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ROCK SPECIFIC HYDRAULIC FRACTURING AND MATRIX ACIDIZING TO ENHANCE A GEOTHERMAL SYSTEM – CONCEPTS AND FIELD RESULTS

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ABSTRACT

Enhanced geothermal systems (EGS) are engineered reservoirs developed to extract economic amounts of heat from low permeability and/or porosity geothermal resources. To enhance the productivity of reservoirs, a site specific concept is necessary to actively make reservoir conditions profitable using specially adjusted stimulation treatments, such as multi fracture concepts and site specific well path design.

The results of previously performed stimulation treatments in the geothermal research well GtGrSk4/05 at Groß Schönebeck, Germany are presented. The reservoir is located at a 4100-4300 m depth within the Lower Permian of the NE German Basin with a bottom hole temperature of 150 °C. The reservoir rock is classified by two lithological units from bottom to top: volcanic rocks (andesitic rocks) and siliciclastics ranging from conglomerates to fine grained sandstones (fluvial sediments). The stimulation treatments included multiple hydraulic stimulations and an acid treatment. In order to initiate a cross-flow from the sandstone layer, the hydraulic stimulations were performed in different depth sections (two in the sandstone section and one in the underlying volcanic section). In low permeability volcanic rocks, a cyclic hydraulic fracturing treatment was performed over 6 days in

conjunction with adding quartz in low concentrations to maintain a sustainable fracture performance. Flow rates of up to 150 l/s were realized, and a total of 13170 m³ of water was injected. A hydraulic connection to the sandstone layer was successfully achieved in this way. However, monitoring of the water level in the offsetting well EGrSk3/90, which is 475 m apart at the final depth, showed a very rapid water level increase due to the stimulation treatment. This can be explained by a connected fault zone within the volcanic rocks. Two gel proppant treatments were performed in the slightly higher permeability sandstones to obtain long-term access to the reservoir rocks. During each treatments, a total of 100 tons of high strength proppants were injected with 500 m³ of cross-linked gel. The subsequent production test in conjunction with flowmeter logging showed an improvement of productivity by a factor of more than 4. Due to assumed residual drilling mud (constituents: calcite, dolomite, aragonite) in the near wellbore vicinity, an acid matrix stimulation was performed thereafter using a coil tubing unit. The following nitrogen lift test demonstrated another increase of productivity by 30 – 50% to an overall increase by a factor of 5.5 - 6.2.

1. INTRODUCTION

Reservoir engineering is a key issue for the development of geothermal technology. Optimum economic utilization of reservoirs can be achieved with profound analysis of the geological system and adequate planning (including reservoir modelling), and understanding of the processes and interaction of the “borehole – reservoir” system. This is based on the long experience of the oil- and gas-industry, which should be directly transferable to geothermal exploitation (Baria et al., 1999; Tester et al., 2006; Falcone & Teodoriu, 2008).

Conventional geothermal resources cover a wide range of uses for power production and direct use under profitable conditions. A large scientific and industrial community has been involved in developing Enhanced Geothermal Systems (EGS) for the last 20 years (e.g. Gérard et al., 2006; Calcagno & Sliaupa, 2008). This concept involves different tracks for enlarging access to heat at depth by improving exploration methods, drilling and reservoir assessment technology for deep geothermal resources, and the stimulation of low permeability reservoirs.

Stimulation treatments must be performed to enhance the productivity of low permeability geothermal reservoirs by inducing artificial fluid pathways. Several concepts of stimulation treatments have been developed to enhance the existing productivity (e.g. Economides & Nolte, 2000), which can be summarized by the terms hydraulic fracturing (Sharma et al., 2004), thermally induced fracturing (Charlez et al., 1996) and chemical/acid stimulation (Nami et al., 2008). In hydraulic stimulation experiments, fluids are injected under high pressure into the rock to generate new fractures or extend existing fractures. These hydraulic fracturing stimulations can be categorized as waterfracs, gel-proppant fracs, and a combination of both called hybrid fracs (Sharma et al., 2004). The procedures are well known in the hydrocarbon industry (Shaoul et al., 2007a, 2007b) as well as in Hot Dry Rock (HDR) technology (Hettkamp et al., 2004; Baumgärtner et al., 2004; Schindler et al., 2008) and have also been applied in hydrothermal systems (Legarth et al., 2003; Legarth et al., 2005; Huenges et al., 2006). Compared to hydrocarbon reservoir stimulation, the application for hydrothermal reservoirs requires a technique that is able to produce considerably higher amounts of fluids (Economides & Nolte, 2000).

The subjects which have to be addressed in conjunction with the EGS concept include quantification of reservoir parameters using laboratory experiments as well as borehole measurements to monitor the reservoir characteristics. The aim is to study the long-term hydraulic flow (Milsch et al., 2009), rock-fluid interaction, mechanical-hydraulic and thermal-hydraulic coupled processes (Blöcher et al., 2009; 2010), the recent stress field, and borehole stability (Moeck et al., 2008; 2009a). In conjunction with operational work, the aforementioned issues support mitigation strategies to avoid reservoir and storage impairment and hence lead to an increase in productivity and sustainability during later use.

The paper is organised as followed. We start with a general discussion of stimulation treatments optimised for different geological environments. This is followed by a short description of the geological setting of the Groß Schönebeck field in the Northeast German

Basin. Then the hydraulic stimulation experiments carried out at the Groß Schönebeck field in 2007 are briefly reviewed and evaluated, followed by a description of the matrix acidizing treatment from 2009. Finally, the outcome of all obtained stimulation treatments in terms of productivity increase and the hydraulic connectivity of the doublet system are discussed.

2. STIMULATION TREATMENTS

General concepts

Since the early 1980s, research at various sites confirmed that shearing rather than tensile fracturing is the dominant process (Pine & Batchelor, 1984; Cornet, 1987; Baria et al., 1999). Natural joints, favourably aligned with the principal stress directions, fail in shear. As a consequence, formations with high stress anisotropy and hence, a high shear stress, should be best candidates for hydraulic fracturing in low permeable rock.

Knowledge about the stress regime is of great importance to understand or even to predict the hydraulic fracturing process (Evans, 2005; Cornet et al., 2007). Borehole breakouts, borehole fractures (Brudy et al., 1997; Zoback et al., 2003; Haimson, 2007), microseismic events (Shapiro et al., 1997; Baisch & Harjes, 2003; Bohnhoff et al., 2004; Michelet & Toksöz, 2007) and stimulation pressures (Zoback & Harjes, 1997; Legarth et al., 2003; Legarth et al., 2005) have been evaluated to confine the orientation and amplitude of the principal stress components.

One method to increase the effective fracture area is the isolation of intervals in the borehole and the successive stimulation of these intervals. With this approach a larger effective fracture area can be obtained than with one massive stimulation over a long open hole section. Such strategy is also favourable to reduce the risk of creating larger seismic events of critically stressed reservoirs.

