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Cyclic waterfrac stimulation to develop an Enhanced Geothermal System (EGS) – conceptual design and experimental results

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Abstract

The design and results of a cyclic hydraulic fracturing experiment performed to enhance the productivity of the geothermal research well at Groß Schönebeck (Germany) are presented. The stimulation carried out in the low-permeability volcanics of the Lower Rotliegend (Lower Permian) included alternating stages with cyclic changes of low and high flow rates with up to 150 L/s over six days in conjunction with the addition of quartz sand to support fracture opening. There was rapid water level increase in an adjacent well due to the stimulation (i.e. water injection). The subsequent production test showed the success of the fracture treatment, with the overall productivity of the treated well being increased by a factor of four.

Keywords: Geothermal; hydraulic fracturing, EGS, Groß Schönebeck, Germany.

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1. Introduction

The scientific principles of reservoir engineering are key for an appropriate development of geothermal resources. An optimum economic utilization of geothermal reservoirs requires analysis of the geological system together with adequate planning, including reservoir modelling and understanding of the processes and interaction of the “borehole–reservoir system”. This is based on the long-time expertise of the oil and gas industry and should be directly transferable to geothermal exploitation (Tester et al., 2006; Falcone and Teodoriu, 2008).

Conventional geothermal resources cover a wide range of uses for power production and direct application. For unconventional systems a large scientific and industrial community has been involved in developing Enhanced Geothermal Systems (EGS) in the last 20 years (e.g. Gérard et al., 2006; Calcagno and Sliupa, 2008). This concept involves different ways to increase access to heat at depth by improving exploration methods, drilling and reservoir assessment technologies for deep geothermal resources, and stimulating low-permeability reservoirs.

Stimulation treatments need to be performed to enhance the productivity of low-permeability geothermal reservoirs by inducing artificial fluid pathways. Several stimulation treatments have been developed to enhance the existing permeability (e.g. Economides and Nolte, 2000); i.e. hydraulic fracturing (Sharma et al., 2004), thermally induced fracturing (Charlez et al., 1996) and chemical/acid stimulation (Bartko et al., 2003; Hardin et al., 2003; Rae and di Lullo, 2003; Nami et al., 2008). In this paper we focus on hydraulic stimulation experiments, where fluids under high pressure are injected into the subsurface rocks to create new fractures or extend existing fractures. These hydraulic fracture stimulations are either waterfracs (i.e. those using water), gel-proppant fracs or a combination of both called hybrid fracs (Sharma et al., 2004). The procedures are well known in the hydrocarbon industry (Shaoul et al., 2007, 2009) as well as in Hot Dry Rock (HDR) technology (Baumgärtner et al., 2004; Hettkamp et al., 2004; Schindler et al., 2008), and have also been applied to hydrothermal systems (Legarth et al., 2003, 2005). Compared with hydrocarbon reservoir stimulation (Economides and Nolte, 2000), application to geothermal systems requires techniques that will radically increase fluid production to make a project economically feasible.

The topics that will be addressed here include quantification of reservoir parameters from laboratory experiments, as well as borehole measurements to monitor changes in reservoir characteristics. The aim is to study long-term hydraulic flow (Milsch et al., 2009), rock-fluid interactions, mechanical-hydraulic and thermal-hydraulic coupled processes (Blöcher et al., 2009a), and the stress field and borehole stability (Moeck et al., 2008b). In conjunction with operational work, these studies support strategies that will lead to productivity increase and sustainability during later use.

The paper is organised as follows. We start with a general discussion about well path design and stimulation treatments optimised for different geological environments. This is followed by a short description of the geological setting of the Groß Schönebeck field (40 km north of Berlin), in the Northeast German Basin. After that we discuss the optimum well path design for the Groß Schönebeck well in relation to hydraulic fracture propagation to obtain the best stimulation results. 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, including the concurrent microseismicity observations and pressure monitoring in a neighbouring well.

2. Well path design

The geometrical layout of the wells has a significant impact on the success of reservoir exploitation. Critical issues for well planning are the distance between the wells, influencing thermal and hydraulic breakthrough, and the direction of the well deviation in relation to the current stress field and fracture zones. One key issue for well path planning in EGS development is the understanding of the stress field, which governs the orientation of tensile fractures, borehole stability, and the state of stress along faults. In particular, the orientation of tensile fractures is perpendicular to the direction of the least principal stress axis; consequently the optimal well path is in the direction of the least principal stress, because this layout crosscuts potential production zones (Zimmermann et al., 2007). However, such a well path is not necessarily the most stable one, depending on the far field stress regime and stress concentrations along the borehole wall.

