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## Hydraulic stimulation of a deep sandstone reservoir to develop an Enhanced Geothermal System: laboratory and field experiments

Günter Zimmermann*, Andreas Reinicke

GeoForschungsZentrum Potsdam, Telegrafenberg, D-14473 Potsdam, Germany

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### Abstract

The geothermal research well GtGrSk4/05 at Groß Schönebeck, Germany, was hydraulically stimulated to develop an Enhanced Geothermal System in the Upper Rotliegend sandstones. Gel-proppant stimulation was selected to enhance reservoir productivity and to maintain it over the long-term. Before the field tests, laboratory experiments were carried out to study embedding effects and long-term hydraulic conductivity changes in intermediate- and high-strength proppant types. Based on the laboratory results it was decided to place in the stimulated fractures large concentrations of a high-strength proppant. The success of the stimulation of GtGrSk4/05 was confirmed by production test and flowmeter log data.

*Keywords*: Geothermal; EGS; Gel-proppant stimulation; Fracture performance; Fracture face skin; Groß Schönebeck; Germany

### 1. Introduction

For more than 20 years the scientific and industrial community has been involved in developing Enhanced Geothermal Systems (EGS) (e.g. Gérard et al., 2006; Calcagno and Sliaupa, 2008). These are engineered reservoirs created using well stimulation or enhancement treatments to allow the extraction of commercial amounts of heat from low-permeability geothermal systems (e.g. MIT, 2006). For the purpose of testing different techniques, the Groß Schönebeck, Germany, site is used as a downhole geothermal laboratory.

Several conceptual approaches to well stimulation treatments for enhancing well productivity have been developed (e.g. Economides and Nolte, 2000); the three main categories are hydraulic fracturing (Sharma et al., 2004), thermally induced fracturing (Charlez et al., 1996) and chemical stimulation (Bartko et al., 2003; Hardin et al., 2003; Rae and di Lullo, 2003; Nami et al., 2008).

The typical hydraulic fracture stimulations used to increase the connection between wells and low-permeability reservoirs include waterfracs, gel-proppant fracs or a combination of both called hybrid fracs (Sharma et al., 2004). These procedures are well known in the hydrocarbon industry (Shaoul et al., 2007, 2009) and have been used in Hot Dry Rock (HDR) geothermal projects (Baumgärtner et al., 2004; Hettkamp et al., 2004; Schindler et al., 2008).

* Corresponding author. Tel.: +49-331-288-1458; fax: +49-331-288-1577
*E-mail address*: zimm@gfz-potsdam.de (G. Zimmermann)

Hydraulic stimulation has also been applied to hydrothermal reservoirs (Legarth et al., 2003, 2005), but hydrothermal applications require techniques that lead to much higher volumes of fluid production than in typical oil and gas wells. Hydraulic gel-proppant stimulations, where a highly viscous gel and proppants (i.e. artificial ceramics) are injected under high pressure, have rarely been used in geothermal wells.

Since the geothermal reservoir at the Groß Schönebeck site consists of a permeable, porous sandstone layer, a gel-proppant treatment seemed to be appropriate to enhance well productivity. The alternative of using a waterfrac stimulation might have had limited success for two reasons. Stimulation of a permeable layer with water is difficult due to the expected leak-off into the permeable rock and the consequent stop of fracture propagation. The other reason is the low shear failure potential when rocks have few natural fractures like the targeted sandstones (Moeck et al., 2009). Hence, the sustainability of artificially generated fractures in this environment is only ensured if done using additives like proppants, especially around production wells where reservoir pressures decrease as fluids are extracted.

The placement of a sufficiently large pack of the proper type of proppant is key to maintain long-term well productivity. Experience from previous fracture stimulations in the adjacent geothermal well EGrSk3/90 (the injection well) showed the importance of selecting the right type and concentration of proppants to guarantee sufficient fracture conductivity (defined as the product of fracture permeability and fracture aperture) in the sandstones. To be more specific, the hydraulic stimulation experiments in EGrSk3/90 suffered from a lack of fracture self-propping in addition to the crushing of the proppant pack (Legarth et al., 2005; Zimmermann et al., 2009). Hence, two different proppant types were tested to assess their effectiveness in achieving long-term hydraulic conductivity in the generated fracture under simulated in situ conditions and the likelihood of causing mechanical damage that might influence the permeability of the reservoir rock and the proppant-filled fracture.

In the following sections, after a short description of the geological setting of the Groß Schönebeck site, we present the laboratory experiments that were done to assess the most suitable proppant type to use in the field experiment. Then, the stimulation schedule and the fracture modelling are described, including the expected geometry of the induced fractures. Finally, the results of the stimulation experiment are presented and evaluated by a production test carried out in conjunction with flowmeter profiling.

## 2. Geology of the Groß Schönebeck area

The Groß Schönebeck geothermal research site is located in the Northeast German Basin, about 40 km north of Berlin, Germany. There, two wells have been drilled to form a doublet (well GtGrSk4/05 is the producer and EGrSk3/90, the injector); the extracted fluids will be used to generate electricity (Zimmermann et al., 2007; 2010). Both wells are more than 4 km deep targeting permeable porous sandstones and fractured volcanic rocks (andesites) of the Lower Permian (Rotliegend Formation). A detailed geological description and regional stratigraphy for the North German Basin can be found in Norden and Förster (2006). Stable 150 °C bottomhole temperatures were measured in EGrSk3/90 at 4300 m depth (Wolfgramm et al., 2003). Data on stabilized downhole temperatures are not available for GtGrSk4/05.

According to laboratory measurements, the Rotliegend sandstones targeted for the hydraulic stimulation experiments have an effective porosity of 8-10 % and a permeability of up to 16.5 mD (Trautwein and Huenges, 2005). These are well-sorted, medium-to-fine grained, fluvial sandstones. The vertical thickness of the sandstone section is approximately 80 m; due to the deviation of the well the apparent thickness is 150 m. Two gel-proppant fracture treatments were performed in this section. Details of the well path design can be found in Zimmerman et al. (2010).