Cases of induced seismicity have been reported from hydraulic stimulation programs in geothermal wells (e.g. Majer et al., 2007), but not all geological formations are prone to these events. Induced seismic events, which could be felt at the surface, have been reported from hard rock environments. Since the permeability in these formations is a fracture-permeability, the pressures generated to fracture the formation can only diffuse through the fracture and fault network, which will lead to a reduction in effective stress. In sedimentary environments, due to their matrix porosity and permeability, elevated pressures will not focus on fracture and fault pathways, but diffuse through the porous matrix. A potentially considerable sedimentary coverage of a hydraulically stimulated hard rock formation will also damp induced seismic events.

Controlling the fracture propagation in the reservoir while stimulating or circulating is an important issue for all projects in low permeable rock (Baria et al., 2006). Microseismic monitoring gives 3D time-resolved pictures of event location and magnitude from which the fractured rock volume can be inferred. This method has evolved to the key technique to map the reservoir in HDR projects (Wallroth et al., 1996; Niitsuma, 2004). In EGS current projects (Soultz, France; Cooper Basin, Australia) the microseismic event distribution serves for the determination of the target area for new wells. More recently, microseismic monitoring has become important to detect and to control larger seismic events, which might occur during stimulation in seismically active areas (Bommer et al., 2005; Majer et al., 2007).

Waterfrac treatments

Waterfrac treatments are applied in low permeable or impermeable rocks with high amounts of water to produce large-scale fractures with low width compared to the gel-proppant treatments (Mayerhofer et al., 1997; Mayerhofer & Meehan, 1998). In general, waterfrac treatments produce long fractures in the range of a few 100 meters with low apertures of approximately 1mm and hence low conductivity. The success of the treatment depends on the self propping of the fractures, i.e. fractures remaining residually open after pressure release. This characteristic is strongly attributed to the potential of shear displacement.

The flow rate during waterfrac treatments can be constant during the whole treatment or vary in a cyclic manner with several high flow rates followed by low stages (Zimmermann et al., 2010). Simulations have shown that the impact of high flow rates for the fracture performance is better, even if the intervals are limited in time, compared to a constant flow rate (Zimmermann et al., 2007).

Enhancing the treatment design comprises adding some abrasive agent in the fluid during the high flow rates such as sand or proppants (Walker et al, 1998). This will help to support the sustainability of conductivity of the fractures created. Using a proppant suspending agent like a linear gel, which gives the proppant mechanical suspension while travelling through the frac, will allow the proppant to travel to the tip of the fracture (Mayerhofer et al., 2000).

Gel-proppant treatments

Gel-proppant treatments are used to stimulate reservoirs with cross-linked gels (consisting of polymers to obtain high viscosities in the range of up to 1 Pa s) in conjunction with proppants of a certain mesh size (typically 0.5 to 1 mm; e.g. Johnson et al., 1993; Legarth et al., 2005; Zimmermann et al., 2009). These gels enclose a so called breaker to undo the cross-linking after the proppants are placed in the fracture. These treatments can be applied in a wide range of formations with varying permeability and a good control of stimulation parameters (Cleary, 1994). Placing the appropriate concentration and type of proppant in the fracture are critical parameters for the success of the hydraulic fracturing treatment (Schubarth & Milton-Tayler, 2004; Zimmermann & Reinicke, 2010). The produced fractures have a short length of about 50-100m, but a higher aperture of up to 10mm compared to the waterfracs. It is especially used to bypass the wellbore skin in high permeable environments (Aggour & Economides, 1999). In general, this kind of treatment is more expensive than a waterfrac treatment.

Typically, the gel-proppant treatments start with a datafrac (also called minifrac) (Johnson et al., 1993; Dietzel & Koehler, 1998) to obtain information about friction and tortuosity of the perforated interval. In this datafrac one would first pump an linear gel (medium viscosity gel with viscosity in the range of 0.1 Pa s) which would give an indication if any near-wellbore problems exist which could potentially adversely effect the placement of the frac treatment. This would then be followed by pumping a cross-linked gel which would give an idea of leakoff (i.e. fluid loss due to the permeability of the rock) as well as help predict closure pressures, fracture geometry and if there is any indication of pressure dependent leakoff.

The mainfrac treatment followed after these pretesting is an injection of gel-proppants with a stepwise increase of proppant concentration with a high viscous cross-linked gel into the fracture. The result of the treatment, i.e. the propagation of the fracture, mainly depends on the slurry rate and the concentration of proppants added and their variation as a function of time.

An adjustment during the treatment is possible and often necessary to avoid a screen-out of the well. One can adjust the treatment varying the flow rate and the proppant concentration in case the pressure progression suspect a failure of the treatment.

Hybrid frac treatments

In hybrid frac treatments (Rushing & Sullivan, 2003), water or linear gel is pumped first to generate fracture length. Then a gel-pad with cross-linked gel is injected, followed by proppants or sand of a certain mesh size with a cross-linked gel to fill the fracture. This method can be applied to low-permeable reservoirs and provide sustainable production rates.

Thermal stimulation

Thermal stimulation has been actively used in high enthalpy geothermal fields in volcanic and metamorphic settings to increase the productivity of wells (e.g. Charlez et al., 1996). The injection of cold water leads to a cooling of the rock in the near well bore environment, or adjacent to existing natural or induced fractures. The cooling of the rock matrix induces a tensile component of stress (thermo elastic stress) near the injection well or adjacent to the injection surface. The value of this thermally induced tensile stress depends on the shape of the cooled region, the thermal and elastic rock properties, the difference between the down hole and surface water temperatures, as well as the injection rate. Various numerical models have been developed to explain and predict thermally induced fracturing in sedimentary rocks. Conditions are also discussed, under which secondary fractures perpendicular to the primary main fracture may open.

Chemical stimulation

Matrix acidizing treatments are designed to remove near wellbore damage, primarily associated with plugging of pores by siliceous particles as the consequence of drilling, completion or stimulation (Economides and Nolte, 2000; Hardin et al., 2003). Matrix stimulation is accomplished by injecting a fluid with low pH (e.g. acid) to dissolve and/or disperse materials that impair well production and is mainly used to treat the near-wellbore region. In a matrix acidizing treatment, the acid used is injected at a pressure low enough to prevent formation fracturing (Rae and di Lullo, 2003).

Acid fracturing combines hydraulic fracturing and acid injection. The goal is to produce a conductive fracture, with the exception that the conductivity is achieved by acid etching instead of hydraulic fracturing (Economides and Nolte, 2000).

3. GEOLOGY

The Groß Schönebeck field is a key site for EGS research in the North German Basin (Figure 1). The field has two deep research wells forming a doublet of one injection well and one production well. This doublet has served as a down-hole geothermal laboratory. The geothermal reservoir is 4,100 - 4,300 m deep with a bottom hole temperature of 150 °C and is comprised of Upper Rotliegend of the Lower Permian sandstones deposited in fluvial environments at the southeastern flank of the North German Basin. The sandstone reservoir is underlain by Lower Rotliegend of the Lower Permian volcanic rock and capped by Upper Permian evaporites.

