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The GeneSys-Project: Extraction of Geothermal Heat from Tight Sediments

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ABSTRACT

A single hole concept to recover hot water for direct use from tight sedimentary rock formations at great depth has been tested in an abandoned gas well in the Northern German Basin about 80 km NE of Hanover. The concept assumes that though the overall permeability of these formations is low open flow paths (faults, fracture zones, or intersections of them) exist even at great depths and that these paths can be accessed from a borehole by creating extremely large hydraulic fractures. The hot water produced from these features will be reinjected after use via the annulus of the same borehole into a permeable rock formation at more shallow depths. The GeneSys concept (Generated Geothermal Systems) can be economic for consumers of medium size (a few MW) and will in case of success be applied in a 3500 m deep borehole planned for 2005 on the campus of the GEOZENTRUM Hannover for space heating of its offices and laboratories. The concept should be applicable at almost any site in the Northern German Basin and is attractive especially for sites where abandoned gas or oil wells are available.

In order to test the concept massive water-frac tests were performed in a sandstone layer of the Buntsandstone-formation at a depth of 3800 m by injecting more than 20,000 m³ of water at flow rates up to 50 l /s and at a well-head pressure of about 330 bar. Post-frac venting tests showed that the created fracture has a high storage capacity (about 100 m³/bar) and covers an area of several 100.000 m², indicating that the fracture not only propagated in the sandstone layer, but also fractured the adjacent clay-stone horizons. They also showed that the fracture or at least part of the fracture stayed open during pressure release thus allowing venting flow rates of about 30 m³/h at fluid pressures well below the frac-extension pressure. Long term extrapolations of the venting flow rate however showed that the desired flow rate of 25 m³/h can not be maintained over a prolonged time period since the production and reinjection horizon (at 1200 m depth) do not communicate and the overall yield of the formation accessed by the fracture is too low.

The results of cyclic tests (“huff-puff”), consisting of a cold water injection period, a warm-up period and a venting period on contrary were very promising. The fluid volumes and production temperatures achieved during these tests show that this can be an alternative concept for heat extraction from tight sedimentary rock.

1. INTRODUCTION

In comparison to the specific energy content of oil and gas (10 kWh/kg), the specific energy content of hot water only amounts to approximately one hundredth of that. For an economic operation of deep geothermal wells this requires production rates that usually exceed 10 l/s by far and the minimum transmissivity of water bearing formations needs to be in the order of 1 to 10 Darcymeter. This is much more than the usual requirements for the production of oil and gas and is only met by high porous sandstones, jointed rock or karstic limestone. To overcome these limitations, the GeneSys-project was initiated at the GEOZENTRUM Hannover. It is intended to investigate concepts that allow the usage of the widely spread low permeable sediments for geothermal energy extraction and finally to supply heat for the complex of buildings of the GEOZENTRUM Hannover.

The water-frac technique successfully applied in crystalline rocks for the creation of Hot-Dry-Rock systems is supposed to be the key technology. By this means large scale fractures covering areas in the order of km² will be created in the sediments to increase the productivity of the well to relevant flow rates.

The proposed concept envisioned that, by the creation of large fractures the well is connected to water bearing joints, faults, fracture zones or porous layers not directly accessed by the borehole. The hot water produced from these features will be reinjected after use via the annulus of the same borehole into a permeable rock formation at more shallow depths.

Such a one-well-concept, where the well is simultaneously used for production and re-injection, can be operated economically even for a relatively low power output in the order of few MW_{th} and is suitable for providing heat to large buildings, or districts, where a district heating system is available.

