3c250:HFTDTR%3e2.0.CO;2](https://doi.org/10.1130/0016-7606(1976)87%3c250:HFTDTR%3e2.0.CO;2)
- Bröker K, Ma X (2022) Estimating the least principal stress in a granitic rock mass: systematic mini-fract tests and elaborated pressure transient analysis. *Rock Mech Rock Eng* 55:1931–1954. <https://doi.org/10.1007/s00603-021-02743-1>
- Budach I, Moek I, Lüschen E, Wolfgramm M (2018) Temporal evolution of fault systems in the Upper Jurassic of the Central German Molasse Basin: case study Unterhaching. *Int J Earth Sci (Geol Rundsch)* 107:635–653. <https://doi.org/10.1007/s00531-017-1518-1>
- Dart RL, Swolfs HS (1992) Subparallel faults and horizontal-stress orientations: an evaluation of in-situ stresses inferred from elliptical wellbore enlargements. Structural and tectonic modelling and its application to petroleum geology. Elsevier, pp 519–529
- Desroches J, Kurkjian AL (1999) Applications of wireline stress measurements. *SPE Reserv Eval Eng* 2:451–461. <https://doi.org/10.2118/58086-PA>
- Deutsche Stratigraphische Kommission (DSK) (2022) Stratigraphische Tabelle von Deutschland Kompakt 2022 (STDK 2022). <https://doi.org/10.48440/DSK.STDK.2022>
- Diederichs MS (2003) Manuel Rocha Medal Recipient Rock fracture and collapse under low confinement conditions. *Rock Mech Rock Eng* 36:339–381. <https://doi.org/10.1007/s00603-003-0015-y>
- Draws MC, Bauer W, Caracciolo L, Stollhofen H (2018) Disequilibrium compaction overpressure in shales of the Bavarian Foreland Molasse Basin: results and geographical distribution from velocity-based analyses. *Mar Pet Geol* 92:37–50. <https://doi.org/10.1016/j.marpetgeo.2018.02.017>
- Draws MC, Seithel R, Savvatis A, Kohl T, Stollhofen H (2019) A normal-faulting stress regime in the Bavarian Foreland Molasse Basin? New evidence from detailed analysis of leak-off and formation integrity tests in the greater Munich area, SE-Germany. *Tectonophysics* 755:1–9. <https://doi.org/10.1016/j.tecto.2019.02.011>
- Economides MJ, Nolte KG (eds) (2000) Reservoir stimulation, 3rd edn. Wiley, Chichester
- Elkatatny S (2017) Real-time prediction of rheological parameters of KCl water-based drilling fluid using artificial neural networks. *Arab J Sci Eng* 42:1655–1665. <https://doi.org/10.1007/s13369-016-2409-7>
- Erhardt S, Kraus L (1975) Erdgasspeicher Bierwang. *Technische Mitteilung* 68:346–352
- Eskens LHJ, Andrić-Tomašević N, Süß PM, Müller M, Herrmann R, Ehlers TA (2024) Lithospheric- and crustal-scale controls on variations in foreland basin development in the Northern Alpine Foreland Basin. *Tectonophysics* 878:230283. <https://doi.org/10.1016/j.tecto.2024.230283>
- Faulkner DR, Mitchell TM, Healy D, Heap MJ (2006) Slip on “weak” faults by the rotation of regional stress in the fracture damage zone. *Nature* 444:922–925. <https://doi.org/10.1038/nature05353>
- Fjaer E (ed) (2008) Petroleum related rock mechanics, 2nd edn. Elsevier, Amsterdam, Boston
- Fuchs K, Clauss B (1988) Borehole Breakout Method for stress determination—theory and practice. In: KTB Report 88-8: Arbeitsgruppe 3 ; Spannungsmessungen und Bohrlochstabilität. Niedersächsisches Landesamt für Bodenforschung, pp 66–83
- Gölke M, Coblenz D (1996) Origins of the European regional stress field. *Tectonophysics* 266:11–24. [https://doi.org/10.1016/S0040-1951\(96\)00180-1](https://doi.org/10.1016/S0040-1951(96)00180-1)
- Gronseth JM, Kry PR (1982) Instantaneous shut-in pressure and its relationship to the minimum in-situ stress. In: Zoback MD, Haimson BC (eds) Workshop on hydraulic fracturing stress measurements. Menlo Park, California, pp 147–166