The main targets are the permeable sandstones of the Upper Rotliegend (Dethlingen Formation/Lower Elbe subgroup) and the volcanic rocks (andesites) of the Lower Rotliegend, where permeability is mainly due to connected fractures. It is intended to use this system of fractures to optimize the total productivity of the well. The Dethlingen sandstones represent an effective reservoir horizon with a connected porosity of 8-10%, and an in situ permeability of up to 16.5 mD (Trautwein, Huenges, 2005). The Elbe-Basis-sandstone in the lower part of the Dethlingen Formation exists in NE Brandenburg as 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 profiles is characterized by major NW trending faults and NE to N trending minor faults. With regard to the current stress field, the NE trending faults bear the highest shear stress. Since critically stressed faults are described as hydraulically transmissive (Barton et al., 1995; 1996), the NE trending faults are expected as main fluid pathways in the reservoir. The GtGrSk4/05 well ends in the direct vicinity of a NE trending and W dipping minor fault (Moeck et al. 2009b). Two gel-proppant fracs were carried out in the sandstone horizon. The well path of the deviated well Gt GrSk4/05 consists of an inclination between 37 to 49° in the reservoir rock with an orientation from 288 to 296°N alongside the minimum horizontal stress direction (Holl et al., 2004). The fracture propagation is consequently parallel to the direction of the maximum horizontal stress (18°N) and hence perpendicular to the well path orientation (Zimmermann et al., 2010).

4. STIMULATION EXPERIMENTS

Waterfrac stimulation treatment

The stimulation treatment was carried out between August 9 and August 14, 2007 (Zimmermann et al., 2010) (Figure 2). When flow rates were high, a friction reducing agent was used in the well, which limited the maximum well head pressure to 580 bar. To avoid iron scaling of the injected water, acetic acid was added to set the pH to 5. When flow rates were high (150 l/s), low concentrations of quartz sand (20/40 mesh size) were added to support a sustainable fracture width. Transport of the sand in the fracture and the well was realized solely due to the high flow velocity, because a gel to support the transport was not an option due to the pH value restriction.

In total, 13,170 m³ of fluids and 24.4 tons of meshed quartz sand were injected into the volcanic rocks. A maximum well head pressure of 586 bars was achieved at the maximum flow rate of 9 m³/min (150 l/s). The total duration of the treatment was 6 days (Zimmermann et al., 2010).

The stimulation treatment was accompanied by passive microseismic monitoring in the adjacent well E GrSk3/90. For that purpose, a seismic sensor was installed at a 3,800 m depth to locate and control the produced fractures. A low microseismic activity was recorded with moment magnitudes M_W ranging from -1.0 to -1.8 (Kwiatek et al., 2008). Slip tendency analysis (e.g. Morris et al., 1996) suggests a critically stressed reservoir in the sandstones, whereas the volcanic rocks are low stressed (Moeck et al., 2009a).

Gel-Proppant stimulation of sandstone sections

The stimulation treatment in the sandstones of the lower Dethlingen was carried out from August 18 - 19, 2007 (Zimmermann & Reinicke, 2010)(Figure 3). The proppants were transported by a cross-linked gel with high viscosity. Two kind of high strength proppants were applied: coated and uncoated. Both had a diameter of 0.4 - 0.8 mm (20/40 mesh size). The coated proppants are covered with resin to keep the grains together and were consequently used at the end of the treatment to support the sustainable fracture opening in the vicinity of the well bore.

The treatment began with an injection test with flow rates between 0.3 m³/min and 0.57 m³/min. In total, 250 m³ were injected into the reservoir at a maximum well head pressure of 416 bar.

Subsequently, a leak off test was carried out to obtain the fracture closure pressure (65.8 MPa) and the closure stress gradient (0.016 MPa/m), which is the ratio of fracture closure pressure and vertical depth.

Then a step-rate test followed to calculate the friction and tortuosity at the perforation. These fracture entry friction losses (ΔP_{entry}) are a combination of perforation friction ΔP_{PF} and tortuosity or near-wellbore friction ΔP_{NW}. Perforation friction is the loss of kinetic energy of the fluid as it flows through a small perforation hole at high velocity. Perforation friction is proportional to the injection rate Q_i squared. Near wellbore friction is the pressure loss affected by a tortuous flow path while entering the formation and reorienting into the direction of the fracture plane; it is proportional to the square root of Q_i.

A step-rate entry test was conducted to determine fracture entry losses (ΔP_{entry}). For each flow stage the change in P_{BH} for a rapid change in flow rate is recorded and plotted as a function of flow rates. A dual-curve fitting algorithm with regard to the equation

$$\Delta P_{entry}\left(Q_i\right) = k_{PF} Q_i^2 + k_{NW} Q_i^{0.5}$$

is used to determine the values of the proportional constants k_{PF} and k_{NW}.

The pressure data from the step rate test were utilized to calculate the fracture entry friction losses. A ΔP_{entry} of 8 MPa was found at 4.2 m^3/min. The proportional constants k_{PF} and k_{NW} were determined to 2.2 MPa min^2/m^6, respectively 19.4 MPa $(min/m^3)^{1/2}$. The pressure drops caused by tortuosity and perforation friction are almost equal at 4 m^3/min flow rate. These are indications that not all perforations are accepting fluid on the one hand; on the other hand these perforations are not perfectly aligned in direction of the maximum horizontal stress.

Finally, the gel-proppant treatment was performed, in which 95 to of proppants and 280 m^3 of cross-linked gel were injected into the Lower Dethlingen formation with a flow rate of 4 m^3/min. The schedule of this treatment is given in Figure 3.

The second gel-proppant treatment was carried out from August 23 - 24, 2007 in the sandstones of the Upper Dethlingen. The bridge plug was set at a 4123 m depth, and the interval above was perforated from 4118 - 4122 m. The treatment was similar to the previous ones, with the exception that a slightly lower flow rate was applied (Figure 4). The reason for a lower flow rate of 3 m^3/min compared to the previous treatment was to avoid propagation of the fracture upwards into the siltstones. The treatment started with an injection test with flowrates ranging from 0.3 - 0.62 m^3/min and a total volume of 170 m^3. The leak off test analysis yielded a closure stress gradient of 0.15 bar/m. In the following stimulation treatment, 113 tons of proppants and 310 m^3 of cross-linked gel were injected (see Figure 4). At the end of the treatment the flow rate was increased to 3.5 m^3/min due to an increased fracture net pressure to assure that the total amount of proppants could safely be placed in the fracture.

Matrix acidizing stimulation

The matrix acidizing treatment was performed in conjunction with well cleaning from April 22 – 24, 2009 using a coil tubing (CT) unit (2", 5000 m on a coil) to obtain the best positioning of the acid in the geothermal reservoir between 4360 m and 4100 m measured depth (MD). It was the aim of this treatment to dissolve the residual drilling mud (constituents: calcite, dolomite, aragonite) in order to achieve better access to the post perforated sections and enhance the productivity. Approximately 10 m^3 of hydrochloric acid (7.5 % concentration) were placed in the post perforation sections above 4360 m MD for 30 minutes and then flushed out with water.