The simplest design consists of a single vertical production well. Sustainability in such a case is achieved only if ground water recharge compensates production, thereby reducing the risk of depletion of the geothermal reservoir. The basic types of a sustainable design are doublet or triplet systems consisting of one or two production wells and one injection well to complete the water circulation system. Multi-well designs with several patterns of vertical wells such as hexagonal or five spot patterns can be used to enlarge the effective heat transfer area (Armstead and Tester, 1987). The optimisation of the number of wells include several constraints which depend on the geological characteristics of the reservoir, the target depth (and hence the drilling costs), the initial productivity of the reservoir rocks and the cost of the stimulation treatments required to enhance this productivity.

The arrangement of two wells follows two conflicting goals. On the one hand, the wells should be located in such a way that the pressure in the reservoir would not drop significantly during production, which suggests a comparatively small separation of the wells. On the other hand, a short circuit between the wells, implying a temperature drop in the production well, must be avoided. In general, there are two options:

- Corresponding to the classical Hot Dry Rock approach, the stimulated fractures are aligned along the line connecting the two wells. In this case, the well doublet is in the direction of the maximum principal stress (σ_H). Hence, the major contribution to enhanced permeability is mainly due to shearing of natural and artificial fractures in a nearly impermeable environment.
- Arrangement of stimulated fractures perpendicular to the line connecting the wells, i.e., the orientation of the doublet is in the direction of the least principal stress, and fluid flow is through naturally permeable rocks, primarily consisting of a permeable matrix.

Both arrangements of the doublet (parallel and perpendicular to the minimum principal stress; σ_h) in a reservoir with some matrix permeability result in a pressure decrease at the production well and a pressure increase at the injection well (Huenges et al., 2006). The risk of a thermal short circuit of the system is most probable in the parallel case. Therefore the perpendicular case is the appropriate arrangement for a deep sedimentary reservoir with some matrix permeability and is valid as long as no extended natural fracture systems are connected (Legarth et al., 2005; Zimmermann et al., 2005).

Besides the idea of drilling along a certain stress direction, another concept is the targeting of a promising fault system with suspected high natural fluid flow. In that case, stress changes along

the borehole wall and the borehole stability need to be considered. This could be done either by stimulation treatments or by well paths intersecting the fault zone, as in the European HDR project in Soultz-sous-Forêts, France (Willis-Richards, 1995; Baria et al., 1999; Baumgärtner et al., 2004; Hettkamp et al., 2004). In a naturally fractured reservoir a deviated well can intersect multiple fractures and connect them to the well. This design can be supported by multiple stimulation treatments to enhance the number of connected fractures and hence the productivity of the well.

The design for the waterfrac stimulation experiment at the Groß Schönebeck site comprised the use of two different lithologic layers. With this stimulation treatment a fracture was induced that propagated from the bottom of the well (in naturally fractured volcanic rocks) upwards to the overlying layer (permeable sandstones) where upward fracture propagation stopped for mechanical reasons and was followed by a leak-off into the sandstones. During the subsequent high-flow stages, fracture growth was dominated by propagation in the horizontal direction, leading to additional fracture length. The fluid flow between the wells occurs mainly through the permeable sandstone layer.

3. Geology of the Groß Schönebeck area

The Groß Schönebeck field is a key EGS research site in the North German Basin. The field has two deep research wells forming a well doublet with one injection and one production well, both used as downhole geothermal laboratories. The geothermal reservoir is at 4100-4200 m depth and comprises Upper Rotliegend (Lower Permian) sandstones deposited in a fluvial environment on the south eastern flank of the Basin. The sandstone reservoir is underlain by Lower Rotliegend volcanics and is capped by Upper Permian evaporites (**Fig. 1**). The main targets are the permeable sandstones of the Upper Rotliegend (Dethlingen Formation/Lower Elbe subgroup), as well as the volcanic rocks (andesites) of the Lower Rotliegend, where permeability is mainly associated with natural fractures. It is intended to use this system of fractures to optimize total well productivity.

The Dethlingen sandstones represent a reservoir horizon with a porosity of 8-10 % and an in situ permeability of up to 16.5 mD (Trautwein and Huenges, 2005). In the study area the Elbe base sandstone (lower part of the Dethlingen Formation) is a well-sorted, middle-to-fine grained, poorly cemented sandstone. The effective reservoir thickness is approximately 80 m; due to the deviation of the well the apparent thickness is 150 m.

The fault pattern interpreted from 2D seismic data is characterized by major NW-trending faults and NE-to-N trending minor faults. In the current stress field the NE-trending faults bear the highest ratio of shear to normal stresses exhibiting a critically stress state in the sandstones and a highly stressed state in the volcanic layer. Since critically stressed faults are described as hydraulically transmissive (Barton et al. 1995, 1996), these NE-N trending faults are expected to be the main fluid pathways in the reservoir (Moeck et al. 2008a). The bottom of well Gt GrSk4/05, drilled in 2006, is in the direct vicinity of a NE-trending and W-dipping minor fault (Fig. 1; Moeck et al. 2008a). In the sandstone horizon two gel-proppant fracs were carried out.