## 3. Laboratory experiments

### *3.1. Proppant selection and testing*

When selecting proppants one must consider the hydraulic conductivity of the reservoir under in situ stress conditions since it is affected by mechanical stresses on the proppant pack that could lead to proppant crushing and embedding in the formation (Economides and Nolte, 2000). Understanding the hydraulic and mechanical interrelations in the rock-proppant system is indispensable in order to achieve sustainable long-term productivity from a reservoir. Proppant concentration, type, and size influence the fracture width (aperture) and long-term conductivity of fractures under production conditions (Baree et al., 2003; Wen et al., 2007).

Although a variety of fracture damage mechanisms such as fluid invasion (Cinco-Ley and Samaniego-V., 1977; Romero et al., 2003), chemical interactions and clay swelling (Lynn et al., 1998; Moghadasi et al., 2002; Nasr-El-Din 2003; Weaver et al., 2009), particle transport and filtrate invasion (Veerapen et al., 2001; Al-Abduwani et al., 2003) and proppant pack permeability alteration (Wen et al. 2007) have been investigated, hydraulic-mechanical interactions at the fracture face have not been studied.

In order to evaluate the permeability reduction at the fracture face, three different types of permeabilities in the rock-proppant system have to be taken into account (see **Fig. 1**): (a) rock permeability, (b) fracture face permeability and (c) proppant pack permeability (i.e. the permeability of the pack filling the fractures). For this purpose, a cylindrical element of the fracture wall with the adjacent proppant pack is tested experimentally using two different flow cells:

● BiDirectional Flow Cell. The BDFC simulates the geometric flow conditions in reservoirs intersected by a proppant-filled fracture and is used to quantify the permeability reduction at the fracture face, as well as in the proppant pack. A detailed description of this cell is given in Reinicke (2009).

● Long-Term Flow Cell. The LTFC (a high pressure-high temperature apparatus) investigates rock-proppant interactions under in situ geothermal reservoir conditions. Milsch et al. (2010, this issue) describe this cell in detail.

The hydraulic proppant fracturing (HPF) experiment in Groß Schönebeck well EGrSk3/90, has shown that a small proppant pack (1.9 kg/m²) of intermediate-strength proppants (ISP) (20/40 mesh; diameter: 0.4-0.8 mm) can be damaged and embedded in the formation during production (Legarth et al., 2005). Hence, we decided to place a higher concentration (up to 10 kg/m²) of high-strength proppants (HSP) in the fracture when stimulating well GtGrSk4/05. Therefore, two different laboratory setups (BDFC and LTFC) were used to investigate mechanical damage at the fracture face, fracture permeability changes, and long-term stability of these two types of proppant.

*3.2. Experimental results*

Six laboratory experiments were conducted, three with the BDFC and three with the LTFC (**Table 1**). Experiments 1 and 4 investigated the properties of intact rock specimens, while Experiments 2, 3, 5 and 6 studied rock-proppant systems.

Specimens were prepared from Flechtingen sandstone, sampled from an outcrop of rocks similar to those in the reservoir. It is a Lower Permian (Rotliegend) sandstone containing 65% quartz, 13% feldspar, 9% illite and 4% carbonates (Trautwein, 2005); testing parameters are given in Table 1. A diagram showing schematically the location of the test specimens in the well-rock-fracture system is given in Fig. 1; refer to Reinicke (2009) for a detailed description of the experimental setups.

The BDFC setup provides two flow directions, i.e. normal and parallel to the fracture face, and allows determining the permeability of the rock-proppant system (overall specimen permeability including proppant pack, $k_T$) and of the proppant pack itself ($k_f$). In the first step of the experiment, the initial rock permeability ($k_i$) was determined. Then, a tensile fracture was created in the test specimen.

The BDFC was filled with a proppant pack and the fractured rock specimen aligned on top. During the experiment, a constant confining pressure was applied and the specimen was axially loaded to simulate fracture closure under production conditions. Loading was stopped at defined differential stress levels ($\sigma_{diff}$ = 5, 20, 35, 50 MPa) and the differential pore pressure ($\Delta P$) was measured at a constant flow rate (Q). Permeability was calculated according to Darcy's law (Darcy, 1856). Definitions of differential and effective stresses are given by Jaeger et al. (2007).

The LTFC was employed to investigate the long-term permeability behavior of rock-proppant systems in Rotliegend rocks under simulated geothermal reservoir conditions.

The proppant pack was placed in the artificial fracture created by sawing a slit in the rock. The specimen was hydrostatically loaded and a constant pore pressure, as well as a constant flow rate was applied; the maximum effective stress during the experiment was 27 MPa. Results of Experiments 1-3 are shown in **Figs. 2a** and 2b as a function of differential stress, $\sigma_{diff}$. At the beginning and end of axial loading cycle, $\sigma_{diff}$ is negative since the confining stress is higher than the axial stress.

The initial permeability of this Rotliegend sandstone ($k_i$) is about 200 μD with a permeability change of about 15 % within the applied loading range (Fig. 2a). At $\sigma_{diff}$ = -7 MPa, which corresponds to an axial stress of 3 MPa, the permeability of the rock-proppant systems ($k_T$) already shows a clear reduction compared to $k_i$. At maximum $\sigma_{diff}$, the permeability is reduced to 139 ± 3 μD (ISP) and to 138 ± 3 μD (HSP).

Unloading of the specimen does not result in permeability recovery. The permanent reduction in permeability is most likely an effect of the mechanical interaction between the rock and the proppant, and the accompanying damage and fines production at the fracture face. Localization of acoustic emission events in loaded rock-proppant systems shows that during fracture closure most of the damage occurs at the fracture face, particularly at the rock-proppant contact (Reinicke et al., 2006). The damage at the fracture face starts at low externally applied stress and leads to fine production and pore blocking reducing the permeability at the fracture face (**Fig. 3a**). A detailed analysis of this mechanical fracture damage effect and its influence on productivity can be found in Reinicke (2009).