5 RESULTS

Productivity increase after stimulation treatments

A total of four stimulation treatments were performed in the Groß Schönebeck GtGrSk4/05 well. The three hydraulic stimulations in well GtGrSk4/05 were carried out separately in two sandstone sections and the volcanic rocks. To determine the success of these hydraulic stimulation treatments, a production test was carried out for all sections together. The individual contribution of each section was determined by flow meter profiling (Zimmermann et al., 2010). The corresponding productivity index increased from 2.4 m^3/(h*MPa) before stimulation to 10.1 m^3/(h*MPa) after stimulation (Table 1).

After the matrix acidizing stimulation, another production test was carried out to determine the improvement of productivity. For that reason, the coil tubing was lifted up to 2350 m depth, and nitrogen was injected into the coil to lift the water out of the annulus of the well (so called nitrogen lift test). A pressure-temperature memory gauge was installed at the bottom of the coil to measure the pressure and temperature below the coil in order to allow a reliable calculation of the reservoir pressure.

The flowrate was calculated from tank volume change in 10 minute intervals. In total, 140 m³ of water were produced during approximately 4 hours, as shown in Figure 5. The bottom-hole pressure was calculated from the gauge, assuming a 90 % share of formation water below the gauge and recalculating the density of this water from the change of the gauge temperature. The changes of the gauge temperature and pressure with time are shown in Figure 6.

The productivity index, which was calculated from the change in flowrate and associated change in bottom-hole pressure, reached a value between 13 - 15 m³/(h MPa) (Figure 7; Table 1). Since the lift test was quite short and stable conditions could not be achieved, the obtained productivity index should be treated as a first estimate, which has to be verified in a more suitable long term test. This is scheduled for the end of 2010 in conjunction with long term communication experiments between both wells.

Hydraulic connection between the wells

According to the recording of the water level in the well EGrSk3/90 during the stimulation treatments the establishment of a connection between the wells of the doublet could be confirmed (Zimmermann et al., 2010). This pressure response was due to the massive pressure increase of up to 43 MPa above reservoir pressure during the highest flow rates of the waterfrac stimulation in the volcanic rock section of the well GtGrSk4/05 (Moeck et al., 2009a). The response in the adjacent well, which is 475 m apart from the other well at reservoir depth, reached a water level increase of ten meters during the first five days (Figure 8). After 23 days the well artesian conditions were achieved with a total water level increase of 71 m. Thereafter, the pressure was monitored with a pressure sensor for another 11 days and a pressure increase of 0.1 MPa (equivalent to 10 m) was observed.

In 2009 a few short pulse tests were performed (Figure 9) to investigate the pressure response at low differential pressure and in the opposite direction, i.e the pressure in the well EGrSk3/90 was released and the water level in GtGrSk4/05 was measured. Even if the pressure release was quite low in the range 0.5 - 1.5 MPa, there is a clear indication of a pressure response in the other well. But there seems a difference in the response time if compared to the nearly instantaneous response during the stimulation treatment. A possible reason might be the difference of hydraulic pathways of low and high differential pressure. At low differential pressure the connection between the wells is mainly established through the permeable sandstone layer (Blöcher et al., 2010), whereas the fast response is due to an existing fault (Moeck et al., 2009b), which is connected via the generated hydraulic fractures and only activated at high differential pressure.

6 CONCLUSION

Some lessons were learned from the experiences of the stimulation methods applied at the Groß Schönebeck field used to develop an EGS. The achievements of the hydraulic waterfrac treatment and the gel-proppant treatments indicated that the stimulation methods should be laid out individually depending on the reservoir rock properties, stratigraphic sequences, and structural geological setting to achieve best results.

If hydraulic fracturing is performed, the sustainability of fracture openings must be assured. In case of generating mostly tensile fractures without shear displacement, supporting procedures like adding meshed sand or proppants should be performed to keep the fractures open. This is especially the case for production wells with reduced formation pressure during production. During the stimulation treatments, the propagation of fractures and the final extension can be controlled by the flow rate, the treatment duration, and the utilization of fluids with different viscosities (linear or cross-linked gels). This opens the possibility to control the propagation of the fracture in height and length and leads to an optimal connection to the reservoir rocks. Increasing the flow rate will mainly lead to an increase in fracture length, whereas lower flow rates lead to an increase in width (aperture) and height. Moreover, all this is related to the leakoff (fluid loss) due to the permeability of the rock. On this basis one can develop a strategy of an individual layout with regard to the specific conditions of the reservoir.

For the situation at the Groß Schönebeck site, different layers are involved in the fracture propagation process. For the hydraulic fracture treatment initiated in the volcanic rock section, fracture length is mainly achieved during the high flow rates (9 m^3/min), since the fluid loss into the overlaying sandstones had to be compensated to maintain horizontal fracture propagation. Furthermore, this fluid loss limits the upper height of the fracture. In the lower sandstone layer, moderate flow rate (4 m^3/min) in conjunction with high viscous gel led to fracture propagation horizontal and downwards into the high permeable layer. Fracture propagation was maintained since the high viscosity of the gel prevented the fluid loss into the formation. In the upper sandstone layer the flow rate was reduced (3 m^3/min) compared to the lower sandstones to obtain a fracture propagation mainly downwards.

Designing a special concept of the well path, including sub horizontal sections in the reservoir and special alignment according to the stress field, offers the possibility for multiple fracture treatments in a well to develop the geothermal field.

Due to the performed hydraulic stimulations, the productivity of the well was enhanced by more than a factor of 4. The subsequent acid stimulation dissolved the residual drilling mud in the vicinity of the well bore and led to a further increase of well productivity by 30 – 50 %, leading to a total increase in productivity by a factor between 5.5 and 6.2. Monitoring water level after stimulation in the adjacent well and vice versa during pulse tests confirmed that both wells are hydraulically connected to each other.

The well doublet is now prepared for a future thermal water loop and subsequent installation of a binary geothermal power plant. Technical and scientific challenges were successfully met with the strategy to define the applied stimulation design and with the stimulation operation itself. The stimulation treatments and the considerations about the well path design can, in principle, be applied to other environments with modifications. Hence, the results provide essential knowledge for developing future stimulation strategies in deep sedimentary geothermal systems like those in the Central European Basin and elsewhere.

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Figure captions

Figure 1 Alignment of the well paths and the fracturing treatments of the doublet system at the Groß Schönebeck EGS research site. In the targeted reservoir rock the well GtGrSk4/05 is deviated towards the direction of the minimum horizontal stress.

Figure 2 Schedule of the cyclic waterfrac treatment performed in the Volcanic rock section with flow rates up to 150 l/s. The pressure curve represents well head pressure and reached a maximum of 586 bar.

Figure 3 Schedule of the gel-proppant treatment in the Lower Dethlingen sandstones starting with a leakoff test and a step-rate test. The pressure curve represents well head pressure. The pressure drop during the treatment is a gravity effect due to the increasing proppant concentration in the well bore column.

Figure 4 Schedule of the gel-proppant treatment in the Upper Dethlingen sandstones starting with a leakoff test and a step-rate test. The pressure curve represents well head pressure.

Figure 5 Schedule of production test after acid stimulation of the reservoir rocks. In the beginning, the coil tubing was positioned at 2350 m.