The design of the doublet system including the scheduled fracture treatments is displayed in Fig. 1. The well path of the deviated well Gt GrSk4/05 has a 37 to 49° inclination in the reservoir rock with an orientation from 288 to 296°N, parallel to the minimum horizontal stress direction (Holl

et al., 2004; Moeck et al., 2008a). The frac propagation is consequently parallel to the direction of the maximum horizontal stress (18°N) and hence perpendicular to the well path orientation.

Based on the lithological column with its known values for rock density and thickness (Moeck et al. 2008a), the vertical stress (σ_V) is 100 MPa in the sandstone layer and 103 MPa in the volcanic layer. The stress regime in the sandstone is known as transitional from normal to strike-slip faulting, indicated by $\sigma_H \sim 98$ MPa, similar to the vertical stress and $\sigma_h \sim 55$ MPa (**Fig. 2**). The value for σ_H is derived from borehole breakout analysis (Moeck et al., 2007), whereas the value for σ_h is interpreted from leak-off tests carried out in both wells at the site (Gt GrSk4/05 and E GrSk3/90; **Fig. 2**).

Leak-off tests are hydraulic tests to induce small scale artificial tensile fractures. The fracture opening pressure necessary to induce these fractures is similar to the magnitude of the minimum principal stress. In the volcanic layer σ_H is assumed to be similar to σ_V , thus being 105 MPa or even higher due to the higher uniaxial compressive strength of the volcanic rock. The minimum principal stress is known from a leak-off test (i.e. $\sigma_h = 72$ MPa). The only stress value that is assumed and not analysed is σ_H in the volcanic layer. According to the frictional equilibrium theory (Peška and Zoback, 1995; Jaeger et al., 2007) the value of σ_H can range between 100-140 MPa in this stress regime, but we assume a stress value close to σ_V , equivalent to the sandstone layer (Moeck et al., 2009).

Slip tendency is the ratio of resolved shear stress to resolved normal stress on a fault surface (Morris et al., 1996) and can be applied to assess the reactivation potential of shear and dilational fractures (Moeck et al. 2009). Our calculations indicate that the fault reactivation potential for any faults in the volcanic layer is very low. The maximum slip tendency in the volcanic layers of the Groß Schönebeck geothermal reservoir is 0.5, i.e. below the value of the frictional strength of a rock mass at that reservoir depth (about 0.8; Byerlee, 1978). This is consistent with the observed low seismicity and minor shear displacement.

4. Results

4.1. Path of well Gt GrSk4/05

Well Gt GrSk4/05 reached the target horizon along the planned borehole track (Fig. 1). To avoid formation damage caused by drilling mud infiltration, the reservoir below 3900 m measured depth (MD) was drilled near-balanced with a mud density of 1030 kg m^{-3} . Borehole breakouts at 3940 m (MD) forced the increase of the mud pressure to 1100 kg m^{-3} . This specific mud pressure was chosen as a result of a geomechanical study investigating the initiation of borehole breakouts in the reservoir within the in-situ stress field, which is a transitional stress regime from normal to strike slip faulting (Moeck et al., 2007, 2008b).

The borehole was drilled along the least principal stress direction with an inclination of up to 49°. This drilling direction is the most stable condition because it is subject to zero stress anisotropy. Well path control was given by a 3D geological model that was continuously updated during the drilling process. The interpretation of a final logging run was used to determine the stimulation and perforation zones in the reservoir.

4.2. Fracture treatments in Gt GrSk4/05

Three different fracture treatments were scheduled starting with the volcanic section at the bottom of the well. The entire well was cased and cemented with the exception of the bottom 20

m, where a perforated liner was installed. After the first treatment at the bottom of the well (waterfrac treatment in volcanics), this section was isolated by a bridge plug. Prior to the next stimulation treatment (gel-proppant treatment in the Lower Dethlingen sandstones), a selected interval was perforated. The selection was based on the results of borehole measurements to obtain the most suitable interval for fracture initiation. The same considerations applied to the second gel-proppant treatment done in the Upper Dethlingen sandstones. These treatments are summarized in **Table 1**.

We expected convergent flow issues (in all three zones) as the additional flow through the dominant created fracture will be entering through a very small area of pipe. This narrow fracture would intersect the wellbore at about 45°, implying that only one or two perforations would accept most of the flow. To counter this effect, we kept the perforation intervals small (4 meter) while using a high shot density perforating technique (20 shots/m; big hole charges oriented circumferentially).