A review panel of experts from the GEOZENTRUM Hannover and the industry recommended to test this concept in an abandoned gas well before drilling a new well on the campus of the GEOZENTRUM. In summer 2003 Exxon Mobil Production Germany (EMPG, Hannover) handed over the gas exploration well Horstberg Z1 to the Federal Institute for Natural Resources and Geosciences (BGR), which is part of the GEOZENTRUM Hannover. After extensive preparatory work, which also included the takeover of the legal mining responsibility as the operator of the well, experiments started in September 2003 and continued until April 2004. The experiments were intended to investigate the following questions:

- Will the fractures initiated in the sandstone layers be able to propagate through the adjacent clay stones horizons?
- Will self-propping keep the fractures open after pressure release and, will the residual fracture width and transmissivity suffice to provide relevant production rates?

- Will the fractures connect the well to water bearing discontinuities?

- Will it be possible to maintain a permanent production of hot water with simultaneous re-injection into a shallow horizon?

2. TEST SITE AND WELL HORSTBERG Z1

2.1 Location and Geology

The well Horstberg Z1 has been drilled in 1987 and is located some 80 km north-east of Hannover. It has been drilled into an inversion structure, striking NEE-SWW, that is bound by saltdomes on either sides. The stratigraphy is typical for the Northern German Basin (Fig. 1 and 2). The Middle Buntsandstone (3636 m – 3926 m) including the subformations Volpriehausen-, Detfurth- and Solling Sandstone was selected as production horizon. The thickness of these sandstone layers ranges from approx. 6 m to 20 m. The porosities as given in the drilling documentation vary from 3% to 11%. Due to the low porosities and thickness, it can be assumed that the total transmissivity is too low to provide the desired production flow rate of 25 m³/h. The Middle Buntsandstone is therefore appropriate for testing the proposed concept. For the re-injection the “Kalkarenit” (depth 1150 m to 1250 m) was selected. This horizon is routinely used by the oil and gas industry for the re-injection of huge volumes of produced formation fluid and, it can therefore be assumed that a continuous injection of 25 m³/h is feasible.

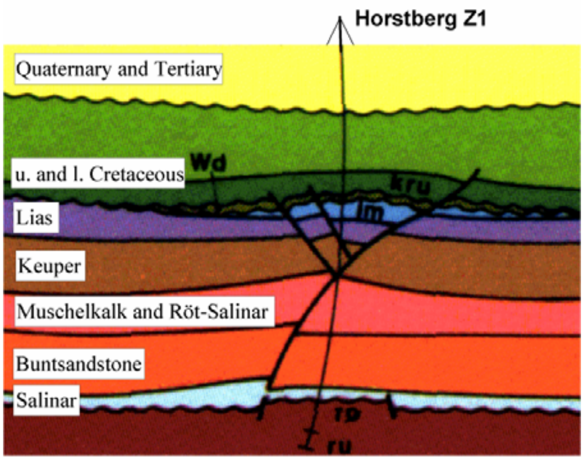

Figure 1: Schematic cross-section of the Fassberg inversion-structure and the relative location of the well (from Baldschuhn et al., 1991).

2.2 Completion of the well

The well was originally intended for the production of gas from the “Rotliegende” formation however, no economic production was achieved. The well is equipped with a 7” casing (32 lbs/ft) that is cemented from final depth to 2035 m. It has an internal yield of 750 bar. These specifications allow injection operations at high pressures and flow rates and separate perforation of single horizons within the formation of the Middle Buntsandstone. The re-injection horizon “Kalkarenit” is accessible via the 9 5/8’’– 13 3/8’’ annulus.

Before the EMPG transferred the well to BGR, it was plugged back from the final depth of 4918 m to 4120 m. The completion of the well relative to the stratigraphy is displayed in Figure 2.