Figure 6 Gauge pressure and gauge temperature changes (at 2350 m depth) during the production test.

Figure 7 Calculation of productivity index (PI) from flow rate and formation pressure. The slope of the straight line yields the PI (14.68 $m^3/(h\ MPa)$), which can be treated as an upper limit of the achieved productivity.

Figure 8 Change of water level in well EGrSk3/90 after hydraulic waterfrac stimulation of well GtGrSk4/05. The spikes are caused by the shifting of the pressure sensor. The water level rose from 71 m below surface to artesian conditions 23 days after the stimulation treatment. The fast response is due to a fault zone which connects both wells via the produced hydraulic fractures (Moeck et al., 2009b).

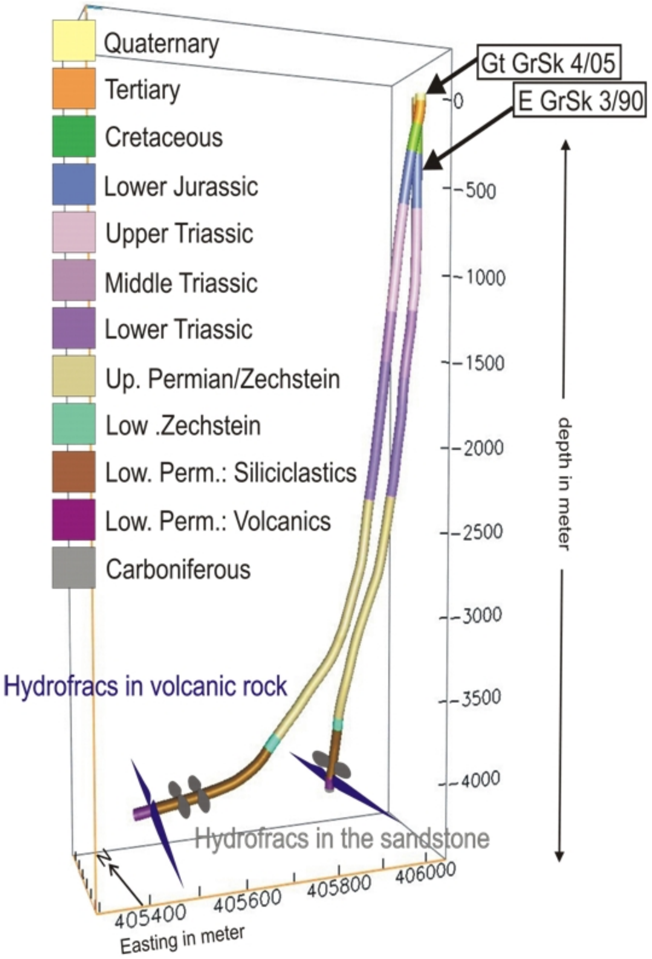
Figure 9 Pressure response of well GtGrSk4/05 after pulse tests in the well EGrSk3/90. The response is retarded compared to the high pressure response. At low differential pressure the connection between the wells might be established through the permeable sandstone layer (Blöcher et al., 2010).

Table 1

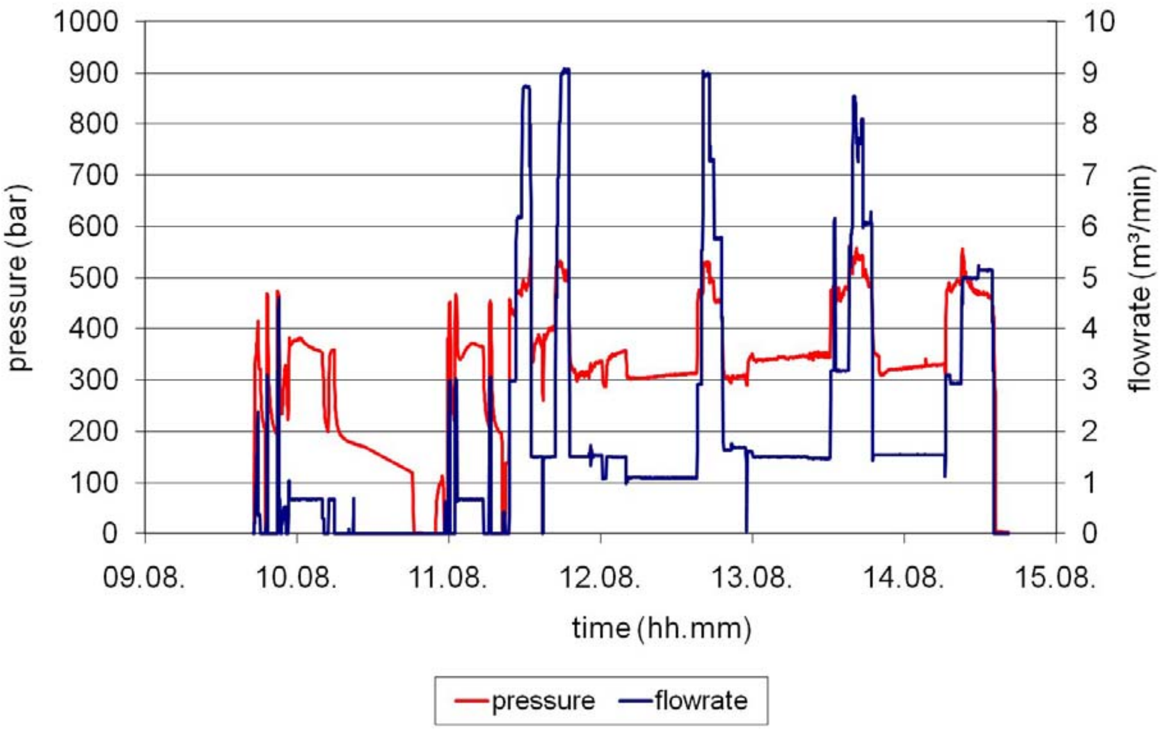
Summary of the stimulation treatments in Groß Schönebeck well Gt GrSk 4/05. Results represent individual flow data from the volcanics and the Upper and Lower Dethlingen sandstones, the result from the matrix acidizing, as well as the cumulative result