4.3. General design of the waterfrac treatment

A 3D fracture simulator (FRACPRO) was used to compute fracture dimensions (Cleary, 1994). This modelling software addresses the prediction of pressure response in the well to planned stimulation treatments and the selection of appropriate equipment to handle expected wellhead pressures, friction and near wellbore tortuosity. A tensile fracture (mode I) propagating perpendicular to the minimum principal stress is assumed. It is well known from former stimulation treatments at this site that the number and magnitude of microseismic events is low and hence only minor shear displacements occur (Zimmermann et al., 2009). Hence the stress intensity factor K_I is the essential variable controlling the propagation of the fracture. For the theory of the mechanics of hydraulic fracturing we refer to Yew (1997) and Guéguen and Boutéca (2004).

The goal of the fracture treatment in the volcanic section at the bottom of the well was to obtain a fracture half-length of approximately 150-200 m with a corresponding fracture height of 80-100 m. The mean aperture of the fracture should be in the range of 5-10 mm. This would result in a total fracture volume of about 100-200 m³. The corresponding reservoir rock mechanics and hydraulic parameters involved in the treatment are summarized in **Table 2**.

The general design comprised several high flow rate intervals; these were of short duration because of limited water availability from nearby freshwater wells (about 50 L/s), and the existing storage tank capacity (about 1000 m³). The high rates (150 L/s) were expected to give better fracture performance than a constant rate of 50 L/s, even if the intervals were limited in time. To fill the tanks, provision was made to reduce the flow rate to 20 L/s after the high flow rate intervals. This was expected to be far above the flow rate need to keep the fracture open. For budget reasons, the number of cycles was limited to a total treatment duration of about five days (**Fig. 3**).

Alternating stages of high and low flow rates provide the opportunity to control the main direction of fracture propagation. If, as in this case, a vertical fracture is concerned, a higher flow rate leads to increased fracture propagation in the direction of maximum horizontal stress and hence increases the fracture half-length. Low flow rates increase the height of the fracture as well as the fracture aperture.

In the particular case of the Groß Schönebeck site, the volcanic rock layering in the reservoir limits the maximum height of the fracture. During the low flow rate at the beginning of the treatment the fracture propagates mainly upwards; it stops when the fracture reaches the

permeable sandstones. This is due to the fact that these permeable sandstones cause a leak-off and lead to a pressure reduction at the tip of the fracture. Downward fracture propagation is constrained due to the nearly impermeable underlying folded Carboniferous sedimentary rocks, which would require a higher frac pressure.

The fracturing process was numerically simulated by incorporating the rock mechanics and hydraulic parameters of **Table 2** into the model and applying the schedule of alternating flow rate stages. According to this simulation the projected fracture treatment would lead to an estimated fracture half-length of 180 m and an average fracture width of 17 mm (**Figs. 4 and 5**). Fracture propagation in the horizontal direction takes place mainly during the cyclic high flow rates; the fracture half-length increasing with every cycle (**Fig. 4**). The fracture growth in height and length during one-hour steps is displayed in **Fig. 5**.

4.4. Results of waterfrac stimulation treatment in Gt GrSk4/05

The stimulation treatment in Gt GrSk4/05 was carried out between 9 and 14 August 2007. In total, 13,170 m³ of fluids and 24.4 tons of quartz sand were injected into the volcanic rocks. The maximum well head pressure reached 58.6 MPa at the maximum flow rate of 150 L/s. The total duration of the treatment was 6389 minutes (**Fig. 6**). During the high flow rate injection a friction reducing agent was used in the well, which limited the maximum wellhead pressure to 58 MPa. To avoid iron scaling by the injected water, acetic acid was added to set the pH to 5. During injection at 150 L/s, low concentrations of quartz sand (20/40 mesh size) were added to support a sustainable fracture width. The transport of the sand in the fracture and wellbore was made possible by the high flow velocity; the low pH precluded the use of a gel.

Modelling of fracture propagation based on the field data flow rate was done using FRACPRO. The computed maximum fracture width at the end of the last stage was 19.5 mm (**Fig. 7**). The total height and total half-length at the end of the treatment were estimated to be 90 m and 190 m, respectively (Fig. 7). **Fig. 8** gives another view of the modelled fracture. Lithology and stress profile are displayed as well as the fracture width and the development of the fracture geometry.

Comparing simulation results (Figs 4 and Fig. 5) with field data results (Figs 7 and 8) reveal the difference between optimum stimulation (with six high flow rate stages in five days) and constraints in the realization of a real stimulation treatment (with four high flow rate stages in six days). The chronological sequence of the fracture propagation is more homogeneous for the simulated case when compared with the modelled evolution for the real treatment. However, the final fracture half-length is similar for the simulated and actual flow rates.

