State of Stress in Exhumed Basins and Implications for Fluid Flow – Insights from the Illizi Basin, Algeria

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Abstract

The petroleum prospectivity of an exhumed basin is largely dependent on the ability of pre-existing traps to retain oil and gas volumes during and after the exhumation event. Although faults may act as lateral seals in petroleum traps, they may start to become hydraulically conductive again and enable fluid flow and hydrocarbon leakage during fault reactivation. Herein, we constrain the present-day *in situ* stresses of the exhumed Illizi Basin in Algeria, and demonstrate that the primary N–S and NW–SE (vertical strike-slip) fault systems in the study area are close to critical stress (i.e., incipient state of shear failure). In contrast, the overpressured and unexhumed Berkine Basin and Hassi Messaoud areas to the north do not appear to be characterized by critical stress conditions. We present conceptual models of stress evolution and demonstrate that a sedimentary basin with benign *in situ* stresses at maximum burial may change to being characterized by critical stress conditions on existing fault systems during exhumation. These models are supportive of the idea that breaching of a closed, overpressured system during exhumation of the Illizi Basin may have been a driving mechanism for regional updip flow of high-salinity formation water within the Ordovician reservoirs during Eocene–Miocene time. This work also has implications for petroleum exploration in exhumed basins. Fault-bounded traps with faults oriented at a high-angle to the maximum principal horizontal stress direction in strike-slip or normal-faulting stress regimes are more likely to have retained hydrocarbons in exhumed basins in comparison to fault-bounded traps with faults that are more optimally oriented for shear failure and, therefore, have a greater propensity to become critically stressed during exhumation.

Keywords: *in situ* stress, critical stress, exhumation, faults, fluid flow, Illizi Basin

The relative timing of petroleum charge and trap formation in sedimentary basins is a critical factor in the formation of petroleum accumulations in the subsurface (e.g. Magoon & Dow 1994). In normally subsiding basins, active petroleum generation in mature organic-rich source rock results in the expulsion of petroleum fluids that migrate under hydrodynamic and buoyancy forces within carrier beds to ultimately accumulate in petroleum traps or escape to the surface (e.g. Schowalter 1979). However, many sedimentary basins around the world are no longer under conditions of maximum burial and have been subjected to one or more exhumation events during their history (Japsen 1998, Issler *et al.* 1999, Doré *et al.* 2002, Corcoran & Mecklenburgh 2005, Underdown & Redfern 2007, Hillis *et al.* 2008, Dixon *et al.* 2010, Green & Duddy 2010, Japsen *et al.* 2010, Japsen *et al.* 2012, English *et al.* 2016d). Although low levels of petroleum generation may continue during the initial cooling phase (English *et al.* 2016e), the exhumation and cooling of source rocks generally leads to the cessation of active petroleum generation within the basin. Unless the exhumed basin is situated along a migration route from an adjacent normally subsiding basin that is actively generating hydrocarbons, post-exhumation charging of petroleum traps can only occur via the redistribution of hydrocarbons already existing within the basin (e.g. Doré *et al.* 2002, English *et al.* 2016e) or via late-stage exhumation charge during final depressurization of the source rock (English *et al.* 2016a). Aside from these potential post-exhumation charge or remigration mechanisms, the petroleum prospectivity of an exhumed basin is largely dependent on the ability of pre-existing traps to retain oil and gas volumes during and after the exhumation event.

Fluid flow in the subsurface is driven by gradients in fluid potential, which can result from variations in excess water pressure, the natural buoyancy of lower density petroleum fluids within water-saturated rock, and differences in the capillary pressure required for petroleum fluids to displace water from the rock it is trying to penetrate (England *et al.* 1987). In a petroleum trap, the top-seal represents the lithology that prevents the continued vertical migration of petroleum fluids because the capillary entry pressure of the seal exceeds the upwards buoyancy pressure acting on the petroleum phase underneath. Additionally, faults may act as lateral seals in petroleum traps if they juxtapose permeable reservoir rocks against sealing lithologies (Allan 1989, Yielding *et al.* 1997) or if the fault zone itself has become impermeable (e.g. due to clay smearing; Bouvier *et al.* 1989). However, these fault zones may start to become

conductive again and accommodate fluid flow during fault reactivation (Jones & Hillis 2003). Active and critically-stressed faults and fractures can provide high permeability conduits for fluid flow (e.g. Sibson 1994, Barton *et al.* 1995, Sibson 2000, Finkbeiner *et al.* 2001, Rogers 2003, Wiprut & Zoback 2002).

A recent subsurface study based on fluid inclusion and present-day formation water chemistry data from Ordovician sandstones has indicated that long distance, lateral, brine migration and mixing have occurred within the Illizi Basin, Algeria (English *et al.* 2016c). The chemistry of the formation water in the Ordovician sandstone is consistent with derivation from a Triassic–Liassic halite-bearing sequence deposited in the Berkine Basin, which is located > 400 km to the north (Fig. 1). The fluid inclusion record confirms that an early stage, low-salinity brine in the Ordovician sandstones in the Illizi Basin was displaced by a higher salinity fluid (English *et al.* 2016c, English *et al.* 2016e) during ~1.0–1.4 km of exhumation that occurred during the Eocene–Miocene (English *et al.* 2016d) (Fig. 2). Potentiometric maps indicate the presence of an active gravity-flow hydrodynamic regime on the southern flank of the exhumed Illizi Basin and an overpressured system beneath the Triassic salts of the unexhumed Berkine Basin to the north (Chiarelli 1978), and it has been proposed that the release of fluid overpressure during exhumation of the Illizi Basin may have been a critical contributor to updip fluid flux (English *et al.* 2016c).

From a structural perspective, the Illizi and Berkine basins are generally characterized by vertical N–S, NNW and NNE oriented Pan-African basement faults (Fig. 1), while NNE to NE trending basement-involved high-angle Triassic normal faults are locally important in the Berkine Basin. The long-lived vertical strike-slip faults have been reactivated at various points during the geological evolution of the basin with episodes of transpressional or transtensional deformation depending on the orientation of the faults relative to the far-field tectonic stresses at that time (Galeazzi *et al.* 2010). Herein, we constrain the present-day *in situ* stresses of the Illizi Basin and establish if the primary (vertical strike-slip) fault systems within the basin are likely to be critically-stressed. We compare these findings with the *in situ* stresses that have been described from the overpressured Berkine Basin to the north, and conceptually investigate if exhumation of an overpressured sedimentary basin is likely to reactivate pre-existing fault

systems and facilitate basin-scale fluid flow during depressurization. The implications for petroleum system analysis will also be discussed.

Approach

Subsurface *in situ* stresses can be described in terms of three orthogonal principal stress components denoted as maximum principal stress (S_1), intermediate principal stress (S_2), and minimum principal stress (S_3), which by definition are related as follows: $S_1 \geq S_2 \geq S_3$. When one of the principal stresses is vertical, the three orthogonal principal stress components can also be represented by vertical stress (S_v), minimum horizontal stress (S_{hmin}), and maximum horizontal stress (S_{Hmax}). Anderson (1951) described three stress regimes, which are defined based on relative magnitudes: normal faulting ($S_v \geq S_{Hmax} \geq S_{hmin}$), strike-slip faulting ($S_{Hmax} \geq S_v \geq S_{hmin}$), and reverse faulting ($S_{Hmax} \geq S_{hmin} \geq S_v$). The equal signs would correspond to transtensional and transpressive environments respectively. Furthermore, the failure of rock in the subsurface is governed by a relationship between the principal effective stresses and a failure criterion. Terzaghi's effective stress definition is adopted in failure criteria and corresponds to the difference between externally applied stress (S) and the internal pore pressure (P_p) (e.g., Terzaghi 1943, Jaeger *et al.* 2007, Fjær *et al.* 2008). Herein, we will denote the maximum, intermediate and minimum effective stresses as σ_1 , σ_2 and σ_3 respectively, and use σ_v , σ_{hmin} and σ_{Hmax} when discussing the vertical, minimum horizontal and maximum horizontal effective stresses. We utilize the Mohr-Coulomb failure criterion whereby instability or shear failure occurs beyond a limiting ratio of maximum to minimum effective stress. This ratio is governed by the frictional properties of a pre-existing, cohesion-less, and optimally-oriented fault zone (referenced and discussed in greater detail below).