- Gruenthal G, Bosse C (1996) Probabilistische Karte der Erdbebengefährdung der Bundesrepublik Deutschland - Erdbebenzonierungskarte für das Nationale Anwendungsdokument zum Eurocode 8 : Forschungsbericht. Scientific Technical Report; 96/10. <https://doi.org/10.2312/GFZ.B103-96103>
- Gudmundsson A (2004) Effects of Young’s modulus on fault displacement. *C R Geosci* 336:85–92. <https://doi.org/10.1016/j.crte.2003.09.018>
- Haimson BC, Cornet FH (2003) ISRM suggested methods for rock stress estimation—Part 3: hydraulic fracturing (HF) and/or hydraulic testing of pre-existing fractures (HTPF). *Int J Rock Mech Min Sci* 40:1011–1020. <https://doi.org/10.1016/j.ijrmms.2003.08.002>
- Haimson B, Fairhurst C (1967) Initiation and extension of hydraulic fractures in rocks. *Soc Pet Eng J* 7:310–318. <https://doi.org/10.2118/1710-PA>
- Heidbach O, Rajabi M, Di Giacomo D, Harris J, Lammers S, Morawietz S, Pierdominici S, Reiter K, von Specht S, Storchak D, Ziegler MO (2025) World stress map database release 2025. Dataset. <https://doi.org/10.5880/WSM.2025.001>
- Hickman S (2015) Stress, fracturing and borehole integrity: implications for drilling, completion and disposal of radioactive waste at 3–5 km depth in crystalline rock
- Hickman S, Zoback M (1983) The interpretation of hydraulic fracturing pressure-time data for in-situ stress determination. In: Hydraulic fracturing stress measurements, pp 44–54
- Hoek E (1965) Rock fracture under static stress conditions. Dissertation, University of Cape Town
- Hoek E (2023) Practical rock engineering. North Vancouver, British Columbia
- Hoek E, Brown ET (1997) Practical estimates of rock mass strength. *Int J Rock Mech Min Sci* 34:1165–1186. [https://doi.org/10.1016/S1365-1609\(97\)80069-X](https://doi.org/10.1016/S1365-1609(97)80069-X)
- Hubbert MK, Willis DG (1957) Mechanics of hydraulic fracturing. *Trans AIME* 210:153–168. <https://doi.org/10.2118/686-G>
- Ito T, Evans K, Kawai K, Hayashi K (1999) Hydraulic fracture reopening pressure and the estimation of maximum horizontal stress. *Int J Rock Mech Min Sci* 36:811–826. [https://doi.org/10.1016/S0148-9062\(99\)00053-4](https://doi.org/10.1016/S0148-9062(99)00053-4)
- Jaeger JC, Cook NGW (1979) Fundamentals of rock mechanics, 3rd ed, repr. Chapman and Hall, London
- Jarosiński M, Bobek K, Wojtowicz M, Wyglądała M, Kępiński M (2024) Are the Carpathians tectonically active?: geomechanical study in deep boreholes in the outer Carpathians (Poland). *Tectonophysics* 890:230505. <https://doi.org/10.1016/j.tecto.2024.230505>
- Jeßberger J, Uhrmann H, Schölderle F, Pfrang D, Heberle F, Zoseder K, Brüggemann D (2025) Medium-deep geothermal resources in the Molasse Basin: a geological, techno-economic, and ecological study of large-scale heat pump integration. *Renew Energy* 248:123147. <https://doi.org/10.1016/j.renene.2025.123147>
- Jung H, Sharma MM, Cramer DD, Oakes S, McClure MW (2016) Re-examining interpretations of non-ideal behavior during diagnostic fracture injection tests. *J Pet Sci Eng* 145:114–136. <https://doi.org/10.1016/j.petrol.2016.03.016>
- Konstantinovskaya E, Malo M, Castillo DA (2012) Present-day stress analysis of the St. Lawrence Lowlands sedimentary basin (Canada) and implications for caprock integrity during CO2 injection operations. *Tectonophysics* 518:119–137. <https://doi.org/10.1016/j.tecto.2011.11.022>

- Kraus L (1969) Erdöl- und Erdgaslagerstätten im ostbayerischen Molassebecken. *Erdöl-Erdgas-Zeitschrift* 85:442–454