4.5. Production test

After stimulation of the volcanic rocks, two more intervals in well Gt GrSk4/05 were stimulated using gel-proppant treatments (**Table 1**); these are described in more detail in Zimmermann and Reinicke (2010). The three hydraulic stimulations were carried out separately in two sandstone sections and the volcanic section. To determine the effects of these procedures a production test was carried out that involved flow from all sections in the well.

The test was performed with a nitrogen lift in conjunction with flowmeter profiling to distinguish between the stimulated intervals. Prior to this, additional perforations (deep penetration charges) were carried out in the sandstone section above the volcanic rocks. Approximately 356 m³ of

fluids were produced during a 11.8-hour period. The contribution of each section was determined from the flowmeter log.

Table 1 summarizes the productivity improvement of each stimulation treatment in well Gt GrSk4/05. The productivity index was calculated as being 0.281 L/(sec bar). **Fig. 9** displays the flow rate and pressure response in the reservoir measured by the flowmeter tool that was installed at 4110 m depth (MD). During this production test two flowmeter runs (up and down the borehole) were performed to obtain the inflow (**Fig. 10**) and temperature (**Fig. 11**) profiles.

Fig. 10 shows the cumulative flow and the individual contributions of the inflow zones. The results show that 30 % of flow originates from the volcanic rocks. Nearly 50 % can be attributed to the first gel-proppant treatment and 15 % due to the second gel-proppant treatment. Only 5% can be assigned to the additional perforations (see above). A possible reason might be the drilling fluid, which was used to build a filter cake at the borehole wall to protect the reservoir. These intervals might be acidized to enhance the performance of these added perforations.

4.6. Stimulation treatments in E GrSk3/90

Three stimulation treatments were also performed in well E GrSk3/90. The first one was carried out in the sandstone section; the other two included the underlying volcanic rocks as well (**Table 3**) (for details see Zimmermann et al., 2009).

4.7. Modelling water circulation in the reservoir

A 3D reservoir model was developed to simulate and understand the circulation of water in the subsurface, particularly between wells. It was based on a structural geological model (Moeck et al., 2008a) and stress field analysis (Moeck et al., 2009); details are given in Blöcher et al. (2009b). The model incorporates the full thermal-hydraulic coupling of various petrophysical parameters. In particular, it includes temperature-dependent thermal conductivities and heat capacities, as well as pressure, temperature and salinity dependent fluid density and viscosity. These parameters were determined by laboratory and field experiments.

Fig 12 shows the W-E projection of the reservoir that includes the fractures that were created. Most of the water flowing between wells is in the direction of minimum horizontal stress. In other words, it mainly occurs through the permeable sandstone layer, whereas in the volcanic layer, the flow of water into and out of wells has been enhanced by the hydraulic stimulations.

4.8. Monitoring of well E GrSk3/90

During the stimulation treatment of Gt GrSk4/05 the water level in adjacent well E GrSk3/90 was monitored (**Fig. 13**). After starting the first massive stimulation there was a nearly instantaneous pressure increase in E GrSk3/90 although the distance between the wells is about 475 m at reservoir level. The reason for this response is still an open question and could be due to the presence of a fault zone close to the wells; this still needs to be investigated.

Microseismicity was monitored during the last stimulation treatment of well E GrSk3/90 by sensors installed in shallow 100-meter deep wells, but no events could be registered. The same configuration was used when Gt GrSk4/05 was stimulated, but again no microseismic events were observed (Kwiątek et al., 2008). Therefore, in addition microseismicity was monitored by a three-axis geophone installed in E GrSk3/90 at 3800 m MD.

Analysis of the microseismic events registered by the deep monitoring station revealed a very low seismicity during and after stimulation (80 events during six days), with moment magnitudes (M_w) ranging from -1.8 to -1.0. The geophone mainly recorded induced seismic events towards the end of the major stimulation phases with highest flow rates. These events indicated an upward trend starting in the upper part of the openhole section in the volcanic rocks, suggesting a subvertical fracture (52° dip) with an upward fracture growth into the sandstone layer (**Fig. 14**). The orientation of the seismic events is approximately in the north-south direction and hence similar to the maximum horizontal stress direction ($18^\circ N$) (Kwiatek et al., 2008, 2009).

5. Conclusions

The Lower Permian sandstones and volcanic rocks of the Northeast German Basin, found at four km depth near Groß Schönebeck, have been explored and stimulated for future geothermal energy production. The research strategy consists of a comprehensive reservoir characterization, understanding of reservoir behaviour through 3D modelling under production conditions, geomechanical analysis of the reservoir and borehole wall in the current stress field to quantify borehole stability, and finally drilling and well stimulation.