In order to evaluate the probability of fluid leakage along bounding faults, or/and leakage through top seals, it is important to understand the burial and exhumation history of the basin, in addition to the present-day *in situ* pore pressure and stress state. A variety of techniques for estimating the magnitude and timing of exhumation have been studied and are well accepted in the literature (e.g. Corcoran & Doré 2002). These techniques provide a reliable understanding of a particular basin's burial history as well as the timing of petroleum generation and charging of

petroleum traps (e.g. Illizi Basin - English *et al.* 2016e). Pore fluid pressure (P_p) and total overburden stress (S_v) are generally well constrained in subsurface wellbores because adequate measurements and logging runs are frequently available, and can be readily interpreted. The orientation of S_{Hmax} is available in many basins through the World Stress Map project (Heidbach *et al.* 2009), and it can also be locally constrained through analysis of well logs that detect characteristic features (e.g., borehole breakouts, drilling-induced tensile wall fractures, acoustic anisotropy) unambiguously induced by the *in situ* far-field stress state.

The most reliable and direct measurements of *in situ* minimum principal stress (S_3) magnitude are those derived from analysis of injection tests (e.g., leak-off tests, extended leak-off tests, minifrac, wireline fracs, diagnostic formation injection tests, step-rate tests). When properly conducted, ideally with a downhole pressure gauge, these tests measure (1) the downhole fluid pressures required to create and propagate hydraulically induced fractures, and (2) the pressures under which these newly created fractures close. The instantaneous shut-in pressure (ISIP) is, by definition, the pressure during hydraulic fracturing immediately after shut-in. It is generally lower than the fracture propagation pressure (FPP) but greater than the fracture closure pressure (FCP). The ISIP can be considered a reliable upper bound for S_3 magnitude. However, this pressure can be significantly in excess of S_3 depending on the treatment and the rock type. In particular, in tight formations such as the Ordovician sandstone in the study area, the ISIPs are generally above the interpreted FCPs. The FCP is the fluid pressure that counteracts the stress in the rock perpendicular to the plane of the induced fracture at the point of closure. Hence, the FCP is considered to be equal to, or slightly lower than, the magnitude of S_3 , and it provides an estimate of S_{hmin} in normal-faulting and strike-slip faulting stress regimes, and an estimate of S_v in a reverse-faulting stress regime. The FCP is interpreted after monitoring the pressure diffusion as a function of time after the well is shut-in (i.e., no flow). A detailed summary of the various regression methods for interpreting the FCP is provided by Barree *et al.* (2007).

In contrast to the minimum principal stress, the magnitude of S_{Hmax} cannot be directly measured. One approach for constraining the magnitude of S_{Hmax} is based on frictional limits theory which states that the ratio of the maximum effective stress (σ_1) to the minimum effective stress (σ_3) is limited by the magnitude required to cause faulting on pre-existing, optimally

oriented fault planes (Zoback & Healy 1984, Townend & Zoback 2000). The Mohr-Coulomb frictional sliding criterion on an optimally oriented fault is given by (e.g. Jaeger *et al.* 2007, Zoback 2007):

$$\frac{\sigma_1}{\sigma_3} = \frac{(S_1 - P_p)}{(S_3 - P_p)} \leq \left(\sqrt{(1 + \mu^2)} + \mu \right)^2 \quad (1)$$

where μ is the coefficient of friction. Essentially, the Mohr-Coulomb criterion states that for any given magnitude of σ_3 , there is a maximum limit to the magnitude of σ_1 established by the frictional strength of the pre-existing faults. Based on a global compilation of *in situ* stress measurements, the ratio of maximum and minimum effective stresses (σ_1/σ_3) are observed to correspond to a crust in equilibrium with, or at least limited by, frictional failure with μ in the range of 0.6 to 1.0 (Zoback & Healy 1984, Townend & Zoback 2000). This is the same range for coefficient of friction that has been observed in laboratory experiments (Byerlee 1978). If we assume a typical value of 0.6 for μ , the limiting ratio of the maximum and minimum effective stresses (σ_1/σ_3) is equal to 3.1. Utilizing this hypothesis, and Anderson's classification system for faulting, it is possible to construct a stress polygon (Fig. 3) that constrains the range of possible stress states and magnitudes at a particular depth and given pore pressure (Zoback *et al.* 1986, Moos & Zoback 1990). The boundaries of the stress polygon define the maximum allowable differential stress (for a given pore pressure), limited by the strength of pre-existing faults within the crust. The region within the stress polygon captures the range of possible stress states for each particular faulting regime (Fig. 3; NF, normal-faulting; SS, strike-slip faulting; RF, reverse-faulting).

For the purposes of our study, we modify the stress polygon in Figure 3 by plotting the horizontal principal effective stresses normalized by the vertical effective stress, and hence construct an equivalent effective stress ratio (ESR) polygon. The ESR polygon enables us to depict stress and pressure data from various depths and locations within the same diagram. As stated above, the inherent assumption with the stress polygon approach is that the state of stress is limited by faults that are optimally oriented for frictional shear failure in the present-day stress regime. In this study, we also assess how the frictional limit will vary as a function of fault angle. This becomes relevant when the pre-existing faults are sub-optimally oriented for reactivation, but may still act to limit the maximum differential effective stress. Hence, in addition to

constructing the perimeter of the ESR polygon as a function of μ , we can also use the angle β (Fig. 4), which is defined as the angle between the normal of the sliding fault plane and the maximum principal stress direction. In fact, the parameters μ and β are closely related via the following equation (e.g. Jaeger *et al.* 2007, Fjær *et al.* 2008):

$$\beta = \frac{\pi}{4} + \frac{\tan^{-1} \mu}{2} \quad (2)$$

Geomechanical Characterization of the Illizi Basin

The Illizi and Berkine basins in southeastern Algeria contain more than 6000 m of Paleozoic–Mesozoic strata (Echikh 1998, Dixon *et al.* 2010, Galeazzi *et al.* 2010). This study focuses on geomechanical data collected from a large (80 km by 50 km) Ordovician gas-condensate field in the southern Illizi Basin (Fig. 1), where intraplate uplift resulted in ~1.0–1.4 km of exhumation during the Eocene–Miocene (English *et al.* 2016d). This field is a large, low-relief four-way structural closure with a hydrocarbon column in excess of 100 m. The reservoir is Upper Ordovician (Ashgill) glacial to glacio-marine Unit IV sandstone, and this sequence is capped by the lower Silurian mudrocks which provide both the source rock and seal (English *et al.* 2016e). Other Ordovician fields in the Illizi Basin include Tin Fouyé Tabankort, Ohanet and In Amenas (Fig. 1).

Mechanical Properties

Rock strength testing on core is necessary to constrain the *in situ* stress tensor – in particular the magnitude of S_{Hmax} – when using the stress polygon approach (Moos & Zoback 1990). The results from a series of uniaxial and triaxial mechanical tests conducted on Silurian shale and Ordovician sandstone cores are summarized in Table 1.

The unconfined compressive strength (C_0) of the Ordovician sandstone exhibits values ranging from 90 MPa to 191 MPa with a mean of 144 (± 36) MPa. Even though this is a wide range, these sandstones can be described as strong, primarily due to their well-cemented, low porosity characteristics (see English *et al.* 2016b). It is noteworthy that the weakest sandstone in

the dataset (90 MPa) has relatively high porosity (11%), while the relatively stronger samples have lower porosities (< 6%). Table 1 also shows a suite of Ordovician IV-3 sandstone samples (Well D, ~1922 m depth) tested at different confining pressures. The resulting peak strength values enable us to derive a value for C_0 and the coefficient of internal friction (μ_i) by using regression analysis. Since the resulting peak stress at failure for the sample tested at 4.1 MPa confinement appears comparatively low, we excluded it from the regression analysis. Using the remaining three samples, we calculated an unconfined compressive strength of $C_0 = 108$ MPa (which is within the range of values obtained from the unconfined tests) and a coefficient of internal friction of $\mu_i = 1.42$ (a typical value for strong sandstones).