- Kuhlemann J, Kempf O (2002) Post-Eocene evolution of the North Alpine Foreland Basin and its response to Alpine tectonics. *Sediment Geol* 152:45–78. [https://doi.org/10.1016/S0037-0738\(01\)00285-8](https://doi.org/10.1016/S0037-0738(01)00285-8)
- Lee M, Haimson B (1993) Laboratory study of borehole breakouts in Lac du Bonnet granite: a case of extensile failure mechanism. *Int J Rock Mech Min Sci Geomech Abstr* 30:1039–1045. [https://doi.org/10.1016/0148-9062\(93\)90069-P](https://doi.org/10.1016/0148-9062(93)90069-P)
- Leusheva E, Alikhanov N, Morenov V (2022) Barite-free muds for drilling-in the formations with abnormally high pressure. *Fluids (Basel)* 7:268. <https://doi.org/10.3390/fluids7080268>
- Mardia KV (1972) *Statistics of directional data*. Academic Press, London, New York
- Mastin L (1988) Effect of borehole deviation on breakout orientations. *J Geophys Res* 93:9187–9195. <https://doi.org/10.1029/JB093iB08p09187>
- McClure MW, Blyton CA, Jung H, Sharma MM (2014) The effect of changing fracture compliance on pressure transient behavior during diagnostic fracture injection tests. In: SPE annual technical conference and exhibition. SPE, Amsterdam, The Netherlands, p SPE-170956-MS. <https://doi.org/10.2118/170956-MS>
- McClure MW, Jung H, Cramer DD, Sharma MM (2016) The fracture-compliance method for picking closure pressure from diagnostic fracture-injection tests. *SPE J* 21:1321–1339. <https://doi.org/10.2118/179725-PA>
- Megies T, Wassermann J (2014) Microseismicity observed at a non-pressure-stimulated geothermal power plant. *Geothermics* 52:36–49. <https://doi.org/10.1016/j.geothermics.2014.01.002>
- Moos D, Zoback MD (1990) Utilization of observations of well bore failure to constrain the orientation and magnitude of crustal stresses: application to continental, Deep Sea Drilling Project, and Ocean Drilling Program boreholes. *J Geophys Res* 95:9305–9325. <https://doi.org/10.1029/JB095iB06p09305>
- Morawietz S, Heidbach O, Reiter K, Ziegler M, Rajabi M, Zimmermann G, Müller B, Tingay M (2020) An open-access stress magnitude database for Germany and adjacent regions. *Geotherm Energy* 8:25. <https://doi.org/10.1186/s40517-020-00178-5>
- Müller M, Nieberding F, Wanninger A (1988) Tectonic style and pressure distribution at the northern margin of the Alps between Lake Constance and the River Inn. *Geol Rundsch* 77:787–796. <https://doi.org/10.1007/BF01830185>
- Niederhuber T (2025) FAC-tool V1.0. Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/q7yss5j69ve0xsk3>
- Niederhuber T (2026a) Four arm caliper tool (FAC). Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/atd5faew7zpz9hz7>
- Niederhuber T (2026b) Six arm caliper tool (SAC). Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/wa98ty6g7rqb0huh>
- Niederhuber T (2026c) Stress feature result viewer (SFRV). Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/c9g00w1nuen13ytg>
- Niederhuber T (2026d) Stress profiles using directional statistics (SPUDS). Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/kxaxathbk6bzcc5t>
- Niederhuber T (2026e) Stress profiles from borehole breakout opening width (SFBO). Karlsruhe Institute of Technology [Software]. <https://doi.org/10.35097/w9fv3d8s2rwxcpvy>
- Niederhuber T, Müller B, Rudolph T, Schilling F, Schmitt DR (2019) Reservoir stress path for underground gas storage. In: AGU fall meeting abstracts, vol 2019, p T31E-0340
- Niederhuber T, Rische M, Müller BIR, Röckel T, Allgaier F, Fischer KD, Schilling FR, Friederich W (2025a) How can mining data be used for regional stress derivation?—recommendations based on examples from the Ruhr area. *Geomech Energy Environ* 41:100648. <https://doi.org/10.1016/j.gete.2025.100648>
