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Productivity Enhancement by Hydraulic Fracturing and Circulation of Thermal Water at the Test Site Horstberg in the North German Basin

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ABSTRACT

The well Horstberg in the North German Basin is a geothermal research site of the Federal Institute for Geosciences and Natural Resources (BGR) in Germany. The deep well is completed in an alternating sequence of clayey and sandy Triasic sediments (Buntsandstone) with a final depth of 4.120 m. The experiments in Horstberg aim towards the development of geothermal utilisation concepts in low permeable sedimentary rock. The investigated key method is hydraulic stimulation.

In 2003 first hydraulic stimulation experiments were conducted in the very low permeable sandstone of the Volpriehausen sequence at 3.920 m depth. Access to the formation was achieved by a special perforation technique, by a propellant stimulation. A surprisingly high wellhead pressure of more than 400 bar had to be applied for fracturing and limited the execution of the stimulation operations. In the largest stimulation test about 600 m^3 of freshwater were injected at a pressure of about 460 bar. Succeeding venting tests revealed a poor fracture performance and no significant productivity enhancement.

In contrast, in the Detfurth sandstone some 130 m above the Volpriehausen, a successful hydraulic stimulation was conducted. By the injection of about 20.000 m^3 freshwater without proppants or additives a large fracture area was created. Based on pressure decline analysis and on fracture propagation modelling the created fracture area could be estimated to about 350.000 m^2. After the stimulations several hydraulic tests showed, that a significant part of the originally created fracture remained highly conductive even at a pressure below the undisturbed fluid pore pressure. An extended formation linear flow regime was observed from which a remaining “infinite” conductive fracture area in the order of 10.000 m^2 was derived. Over several years no deterioration of the fracture performance was observed. The comparison of hydraulic tests before and after the stimulation indicates a more than tenfold increase in productivity. However, the productivity is still insufficient for commercial energy production in a geothermal doublet system. Only if the created fracture acts as heat exchanger itself the geothermal utilisation might be possible.

The great differences in the success of the hydraulic stimulation operations in the two sandstone layers are noteworthy. Reasons for the poor fracture performance in the Volpriehausen might be the type of perforation, the low stimulation volume and the different state of stress. Due to the applied special perforation technique (propellant stimulation) some deep channels might have been created which are not favourable aligned to the stress field and thereby lead to friction losses while producing. Further, a large injection volume seems to be necessary to induce a substantial and remaining fracture and the stress conditions are less favourable in the Volpriehausen for shearing.

Due to the stimulation operation in the Detfurth sandstone a hydraulic link to the upper and significantly higher permeable Solling sandstone was formed. This opened up the possibility for thermal water circulation between two sandstones via an artificial fracture. A first circulation experiment was conducted already in 2004. Now further circulation experiments are planned in order to study the fluid flow over the fracture and to determine its potential for heat extraction. The hydromechanical properties of the fracture are of special importance in those circulation experiments.

1. INTRODUCTION

Up to now geothermal development is mainly bound to hydrothermal resources in permeable rock. In Germany the Molasse Basin around Munich is in the focus of geothermal exploration (Weber et al., 2015). Here a highly permeable and deep seated aquifer in carstic sediments has been used for geothermal energy generation. However, in other regions, like in the North German Basin, the geothermal potential is much higher if concepts and technologies were available for recovering low permeable sedimentary rock.

The well Horstberg serves as research well to investigate concepts for recovering geothermal energy from low permeable sediments in the North German Basin. Hydraulic stimulations (waterfrac) and the creation of artificial fractures are the key for that. The concept of hydraulic stimulation has successfully been applied in crystalline rocks in several EGS projects. Due to the injection of large water volumes large scale fractures covering areas in the order of km² had been created or stimulated (Jung, 2013). In some cases a hydraulic link between two wells was established by stimulation allowing the circulation of thermal water and energy extraction. However, almost no experiences exist so far about the potential of hydraulic stimulation in sedimentary rock.

At the well Horstberg hydraulic stimulations were conducted in two low permeable sandstones. The results of these operations with respect to the created fracture area, fracture conductivity and productivity enhancement are shown and discussed. Further, the option of circulating water within the well via an artificial fracture as a special utilisation concept is addressed.

2. TEST SITE, WELLBORE AND GEOLOGY

The well Horstberg Z1 is located some 80 km north-east of Hannover in Germany. It has been drilled into an inversion structure, striking NEE-SWW, that is bound by saltdomes on both sides (Fig. 1). The stratigraphy is typical for the Northern German Basin. Sedimentary successions from the Permian Rotliegend at the bottom up to the Quaternary at the top were encountered (Fig. 2).

The well was initially designed for the commercial production of gas from the Rotliegend formation. However, no economic gas production was achieved. Before the start of geothermal investigations, the well was plugged back from the final depth of 4918 m to 4120 m. By this, gas bearing layers in the lower most part of the well were sealed and the accessible part of the well reaches down to the Lower Buntsandstone.