Fig. 2b shows the change in proppant pack permeability ($k_f$) with differential stress ($\sigma_{diff}$). The initial values of $k_f$ were 390 ± 160 D and 338 ± 105 D for ISP and HSP, respectively. The ISP permeability was reduced drastically to 81 ± 16 D at maximum $\sigma_{diff}$ , while the HSP permeability decreases to 228 ± 90 D. For the applied stress levels HSP permeabilities are within the range of manufacturer's data (300-550 D), whereas the ISP permeabilities show a significant discrepancy with the manufacturer's data (210-570 D) (http://www.carboceramics.com/English/oilfield/oilfield.html).

Technical problems inhibited measurement of ISP permeability for $\sigma_{diff}$ of 5 MPa and -7 MPa. After unloading and opening the specimen, it became apparent that the proppant had been destroyed and that fine material was blocking pores within the proppant pack (**Fig. 4b**). These fines were mainly from crushed proppants.

The long-term Experiments (Nos. 4 and 6) were carried out at $\sigma_{eff}$ = 10 MPa; in Experiment 5 the effective stress was increased up to 27 MPa in order to simulate pressure drawdown conditions during testing (nitrogen lift test) operations in well EGrSk3/90 (Legarth et al., 2005). The effective stress of 10 MPa corresponds to the expected effective stress acting on the proppant pack in well GtGrSk4/05 during the test. The results are plotted in Figs. 4 **and 5**.

In the three long-term flow experiments, the permeability reached a constant level after some time. The initial permeability ($k_i$) of the intact specimen used in Experiment 4 was 860 ± 60 μD. After eight days, no further permeability reduction was observed and the permeability stabilised at 120 ± 7 μD, corresponding to a permeability reduction of 86% (Fig. 4).

The results for the HSP rock-proppant system are similar to those for Experiment 4. The long-term permeability ($k_T$) was 109 ± 7 μD; i.e. there was a permeability reduction of 85 % (Fig. 4). In contrast, the ISP rock-proppant system showed a higher reduction (i.e. 93%); the long term-permeability was 38 ± 2 μD (Fig. 5)

Fig. 5 shows the permeability evolution during the ISP experiment as a function of time, temperature and effective stress. Initially, the specimen was loaded using a small effective stress of 2 MPa at 40 °C temperature (Bar a in Fig. 5). An about 50% permeability reduction was observed within the first four days (Bar b in Fig.5), which may be attributed to the chemical-mechanical interaction between the rock and fluid. The Flechtingen sandstone specimen contained about 6 % kaolinite and 9 % illite (Trautwein, 2005). In contact with the pore fluid, kaolinite is dispersed and migrates through the void space, while illite swells under favourable ionic conditions, and subsequently is mobilised (Civan, 2000). The dispersed clay particles can accumulate in the pore throats, thereby blocking fluid flowpaths within the rock and reducing its permeability.

Increasing the effective stress from 2 MPa to 10 MPa on day 7 (Bar c in Fig. 5) led to a further decrease in permeability (from 320 to 170 μD). This further reduction by 50 % is due to consolidation. Increasing the temperature to 150 °C (Bar d in Fig. 5) caused a further decline in permeability to 48 μD (day 8).

Increasing the effective stress to 20 MPa and 27 MPa at the end of Experiment 5 (day 36; Bar f in Fig. 5g) led, respectively, to a permeability reduction of about 11% and 16% with respect to the long-term permeability of 38 ± 2 μD (Bar e in Fig. 5g). The 16% permeability decrease is larger than the change observed in the intact Flechtingen sandstone; for illustration purposes, this change is plotted as a line in Fig. 5 (right panel). This comparison indicates that the mechanical interaction at the rock-proppant interface has affected permeability during the long-term experiment, comparable to the experiments using the BDFC.

As shown by Weaver et al. (2009), chemical effects can have a significant influence on rock-proppant performance in high temperature-high pressure environments. High temperature had a major impact on permeability in Experiment 5 that used ISP. This long-term experiment indicates that thermal-hydraulic and chemical processes, in addition to the mechanical effects, can influence the evolution of permeability in a rock-proppant system. In contrast, the high-strength proppants do not show this temperature influence, the long-term permeability of the HSP rock-proppant system (Experiment 6) is similar to that of the intact specimen (Experiment 4).

### *3.3. Implications for hydraulic stimulations*

In laboratory experiments the permeability of the rock-proppant system stabilizes after a sufficiently long time. Therefore, one would expect that at constant drawdown conditions reservoir permeabilities would not show long-term effects related to mechanical interactions between the proppants and the fracture faces. However, this is only true if HSP are used.

Our experimental results show that the ISP is more stress-sensitive than the HSP. The permeability of the ISP pack was reduced by 75 % with respect to the initial value, whereas that of the HSP only decreased by 40 %. Even under high effective stresses the HSP have provided sufficient fracture conductivity, in contrast to the ISP. Therefore, the HSP is a better choice for hydraulically stimulating the sandstones intersected by the Groß Schönebeck wells.

## 4. Field experiments

### *4.1. Design of gel-proppant treatments*

Prior to stimulating well GtGrSk4/05, the procedure was simulated using the 3D frac code FRACPRO (Cleary, 1994) to determine, for example, expected well pressure changes and dimensions of the created fracture (Zimmermann et al., 2007). The mechanical and hydraulic parameters of the reservoir rocks penetrated by the well used in the calculations are summarized in **Table 2**. For the theory of the mechanics of hydraulic fracturing we refer to Yew (1997), Economides and Nolte (2000) and Guéguen and Boutéca (2004).

According to the simulation, the projected fracture treatment described in Zimmermann et al. (2007) would lead to a fracture half-length of 50 m and a fracture height of 80 m. When assuming a proppant concentration in the fracture of up to 18 kg/m², the calculated average fracture width is 12 mm. In summary, the stimulation would result in a total fracture volume of about 50 m³.