- Niederhuber T, Rische M, Müller BIR, Röckel T, Allgaier F, Fischer KD, Schilling FR, Friederich W (2025b) Geomechanics of flooding-induced microseismicity-implications for post-mining environments. *JGR Solid Earth* 130:e2025JB031323. <https://doi.org/10.1029/2025JB031323>
- Nolte KG (1979) Determination of fracture parameters from fracturing pressure decline. In: SPE annual technical conference and exhibition. SPE, Las Vegas, Nevada, p SPE-8341-MS. <https://doi.org/10.2118/8341-MS>
- Nolte KG, Economides MJ (1989) Fracturing diagnosis using pressure analysis. *Reservoir Stimulation* 7–28
- Obermeier P, Duschl F, Drews MC (2025) Lithologically constrained velocity–density relationships and vertical stress gradients in the North Alpine Foreland Basin, SE Germany. *Solid Earth* 16:425–440. <https://doi.org/10.5194/se-16-425-2025>
- Ortiz R, AE, Renner J, Jung R (2011) Hydromechanical analyses of the hydraulic stimulation of borehole Basel 1: hydromechanical analyses of borehole Basel 1. *Geophys J Int* 185:1266–1287. <https://doi.org/10.1111/j.1365-246X.2011.05005.x>
- Peška P, Zoback MD (1995) Compressive and tensile failure of inclined well bores and determination of in situ stress and rock strength. *J Geophys Res* 100:12791–12811. <https://doi.org/10.1029/95JB00319>
- Plumb RA (1989) Fracture patterns associated with incipient wellbore breakouts. In: ISRM international symposium
- Plumb RA, Hickman SH (1985) Stress-induced borehole elongation: a comparison between the four-arm dipmeter and the borehole televiwer in the Auburn geothermal well. *J Geophys Res* 90:5513–5521. <https://doi.org/10.1029/JB090iB07p05513>
- Raaen AM, Horsrud P, Kjörholt H, Økland D (2006) Improved routine estimation of the minimum horizontal stress component from extended leak-off tests. *Int J Rock Mech Min Sci* 43:37–48. <https://doi.org/10.1016/j.ijrmms.2005.04.005>
- Reinecker J, Müller BIR (2007) Spannungsorientierungen aus Kaliperdaten von Explorationsbohrungen der Jahre 1981 bis 1995 in Bayern - Bericht, Teil II. World Stress Map Project, Karlsruhe
- Reinecker J, Tingay M, Müller B (2003) Borehole breakout analysis from four-arm caliper logs. *World stress map project* 1–5
- Reinecker J, Tingay M, Müller B, Heidbach O (2010) Present-day stress orientation in the Molasse Basin. *Tectonophysics* 482:129–138. <https://doi.org/10.1016/j.tecto.2009.07.021>
- Reiter K (2021) Stress rotation – impact and interaction of rock stiffness and faults. *Solid Earth* 12:1287–1307. <https://doi.org/10.5194/se-12-1287-2021>
- Reiter K, Heidbach O, Ziegler MO (2024) Impact of faults on the remote stress state. *Solid Earth* 15:305–327. <https://doi.org/10.5194/se-15-305-2024>
- Rennels DC, Hudson HM (2012) *Pipe flow: a practical and comprehensive guide*. Wiley, Hoboken
- Röckel L, Ahlers S, Müller B, Reiter K, Heidbach O, Henk A, Hergert T, Schilling F (2022) The analysis of slip tendency of major tectonic faults in Germany. *Solid Earth* 13:1087–1105. <https://doi.org/10.5194/se-13-1087-2022>
- Rohrer H, Mooren D, Georgi K (2001) *Erdgasspeicher Breitbrunn/Eggstätt - Angewandte Geowissenschaften in Planung, Orientierung und Bewertung der Speicherbohrungen*. *Erdöl Erdgas Kohle* 117:292–299
- Rummel F (1986) Abschlussbericht Hydrofrac-Spannungsmessungen in der Schachanlage “Haus-Aden.” Ruhr Universität Bochum
- Rutqvist J, Tsang C-F, Stephansson O (2000) Uncertainty in the maximum principal stress estimated from hydraulic fracturing measurements due to the presence of the induced fracture. *Int J Rock Mech Min Sci* 37:107–120. [https://doi.org/10.1016/S1365-1609\(99\)00097-0](https://doi.org/10.1016/S1365-1609(99)00097-0)