The well is almost vertical with an inclination angle of about 10° in the Middle Buntsandstone. The difference between true vertical depth (TVD) and measured depth is about 25 m in this formation. If not mentioned otherwise in this paper depth values refer to measured depth.

Prior to geothermal operations, an undisturbed temperature-depth profile was measured. At the final depth of the well (4120 m) a maximum temperature of 158°C was recorded (Fig. 2). This temperature is approximately 30 K above the average temperature estimated for this region. In particular, the low thermal conductivities in the Cretaceous and Jurassic formations may explain the high temperatures.

The Middle Buntsandstone (3.640 m – 3.930 m) was selected as target for geothermal investigation because of its suitable temperature and depth as well as for its widespread occurrence in the North German Basin (Jung et al., 2005). Sandstone layers occur in the subformations Volpriehausen, Detfurth and Solling. The thickness of these layers ranges from 6 m to 20 m and its porosity is low (6-11 %). Even the Solling sandstone, which has the best hydraulic properties and greatest thickness of the three layers, has an insufficient hydraulic conductivity for hydrothermal energy extraction. Only due to the creation of artificial fractures, geothermal utilisation concepts may be tested or applied.

The state of stress in the target formation Buntsandstone is still a matter of investigation. The stress field is most likely strongly effected by the adjacent saltdomes and varies over short distances. Geomechanical investigation at the test site suggests a direction of the maximum principal stress in parallel to the inversion structure (NEE-SWW). It can therefore be assumed that an artificial fracture will propagate in this direction. However, this statement is still unproven, since no stress indicators are available in the well and the geophysical monitoring of the stimulation operations provided no results (Orzol et al., 2005).

The Buntsandstone at Horstberg is an overpressurised reservoir. Under equilibrium conditions the wellhead pressure is about 140 bar. Therefore, by just opening the well it is producing.

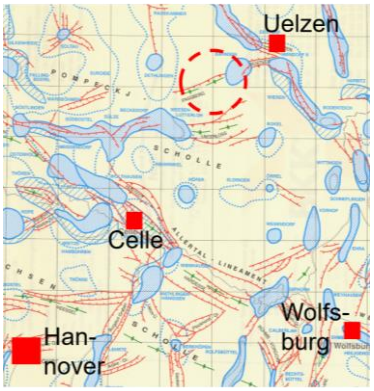


Figure 1: Location of the well Horstberg in north Germany (centre of the red circle), tectonic elements, salt structures (blue) and larger towns.

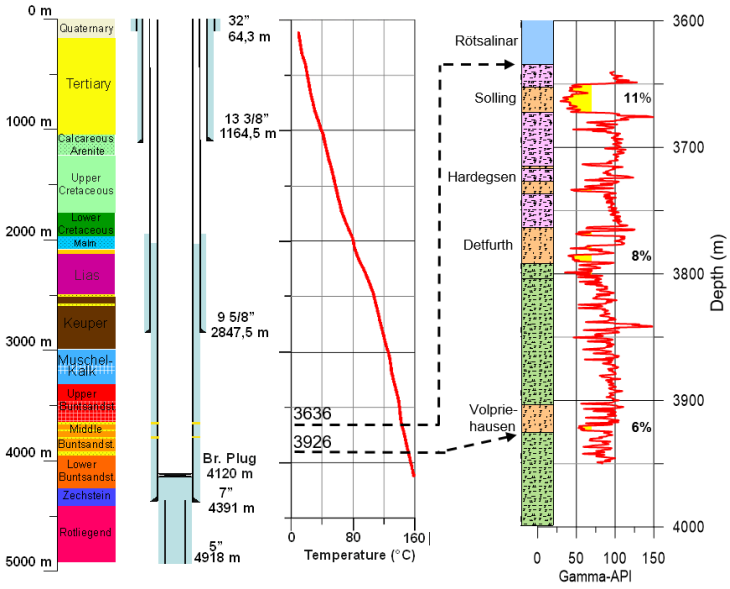


Figure 2: Geological profile, wellbore completion, temperature, lithology and gamma ray in the Middle Buntsandstone of the wellbore Horstberg. The sandstones are marked yellow in the gamma ray-log (cut-off: 70 API) and its porosities are indicated.

3. HYDRAULIC STIMULATION IN THE VOLPRIEHAUSEN SANDSTONE

The first hydraulic stimulation (waterfrac) was performed in the deepest sandstone of the Middle Buntsandstone in the Volpriehausen. Beforehand the interval between 3.920,5 and 3.926,5 m was perforated twice: In a standard procedure creating big holes followed by a propellant stimulation/perforation. The propellant stimulation was applied for deep penetration and to initiate artificial fractures in the vicinity of the wellbore. Despite the perforations, no hydraulic access to the Volpriehausen sandstone was achieved. It could neither be injected nor produced out of the sandstone, indicating a very low permeability of the sandstone (< 100 µD). Only after exceeding the fracturing pressure, water could be injected. The wellhead pressure for fracturing exceeded

400 bar and was higher than expected (Fig. 3). Several stimulation tests were carried out, starting with a low rate of 0,04 l/s and interrupted by venting tests to study the frac performance. In the last step approximately 600 m^3 of fresh water without additives were injected at an average rate of 7,2 l/s and at a wellhead pressure of appr. 460 bar (Fig. 4).