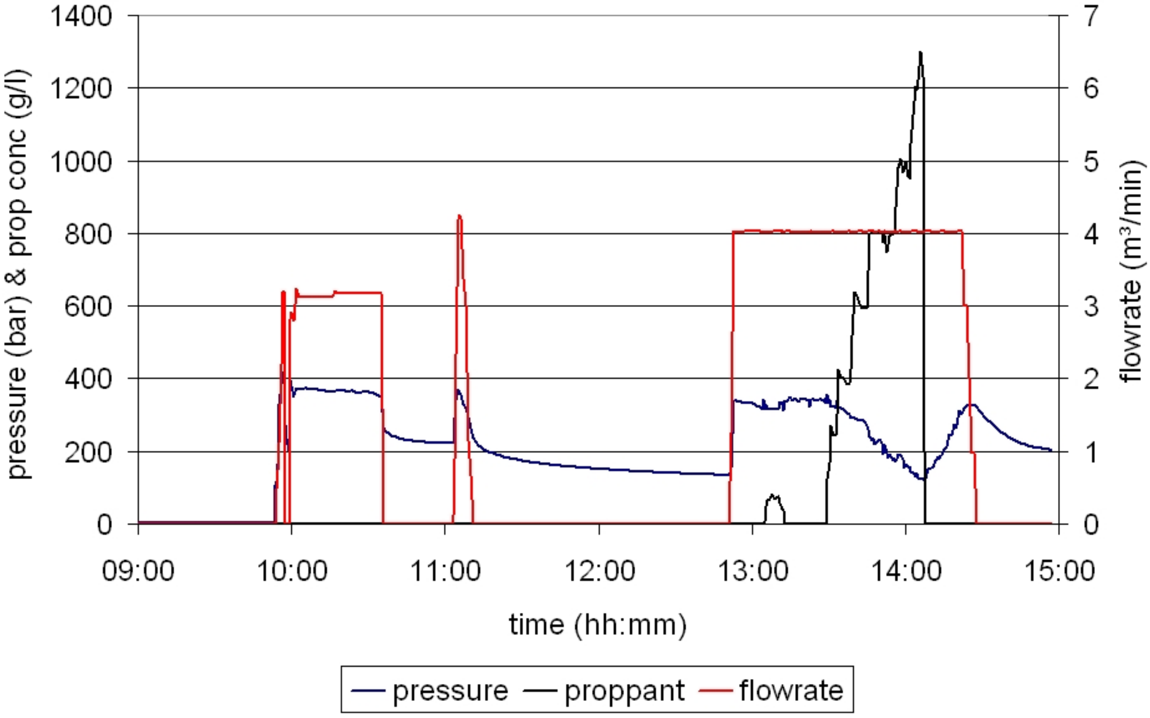
Tested well section	**Treatment applied**	**Duration (days)**	**Volume (m^3)**	**Flow rate (L/s)**	**Productivity (L/s/bar)**	**Productivity improvement factor**	**Located microseismic events**
Volcanics	-	0.06	4.4	0.83	0.004	Initial PI	-
Volcanics	Waterfrac with sand	0.5	356	8.2	0.0849	22	78
Lower Dethlingen 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
Dethlingen sandstones	Matrix acidizing	0.17	140	9.7	0.36 - 0.41	1.3 - 1.5	
Sum before stimulation					0.066	Initial PI	
Sum after hydraulic stimulations					0.28	4.25	
Sum after all stimulations					0.36 - 0.41	5.5 - 6.2	