### *4.2. Stimulation of the sandstone formation*

A gel-proppant treatment should be designed to create sufficient hydraulic connection between the wellbore and the reservoir formation so as to increase well productivity. The procedure consists of: (1) an extended leak-off test (e.g. Gaarenstroom et al., 1993; White et al., 2002); (2) a step-rate test; and (3) the regular stimulation treatment.

The Lower Dethlingen Formation sandstones were stimulated in well GtGrSk4/05 on 18-19 August 2007. The targeted interval between 4204 and 4208 m measured depth (MD) was isolated with a bridge plug at 4300 m MD and then perforated (20 circumferential, 15 mm diameter shots per meter).

Coated and uncoated high-strength proppants (HSP) of 0.4 to 0.8 mm diameter (20/40 mesh size) were used in the stimulation. Coated proppants are covered by a resin that keeps the "proppant grains" together creating a barrier near the wellbore region that inhibits the flow-back of these grains into the well during production. The coated proppants (approximately 20 % of the total amount) were used at the end of the treatment to maintain fracture opening near the wellbore. Transport of the proppants was provided by a cross-linked gel of high (about 1000 mPa·s) viscosity.

Well treatment started with an injection test with flow rates in the 5.0-9.5 L/s range. A total of 250 $m^3$ were injected into the reservoir at a maximum wellhead pressure of 41.6 MPa. At the end of this test, the wellhead pressure and injection rate were constant; i.e. 37 MPa and 9.5 L/s, respectively, indicating that the initial injectivity index (ratio between flow rate and differential pressure) was 0.92 $m^3/(h \cdot MPa)$. Friction losses in the wellbore are not included in the calculations since only wellhead pressures were measured.

A leak-off test was carried out (**Fig. 6a**) to obtain the fracture closure pressure (65.8 MPa) and the fracture gradient (0.016 MPa/m), which is the ratio of fracture closure pressure and vertical depth of fracture initiation (at 4107 m total vertical depth). At the beginning, a low proppant concentration (100 g/L) slug was pumped into the well to plug multiple, less conductive fractures and to erode the near-wellbore region to ensure a successful hydraulic stimulation.

This was followed by a step-rate test in order to calculate friction losses and tortuosity at the perforated interval. Finally, the gel-proppant treatment was done according to the schedule assumed in the simulation. Using a stepwise increase of proppant concentration, a total of 95 tons of HSP, including 24 tons of coated proppants and 280 $m^3$ of cross-linked gel, were placed into the fracture of the Lower Dethlingen Formation, at a flow rate of 67 L/s.

### *4.3. Calculation of fracture geometry and conductivity*

Applying the FRACPRO code we modeled fracture propagation and calculated fracture geometry and conductivity, based on field data collected during well treatment, including flow rate and proppant concentration. Figs. 6b and 6c display the calculated fracture widths, heights, and lengths. The computations gave a total fracture height of 115 m and a total half-length of 57 m. The total fracture height is the difference between the upper and lower heights (see Fig. 6b). The upper height indicates the propagation of the fracture upwards from the perforation and the lower height the propagation downwards. At the end of the treatment an average fracture width of 5.3 mm was obtained with a maximum fracture width of almost 10 mm at the borehole perforations.

**Fig. 7** gives another view of the modeled fracture. It shows the lithologic, stress and permeability profiles, as well as the fracture width, fracture conductivity and proppant concentration. The model predicts that a high concentration (up to 15 $kg/m^2$) of proppant was achieved in the lower half of the fracture. On the basis of these modeling results, we assume a maximum fracture conductivity of 1 darcy-meter (Dm) and that a multi-layer (up to 10 layers) proppant pack has been placed.

To conclude, the model suggests that the hydraulic stimulation of the permeable sandstones of the Lower Dethlingen Formation was successful. A highly conductive multilayer proppant pack has been placed in the created fracture, which will provide sustainable, long-term production from that pay zone. The success of this treatment was validated by a subsequent production test (see next section).

### *4.4. Well production test*

A total of three stimulation treatments were performed in well GtGrSk4/05 (Zimmermann et al., 2010). After the last one a production test in conjunction with flowmeter profiling was carried out to obtain data on the stimulated intervals. This test was done as a casing lift test (CLT) with a nitrogen lift. During it approximately 356 $m^3$ of fluid were produced in an 11.8 hour period. The calculated productivity index was 10.1 $m^3/(h \cdot MPa)$.

During production, two flowmeter runs (up and down between 4110 m MD to total depth, at 4400 m MD) were performed to obtain the inflow profile (**Fig. 8**). It showed that nearly 50 % of the fluid flowing into the wellbore could be attributed to this gel-proppant treatment (Zimmermann et al., 2010).

The success of the fracture treatment can be estimated by comparing the calculated injectivity indices for the sandstone layer before and after well stimulation. The calculated injectivity index of the sandstone layer before the treatment was about 1 $m^3/(h \cdot MPa)$; the corresponding productivity index should be the same for moderate differential pressures (Zimmermann et al., 2009). The share of the productivity index attributed to the sandstone layer after stimulation is 50 % of the total flow rate and hence leads to a productivity index of approximately 5 $m^3/(h \cdot MPa)$ for the stimulated sandstone layer. Hence, the treatment increased the productivity of this layer five-fold.

## 5. Conclusions

Lower Permian sandstones of the Northeast German Basin, found at four km depth near Groß Schönebeck, have been hydraulically stimulated for future geothermal energy production. A gel-proppant stimulation was performed in the sandstone section of the Lower Dethlingen Formation to connect the wellbore to a large reservoir rock volume.

The design of the stimulation was based on laboratory experiments done on various proppant types and on numerical simulations analyzing different treatment schedules. The laboratory tests indicated that high-strength proppants (HSP), 20/40 mesh size, would provide long-term fracture permeability, even under high effective stress conditions.