In all venting tests the pressure and flow rate dropped drastically within a short time indicating poor hydraulic fracture properties. The fracture performance did not significantly improve during the frac tests with increasing flow rates. While venting after the largest frac the production rate decreased from about 10 l/s to less than 1 l/s within a few hours whereas the wellhead pressure dropped from 450 bar to almost zero (Fig. 4). Only about 110 m^3 of water could be produced back in two venting periods (less than 20 % of the injected volume).

Obviously, significant friction losses in the fracture close to the wellbore were responsible for the poor fracture performance. Here the typically assumed behaviour of fractures created by fluid injection without proppants was observed. The fracture "closes" in the vicinity of the wellbore accompanied by a drastic reduction of the production rate. Potentially, in further fracture test with significantly higher rate and volume the fracture performance might have been improved by erosion of the fracture. However, the hydraulic equipment available on site was not appropriate for higher rates at a pressure level of more than 400 bar. Therefore, no further tests were carried out in the Volpriehausen sandstone and this horizon was abandoned.

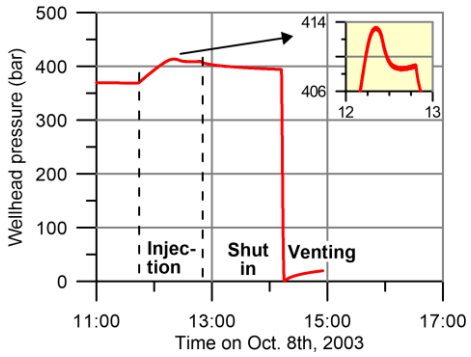


Figure 3: Wellhead pressure at the first frac test (minifrac) in the Volpriehausen sandstone. Injection rate: 0,04 l/s.

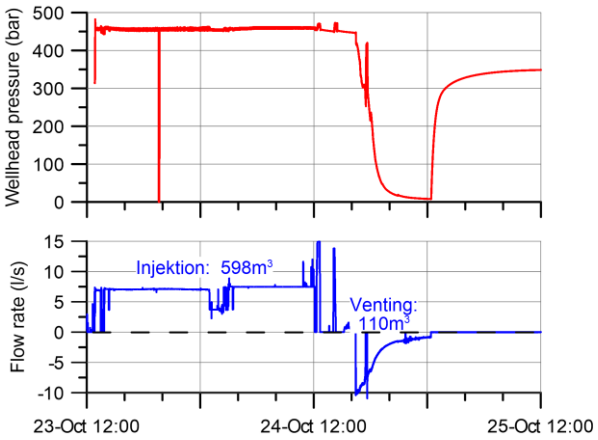


Figure 4: Wellhead pressure and flow rate at the largest frac in the Volpriehausen sandstone.

4. HYDRAULIC TESTS IN THE DETFURTH SANDSTONE

4.1 Initial hydraulic properties

Access to the second horizon, in the Detfurth sandstone, was created by perforating the interval between 3787 and 3791 m some 130 m above the perforated section in the Volpriehausen. At the moment of perforation the well was flowing at a rate of less than 0,5 l/s due to some remaining overpressure from stimulation in the Volpriehausen (Fig. 5). Opening of the second interval lead to a significant increase of flow. It increased to more than 1 l/s showing a significant permeability of the Detfurth sandstone. In contrast to the Volpriehausen it was possible to produce out of the Detfurth by just opening the formation. Further, the flow out of the Detfurth sandstone indicates an overpressurised reservoir. If the formation water pressure would have been hydrostatic, no additional flow was to be expected without pumping.

Initial hydraulic parameters of the Detfurth sandstone can be derived from the increase of flow rate after perforation and from the pressure build up after shut-in (Fig. 5). The pressure response at shut-in in the diagnostic plot shows the typical characteristics for radial flow: A hump in the derivative is followed by a stabilisation (Fig. 6). From the stabilised pressure derivative the transmissibility of the Detfurth sandstone can be well determined. Uncertainties in the determination of transmissibility result mainly from the flow history.

Only the combined flow rate from Volpriehausen and Detfurth was measured (Fig. 5). The trend of the declining flow out of the Volpriehausen was extrapolated from the time before perforation until shut-in and then substracted from the measured cumulative flow. In this way, the flow coming from the Detfurth was derived and stepwise approximated for using it in the analysis software (Ecrin, Co. KAPPA Engineering SA). In the last flow period before shut-in a production rate of 0.53 l/s was determined. In the shut-in period some crossflow from the Volpriehausen into the Detfurth has to be considered because of the still higher pressure in the Volpriehausen. Based on the different pressure levels in both formations and on the flow rate of the Volpriehausen a maximum crossflow of 0.09 l/s at shut-in was calculated and accounted for in the analysis.