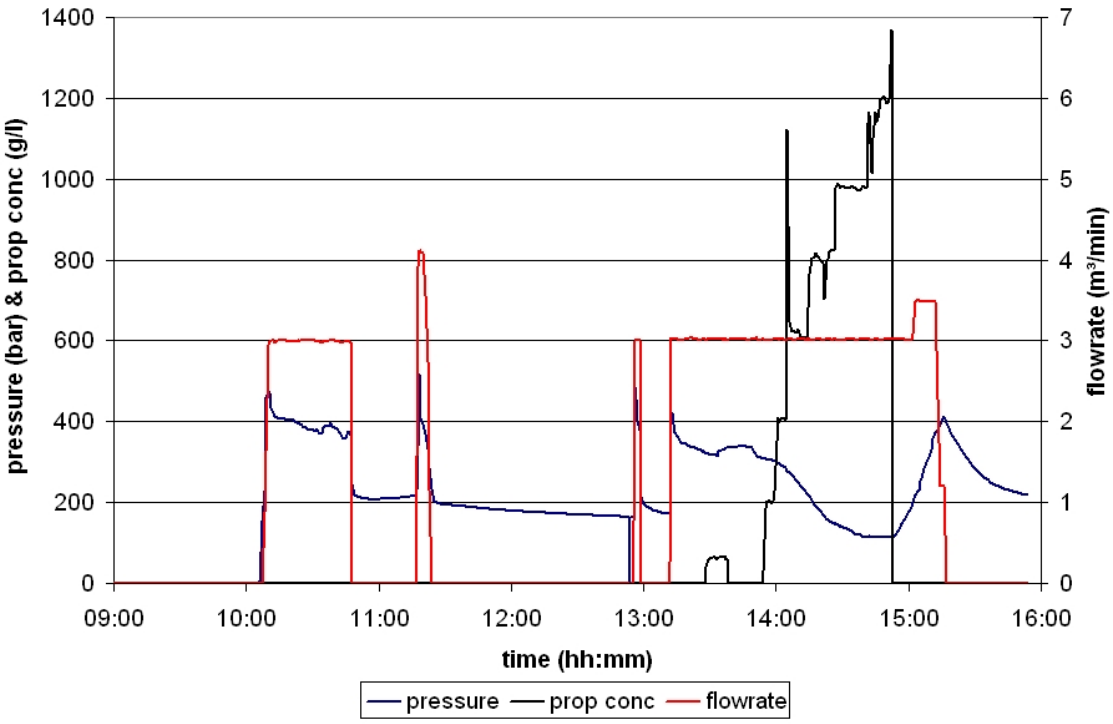
PI: Productivity index

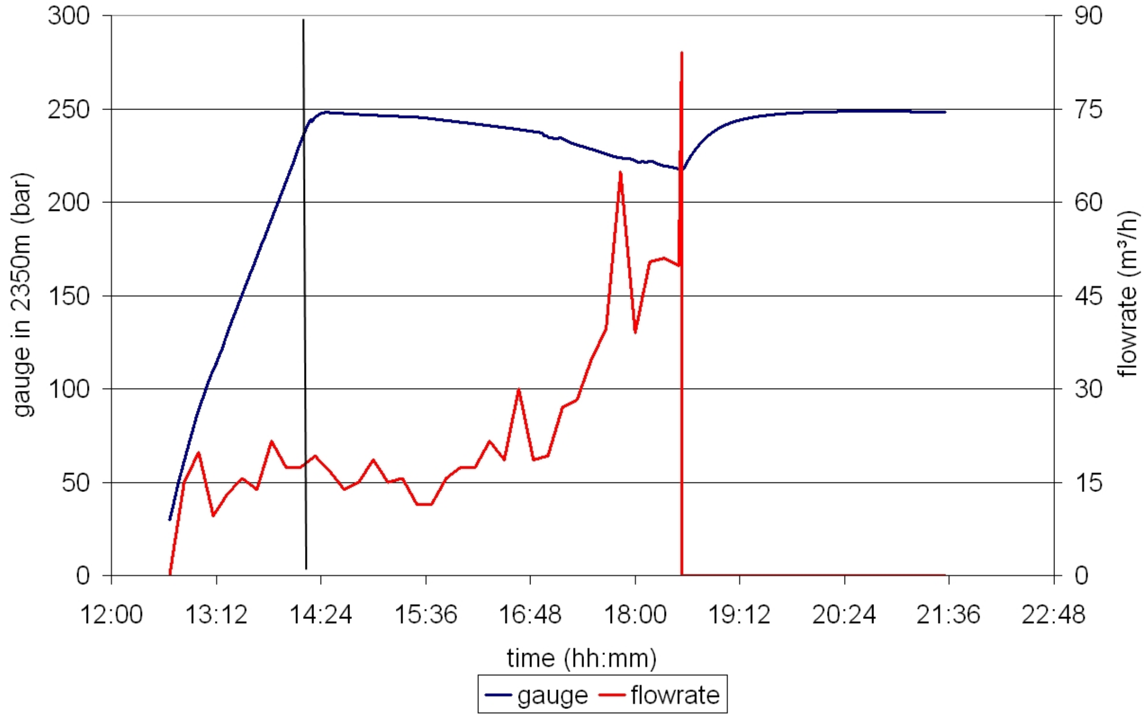

Quaternary
Tertiary
Cretaceous
Lower Jurassic
Upper Triassic
Middle Triassic
Lower Triassic
Up. Permian/Zechstein
Low .Zechstein
Low. Perm.: Siliciclastics
Low. Perm.: Volcanics
Carboniferous
Gt GrSk 4/05
E GrSk 3/90
0
500
1000
1500
2000
2500
3000
3500
4000
depth in meter
Hydrofracs in volcanic rock
Hydrofracs in the sandstone
N
405400
405600
405800
406000
Easting in meter

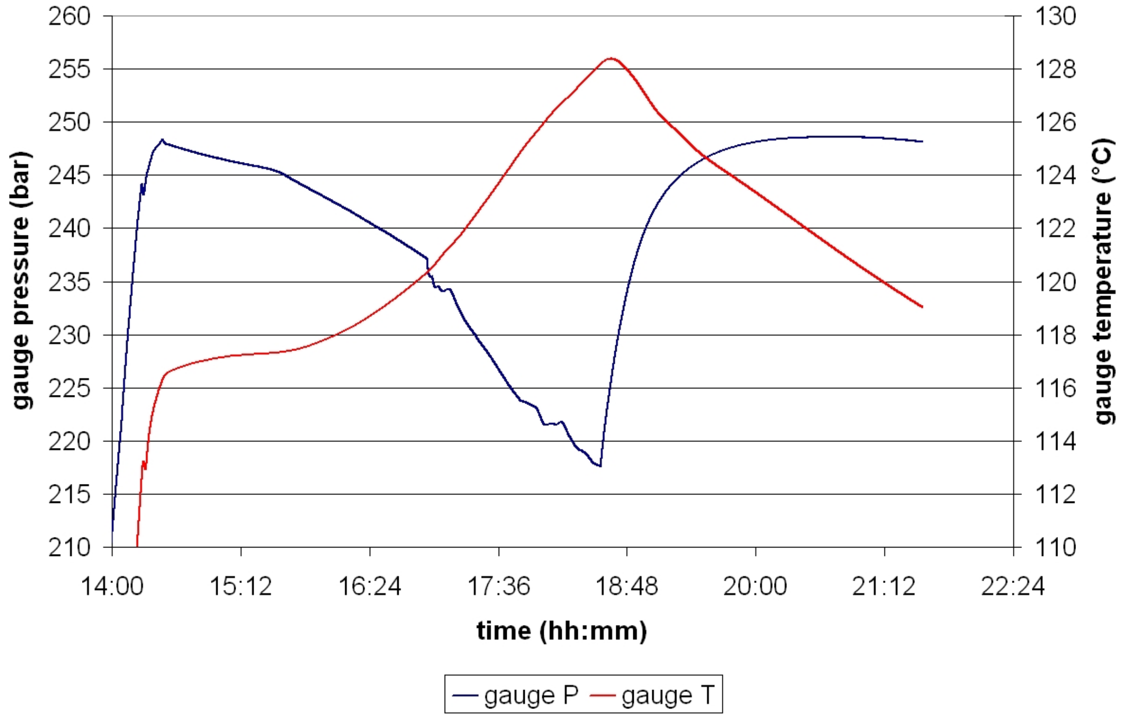

N
Berlin
Germany

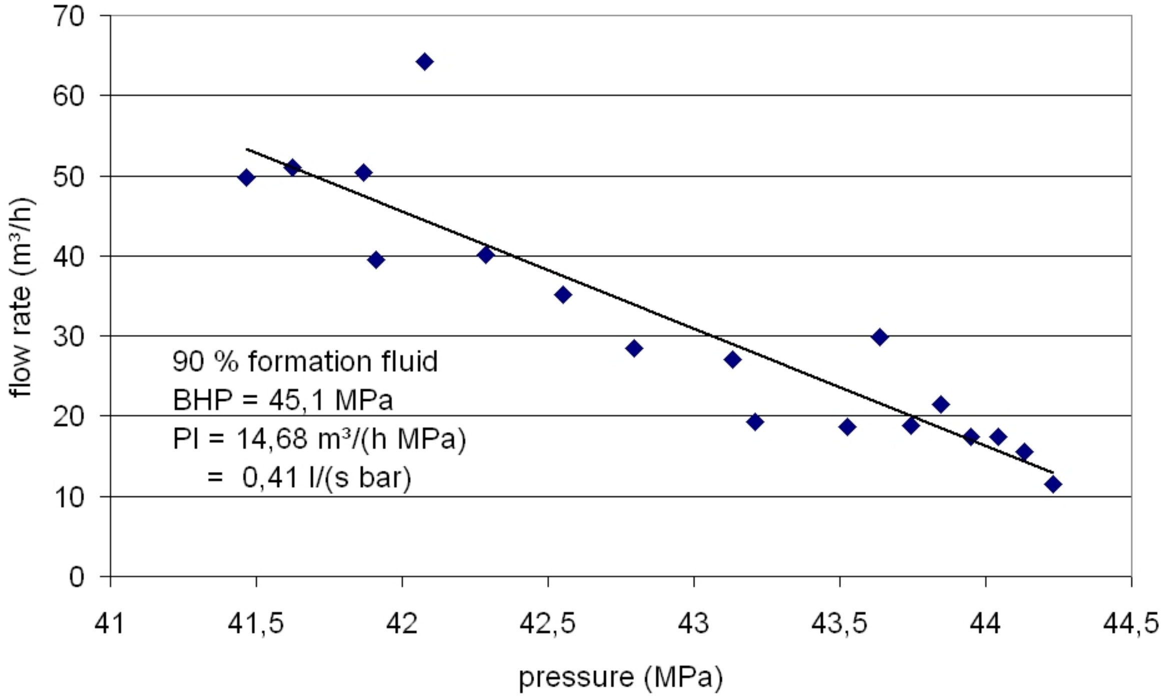

pressure (bar)
flowrate (m³/min)
1000
900
800
700
600
500
400
300
200
100
0
10
9
8
7
6
5
4
3
2
1
0
09.08.
10.08.
11.08.
12.08.
13.08.
14.08.
15.08.
time (hh.mm)
pressure
flowrate