During the stimulation of the volcanic rocks penetrated by well Gt GrSk4/05 a total of 13,170 m³ of water was injected in four cycles with flow rates up to 9 m³/min and a final phase with a flow rate of 5 m³/min. The aim of this stimulation was to establish a hydraulic connection between the volcanics and the sandstones of the Upper Rotliegend. During these four cycles 24.4 tons of sand was placed in the volcanic rocks to support the opening of the artificially created fractures beyond their self-propping potential.

Furthermore two gel-proppant treatments were performed to connect the well to the high-permeability layers of the Upper and Lower Dethlingen sandstones (Zimmermann and Reinicke, 2010). The success of these treatments was demonstrated by the results of a production test, which in conjunction with a flowmeter log allowed determining the contributions of each layer. The analysis showed that 30 % of the total flow came from the volcanic rocks and 70 % from the sandstones.

The productivity of the well Gt GrSk4/05 is lower than expected, especially in the sections perforated after the stimulations. This might be due to the drilling fluid, which was used to build a filter cake at the borehole wall to protect the reservoir. Acidizing these intervals is scheduled and should enhance the performance of these intervals and further increase the productivity of the well.

From the outcome of the stimulation methods utilized at the Groß Schönebeck field to develop an EGS several lessons were learned. The results of the waterfrac and the gel-proppant treatments indicate that the stimulation methods should be designed on an individual basis, depending on the reservoir rock properties and the stratigraphic sequence at the site. If a waterfrac is used, the sustainability of fracture opening must be assured. When the fractures generated are mostly tensile, without shear displacement, aperture-supporting procedures like adding sand or proppants should be taken into account to keep the fractures open. This is especially true for wells producing from formations showing large pressure drawdowns due to exploitation.

During stimulation treatments the propagation and final extension of fractures can be controlled by the flow rate. This opens the possibility of controlling the propagation of the fracture in height and length and an optimum connection to the reservoir rocks. Designing the well path including sub-horizontal sections in the reservoir and special alignments according to the stress field offers the possibility for multiple fracture treatments to develop a geothermal field. All the above mentioned attributes were applied to well Gt GrSk4/05 and all the goals of the drilling and stimulation operations were met with success. A well doublet is now ready at Groß Schönebeck for a future thermal water loop and subsequent installation of a binary geothermal power plant, intended to be used initially as a pilot power plant for geothermal research.

After some modifications that take into consideration site characteristics, the stimulation treatments and the considerations about well path design used at Groß Schönebeck can be applied in principle to other sites. Hence, the results provide essential knowledge for developing future stimulation strategies in deep sedimentary geothermal systems like the Central European Basin and elsewhere.

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Figure captions

Fig. 1. Groß Schönebeck, Germany, EGS research site. (Left) Geological model developed on the basis of 2D seismic and wellbore data. Well Gt GrSk4/05 is directed towards a NE-striking/W-dipping fault. (Right) Alignment of the well paths and the fracturing treatments of the doublet system at the site.. Up.: Upper; Low.: Lower

Fig. 2. Stress regimes and associated faulting. σ_V : vertical stress; σ_H : maximum principal stress; σ_h : minimum principal stress. Fracture propagation direction is indicated by the arrows.

Fig. 3. Schedule and modelled pressure development of a cyclic waterfrac treatment with six cycles. Maximum flow rate is 150 L/s (9 m³/min) with an expected bottomhole pressure of 96.9 MPa.

Fig. 4. Evolution of fracture geometry resulting from the injection schedule shown in Fig. 3.

Fig. 5. Modelled fracture geometry resulting from the injection schedule shown in Fig. 3. Each stage represents one hour of fracture propagation. The stress profile shows the minimum principal stress (σ_h) for each formation. TVD: true vertical depth.

Fig. 6. Actual schedule of the stimulation treatment in the volcanic rocks.

Fig. 7. Modelled evolution of fracture geometry during waterfrac treatment in well Gt GrSk 4/05.

Fig. 8. Fracture geometry resulting from the waterfrac treatment. Each stage represents one hour of fracture propagation. The stress profile shows the minimum principal stress (σ_h) for each formation. TVD: true vertical depth.

Fig. 9. Schedule of the production test (including the shut-in period). Flow rate and reservoir pressure were measured by a flowmeter installed in well Gt GrSk4/05 at 4110 m depth.

Fig. 10. Inflow profile based on flowmeter log obtained during the production test, showing the individual contributions to the inflow from the stimulated sections and post perforated intervals.

Fig. 11. Temperature profiles measured during the production test. Two flowmeter runs (up and down respectively) were performed to obtain these profiles in the stimulated sections.

Temperature inversion in this depth section is due to the injection of cold water during the stimulations. Undisturbed reservoir temperature in this depth is 150 °C.