Besides the flow history, the viscosity of the fluid is an important factor of uncertainty which directly affects the transmissibility. For the encountered temperature (~140°C), pressure (~600 bar) and salinity (~280 g/kg_w) the dynamic viscosity was assumed as $(3,5 \pm 0,5)x10^{-4}$ Pa*s (Mao&Duan, 2008).

Table 1: Input and output parameter for pressure analysis of the shut-in period shown in Fig. 6 and Fig. 7.

Input Parameter		Output Parameter	
Thickness:	10 m	Transmissibility:	$(1.0\text{-}1.5)*10^{-14}$ m^3
Porosity:	0.05	Permeability:	(1.0 – 1.5) mD
Specific storage:	$5*10^{-11}$ Pa^{-1}	Skin:	-0.8 – -0.4
Dynamic viscosity:	$(3.5 \pm 0{,}5)x10^{-4}$ Pa*s		

According to the test analysis the permeability of the Detfurth sandstone is in the low millidarcy range but depends on the assumption of the thickness of the outflow zone (Tab. 1). Here a sandstone thickness of 10 m was assumed in accordance to the gamma log (Fig. 2). The negative skin indicates a stimulated zone around the wellbore. Likely, the perforation was very effective so that the perforation itself caused already some stimulation.

Applying the parameters derived above, the pressure response at shut-in can very well be matched (Fig. 7). However, the succeeding injection period with an injection rate of 1.7 l/s can not be matched. Here the flattening of the pressure curve already indicates fracturing, so that the calculated pressure is significantly higher than the observed one.

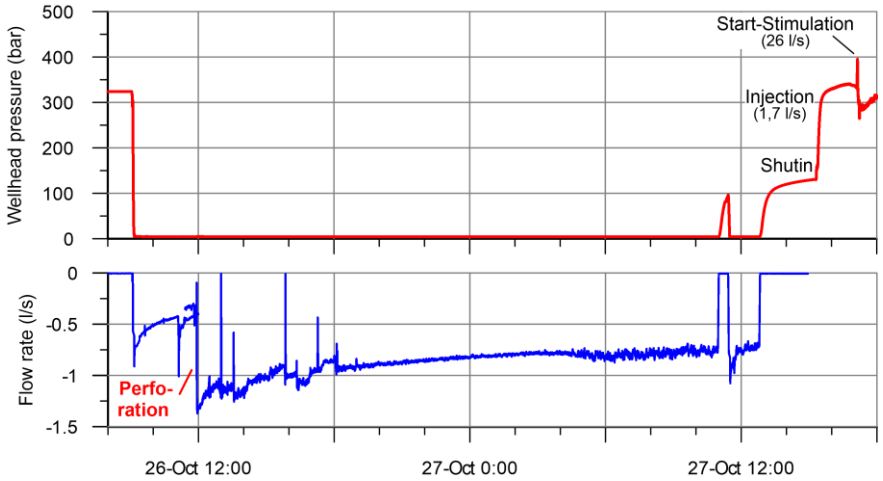


Figure 5: Wellhead pressure and flow rate (production) in the time period between perforation and start of stimulation of the Detfurth sandstone. In the beginning the well was opened and vented after the stimulation in the Volpriehausen.

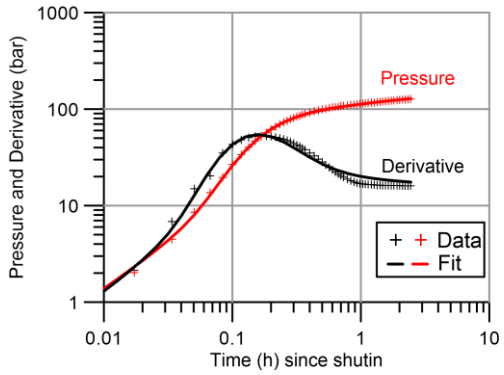


Figure 6: Diagnostic plot for the shut-in period on Oct, 27th after the free flowing phase. The downhole pressure difference is plotted referred to the initial pressure at shut-in.

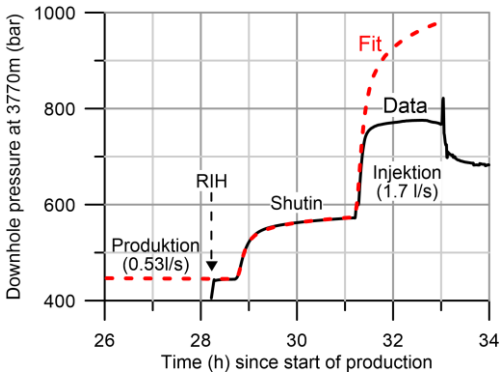


Figure 7: Pressure match for the shut-in period on Oct, 27th. RIH: Pressure gauge, run into hole.

4.2 Hydraulic stimulation and fracture area

One day after perforating a massive hydraulic stimulation was started in the Detfurth sandstone. The experiences from successful waterfracs in crystalline rock were applied for the design of the operation (Jung et al., 2005). About 20.000 m^3 of fresh water were injected at a mean flow rate of 50 l/s. Details of the stimulation and of the accompanying geophysical monitoring are given elsewhere (Orzol et al., 2005). Here the created fracture area and shape as well as the fracture performance are discussed.