By comparison, the confined compressive strength of the Silurian shale is relatively low (29-37 MPa) indicating a much weaker rock. The marked difference in mechanical properties between the Ordovician sandstone and the Silurian shale is also apparent in the measured Young's modulus and Poisson's ratio. Across the uniaxial and triaxial tests (19 measurements), the Ordovician sandstone Young's moduli range from 41 GPa to 70 GPa with a mean of 50 (± 7) GPa, and Poisson's ratio varies from 0.06-0.18 with a mean of 0.12 (± 0.03). In contrast, the Silurian shale Young's moduli are much lower ranging from 6-8 GPa whilst the Poisson's ratio is higher ranging from 0.25-0.26 (both based on only 2 measurements). Hence, the Silurian shale is a much softer and compliant formation in comparison to the Ordovician sandstones.

Pore Pressure

In general, the Illizi Basin is normally pressured and present-day potentiometric maps suggest northward hydrodynamic flow of meteoric water from elevated outcrops in the south (Chiarelli 1978). The reservoir pressure within the Ordovician reservoir in the field is 20.2 MPa at a depth of 1917 m measured depth (-1462 m true vertical depth subsea), which equates to a pressure gradient of 10.6 kPa/m with respect to surface. The pore pressure is slightly elevated with respect to a hydrostatic gradient due to the presence of a gas column (Fig. 5) and the presence of high-salinity formation water (English *et al.* 2016c). As the field is not yet in production, virgin pore pressure conditions have been assumed throughout the study.

Vertical Stress Magnitude

The total vertical stress or overburden stress (S_v) can be approximated by the weight of the overlying rocks (e.g. Zoback *et al.* 2003, Zoback 2007, Jaeger *et al.* 2007):

$$S_v = \int_0^z \rho g dz \quad (3)$$

where ρ is the density of the overburden, z is depth and g is the gravitational acceleration. Wireline density log measurements from seven (7) vertical wells in the study area were used to estimate the bulk density of the rock column. The bulk density of the shallowest preserved section, where no open hole log measurements are available, was estimated via a linear extrapolation of the underlying section. This was appropriate since this sequence is overcompacted due to deeper burial in the past, and no major unconformities exist in the preserved stratigraphic column. The vertical stress profiles obtained for the study area are shown in Figure 5. The resulting overburden curves are consistent from well to well. At 2 km depth, the average overburden stress gradient is 24.9 kPa/m, although it predominantly ranges from 24.8 kPa/m to 25.2 kPa/m with one outlier at 24.4 kPa/m. The relatively high magnitudes are a result of the overcompacted nature of the sedimentary rocks because of deeper burial in the past (English *et al.* 2016e). The small variations in vertical stress across the study area may in part be a function of spatial variation in exhumation patterns and in part a function of lateral changes in facies and lithologies through the rock column.

Maximum Horizontal Stress Azimuth

The orientation of the maximum horizontal stress (S_{Hmax}) in the Illizi Basin can be determined using drilling-induced tensile fractures (DITFs) and stress-induced borehole breakouts observed on electrical and/or acoustic image logs. In the study area, image logs are available from eleven wells with coverage exclusively over the basal Silurian shale and Ordovician reservoir sequence. Table 2 presents the statistics (i.e., mean as well as standard error) of S_{Hmax} azimuth based on both DITF and breakout orientations from the image logs. The mean azimuths for each well (based solely on the DITFs) are plotted on a Top Ordovician depth structure map in Figure 6. The quality of each data point is assigned based on the criteria of the

World Stress Map project (Heidbach *et al.* 2009). DITFs represent the predominant wellbore failure feature in the Ordovician sandstones. These features can be generated either by high overbalance in the well during drilling (i.e., mud weights appreciably above the formation pore pressure) or they are indicative of tectonic environments with a large difference between the magnitude of the two horizontal stresses (e.g., strike-slip faulting stress-state; Fig. 3; Zoback 2007). In this study, the wells were only drilled with slight overbalance (ΔP = mud pressure – pore pressure ≈ 1.3 MPa), and the common presence of DITFs likely reflects a high differential in the horizontal stresses. The orientation of S_{Hmax} is generally NW–SE to NNW–SSE based on the average values for both the observed DITFs (325°N) and borehole breakouts (320°N) (Table 2). Well C is the only anomaly where the S_{Hmax} orientation is interpreted to be north–south (Fig. 6; Table 2); the explanation for this stress rotation remains poorly understood but it is possible that it is purely a local feature related to a minor fault. The average 320°N azimuth for S_{Hmax} (based on DITFs) is regionally consistent when integrated with observations from other Ordovician fields in the Illizi Basin (Fig. 1) including Tin Fouyé Tabankort (320°N, Donati *et al.* 2016) and Tiguentourine (336°N, Patton *et al.* 2003), and it is broadly perpendicular to the Atlas Front to the north (Fig. 1). Furthermore, when comparing the observed S_{Hmax} azimuths with the orientation of the major fault systems in the Illizi Basin (Figs. 1 and 6), we conclude that these faults often fall within a range of 30° to 40° from the regional S_{Hmax} azimuth. The significance of this observation will be discussed below.

Minimum Horizontal Stress Magnitude

A series of thirty two injection tests from eight (8) wells were analysed in this study, and enable us to constrain S_3 for the Ordovician reservoir in the study area. Note that for normal and strike-slip tectonic environments, the minimum principal stress is the minimum horizontal total stress (i.e., $S_3 = S_{hmin}$). A variety of different types of injection tests were used in the area, including minifracs, step rate tests (SRTs), diagnostic injection formation tests (DFITs), and tests run using the Reservoir Characterization Instrument™ (RCI™) (Table 3). All tests were executed successfully, and the acquired data is of satisfactory to very good quality and is suitable for detailed analysis. The ISIP, FPP, and FCP were interpreted in each of these tests – the latter by using both square-root (time) and Nolte-G derivative analyses (Fig. 7) (see detailed description

of analytical techniques in Barree *et al.* 2007). Maximum and minimum FCP picks were also identified during the G-function and square-root (time) derivative analyses of the pressure fall-off data to characterize the range of possible values (Fig. 7), and a quality index was assigned to each data point (Table 3). Based on the FCP points, values for the S_{hmin} gradient exhibit a wide range from as low as 12.7 kPa/m to as high as 23.4 kPa/m (Table 3). This range for S_{hmin} partially overlaps with the theoretical frictional limits for the normal-faulting stress regime assuming that S_v is the maximum principal stress and that μ ranges from 0.6–1.0. The highest gradients were interpreted in Well F (18.2 kPa/m and 23.4 kPa/m) with the highest value being within 6% of the average overburden gradient at 2 km depth. The origin of the higher stress in Well F is poorly understood. The highest FCP pick in Well F comes from the lower injection volume DFIT, while the subsequent higher injection volume minifrac data displays some evidence for multiple closure events in the fall-off data (see wide range of FCP estimates in Table 3). Therefore, one possible explanation for the anomalously high FCP is that the initial DFIT was detecting closure of a natural fracture that is not oriented parallel to S_{Hmax} , and hence this FCP does not give a representative estimate of S_{hmin} . All other wells indicate minimum principal horizontal stresses that are appreciably lower with gradients generally in the 13.5 kPa/m to 16.5 kPa/m range (Fig. 5).

The overall clustering of the S_{hmin} gradients in the 13.5 to 16.5 kPa/m range is in line with observations from other Ordovician fields in the Illizi Basin. Patton *et al.* (2003) reported a S_{hmin}/S_v ratio of 0.59 for the Tiguentourine field, which would have the typical S_{hmin} gradients in this field in the 14.5 to 15.0 kPa/m range. Based on 20 different tests in the Tin Fouyé Tabankort field, the fracture gradient is reported to range from 12.2 kPa/m up to 31.7 kPa/m (Baylocq *et al.* 1998); excluding the two highest and anomalous measurements, the average of the remaining 18 measurements is 16.0 kPa/m.