- Santarelli FJ, Tronvoll JT, Svennekjaer M, Skeie H, Henriksen R, Bratli RK (1998) Reservoir stress path: the depletion and the rebound. In: SPE/ISRM rock mechanics in petroleum engineering. SPE, Trondheim, Norway, p SPE-47350-MS. <https://doi.org/10.2118/47350-MS>
- Schmitt DR, Haimson B (2017) Hydraulic fracturing stress measurements in deep holes. Rock mechanics and engineering volume 1: principles. CRC Press, pp 183–225
- Schmitt DR, Currie CA, Zhang L (2012) Crustal stress determination from boreholes and rock cores: fundamental principles. Tectonophysics 580:1–26. <https://doi.org/10.1016/j.tecto.2012.08.029>
- Schölderle F, Pfrang D, Ernst V, Winter T, Zosseder K (2025) Productivity zoning and petrophysical assessment in the Munich metropolitan area for hydro-geothermal utilization using multivariate methods. Geotherm Energy 13:21. <https://doi.org/10.1186/s40517-025-00342-9>
- Seithel RJ (2019) Geomechanical characterization of geothermal reservoirs in the Bavarian Molasse Basin. Dissertation, Karlsruher Institut für Technologie (KIT)
- Seithel R, Steiner U, Müller B, Hecht C, Kohl T (2015) Local stress anomaly in the Bavarian Molasse Basin. Geotherm Energy 3:4. <https://doi.org/10.1186/s40517-014-0023-z>
- Seithel R, Gaucher E, Mueller B, Steiner U, Kohl T (2019) Probability of fault reactivation in the Bavarian Molasse Basin. Geothermics 82:81–90. <https://doi.org/10.1016/j.geothermics.2019.06.004>
- Shatyrbayeva I, Bohnsack D, Duschl F, Drews MC (2023) Comparison and integration of pore pressure measurements and indicators from drilling data in a deep geothermal energy play in SE Germany. Geoenergy 1:geoenergy2023-038. <https://doi.org/10.1144/geoenergy2023-038>
- Sissingh W (1997) Tectonostratigraphy of the North Alpine Foreland Basin: correlation of Tertiary depositional cycles and orogenic phases. Tectonophysics 282:223–256. [https://doi.org/10.1016/S0040-1951\(97\)00221-7](https://doi.org/10.1016/S0040-1951(97)00221-7)
- Sonder LJ (1990) Effects of density contrasts on the orientation of stresses in the lithosphere: relation to principal stress directions in the Transverse Ranges, California. Tectonics 9:761–771. <https://doi.org/10.1029/TC009i004p00761>
- StMWi (2021) Lagerstätten und Rohstoffwirtschaft in Bayern. https://www.stmwi.bayern.de/fileadmin/user_upload/stmwi/Energie/Rohstoffe/2021-10-20_Rohstoffe_in_Bayern_Erdoel_und_Erdgas.pdf. Accessed 28 Aug 2026
- Strobel G, Kosack C, Brombach P, Hagemann (2023) HySTORAGE: preliminary investigations of possible hydrogen losses with focus on a planned hydrogen storage field test in Bierwang. In: Tagungsbericht. Celle
- Teufel LW (1996) Influence of pore pressure and production-induced changes in pore pressure on in situ stress. Sandia National Laboratories, Albuquerque, New Mexico and Livermore. <https://doi.org/10.2172/208315>
- Teufel LW, Rhett DW, Farrell HE (1991) Effect of reservoir depletion and pore pressure drawdown on in situ stress and deformation in the Ekofisk Field, North Sea. In: The 32nd U.S. symposium on rock mechanics (USRMS)
- Tingay M, Muller B, Reinecker J, Heidbach O (2006) State and origin of the present-day stress field in sedimentary basins: new results from the world stress map project. In: Golden Rocks 2006, The 41st U.S. Symposium on Rock Mechanics (USRMS)
- Townend J, Zoback MD (2000) How faulting keeps the crust strong. Geology 28:399. [https://doi.org/10.1130/0091-7613\(2000\)28%3c399:HFKTCS%3e2.0.CO;2](https://doi.org/10.1130/0091-7613(2000)28%3c399:HFKTCS%3e2.0.CO;2)