The stimulation was carried out in three main steps interrupted by shut-in periods and a venting test (Fig. 8). The wellhead and downhole pressures during stimulation are more than 100 bar lower than in the Volpriehausen indicating a drastic change in the stress conditions over the short vertical distance of some 130 m. This significantly lower pressure in the Detfurth was an unambiguous evidence that the injected water during stimulation exclusively penetrated into the Detfurth formation although the perforation in the Volpriehausen was still open.

Pressure curves during a hydraulic stimulation are difficult to interpret because of the overlap of hydraulic and mechanical effects. The slight increase of pressure while injecting can qualitatively be interpreted as a fracture growth into adjacent formations (clay) with higher stress. More information about fracture growth can be derived from the shut-in periods or from the interim venting test. Tischner et al. (2015) derived a minimum fracture area of 200.000 m^2 based on the pressure decline at venting and in the shut-in periods. Jung et al. (2005) concluded an upper limit of the fracture area of 500.000 m^2 from the pressure decline at the final shut-in. The latter estimation was obtained by assuming that the fluid loss into the formation at the end of test was equal to the full injection flow rate of 50 l/s.

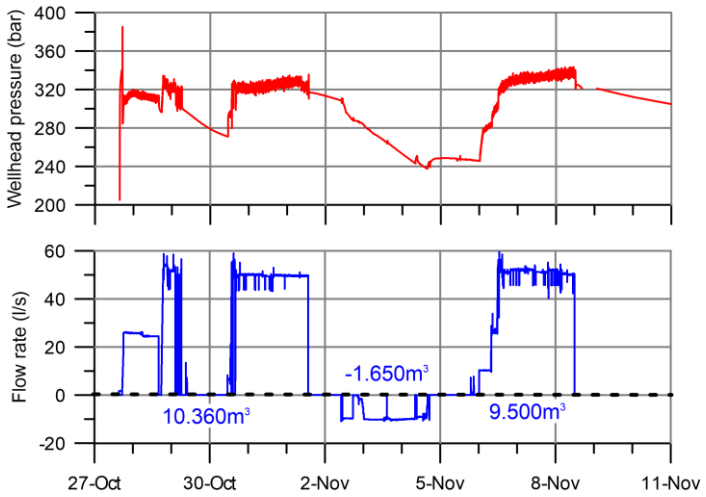


Figure 8: Wellhead pressure and injection rate for the hydraulic stimulation of the Detfurth sandstone in 2003. A positive rate means injection and a negative one production.

Another approach to investigate the frac properties is the modelling of fracturing process applying specially designed software. Figure 9 shows the calculated fracture geometry using the software FieldPro (Co. RESnet). Parameters essentially controlling the fracture propagation are the permeability of the sandstones and the minimum horizontal stress (Tab. 2). For the sandstone layers of the Solling and Detfurth these parameters were derived from hydraulic and frac tests respectively. For the clay and salt layers typical permeabilities reported in the literature were used (Shao et al., 2011). The vertical stress profile was calculated based on the overburden and on the poisson ratio (Thiercelin & Roegiers, 2000). The calculated stress data were then calibrated on the measured ones in the sandstones of the Detfurth and Solling. Additionally, a stress barrier at about half the distance between Detfurth sandstone and Volpriehausen sandstone was assumed to account for the observed significant different stress levels in both layers.

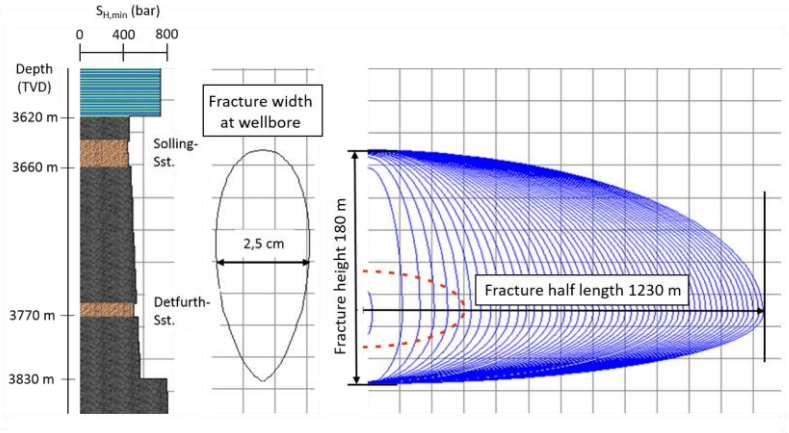


Figure 9: Fracture propagation in the vertical plane according to the calculation with FieldPro. The blues lines show the fracture front in time steps of two hours. The calculation was performed with an injection volume of 20.000 m^3 at a rate of 50 l/s and for the minimum horizontal stress profile ($S_{H,min}$) depicted on the left hand site. The fracture width profile is shown for the end of stimulation. The dotted red ellipse symbolizes the area of persisting infinite conductive fracture (see text).