Furthermore, the results of our laboratory and field experiments recommend the use in the fracture of HSPs in conjunction with multilayer proppant packs to achieve good fracture conductivities**.** It was also found that adding resin-coated proppants at the end of the treatment (typically 20 % of the total amount) leads to sustainable and long-term conductivities.

The experiments that were discussed are major steps towards designing procedures to increase the hot water productivity from low-permeability sedimentary reservoirs and demonstrate the importance of hydraulic fracture stimulation in developing geothermal resources for power generation or direct applications.

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## Tables

Table 1
Testing parameters for the rock-proppant interaction experiments using Flechtingen sandstone, and intermediate and high strength proppants (ISP and HSP).
Proppant concentration: 10 kg/m²

| **Using the BiDirectional Flow Cell (BDFC) - Confining pressure: 10 MPa** | | | |
|---|---|---|---|
| | **Rock testing** | **Rock-proppant interaction testing** | |
| Parameters | **Experiment 1** | **Experiment 2** | **Experiment 3** |
| Specimen length | 120 mm | 65.3 mm | 63.3 mm |
| Specimen diameter | 50 mm | 4.8 mm | 3.9 mm |
| Mean pore pressure | 0.13-0.22 MPa | 0.10-0.20 MPa | 0.10-0.22 MPa |
| Differential stress | 0-65 MPa | 0-53.7 MPa | 0-53.8 MPa |
| Strain rate | $8.30\ 10^{-6}\ s^{-1}$ | $1.53\ 10^{-6}\ s^{-1}$ | $1.57\ 10^{-6}\ s^{-1}$ |
| Initial permeability | 196 ± 5 µD | 181 ± 5 µD | 163 ± 4 µD |
| Proppant type | -- | ISP | HSP |
| **Using the Long-Term Flow Cell (LTFC) – Temperature: 40-150 °C** | | | |
| | **Rock testing** | **Rock-proppant interaction testing** | |
| Parameters | **Experiment 4** | **Experiment 5** | **Experiment 6** |
| Specimen length | 40 mm | 43.8 mm | 42.2 mm |
| Specimen diameter | 25 mm | 25 mm | 25 mm |
| Confining pressure | 15-50 MPa | 3–50 MPa | 15–50 MPa |
| Pore pressure | 5-40 MPa | 0.5-40 MPa | 5-40 MPa |
| Effective stress | 10 MPa | 2.5-27 MPa | 10 MPa |
| Initial permeability | 860 ± 60 µD | 540 ± 40 µD | 760 ± 30 µD |
| Proppant type | -- | ISP | HSP |

**Table 2**

Rock mechanics parameters for the deep geothermal reservoir

| **Rotliegend lithology** | **Depth interval (m TVD)** | **Frac pressure (MPa)** | **Closure stress gradient (bar/m)** | **Pore fluid permeability (mD)** | **Young's modulus (GPa)** | **Poisson's ratio** | **Fracture toughness (MPa $m^{1/2}$)** |
|---|---|---|---|---|---|---|---|
| Volcanics | 4211.5 - 4282.0 | 68.4 | 0.16 | 1 | 55 | 0.2 | 1.72 |
| Conglomerates | 4211.5 - 4165.0 | 58.6 | 0.14 | 1 | 55 | 0.2 | 0.42 |
| Lower sandstones | 4165.0 - 4122.0 | 52.2 | 0.125 | 100 | 55 | 0.18 | 0.59 |
| Upper sandstones | 4122.0 - 4036.0 | 59.3 | 0.145 | 10 | 55 | 0.18 | 0.59 |

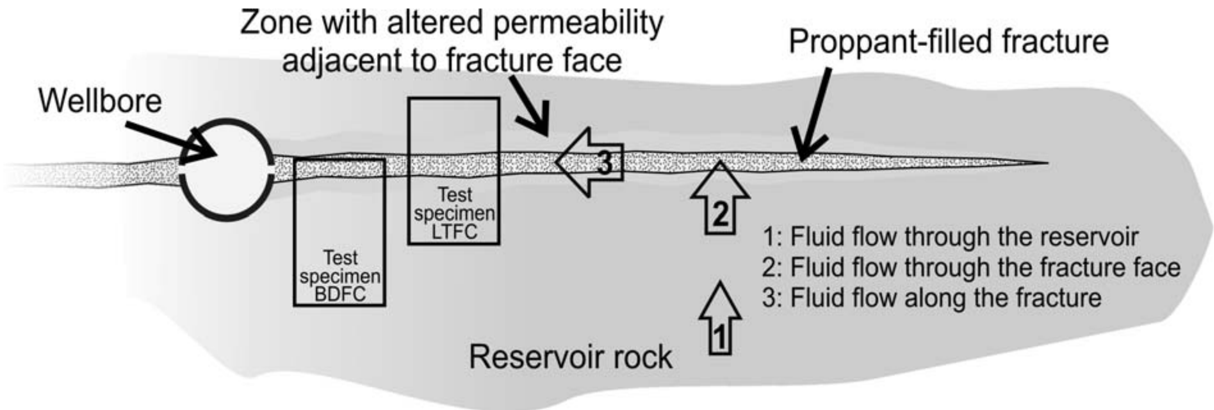


Fig. 1. Schematic diagram showing fluid flow directions in a reservoir with a proppant-filled fracture. Fluid flowing from the reservoir rock (1) and entering the fracture normal to the fracture face (2) is affected by changes in the permeability at that face, before it start flowing along the fracture towards the wellbore of a producing well. To investigate flow impairment at the fracture face the BiDirecional Flow Cell (BDFC) and the Long-Term Flow Cell (LTFC) were used.