Fig. 12. Simulated fluid velocity field in the vicinity of production and injection fractures at steady-state conditions. (Blöcher et al., 2009b). The injection and production rate is 75 m³/h; drawdown at the production well is 515 m and build up at the injection well is 450 m. TVD: true vertical depth; σ_V : vertical stress; σ_H : maximum principal stress; σ_h : minimum principal stress.

Fig. 13. Change of water level in the well GrSk3/90 during the stimulation of the volcanic rock interval in well Gt GrSk 4/05.

Fig. 14. Plan view of the distribution of induced seismic events at the Groß Schönebeck geothermal site as determined from 3D component recordings of the deep borehole seismometer installed in well E GrSk3/90 at 3800 m depth. For comparison purposes the grey-scaled events and the arrow reflect the hypocentral depth and evolution of events plotted in accordance with the borehole trajectory. Semi-transparent fans denote maximum horizontal errors according to Moeck et al. (2009). The injection intervals in the volcanics and sandstones are also shown. Strike and dip of the fracture plane is 17°/52° SE indicating normal faulting. The grey scale (the horizontal bar) at the bottom of the figure indicates true vertical depth (TVD).

Tables

Table 1

Summary of the stimulation treatments in Groß Schönebeck well Gt GrSk 4/05. Results represent individual flow data from the volcanics and the Upper and Lower Dethlingen sandstones, as well as the cumulative result for all layers

Tested well section	Treatment applied	Duration (days)	Volume (m ³)	Flow rate (L/s)	Productivity (L/s/bar)	Productivity improvement factor	Located microseismic events
Volcanics	-	0.06	4.4	0.83	0.004	Initial PI	-
Volcanics	Waterfrac with sand	0.5	356	8.2	0.0849	22	78
Lower Dethlingen sandstones	-	0.3	250	9.5	0.028	Initial PI	-
Lower Dethlingen sandstones	Gel-proppant	0.5	356	8.2	0.142	5	2
Upper Dethlingen sandstones	-	0.2	170	10.3	0.034	Initial PI	-
Upper Dethlingen sandstones	Gel-proppant	0.5	356	8.2	0.057	1.67	Not measured
Sum before stimulation					0.066	Initial PI	
Sum after stimulation					0.281	4.25	

PI: Productivity index

Table 2

Rock mechanics parameters for the reservoir

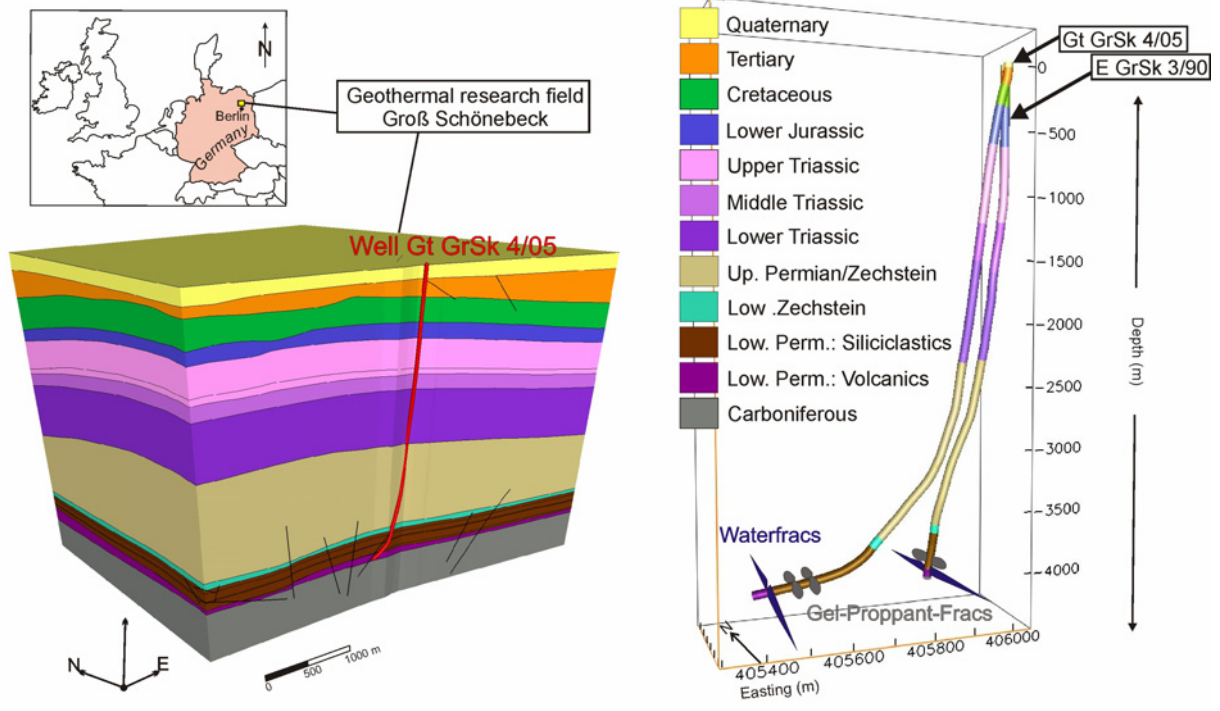
Unit/ lithology	Frac pressure (MPa)	Closure stress gradient (bar/m)	Pore fluid permeability (mD)	Young's modulus (GPa)	Poisson's ratio	Fracture toughness (MPa m ^{1/2})
Volcanics	68.4	0.16	1	55	0.2	1.72
Lower Dethlingen	52.2	0.125	10	55	0.18	0.59
Upper Dethlingen	59.3	0.145	10	55	0.18	0.59