Table 2: Parameters for the calculation of the fracture propagation in Figure 9. S_{Hmin} is the minimal horizontal stress at the bottom of the interval or at the given depth.

Depth TVD [m]	Lithology	Permeability [mD]	Poisson-ratio [-]	Density [kg/m³]	S_{Hmin} [bar] applied	S_{Hmin} [bar] measured
3484 - 3619	Salt	$1 \cdot 10^{-7}$	0.25	2.100	745	
-3637	Clay	$1 \cdot 10^{-4}$	0.23	2.700	653	
-3657	Solling-Sandstone	10.0	0.2	2.650	647	650±5 at 3649m
-3767	Clay	$1 \cdot 10^{-4}$	0.23	2.700	672	
-3777	Detfurth-Sandstone	1.0	0.2	2.650	664	665±15 at 3770 m
-3829	Clay	$1 \cdot 10^{-4}$	0.24	2.700	766	
-4180	Clay	$1 \cdot 10^{-4}$	0.24	2.700	821	785±5 at 3900 m

Modelling the fracture propagation is impacted by uncertainties mainly resulting from the input parameters and model assumptions. However, the main model assumptions, like tensile crack propagation and a horizontal orientation of the minimum stress component, are well justified for the present conditions. Beyond that, essential parameters as stress magnitude and permeability in the sandstone are well constrained by test data.

The modelled fracture area in the most reliable scenario is 350.000 m^2 (Fig. 9) and lies well between the upper and lower limits estimated above (200.000 m^2 and 500.000 m^2 respectively). Thus, different approaches lead to consistent results and the presented modelling results are plausible.

Besides the fracture area the vertical fracture extension is of great importance. In all modelling scenarios the upper sandstone (Solling) acts as a barrier for further fracture propagation. The relativly high permeability and thickness of this sandstone leads to significant leak-off into the matrix and therefore confines the fracture propagation. Although geophysical monitoring of the fracture propagation was not successful, some information about the fracture extension could be derived from temperature logs (Fig. 10). A temperature log was measured nine months after the stimulation. The comparison with the undisturbed temperature profile indicates the vertical fracture extension at the wellbore. A vertical fracture extension of approx. 200 m can be derived which accords very well to the calculated one. Furthermore, the vertical fracture propagation indeed is limited by the Solling sandstone as the calculation predicts.

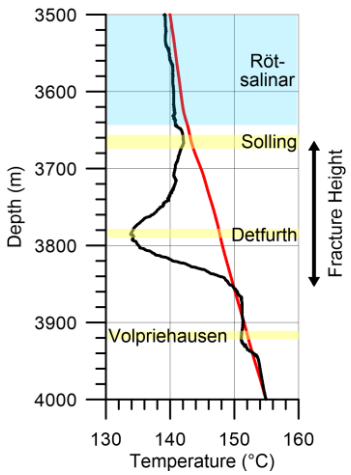


Figure 10: Undisturbed temperature (red) and temperature profile measured nine months after the stimulation (black).

4.3 Fracture performance and productivity enhancement

Hydraulic tests after the stimulation were interpreted with respect to the stimulation performance and productivity enhancement. In February 2004, cyclic injection/production tests were carried out to investigate a cyclic heat extraction concept (Tischner et al., 2010). The observed pressure response showed a completely different hydraulic characteristic compared to the situation before stimulation (Fig. 11 and 12). No radial flow was observed anymore. Instead the pressure shows a pronounced linear flow over an extended time period. It has to be interpreted as formation linear flow indicating a large and highly conductive fracture from which the water penetrates into the matrix. Pressure losses along the fracture are negligible compared to the pressure losses in the matrix. It is noteworthy that the pressure response for the whole series of production and shut-in periods can be fitted with a unique data set. Obviously, the fracture remains stable and its hydraulic fracture properties are hardly dependent on the pressure level in the tested range between reservoir pressure and about 40 bar below.

In 2006, a production test was carried out as constant pressure test with a pressure drop of about 60 bar (Fig. 13). Here the production rate could well be fitted with the same parameter set as for the cyclic injection/production tests. Therefore, the hydraulic properties of the fracture remained stable even for a larger pressure drop than before. In 2007, an injection test with a rate of 2 l/s was carried out (not shown). And again, the same parameter set was applicable but now for fitting a pressure increase up to about 20 bar above the reservoir pressure. These test data demonstrate stable fracture properties for significant pressure changes around the reservoir pressure. Furthermore, no deterioration of the fracture performance was observed in a time period of about three years.

From the hydraulic test analysis an infinite conductive fracture area between 8.000 m^2 and 24.000 m^2 could be derived (Tischner et al., 2015). The uncertainty in the calculation of the fracture area mainly results from an uncertainty of matrix permeability surrounding the fracture. Thus, a part of the originally created fracture remains highly/infinitely conductive (Fig. 9). But the persisting part of the fracture could even be significantly larger if one takes into account that only the infinite conductive part is "visible" in a linear flow regime.