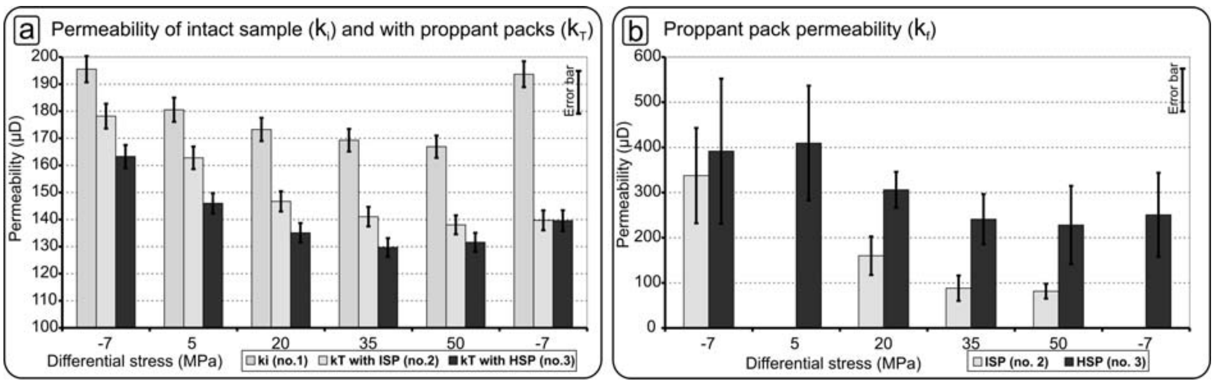


Fig. 2. (a) Permeability of rock-proppant systems as a function of differential stress. (a) Changes in the permeability of intact Rotliegend rock samples ($k_i$ ; Experiment 1) and rock-proppant systems ($k_T$ ; Experiments 2-3). (b) Changes in the permeability of proppant packs ($k_f$ ; Experiments 2-3). ISP: Intermediate-strength proppant; HSP: high-strength proppant.

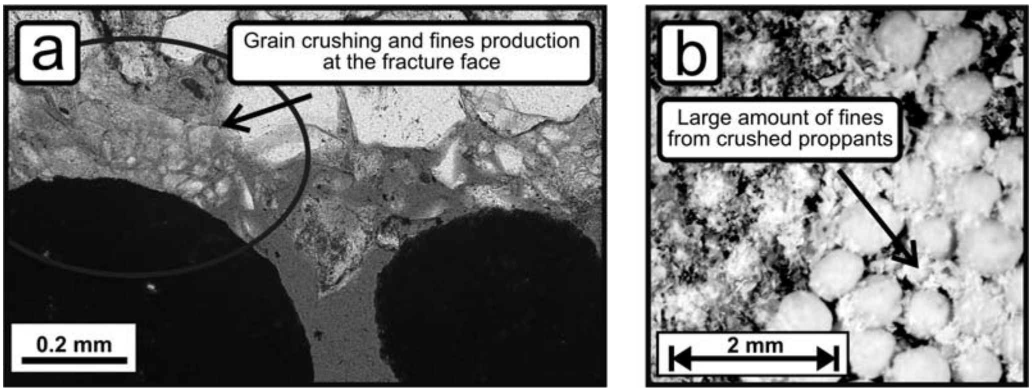


Fig. 3. Microphotographs of rock-proppant interfaces. (a) Grain crushing and fines production at the rock-proppant interface; Dark circular shapes: proppants. (b) Fines produced when an intermediate-strength proppant is crushed.

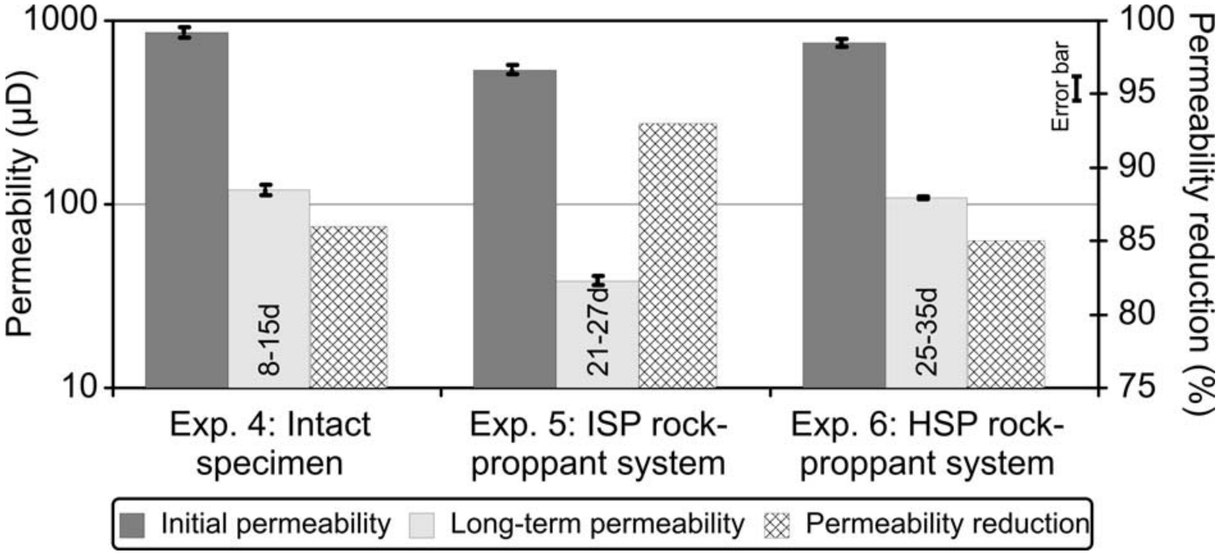


Fig. 4. Long-term permeabilities of a Rotliegend sandstone sample and of rock-proppant systems (ISP: Intermediate-strength proppant; HSP: high-strenght proppant). In all three long-term flow experiments, permeabilities reached a constant level after some time; those times are shown. d: days