Maximum Horizontal Stress Magnitude

The drilling induced tensile fractures observed in the image logs from the vertical wells are mostly (sub-) axial (Fig. 8), and hence we infer that the overburden is a principal stress axis in the Ordovician reservoir of the Illizi Basin. From this, it follows that the *in situ* stress tensor

consists of four independent parameters: one vertical stress magnitude, two orthogonal horizontal stress magnitudes, and one angle. The constraints on the magnitudes of S_v and S_{hmin} , and the orientation of S_{Hmax} have been discussed above, and in this section we discuss the available constraints on the magnitude of S_{Hmax} .

To constrain the magnitude of S_{Hmax} using the stress polygon approach, the distribution of stress-induced failures as a function of depth is required. Drilling-induced tensile fractures (DITFs) are very common across the Ordovician section in the vertical wells studied (Fig. 8), whilst there are very few of these in the Silurian section. Where DITFs are present, a minimum constraint on the magnitude of S_{Hmax} can be derived using the following equation (Zoback 2007):

$$S_{Hmax} = 3S_{hmin} - 2P_p - \Delta P - T_0 - \sigma^{\Delta T} \quad (4)$$

where ΔP is the difference between mud weight pressure and the formation pore pressure, T_0 is the tensile strength of the rock and $\sigma^{\Delta T}$ is the thermal stress. In terms of sign convention here, T_0 is a negative quantity. The thermal stress is given by:

$$\sigma^{\Delta T} = \frac{\alpha_T E \Delta T}{1 - \nu} \quad (5)$$

where α_T is the coefficient of linear thermal expansion, E is Young's modulus, ν is Poisson's ratio and ΔT is the temperature differential between the mud and the formation (and is a positive term when the mud temperature is lower than the formation temperature).

In contrast to the DITFs, only very few breakouts are interpreted within the wells studied. The exception is Well C, where breakouts are more common and this also coincides with an anomalous S_{Hmax} azimuth (Table 2; Fig. 6). Based on the general absence of breakouts in the Ordovician sections, a maximum constraint on the magnitude of S_{Hmax} can be derived using the following equation (Barton *et al.* 1988, Zoback *et al.* 2003):

$$S_{Hmax} = \frac{(C_{eff} + 2P_p + \Delta P + \sigma^{\Delta T}) - S_{hmin}(1 + 2 \cos 2\theta_b)}{1 - 2 \cos 2\theta_b} \quad (6)$$

where C_{eff} is the effective compressive strength of the rock and the angle $2\theta_b$ is related to the width of the breakout (w_{bo}) and given by

$$2\theta_b = \pi - w_{bo} \quad (7)$$

Applying the linearized Mohr-Coulomb criterion, the effective compressive strength is given by

$$C_{eff} = \Delta P \left[(\mu_i^2 + 1)^{\frac{1}{2}} + \mu_i \right]^2 + C_0 \quad (8)$$

where μ_i is the internal friction coefficient and C_0 is the unconfined compressive strength.

As most of the pore pressure and S_{hmin} data come from a narrow depth range, we constructed a single representative stress diagram for the Ordovician reservoir in the study area (Fig. 9). The various parameters assumed in the construction of the stress diagram are given in Figure 9. The input S_{hmin} range is based on the typical gradients of 13.5-16.5 kPa/m (Fig. 5). The fact that DITFs coincide with the interval where minifrac, SRTs, DFITs or RCIs were conducted (Fig. 8) provides robust constraints for the stress polygon analysis. It is important to note that the image logs were run prior to conducting these tests.

The resulting range of possible S_{Hmax} magnitudes in the Ordovician sandstones is highlighted by the purple shading, and is bounded by (1) the onset of tensile failure for rock with zero tensile strength and (2) the onset of shear failure (breakout) for rock with a compressive strength of 90 MPa. This highlighted field corresponds to a set of conditions where DITFs are predicted in the Ordovician section but with no expected breakouts in rock with a compressive strength in excess of 90 MPa (a representative minimum value for the Ordovician sandstones based on Table 1). Based on this analysis, S_{Hmax} magnitudes can range from 25.9 MPa (equal to S_{hmin}) up to 62.0 MPa (Fig. 9) corresponding to S_{Hmax} gradients of 13.5 kPa/m up to 32.3 kPa/m. The corresponding S_{Hmax}/S_v ratios are 0.54 and 1.29, and, hence, the allowable stress conditions straddle the boundary between the normal faulting and strike-slip faulting regimes (Fig. 9).

Critical stress in the exhumed Illizi Basin

Based on the data presented in this study, the stress state for this basin can be described as either strike-slip faulting ($S_{Hmax} \geq S_v > S_{hmin}$) or normal faulting ($S_v \geq S_{Hmax} > S_{hmin}$). Furthermore, the stress state is close to the perimeter of the polygon for sliding friction coefficients (μ) between 0.6 and 1.0, equivalent to β angles between approximately 60° and 70° (Fig. 10). These β angles correspond to fault traces at an angle of 30–35° to S_{Hmax} . Taking the typical S_{Hmax} azimuth as 320–335°, critically stressed vertical (strike-slip) faults and fractures

would strike either 285–305° or 350–010°. Comparing these results with local fault traces and their angular relationship to the mapped S_{Hmax} azimuths (Fig. 6), we conclude that some of the major vertical (strike-slip) faults in the area may be critically stressed under the present-day stress field in the Illizi Basin. Similarly oriented faults are also present elsewhere in the basin (Fig. 1), and the effective stress ratios described from the Tiguentourine field (S_{hmin}/S_v ratio of 0.59 and S_{Hmax}/S_v ratio of 1.04) (Patton *et al.* 2003) are consistent with those in our study (Fig. 10). Hence, we conclude that some of the N–S and NW–SE trending vertical (strike-slip) faults in the basin are likely to be in a state of incipient shear failure and, hence, limit the differential stress (i.e., the difference between S_{Hmax} or S_v and S_{hmin}). Unfortunately, direct seismic evidence for these faults being critically-stressed faults is not available on existing earthquake catalogues (e.g., USGS, EMSC etc.). One possible reason is that an adequate seismic monitoring network to reliably detect (minor) earthquakes is unavailable in this part of the world. Additionally, faults and fractures of these orientations are the most likely to be conductive and permeable under the present-day *in situ* stress conditions.

Comparison of stress conditions to unexhumed Berkine Basin and Hassi Messaoud Ridge

The east–west buried axis of the long-lived Ahara high separates the Illizi Basin from the Berkine Basin to the north (Galeazzi *et al.* 2010). While ~1.0–1.4 km of exhumation is estimated to have occurred in the study area in the Illizi Basin during the Eocene–Miocene (English *et al.* 2016d), the magnitude of this exhumation event decreases northward into the Berkine Basin (Fig. 2), and is minimal in its main depocenter where a largely complete Mesozoic–Cenozoic section is preserved (Yahi 1999, Yahi *et al.* 2001, Underdown & Redfern 2008). Previous sonic compaction analyses in the region have documented the difference in burial history across the region and described undercompacted sediments in the Berkine Basin and overcompacted sediments in the Illizi Basin (Dixon *et al.* 2010).

Potentiometric maps indicate the presence of an overpressured system beneath the Triassic salts of the unexhumed Berkine Basin to the north (Chiarelli 1978). The abnormally high pressures in the present-day Hassi Messaoud region, and the Oued Mya and Berkine basins originate in undercompacted shales sealed by the impermeable Triassic salt (Chiarelli 1978, Yahi

et al. 2001). In parts of the basin characterized by deep Hercynian incision, Mesozoic salt-bearing strata were deposited directly on Cambro-Ordovician rocks (Fig. 1; Zeroug *et al.* 2007, Galeazzi *et al.* 2010). In contrast, the exhumed Illizi Basin is generally characterized by close to hydrostatic conditions (Chiarelli 1978; this study) suggesting that significant overpressure either never existed here or has dissipated since uplift from maximum burial conditions.