A substantial productivity enhancement was achieved due to the stimulation. For the production period of about 4 days the observed rate is more than a factor of ten higher compared to the production rate before the stimulation (Fig. 13). Due to the time dependence of productivity in infinite or closed reservoirs the productivity enhancement becomes smaller for longer times and the productivity is still too low for a hydrothermal system. However, the extended fracture itself can be utilized as heat exchanger in an enhanced geothermal system.

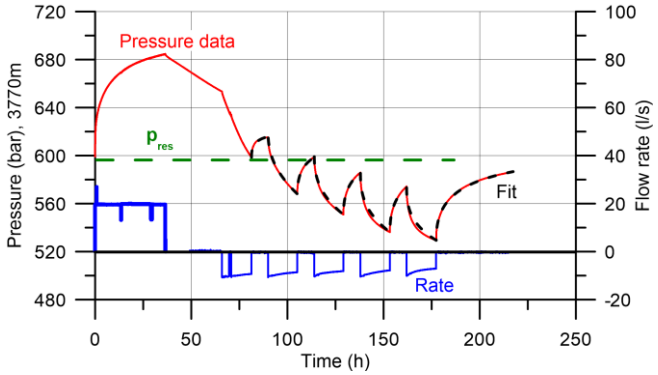


Figure 11: Downhole pressure and flow rate for the cyclic injection/production test in 2004. A negative rate means production. p_{res}: undisturbed pore water pressure.

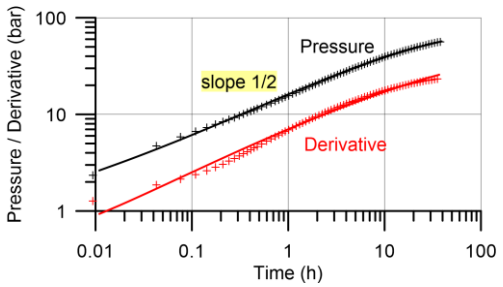


Figure 12: Diagnostic plot for the last shut-in period of the cyclic injection/production test (Fig. 11). The slope of ½ indicates here formation linear flow.

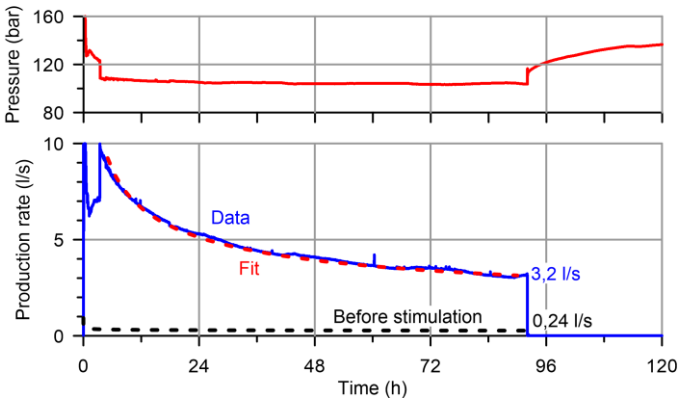


Figure 13: Wellhead pressure and production rate in the production test 2006. "Before stimulation" shows the production rate calculated with the initially derived hydraulic parameters before stimulation.

5. CIRCULATION TESTS

Hydraulic and thermal observations during the stimulation in the Detfurth formation indicated fracture propagation up to the Solling sandstone some 120 m above (Fig. 14). This opened up the possibility of circulation between the Detfurth and Solling formations (Jung et al., 2005). The circulation of thermal water shall demonstrate that an artificially created fracture could potentially be used as heat exchanger in low permeable sedimentary rocks. A packer was installed at 3770 m along with a tubing to separate both intervals within the wellbore as shown in Figure 14. After a successful communication test between both horizons a first circulation experiment was conducted in 2004 (Jung et al., 2005). The tracer response during that experiment clearly revealed the communication between both horizons. Additionally, a thermal short cut along the casing cementation, which might also explain a good hydraulic communication, could be excluded based on the significant tracer breakthrough volume. However, no

stable circulation could be achieved because of a limited production rate out of the Solling sandstone and financially based operational restrictions.

In 2017, a stable circulation experiment was carried out for the first time. Here the injection and production rate were kept constant and at the same level by applying specially adapted high-pressure pumps. Unfortunately, this test later revealed a leakage in the tubing string. Now further circulation experiments are planned after recompleting the well with a new packer and a new tubing string. After recompleting, circulation tests at stable hydraulic conditions (accompanied by tracer tests) shall provide reliable estimations of the effective fracture area and of its potential for heat extraction. Special focus will be put on the hydromechanical behavior of the fracture. With increasing injection pressure the effective heat exchanging area should increase due to ballooning and reopening of additional areas of the originally created fracture. These experiments are highly important for the evaluation of artificial fractures and the perspective of multi stage fracturing and circulation systems in sedimentary rocks.