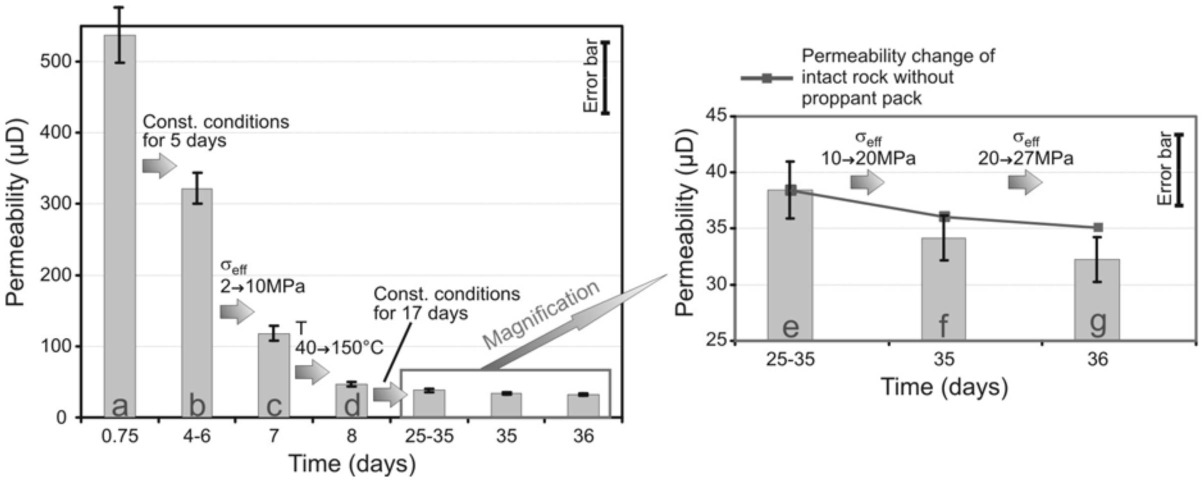


Fig. 5. Long-term laboratory experiment on a Flechtingen sandstone sample and an ISP proppant pack. The figure shows measured permeability changes and details about the experiment. The initial permeability corresponds to that measured at 0.75 days. The long-term (i.e. stabilized) permeability was reached after 25 days (see text). Details on the 25-36 day period are shown in the panel on the right. $\sigma_{eff}$: effective stress

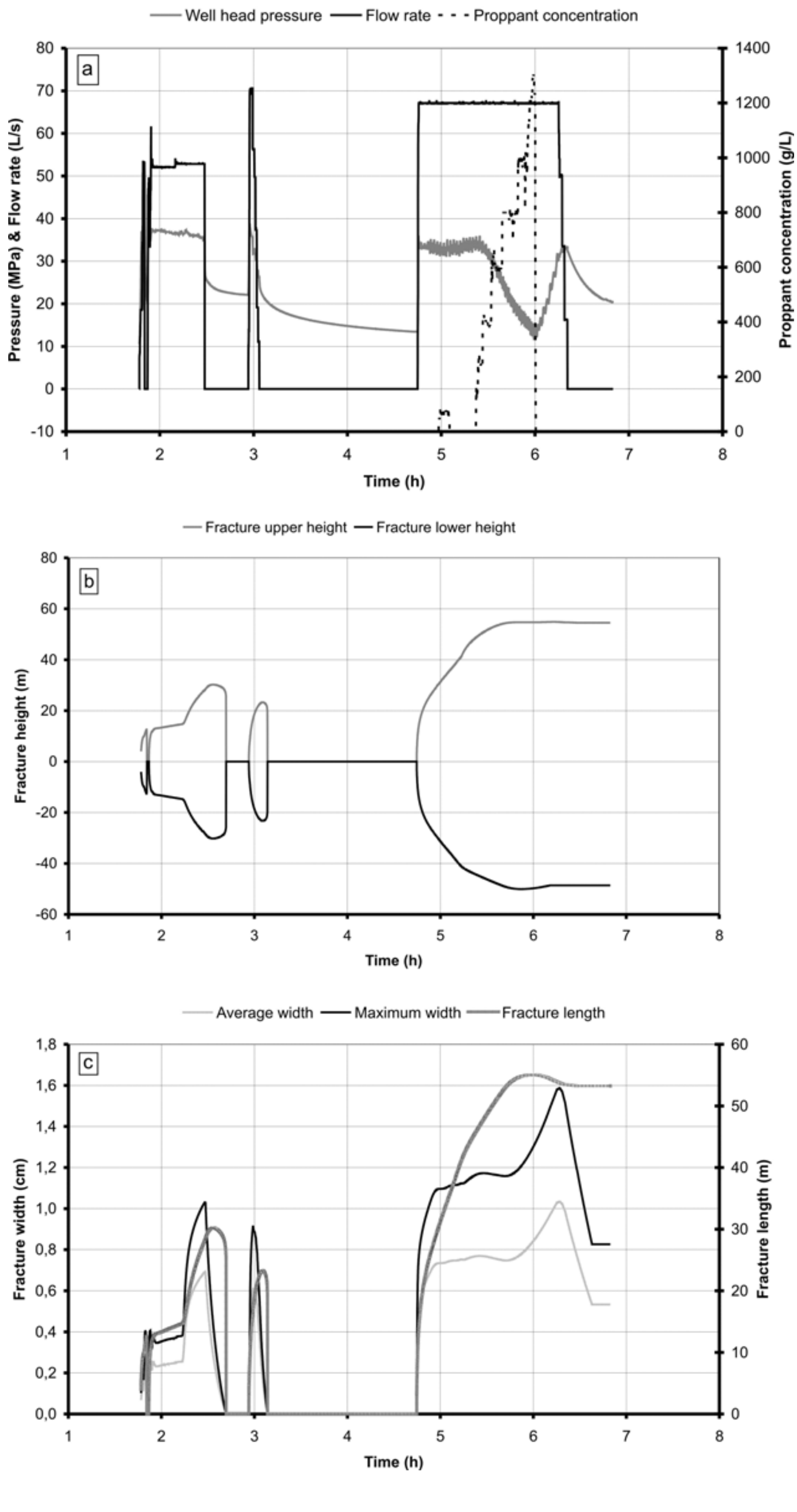


Fig. 6. Gel-proppant stimulation of the Lower Dethlingen sandstones. (a) Data on the leak-off test (mini frac), step-down test and main fracture test performed in Groß Schönebeck well GtGrSk4/05. (b) and (c) Calculated evolution of fracture dimensions. The upper fracture height indicates the propagation of the fracture upwards from the perforation, lower fracture height the propagation downwards. The total fracture height is the difference between upper and lower fracture height.