- Wang H, Sharma MM (2020) A rapid injection flowback test (RIFT) to estimate in-situ stress and pore pressure. J Pet Sci Eng 190:107108. <https://doi.org/10.1016/j.petrol.2020.107108>
- Wolhart SL, Berumen S, Cipolla CL, Barton CA, Branagan PT (2000) Use of hydraulic fracture diagnostics to optimize fracturing jobs in the Arcabuz-Culebra field. In: SPE rocky mountain regional/low-permeability reservoirs symposium and exhibition. SPE, Denver, Colorado, p SPE-60314-MS. <https://doi.org/10.2118/60314-MS>
- Wright CA, Conant RA (1995) Hydraulic fracture reorientation in primary and secondary recovery from low-permeability reservoirs. In: SPE annual technical conference and exhibition. SPE, Dallas, Texas, p SPE-30484-MS. <https://doi.org/10.2118/30484-MS>
- Wright CA, Stewart DW, Emanuele MA, Wright WW (1994) Reorientation of propped refracture treatments in the lost hills field. In: SPE western regional meeting. SPE, Long Beach, California, p SPE-27896-MS. <https://doi.org/10.2118/27896-MS>
- Yale DP (2003) Fault and stress magnitude controls on variations in the orientation of in situ stress. Geol Soc Lond Spec Publ 209:55–64. <https://doi.org/10.1144/GSL.SP.2003.209.01.06>
- Yale DP, Rodriguez JM, Mercer TB, Blaisdell DW (1994) In-situ stress orientation and the effects of local structure—Scott Field, North Sea. In: Rock mechanics in petroleum engineering. SPE, Delft, Netherlands, p SPE-28146-MS. <https://doi.org/10.2118/28146-MS>
- Zain-Ul-Abedin M, Henk A (2020) Building 1D and 3D mechanical earth models for underground gas storage—a case study from the Molasse Basin, Southern Germany. Energies 13:5722. <https://doi.org/10.3390/en13215722>
- Ziegler MO, Heidbach O, Reinecker J, Przybycin AM, Scheck-Wenderoth M (2016) A multi-stage 3-D stress field modelling approach exemplified in the Bavarian Molasse Basin. Solid Earth 7:1365–1382. <https://doi.org/10.5194/se-7-1365-2016>
- Ziegler MO, Seithel R, Niederhuber T, Heidbach O, Kohl T, Müller B, Rajabi M, Reiter K, Röckel L (2024) Stress state at faults: the influence of rock stiffness contrast, stress orientation, and ratio. Solid Earth 15:1047–1063. <https://doi.org/10.5194/se-15-1047-2024>
- Zoback MD (1991) State of stress and crustal deformation along weak transform faults. Philos Trans R Soc Lond A Math Phys Eng Sci 337:141–150. <https://doi.org/10.1098/rsta.1991.0112>
- Zoback MD (2007) Reservoir geomechanics. Cambridge university press, Cambridge
- Zoback MD, Healy JH (1984) Friction, faulting and «in situ» stress. Ann Geophys 2:689–698
- Zoback MD, Zinke JC (2002) Production-induced normal faulting in the Valhall and Ekofisk oil fields. In: Trifu CI (ed) The mechanism of induced seismicity. Birkhäuser Basel, Basel, pp 403–420
- Zoback MD, Moos D, Mastin L, Anderson RN (1985) Well bore break-outs and in situ stress. J Geophys Res 90:5523–5530. <https://doi.org/10.1029/JB090iB07p05523>
- Zoback ML, Zoback MD, Adams J, Assumpção M, Bell S, Bergman EA, Blümling P, Brereton NR, Denham D, Ding J, Fuchs K, Gay N, Gregersen S, Gupta HK, Gvishiani A, Jacob K, Klein R, Knoll P, Magee M, Mercier JL, Müller BC, Paquin C, Rajendran K, Stephansson O, Suarez G, Suter M, Udias A, Xu ZH, Zhizhin M (1989) Global patterns of tectonic stress. Nature 341:291–298. <https://doi.org/10.1038/341291a0>
- Zoback MD, Barton CA, Brudy M, Castillo DA, Finkbeiner T, Grolimund BR, Moos DB, Peska P, Ward CD, Wiprut DJ (2003) Determination of stress orientation and magnitude in deep wells. Int J Rock Mech Min Sci 40:1049–1076. <https://doi.org/10.1016/j.ijrmms.2003.07.001>