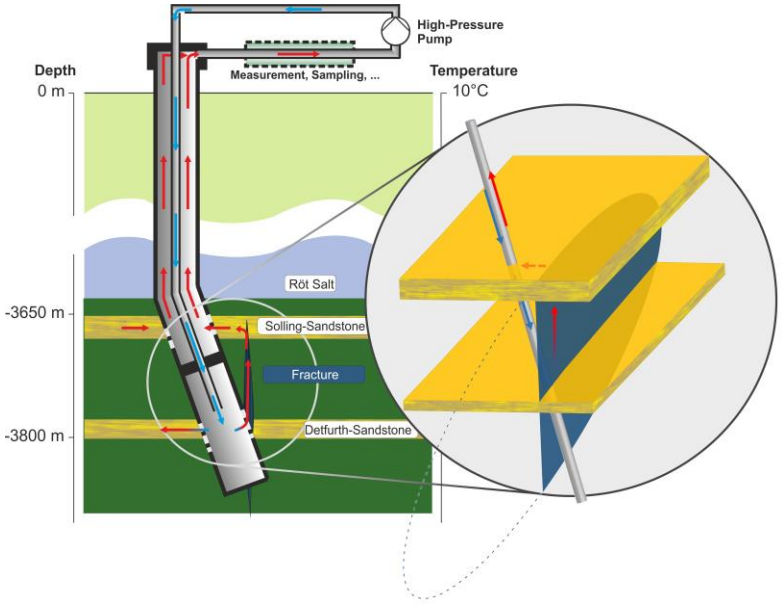


Figure 14: Scheme of the circulation experiments at the well Horstberg. Thermal water is circulated within one well via an artificial fracture.

6. DISCUSSION AND CONCLUSION

The comparison of the hydraulic stimulation operations in the Volpriehausen- and Detfurth sandstone provide valuable insights in those operations. In the Volpriehausen sandstone a poor fracture performance was observed. The wellhead pressure as well as the flow rate decreased drastically in venting tests after the stimulation. Apparently the fracture “closes” due to the increasing friction losses and the production rate decreases drastically in a short time. Here the typically assumed characteristics for hydraulic stimulations in sedimentary rock were observed: The fracture closes if no proppants are applied.

However, in the Detfurth sandstone completely different observations were made. Production and injection tests after the stimulation revealed an infinite conductive fracture. Friction losses in the fracture are negligible even at a pressure below the undisturbed pore pressure. There are likely three main differences between the two stimulation operations that have to be considered.

In the Volpriehausen, a special perforation technique (propellant stimulation) was applied. Deep channels penetrating up to some meters into the formation might have been created due to this type of perforation. But as for any perforation the debris of the explosives can lead to some clogging. Then only a few of the originally created channels were hydraulically active. In the stimulation afterwards the frac propagation might have started from channels which are not aligned well with the general strike direction of the fracture. Then a curved fracture develops until the fracture becomes favourably aligned with the stress direction in the far field. In the curved part of the fracture, an higher stress acts on the fracture faces than in the other part. While producing the fracture will close in the curved part leading to the observed drop of pressure and of production rate.

Another point is the applied flow rate and injection volume. In the Detfurth a much higher volume was injected at a much higher rate than in the Volpriehausen. Therefore, a significantly larger fracture was created. For mechanical reasons a larger fracture area has a higher potential for selfpropping in particular due to shearing. Beyond that, the erosion of the fracture and therefore the created roughness of the fracture surfaces depend on the injected volume and rate. Finally, the temperature drop while injecting large amounts of cool water may lead to inelastic deformation or even to thermal cracks, which can help to keep the fracture conductive.

The stress conditions in the sandstone layers differ considerably. In the Volpriehausen the fracturing pressure was more than 100 bar higher than in the Detfurth although the vertical distance is relatively small (about 130 m). This means that the deviatoric stress in the Volpriehausen is small compared to the Detfurth and therefore the potential for shearing too.

Due to the persistent and infinite conductive fracture in the Detfurth sandstone a more than tenfold increase of productivity was achieved based on hydraulic tests over a time period of some days. Despite of this substantial productivity enhancement the stimulation process was not as effective as in crystalline rock. From crystalline rock the effect of "frozen fractures" is known, meaning that after extended stimulation operations no closing of the fracture at all is observed (Tischner et al. 2007). In contrast, in the Detfurth only a part of the initially created fracture remained highly conductive after the stimulation.

In sedimentary rock extended fractures expand over different layers with different stress conditions. In layers with higher normal stress the fracture width and fracture conductivity will be small compared to layers with lower stress. Applying this to the stimulation in the Detfurth the persistent high conductive fracture zone extends mainly in the sandstone whereas in the adjacent clay layers the hydraulic fracture conductivity is much lower. In principle the layered composition may explain the lower effectiveness of massive hydraulic stimulations of sedimentary rock compared to those operations in crystalline rock.

In order to study the real fracture properties the planned circulation experiments between the two connected sandstones in the Detfurth and Solling are very important. The circulation at different pressure levels in combination with tracer testing supposes to provide valuable insights in the flow pattern along the fracture and thereby about the layer and stress dependent hydraulic fracture properties.

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