Hassi Messaoud Field

The Hassi Messaoud field is located on a Hercynian structure located between the Berkine and Oued Mya basins in Algeria (Fig. 1). The reservoirs comprise Cambrian and Lower Ordovician sandstones at depths greater than 3000 m, with oil reserves initially in excess of 25 billion barrels (Balducci & Pommier 1970, Bacheller & Peterson 1991). On the structure, Triassic clastics and salt unconformably overlie the Paleozoic reservoir sequence. The field is compartmentalized by regional (sub-) vertical fault systems trending NE–SW and NNE–SSW, which are interpreted to be impermeable to the circulation of fluids (Zeroug *et al.* 2007). The maximum horizontal stress azimuth is reported to be 315–320° in the Hassi Messaoud area (Koceir & Tiab 2000), similar to that observed in the Illizi Basin (Fig. 6), and hence the sealing faults that compartmentalize the Hassi Messaoud field are generally sub-perpendicular to S_{Hmax} .

The initial reservoir pressure is reported to be 47.4 MPa at a depth of 3200 m (Bacheller & Peterson 1991), although the field has been in production since the 1960s. The initial reservoir pressure corresponds to an overpressured gradient of 14.8 kPa/m, and this area was clearly not in lateral pressure communication with the normally pressured Illizi Basin to the south. The formation salinity is also extremely high at 400,000 ppm (Bacheller & Peterson 1991), and is likely derived from the overlying evaporitic sequence (English *et al.* 2016c). Assuming an overburden gradient of 24.5 kPa/m gives a S_v magnitude of 78.4 MPa at a depth of 3200 m. The minimum horizontal stress magnitude varies considerably across the field due to the coupling between horizontal stress and pore pressure, and the spatial and temporal variability in levels of depletion over the production history of the field (McGowen *et al.* 1996, Zeroug *et al.* 2007). McGowen *et al.* (1996) presented a dataset of fracture gradient and pore pressure data from the Hassi Messaoud field, which can be used to evaluate what the minimum horizontal stress

gradient may have been at virgin conditions (Fig. 11). Unfortunately, specific depth intervals were not provided in the dataset, so some of the scatter may be due to variations in the true vertical depth in each test. However, the dataset is still instructive and indicates that (1) the fracture gradient generally decreases with decreasing pore pressure, and (2) the fracture gradients can approach magnitudes close to the vertical stress gradient (Fig. 11). Using a best-fit trendline through the data, we estimate an initial S_{hmin} gradient of 23 kPa/m, which corresponds to a magnitude of 73.6 MPa at 3200 m depth. We acknowledge, however, that there is significant uncertainty with respect to this value and some of the data points indicate even higher S_{hmin} gradients.

The magnitude of S_{Hmax} is even less well constrained. Differential strain curve analysis (DSCA) on core measurements has indicated a S_{Hmax}/S_{hmin} ratio of 1.25 (Zeroug *et al.* 2007). Taking this ratio, we find that our estimate for the initial stress state of the Hassi Messaoud field plots inside the stress polygon (Fig. 10), and, therefore, even optimally oriented faults in this area would not be in a critical state of incipient mechanical shear failure. In spite of all the uncertainty, these data indicate that the Hassi Messaoud field is markedly different to the Illizi Basin in terms of *in situ* stresses; it is characterized by significant overpressure, a relatively benign stress field within the strike-slip faulting stress regime (i.e. $S_{Hmax} > S_v > S_{hmin}$), and an absence of critically stressed faults.

Berkine Field

Zeroug *et al.* (2007) presented a case study looking at sanding tendency in the Devonian Strunian reservoir of one of the central Berkine fields. As part of the workflow, the vertical stress was estimated from integrated bulk density logs, rock mechanical properties were calibrated to core data, and the least principal stress (S_{hmin}) was calibrated to hydraulic fracture data. All of these data were utilized to construct a mechanical earth model, and the S_{Hmax} magnitude was calibrated to match the borehole breakouts observed on image logs. Although none of the raw data were presented in this case study (Zeroug *et al.* 2007), we have digitized the resulting stress and pore pressure curves for inclusion in this study. The results from the Zeroug *et al.* (2007) study plot inside the stress polygon and mostly within the strike-slip faulting and normal faulting

fields (Fig. 10). The average values based on these data at a depth of 3400 m are: S_v of 80.5 MPa (23.7 kPa/m), S_{hmin} of 73.0 MPa (21.5 kPa/m), S_{Hmax} of 82.2 MPa (24.2 kPa/m), and pore pressure of 40.8 MPa (12.0 kPa/m). As with the Hassi Messaoud example, even optimally oriented faults in this area would not be in a critical state of incipient mechanical shear failure. Once again, these data indicate that the unexhumed Berkine Basin (Fig. 2) is characterized by a different, relatively benign, *in situ* stress state compared to the Illizi Basin, and the basin is characterized instead by overpressure and the absence of critically stressed faults.

Conceptual evolution of *in situ* stress during exhumation

Assuming that a sedimentary sequence is considered to comprise a series of linear-elastic, homogeneous and isotropic layers, we can utilize poroelastic theory to predict how horizontal stresses change during exhumation (English 2012 and references therein). If we assume that the system is perfectly sealed (i.e. no pore pressures changes) and that there is no lateral strain, we can model the changes in both horizontal principal stresses (ΔS_h) as a function of changing vertical stress (ΔS_v) and changing temperature (ΔT) using the following equation:

$$\Delta S_h = \frac{\nu}{1 - \nu} \Delta S_v + \frac{E}{1 - \nu} \alpha_T \Delta T \quad (9)$$

where ν is Poisson's ratio, E is Young's modulus and α_T is the coefficient of linear thermal expansion.

For the purposes of the conceptual models, we will assume the starting *in situ* stress state is equivalent to the average values from the Berkine field (Fig. 12), and we will assume constant pressure (i.e. sealed compartment), constant Poisson's ratio ($\nu = 0.2$) and a constant temperature gradient (35 °C/km) during exhumation from a depth of 3400 m. Four different stress-path models are presented in Figure 12 with successively decreasing importance of the thermal term: (1) $E = 50$ GPa, $\alpha_T = 1.1 \times 10^{-5} \text{ } ^\circ\text{C}^{-1}$; (2) $E = 40$ GPa, $\alpha_T = 0.9 \times 10^{-5} \text{ } ^\circ\text{C}^{-1}$; (3) $E = 30$ GPa, $\alpha_T = 0.7 \times 10^{-5} \text{ } ^\circ\text{C}^{-1}$; (4) no thermal term. The range of α_T values is representative for sedimentary rocks (English & Laubach 2017), while the range of E values is representative of measured mechanical rock properties for the Ordovician sandstone (Table 1). These assumed parameter variations result in markedly different stress paths depending on the importance of the thermal

term in equation (9) above. Note also from equation (9) that a specified fractional change in either E or α_T has the same effect on the horizontal stress calculations – i.e., a 20% reduction in E will have the same impact on the calculations as a 20% reduction in α_T .

Model 1 moves into the normal faulting field, Model 2 moves out to the edge of the strike-slip faulting field, while Models 3 and 4 move into the reverse faulting field (Fig. 12). When the exhumation stress-path reaches the perimeter of the polygon, which is a function of the predominant fault orientation present in a given basin, the associated *in situ* principal stress magnitudes have caused the fault systems to reach the point of incipient critical shear failure (Fig. 12). In other words, the final stress environment is characterized by a critical differential stress, which is markedly higher than at pre-exhumation conditions. Hence, any faults optimally oriented for shear failure are reactivated and would enable fluids to flow and facilitate the dissipation of excess pore pressure. Note, however, that the stress-paths depicted in Figure 12 only apply until fault re-activation occurs. After this point, the assumption of zero lateral strain used to derive equation (9) no longer applies and stress-paths are expected to deviate from what is shown in the figure. The magnitudes of exhumation required in each model to reach critical stress conditions on optimally oriented faults (where $\mu \approx 0.65$) are 888 m, 1304 m, 1436 m, and 1247 m respectively. Although the four models presented here are conceptual, we note that this range of exhumation magnitude is comparable to that documented in the study area (~1.0–1.4 km; English *et al.* 2016c). The amount of exhumation required for reactivation of optimally oriented faults will depend on the trajectory of the stress path and on the initial stress conditions. Faults in basins with benign stress states (i.e. far from frictional shear failure and plotting in the interior of the stress polygon) will require greater magnitudes of exhumation, or have to be hosted in much stiffer rocks (i.e., very high E values), to reach critical state even if the faults are optimally oriented. In some situations, they may in fact never get reactivated. On the contrary, if the initial stress conditions are not far from the critical state, a lower magnitude of exhumation is required to result in the predominant fault system becoming critically stressed even if they are not optimally oriented for failure.