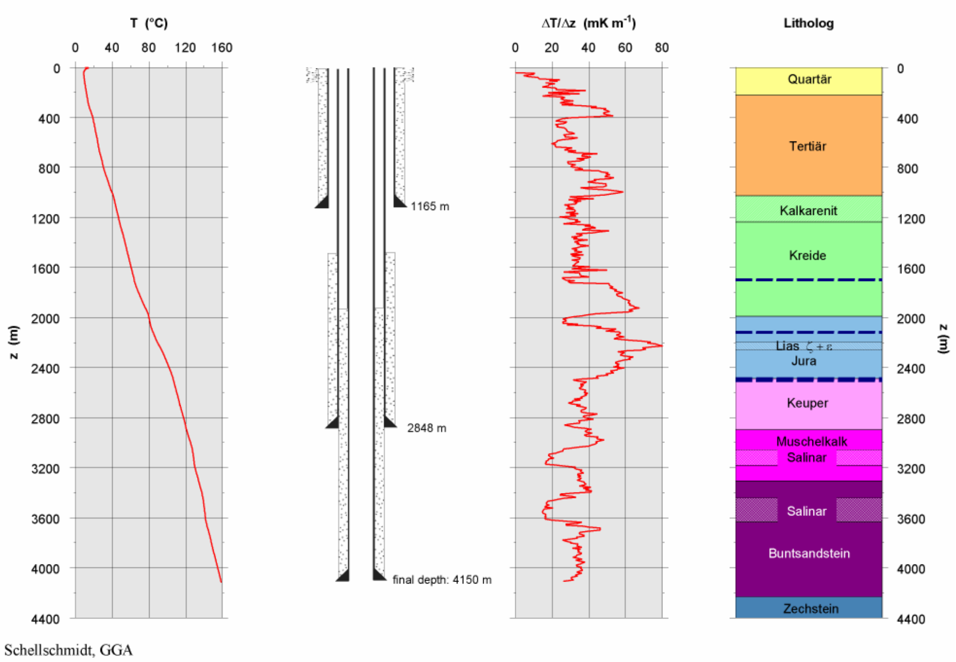

Figure 2: Depth profile of temperature, temperature gradient, stratigraphy and scheme of the well completion of the Horstberg Z1 well.

2.4 Stress Field

For the specific location no definite information on stress directions or magnitudes is known. For the "Subsalinar" formations an extended data set on stress directions and magnitudes has been established from the activities of the oil and gas industry. Hardly any data are available to constrain the stress field for the "Suprasalinar" formation, which, however, contains the formations of interest. A uniform N-S striking direction of the maximum horizontal stress direction can be assumed for the "Subsalinar" formation (Röckel & Lempp, 2003). The "Salinar" formation decouples the stress field in the "Suprasalinar" formation from the "Subsalinar" formation. In the Suprasalinar stress direction and magnitude is influenced by the numerous salt domes and is therefore non uniform on a regional scale.

2.5 Subsurface Temperatures

Prior to hydraulic testing an undisturbed temperature-depth profile was acquired down to the final depth of the well (4120 m) using the wireline logging equipment of the GGA Institute. For the final depth, a maximum temperature of 158°C was recorded (Fig. 2). This temperature is approximately 30°C above the average temperature for that depth in Germany, making the well attractive for geothermal utilisation after the cessation of research activities. Striking are the high temperature gradients in the Cretaceous and Jurassic formations. They may be explained by the low thermal conductivities of the corresponding rocks.

Figure 3: Impression from the stimulation experiments: wellhead with riser in front, ten high pressure pumps (HT400) with low and high pressure manifold in the back (photo by A. Weitze).

2.3 Test Site

The fully developed well site offered optimal conditions for the hydraulic experiments. A 400 kVA electrical power supply, drinking water supply and telephone line were available. Supply of the huge volumes of fresh water required for the water-frac tests was secured by the use of shallow high performance irrigation wells. For the waterfrac tests 10 high pressure pumps with an overall drive power of 4000 kW had been installed at the site (maximum flowrate realized 180 m³/h at 350 bar) (Fig. 3). For the acquisition of hydraulic data and temperatures, two autonomous systems were operated without interruption for more than 9 month.