Table 3

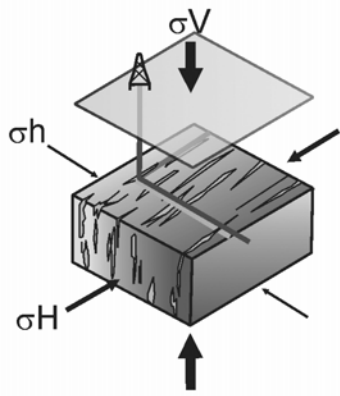
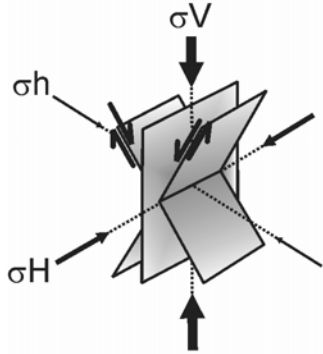
Summary of the stimulation treatments in Groß Schönebeck well E GrSk 3/90 (detailed description are given in Zimmermann et al., 2009). Results from the first test correspond to data from the sandstone section, whereas the following tests represent the entire open-hole section including volcanics and sandstones.

Tested well section	Treatment applied	Duration (days)	Volume (m ³)	Flow rate (L/s)	Productivity (L/s/bar)	Productivity improvement factor	Located microseismic events
Sandstones and volcanics	-	0.51	167	3.75	0.027	Initial PI	Not measured
Sandstones	Gel- proppant	0.58	307	6.22	0.059	2.2	Not measured
Sandstones and volcanics	Waterfrac	0.24	338	16.4	0.112	4.1	Not measured
Sandstones and volcanics	Waterfrac	1.0	859	4.3 - 14.7	0.207	7.7	No events

PI: Productivity index

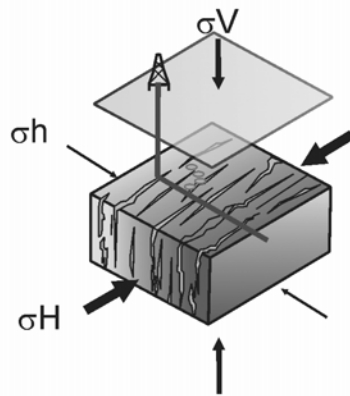
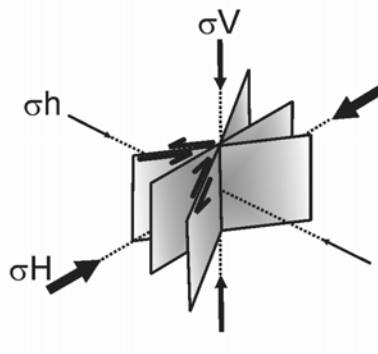


Normal Faulting
 $\sigma_V > \sigma_H > \sigma_h$



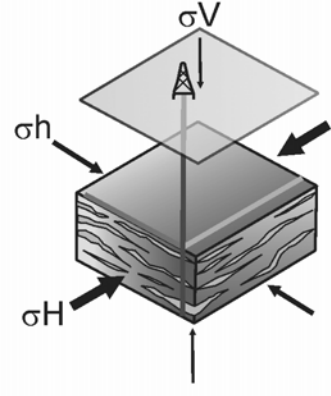
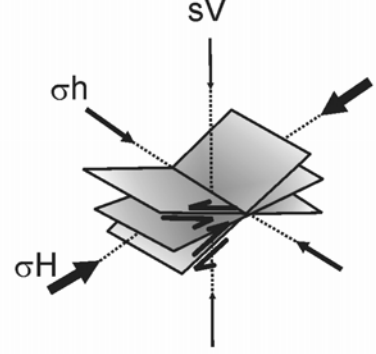
Extensional Regime

Strike-slip Faulting
 $\sigma_H > \sigma_V > \sigma_h$



Strike-slip Regime

Reverse Faulting
 $\sigma_H > \sigma_h > \sigma_V$



Compressional Regime