Discussion and Implications

The comprehensive new dataset presented in this study has characterized the *in situ* stresses of the Illizi Basin in Algeria and established that the primary vertical fault systems in this exhumed basin are likely to be critically stressed (Fig. 6). In contrast, the *in situ* stresses in the overpressured Berkine Basin and Hassi Messaoud areas to the north indicate that these areas that are currently at, or close to, their maximum burial depth (Fig. 2) are not characterized by critical stress conditions (Fig. 10). Although the stress data from the Hassi Messaoud and Berkine fields are somewhat limited, and we did not have the possibility to construct our own independent geomechanical models, the significant overpressure and reservoir compartmentalization observed in the Hassi Messaoud field (Zeroug *et al.* 2007) is consistent with the interpreted absence of critical stress conditions here. In summary, we tentatively conclude from this Algerian study that the overpressured Berkine Basin at close to maximum burial is not characterized by critical stress conditions, while parts of the adjacent exhumed Illizi Basin appear to be at, or close to, critical stress conditions along pre-existing optimally oriented fault systems.

Exhumation – fault reactivation and fluid flow

Fluid inclusion and present-day water chemistry data from Ordovician sandstones in the study area have indicated that lateral long-distance brine migration and mixing have occurred within the Illizi Basin (English *et al.* 2016c). The chemistry of the formation water in the Ordovician reservoir is consistent with derivation from a Triassic–Liassic halite-bearing sequence in the Berkine Basin further north (Fig. 1), and the fluid inclusion record indicates that this high-salinity brine displaced a lower salinity formation water during ~1.0–1.4 km of exhumation that occurred in the study area during Eocene–Miocene time (English *et al.* 2016c, English *et al.* 2016e). It has been proposed that breaching of a closed, overpressured system occurred during exhumation of the Illizi Basin, and that this may have been a driving mechanism for regional updip flow of high-salinity formation water (English *et al.* 2016c). Our conceptual stress path models have indicated that a sealed overpressure compartment may be driven towards critical stress conditions if significant cooling accompanies uplift, and if optimally oriented faults are present (Fig. 12). More specifically, given the magnitude of exhumation in the Illizi Basin and its present-day stress state, we can conclude that the Ordovician section may have in fact

followed a stress path that is akin to models 1 and 2. Therefore, it is possible that Eocene–Miocene exhumation of the Illizi Basin resulted in the reactivation of optimally oriented (N–S and NW–SE) vertical faults that facilitated the southward lateral migration of high-salinity brine into the study area.

Exhumation – implications for fault-bounded traps

The petroleum prospectivity of an exhumed basin is largely dependent on the ability of pre-existing traps to retain oil and gas volumes during and after the exhumation event. Based on our conceptual stress evolution modelling, a sedimentary basin with benign *in situ* stresses at maximum burial may change to being characterized by critical stress conditions on the predominant fault system during exhumation. This can occur even if the faults are not optimally oriented for shear failure but the stress path during exhumation reaches a state where sufficient differential stress is eventually resolved on these fault surfaces. Therefore, faulted hydrocarbon-bearing traps may become susceptible to breaching during exhumation if the fault systems are within the favourable orientation range with respect to S_{Hmax} , and the respective level of critical differential stress is reached to reactivate these. The cooling of petroleum source rocks in exhumed basins generally leads to the cessation of active petroleum generation within the basin, and hence it is unlikely that leaky hydrocarbon traps will be recharged unless the exhumed basin is situated along a migration route from an adjacent normally subsiding basin. One possible implication of this is that fault-bounded traps with strike-slip or normal faults oriented at a high-angle (or perpendicular) to S_{Hmax} may be more likely to seal and retain hydrocarbons in exhuming basins compared to fault-bounded traps with optimally oriented, and potentially critically stressed, faults.

Conclusions

A new geomechanical dataset from the exhumed Illizi Basin in Algeria has demonstrated that the primary N–S and NW–SE vertical (strike-slip) fault systems in this region are likely to be at, or close to, critical stress conditions. In contrast, the overpressured Berkine Basin and Hassi Messaoud areas to the north, which are currently at, or close to, their maximum burial

depth, do not appear to be characterized by critical stress conditions. Conceptual models of stress evolution during exhumation have demonstrated that a sedimentary basin with benign *in situ* stresses at maximum burial may change to being characterized by critical stress conditions on existing fault systems if they are within the range of optimal orientations and reach critical differential stresses during exhumation. Therefore, exhumation of an overpressured sedimentary basin is likely to facilitate basin-scale fluid flow during depressurization if the pre-existing fault systems are reactivated. These models are supportive of the idea that breaching of a closed, overpressured system during exhumation of the Illizi Basin may have been a driving mechanism for regional updip flow of formation water within the Ordovician reservoirs during Eocene–Miocene time. Although this study focusses primarily on a specific case study from Algeria, this methodology may be applied in other basins around the world where fault stability is an important factor for assessing the risk of seal failure. One possible implication of this work for petroleum exploration is that fault-bounded traps with strike-slip or normal faults oriented at a high-angle to S_{Hmax} are more likely to have retained hydrocarbons in exhumed basins in comparison to fault-bounded traps with faults that are more optimally oriented for shear failure and have a greater propensity to become critically stressed during exhumation.

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List of Figures

Figure 1: Location of the study area in the Illizi Basin, Algeria (modified from English *et al.* 2016c). Rectangular black box in the Illizi Basin shows the outline of the study area in Figure 6. The vertical strike-slip faults observed in the Illizi Basin correspond to N–S, NNW and NNE oriented Pan-African basement faults. The white-filled triangles show the locations of the fields discussed in the text. TFT, Tin Fouyé Tabankort; Oh., Ohanet; Tig., Tiguentourine.

Figure 2: Burial history models for the Lower Silurian source rock in each of the areas discussed in this study: A, this study, Illizi Basin (English *et al.* 2016e); B, Berkine area (Yahi 1999); C, Hassi Messaoud field (Tissot & Espitalié 1975). The locations of these areas are given in Figure 1.

Figure 3: Stress polygons can be used to constrain the possible magnitudes of S_{hmin} and S_{Hmax} at a particular depth by utilizing Anderson's faulting theory and Coulomb faulting theory for a given coefficient of sliding friction and pore pressure (modified from Zoback *et al.* 2003). The perimeter of the stress polygon delineates the onset of reactivation on optimally oriented faults. NF, normal faulting; SS, strike-slip faulting; RF, reverse faulting.

Figure 4: Effective stress ratio (ESR) diagrams can be used in place of the standard stress polygon (see Figure 3) so that data from different depths and with different pore pressures can be plotted together on one diagram. This figure shows several different polygon perimeters: the black solid and dashed lines depict two different coefficient of sliding frictions ($\mu = 0.6$ and $\mu = 1.0$); the brown dashed lines depict different β angles (measured between the normal of a fault plane and the maximum principal stress direction).

Figure 5: *In situ* stress and pore pressure data obtained from wells in the study area of the Illizi Basin. The fracture closure pressure and the pore pressure data are all from the Ordovician reservoir section. A detailed breakdown of the fracture closure pressure data is presented in Table 3. Based on the fracture closure pressures, the minimum principal horizontal stress (S_{hmin}) is interpreted to generally be in the 13.5 kPa/m to 16.5 kPa/m range, although some higher magnitudes were observed in Well F. This range for S_{hmin} partially overlaps with the theoretical frictional limits for the normal-faulting stress regime assuming that S_v is the maximum principal stress and that μ ranges from 0.6–1.0.