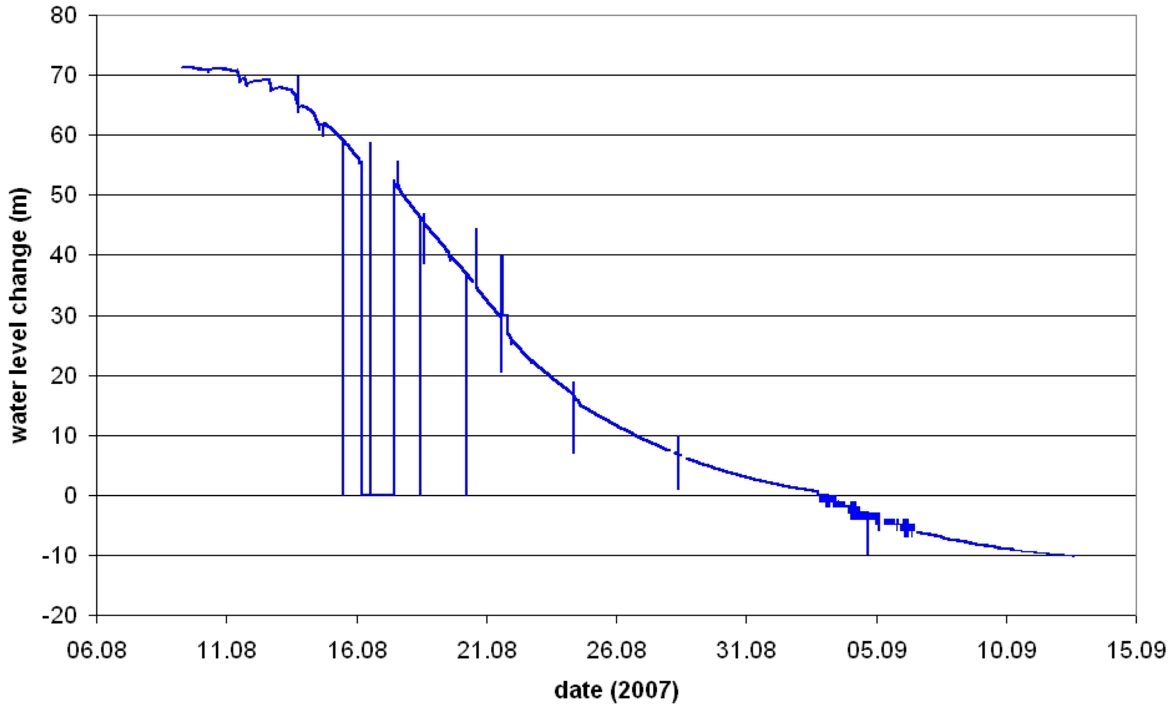

1400
1200
1000
800
600
400
200
0
pressure (bar) & prop conc (g/l)
7
6
5
4
3
2
1
0
flowrate (m³/min)
09:00
10:00
11:00
12:00
13:00
14:00
15:00
time (hh:mm)
pressure
proppant
flowrate

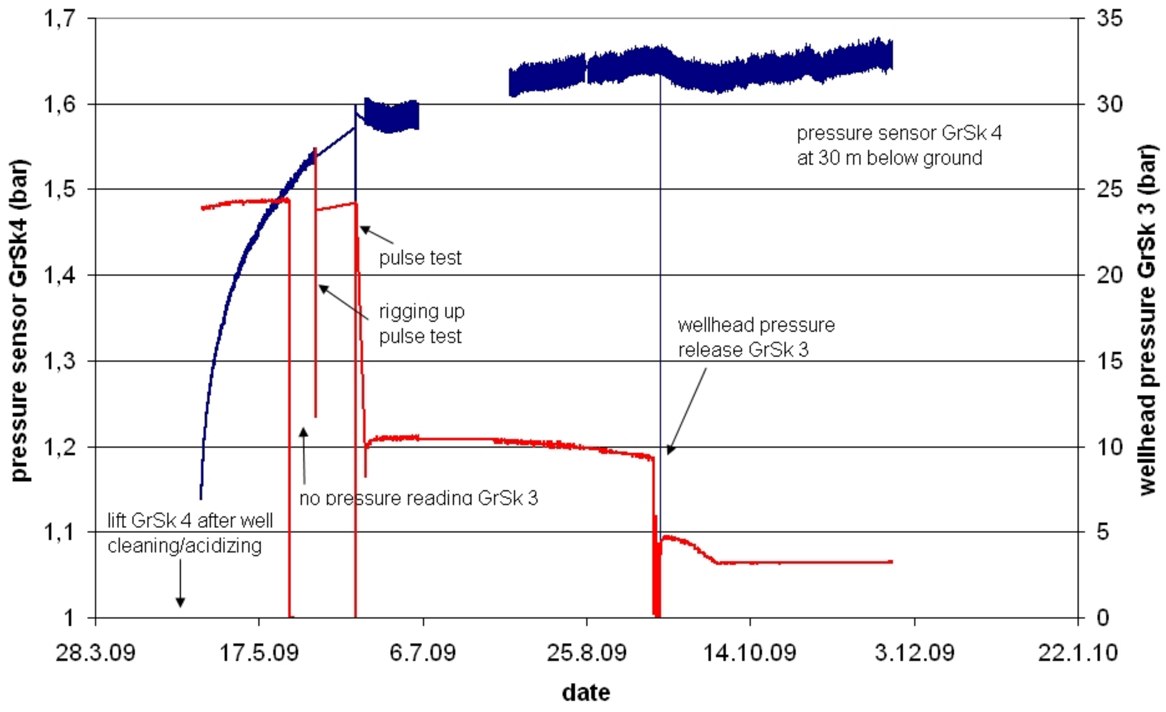

1400
1200
1000
800
600
400
200
0
pressure (bar) & prop conc (g/l)
7
6
5
4
3
2
1
0
flowrate (m³/min)
09:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
time (hh:mm)
pressure
prop conc
flowrate


300
250
200
150
100
50
0
90
75
60
45
30
15
0
gauge in 2350m (bar)
flowrate (m³/h)
12:00
13:12
14:24
15:36
16:48
18:00
19:12
20:24
21:36
22:48
time (hh:mm)
gauge
flowrate


260
255
250
245
240
235
230
225
220
215
210
130
128
126
124
122
120
118
116
114
112
110
gauge pressure (bar)
gauge temperature (°C)
14:00
15:12
16:24
17:36
18:48
20:00
21:12
22:24
time (hh:mm)
gauge P
gauge T


flow rate (m³/h)
pressure (MPa)
90 % formation fluid
BHP = 45,1 MPa
PI = 14,68 m³/(h MPa)
= 0,41 l/(s bar)


water level change (m)
date (2007)


pressure sensor GrSk4 (bar)
wellhead pressure GrSk 3 (bar)
date
1,7
1,6
1,5
1,4
1,3
1,2
1,1
1
35
30
25
20
15
10
5
0
28.3.09
17.5.09
6.7.09
25.8.09
14.10.09
3.12.09
22.1.10
pressure sensor GrSk 4
at 30 m below ground
pulse test
rigging up
pulse test
wellhead pressure
release GrSk 3
no pressure reading GrSk 3
lift GrSk 4 after well
cleaning/acidizing