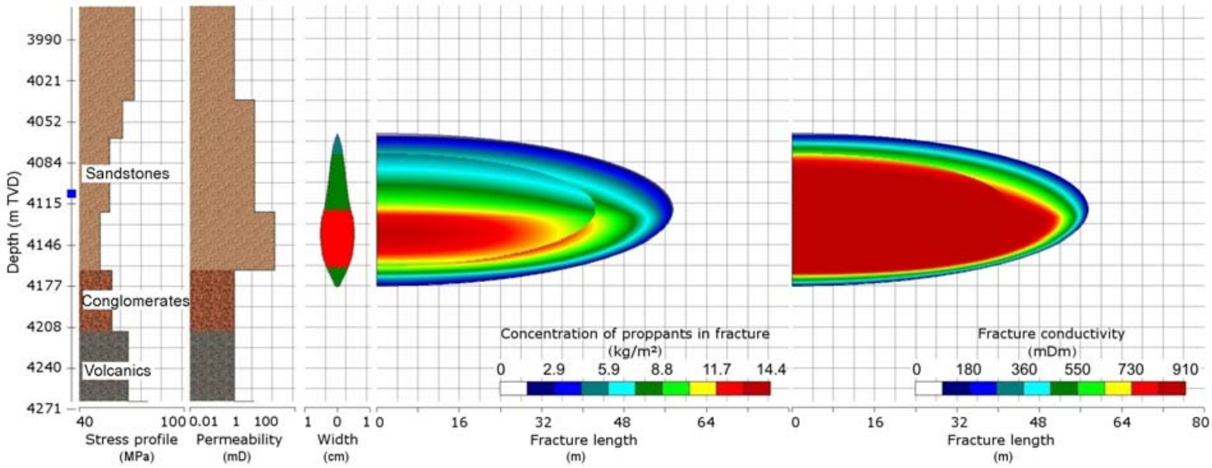


Fig. 7. Gel-proppant simulation of well GtGrSk4/05. Proppant concentration and fracture conductivity modelled on the basis of measured field data. The stress profile shows the minimum principal stress for each formation. TVD: True vertical depth

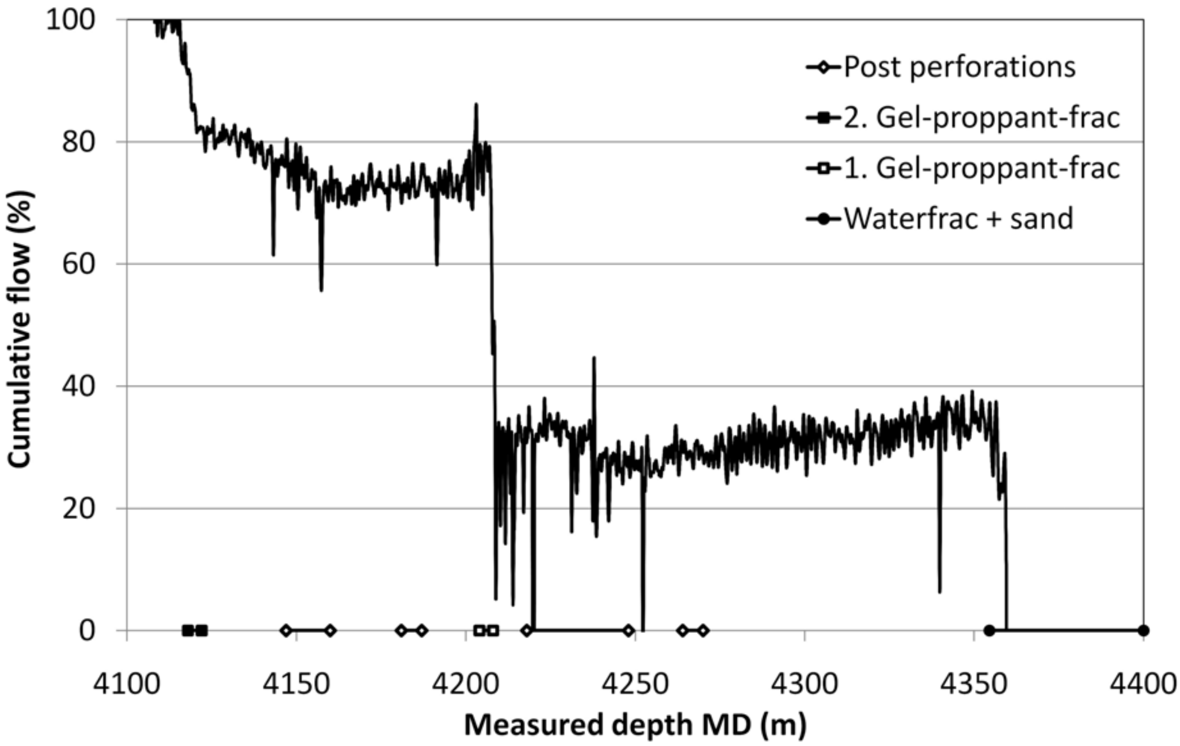


Fig. 8. Inflow profile based on a flowmeter log obtained during the GtGrSk4/05 production test showing the individual contributions to the inflow from the stimulated sections and post-perforated intervals. The gel-proppant treatments are referred to as "1. Gel-proppant frac" and "2. Gel-proppant frac", since two gel-proppant treatments were done in this well (Zimmerman et al., 2010).