Figure 6: Depth map of the Top Ordovician within the study area in the Illizi Basin (see map outline in Figure 1). The field area is situated on a major structural high within the basin and is outlined by the black polygon. The inwardly pointing black arrow pairs mark the mean azimuth of the maximum principal horizontal stress (S_{Hmax}) as determined from drilling-induced tensile fractures in image logs acquired at the well locations labelled A through I and T and S. The map also shows major, interpreted (vertical strike-slip) faults as dark grey lines; these traces indicate N-S and NW-SE trends, which are oriented at approximately 30° to the average S_{Hmax} azimuth. The rose diagram in the upper right-hand corner illustrates the mean S_{Hmax} azimuth from the image log analysis (Table 2) in black, and the corresponding azimuths in grey for fault systems to be critically-stressed in the present-day stress regime assuming sliding friction values between 0.6 and 1.0, corresponding to β angles between 62° and 67° (see equation 2).

Figure 7: Example of fracture closure pressure interpretation from leak-off test in Well B. The fracture closure pressure (FCP) was interpreted in each test using both Nolte-G and square-root (time) derivative analysis (see Table 3). A detailed summary of these approaches is provided by Barree *et al.* (2007). On the G-function plot (A), fracture closure is identified at the departure of the semi-log derivative ($G \, dP/dG$) from the straight line through the origin. During normal leak-off prior to closure, the first derivative (dP/dG) should be constant, and the primary pressure versus G-function curve should be a straight line. On the square-root (time) plot (B), fracture closure occurs at the inflection point on the pressure versus square-root (time) curve; this is most readily identified by locating the maximum amplitude on the first derivative ($dP/d\sqrt{t}$) curve. The slope of the primary pressure curve starts low, increases to a maximum at the inflection point where fracture closure occurs, and then starts to decrease again. Fracture closure can also be identified at the departure of the semi-log derivative ($\sqrt{t} \, dP/d\sqrt{t}$) from the straight line through the origin. A high confidence fracture closure pressure interpretation (quality rank A as per Table 3) should be consistent on both the G-function and square-root (time) plots – as is the case in the example depicted.

Figure 8: (a) Unwrapped resistivity images showing drilling-induced tensile fractures (DITFs) as commonly observed in the Ordovician section of the vertical wells in the study area. All examples shown here correspond to depth intervals where the fracture closure pressure was measured (Table 3). (b) Gamma ray (left track) and observed drilling-induced tensile fractures

(blue ticks) as a function of depth in well A across the entire imaged interval (right track). The green line denotes Pad-1 azimuth indicating that the imaging tool was rotating. This plot demonstrates how ubiquitous drilling-induced fractures are in the Ordovician sandstone.

Figure 9: Two stress polygons for the Ordovician reservoir in the study area. The polygon with the solid black lines is constructed assuming a sliding friction coefficient $\mu = 0.6$ (equivalent to a fault normal angle with respect to S_{Hmax} azimuth of $\beta = 62^\circ$) whereas the one with the dashed black lines corresponds to $\mu = 1.0$ equivalent to $\beta = 67^\circ$. The range of possible horizontal stress magnitudes is highlighted by the purple shaded polygon, and is bound by (1) representative S_{hmin} range of 13.5-16.5 kPa/m, (2) the observed tensile failure with an assumed tensile strength (purple dashed lines) of as low as zero, and (3) the absence of stress-induced wellbore wall shear failure (i.e., breakouts) for rock with a compressive strength (green dotted lines) of as low as 90 MPa (as per the rock mechanics test results in Table 1). Hence, the highlighted field corresponds to an *in situ* stress state consistent with the occurrence of DITFs, but no breakouts, and the set of parameter conditions listed on the lower right. NF, normal faulting; SS, strike-slip faulting; RF, reverse faulting.

Figure 10: Effective stress ratio (ESR) diagram illustrating the current state of stress in the study area of the Illizi Basin. The plot shows several different polygon perimeters: the black solid and dashed lines depict two different coefficient of sliding frictions respectively $\mu = 0.6$ and $\mu = 1.0$; the brown dashed lines depict different β angles (measured between the normal of a fault plane and the maximum principal stress direction). Based on the angular relationship between the local fault traces and the average S_{Hmax} azimuth (Fig. 6), we conclude that the present-day stress field in the Illizi Basin is likely to be limited by the frictional strength of the major fault trends in the area. The effective stress ratios described from the Tiguentourine field in the Illizi Basin are consistent with those in our study. In contrast, the *in situ* stresses in the overpressured and unexhumed Berkine and Hassi Messaoud fields plot within the effective stress polygon, and, therefore, even optimally oriented faults in these areas would not be in a critical state of incipient mechanical shear failure. NF, normal faulting; SS, strike-slip faulting; RF, reverse faulting.

Figure 11: Fracture gradient versus reservoir pressure data from the Hassi Messaoud field (data from McGowen *et al.* 1996). The Hassi Messaoud field has been in production since the 1960s,

and the minimum horizontal stress magnitude varies considerably across the field due to the coupling between horizontal stress and pore pressure, and the spatial and temporal variability in levels of depletion over the production history of the field. Whilst there is an appreciable amount of scatter and unknown degree of uncertainty in these data, they nonetheless indicate that the fracture gradient generally decreases with decreasing pore pressure, and that the fracture gradients in an undepleted state can approach magnitudes close to the vertical stress.

Figure 12: Effective stress ratio (ESR) diagram illustrating the current state of stress in the Illizi and Berkine basins, and also illustrating some conceptual stress paths during exhumation. The conceptual exhumation models adopt the present-day stresses from the Berkine field for their initial conditions, and utilize linear elasticity and poroelastic theory to predict how horizontal stresses change during exhumation. The models also assume constant pressure (i.e. sealed compartment), constant Poisson's ratio ($\nu = 0.2$) and a constant temperature gradient (35 °C/km) during exhumation from a depth of 3400 m. Four different stress path models are presented with successively decreasing importance of the thermal term (as per equation 9); Model 4 is an end-member model with no thermal effects. NF, normal faulting; SS, strike-slip faulting; RF, reverse faulting.

Table 1: Rock mechanical data, Illizi Basin

Table 2: Maximum horizontal stress orientation in Ordovician Unit IV, Illizi Basin

Table 3: Minimum horizontal stress magnitude in Ordovician Unit IV, Illizi Basin

(a)

Well C

Well D

Well G

Well H

(b)

Well A

drilling-induced
tensile fractures

Table 1. Rock Mechanical Data, Illizi Basin

Well	Core Depth (m)	Formation	Lithology	Porosity (%)	Type of Test	Confining Pressure (MPa)	Unconfined Compressive Strength (MPa)	Confined Compressive Strength (MPa)	Young's Modulus (Gpa)	Poisson's Ratio
A	1916.32	Ordovician IV-3	Sandstone	-	Uniaxial	0	130.27	-	50.06	0.13
A	1916.38	Ordovician IV-3	Sandstone	10.76	Uniaxial	0	90.38	-	43.10	0.15
A	1916.36	Ordovician IV-3	Sandstone	-	Triaxial	30	-	348.53	52.11	0.14
A	1918.40	Ordovician IV-3	Sandstone	-	Uniaxial	0	191.02	-	48.71	0.10
A	1918.58	Ordovician IV-3	Sandstone	1.72	Uniaxial	0	155.93	-	47.82	0.06
A	1918.37	Ordovician IV-3	Sandstone	-	Triaxial	35	-	565*	69.50	0.09
A	1927.77	Ordovician IV-2	Sandstone	-	Uniaxial	0	95.97	-	41.71	0.13
A	1927.84	Ordovician IV-2	Sandstone	3.68	Uniaxial	0	170.81	-	50.27	0.08
A	1927.79	Ordovician IV-2	Sandstone	-	Triaxial	35	-	370.56	49.00	0.16
A	1947.39	Ordovician IV-2	Sandstone	-	Uniaxial	0	149.87	-	44.39	0.13
A	1947.31	Ordovician IV-2	Sandstone	5.72	Uniaxial	0	163.96	-	49.63	0.18
A	1947.36	Ordovician IV-2	Sandstone	-	Triaxial	30	-	452.13	58.42	0.12
D	1920.30	Lower Silurian	Shale	-	Triaxial	4.1	-	28.76	7.80	0.26
D	1920.30	Lower Silurian	Shale	-	Triaxial	10.3	-	36.73	6.07	0.25
D†	1921.80	Ordovician IV-3	Sandstone	-	Triaxial	2.1	-	136.10	-	0.11
D	1921.83	Ordovician IV-3	Sandstone	-	Triaxial	4.1	-	104.73	41.10	0.17
D†	1921.77	Ordovician IV-3	Sandstone	-	Triaxial	6.9	-	160.34	43.16	0.11
D†	1921.86	Ordovician IV-3	Sandstone	-	Triaxial	10.3	-	220.47	46.47	0.12
D	1927.83	Ordovician IV-2	Sandstone	-	Triaxial	6.9	-	94.93	43.16	0.13
D	1935.82	Ordovician IV-1	Sandstone	-	Triaxial	6.9	-	230.28	56.12	0.10
D	1942.18	Ordovician IV-1	Sandstone	-	Triaxial	6.9	-	290.39	56.81	0.15

* No failure at 35 MPa confining pressure up to maximum of 576.49 MPa. Failure observed at 565 MPa when confining pressure reduced to 23.57 MPa

† Using these three samples, we estimate that the unconfined compressive strength (C_0) is 108 MPa and the coefficient of internal friction (μ_i) is 1.42. The sample tested at 4.1 MPa confinement appears comparatively low, and was therefore excluded from the regression analysis.

Table 2. Maximum horizontal stress orientation in Ordovician Unit IV, Illizi Basin

Well	Based on Drilling-Induced Tensile Fractures				Based on Borehole Breakouts			
	Mean S_{Hmax} Orientation (°N)	Standard Error	Count	Quality	Mean S_{Hmax} Orientation (°N)	Standard Error	Count	Quality
A	323.5	1.4	810	C	-	-	-	-
B	312.1	1.3	495	C	308.3	8.7	10	D
C	001.8	1.7	557	C	015.5	5.6	59	B
D	321.0	1.0	1039	A	321.4	6.7	6	D
E	313.5	2.5	143	D	-	-	-	-
Ez	326.9	2.0	85	C	-	-	-	-
F	324.8	2.3	168	B	327.2	18.2	7	D
G	335.2	1.1	693	C	337.1	5.0	8	D
H	332.6	1.7	434	A	319.9	13.0	8	D
I	321.4	1.3	78	B	-	-	-	-
S	339.5	3.3	6	D	-	-	-	-
T	321.2	7.1	8	D	306.9	17.3	8	D
Mean	324.7				320.1			

Quality criteria:

A, azimuth believed to be within $\pm 15^\circ$; ≥ 10 distinct events with a combined length ≥ 100 m and s.d. $\leq 12^\circ$

B, azimuth believed to be within ± 15 - 20° ; ≥ 6 distinct events with a combined length ≥ 40 m and s.d. $\leq 20^\circ$

C, azimuth believed to be within ± 20 - 25° ; ≥ 4 distinct events with a combined length ≥ 20 m and s.d. $\leq 25^\circ$

D, questionable azimuth (± 25 - 40°); < 4 distinct events with a combined length < 20 m and s.d. $\leq 40^\circ$

F. no reliable information ($> + 40^\circ$): no reliable events or s.d. $> 40^\circ$

Table 3. Minimum horizontal stress magnitude in Ordovician Unit IV, Illizi Basin

Well	Depth [m TVD]	Unit	Lithology	Test Type	FPP [MPa]	ISIP [MPa]	FCP [MPa]	$S_3 (= S_{hmin})$ Gradient [kPa/m]	FCP Range [MPa]	S_3 Gradient Range [kPa/m]	Quality
A	1915-1919	IV-3	sandstone	SRT	38.8	35.1	30.3	15.8	29.7-31.0	15.5-16.2	A
				minifrac	39.7	34.1	25.9	13.5	24.3-27.8	12.7-14.5	B
B	1920-1922	IV-3	sandstone	DFIT	n/a	31.5	26.9	14.0	26.6-27.2	13.8-14.2	A
				SRT	n/a	n/a	26.9	14.0	26.6-27.2	13.8-14.2	A
				minifrac	n/a	31.5	26.3	13.7	25.9-26.6	13.5-13.8	B
C	1936-1938	IV-2	sandstone	DFIT	n/a	40.8	29.7	15.3	28.3-32.4	14.6-16.7	C
				SRT	n/a	n/a	30.3	15.6	29.7-31.0	15.3-16.0	A
				minifrac	n/a	43.7	31.7	16.4	31.7-37.9	16.4-19.6	B
D	1926	IV-2	silt/sand	RCI™	30.9	n/a	n/a	16.0	n/a	n/a	C
D	1941	IV-1	sandstone	RCI™	n/a	n/a	29.1	15.0	29.0-31.0	14.9-16.0	B
				RCI™	n/a	n/a	30.0	15.5	29.7-31.0	15.3-16.0	B
D	1946-1947	IV-1	sandstone	SRT	n/a	n/a	29.7	15.3	29.0-30.3	14.9-15.6	A
				minifrac	n/a	n/a	30.0	15.4	29.7-30.3	15.2-15.6	A
D	2071	III-3	sandstone	RCI™	n/a	n/a	32.2	15.5	30.0-33.4	14.5-16.2	B
				RCI™	n/a	n/a	31.0	15.0	28.6-31.0	13.8-15.0	B
D	2086-2087	III-3	sandstone	DFIT	n/a	33.2	32.1	15.4	31.6-32.4	15.1-15.5	A
				SRT	n/a	n/a	29.0	13.9	28.6-30.0	13.7-14.4	B
				minifrac	31.7	n/a	31.6	15.1	31.4-31.7	15.0-15.2	B
Ez	1924-1933	IV-1	sandstone	SRT	36.9	35.8	29.7	15.4	28.8-30.3	14.9-15.7	A
				minifrac	36.6	36.0	28.6	14.8	28.3-29.3	14.7-15.2	A
Ez	1935-1954	IV-1	sandstone	SRT	n/a	27.2	26.6	13.7	26.0-27.6	13.4-14.2	B
				minifrac	n/a	30.6	26.9	13.8	26.6-27.2	13.7-14.0	A
Ez	1955-1980	IV-1	sandstone	SRT	n/a	27.9	26.7	13.6	26.2-27.2	13.3-13.8	B
				minifrac	n/a	29.2	28.1	14.3	28.0-28.3	14.2-14.4	B
F	1973-1974	IV-2	sandstone	DFIT	57.9	53.8	46.2	23.4	44.8-47.6	22.7-24.1	A
				minifrac	64.8	55.6	35.9	18.2	35.2-45.5	17.8-23.1	B
G	1931-1958	IV-3	sandstone	DFIT2	n/a	67.0	32.1	16.5	31.9-32.2	16.4-16.6	A
G	1958-1975	IV-3	sandstone	DFIT3	37.1	35.8	31.0	15.8	30.3-31.7	15.5-16.2	A
				SRT	n/a	n/a	31.7	16.1	31.4-32.4	16.0-16.5	A
				minifrac	42.2	38.0	n/a	n/a	n/a	n/a	C
H	1950-1971	IV-3	sandstone	SRT	n/a	n/a	25.2	12.8	24.5-26.2	12.5-13.3	A
				minifrac	n/a	n/a	25.0	12.7	23.7-25.3	12.1-12.9	B

Abbreviations: DFIT, Diagnostic Fracture Injection Test; SRT, Step-Rate Test; RCI™, Reservoir Characterization Instrument™; ISIP, instantaneous shut-in pressure; FPP, fracture propagation pressure; FCP, fracture closure pressure

Quality criteria: A, pressure points clearly interpretable; B, pressure points less clear; C, no pressure points interpretable