3. TEST PROGRAM

3.1 Perforations

For the hydraulic tests, the casing was subsequently perforated in four sections (chronological order):

- 3920.5 m – 3926.5 m, Volpriehausen-Sandstone
- 3787.0 m – 3791.0 m, Detfurth-Sandstone
- 3037.5 m – 3041.5 m, Muschelkalk
- 3664.0 m – 3668.0 m, Solling-Sandstone

For all sections, an interval of 4 m to 6 m was perforated with approximately 200 shots. Either big hole perforators (big diameter of shot hole, small penetration depth (approx. 0.3 m)) and deep penetration perforators (small diameter of shot hole, large penetration depth (up to 1 m)) were used. In the Volpriehausen section a propellant stimulation was performed after perforating to assist fracture initiation. Here, the tool is positioned over the zone-of-interest in the well and ignited. Gases generated by the deflagration of explosives exert a pressure on the formation through the perforated casing and, as burn pressure increases, short fractures are created in the formation. Their growth is maintained by continued gas generation from the tool burn (PrecisionDrilling, customers information). No positive effect of the treatment however, was recognized.

During the experiments described below, it was revealed, that the hydrodynamic pressure loss at the perforations is small and does not significantly influence the injection pressure. The use of a fully cased well also offers the advantage of a high well stability.

3.2 Water-frac-tests

Three water-frac-operations were performed in order to create fracs in the perforated intervals, excluding the Solling formation. As a decrease of the pressure necessary for fracturing with decreasing depth is expected, the first perforation and tests were started in the lowermost interval (Volpriehausen-Sandstone). By this means, the costly utilisation of casing packers was avoided. The procedure was successfully employed in the two lower intervals. In the Muschelkalk formation however, no fracture was initiated, although due to the more shallow depth relative to the Volpriehausen- and Detfurth-Sandstone formation, a much lower fracture initiation pressure was expected.

During the water-frac-tests a total volume of 21,000 m³ of fresh water was injected at maximum rates of up to 50 l/s. With regard to the volume injected, this were the largest frac-operations in sediments, we are aware of.

For nearly all tests downhole recordings of pressure and temperature were acquired by a memory tool that was run on a slick line. By using a slick line equipment a hydraulically tight seal at the riser was secured.

<u>3.2.1 Frac-tests in the Volpriehausen-Sandstone formation</u>

The first tests were performed at low rates (below 0.2 l/s) using an electric powered test-pump. The recorded pressure response clearly indicated the generation of a tension crack, that was propagated afterwards using more powerful diesel-driven pumps. A total of 1,000 m³ fresh-water was injected using flow rates up to 25 l/s. For all tests a high injection pressure was encountered, with the maximum pressure reaching 460 bar at the wellhead. These high pressure were only rarely encountered in wells of the Northern German Basin (Röckel & Lempp, 2003). As the technical equipment did not allow higher flow rates over a prolonged time period at these high pressures, a massive water-frac tests was not performed. . A Venting test performed after the frac experiments showed that the fracture closes to a large extent, when pressure is released. Only for a narrow range of pressure below the fracture propagation pressure, favourable hydraulic properties were encountered.

3.2.2 Frac-tests in the Detfurth-Sandstone formation

Fracture initiation in the Detfurth-Sandstone formation occurred unintentionally after perforating due to the shut-in pressure resulting from the tests in the Volpriehausen-Sandstone at a wellhead pressure of 340 bar (Fig. 4). The fracture was enlarged and propagated by injecting 20,000 m³ fresh water during several frac tests. Though the fracturing pressure is remarkably lower than for the Volpriehausen-Sandstone formation, it is still fairly high compared to other locations in the Northern German Basin. A diagnosis of the downhole pressure records of post-fracturing venting and shut-in periods tests revealed a clear square root of time behaviour of the pressure over prolonged time periods. This is indicative for formation linear flow. The linear flow behaviour is indicative for high conductivity fractures imbedded in a permeable matrix, where $C_r = (w \cdot k_f)/(x_f \cdot k)$ is greater 100 (Bourdarot, 1998), with w: fracture width, k_f: fracture permeability, x_f: fracture half length and k being the matrix permeability of the formation. Analysis yields a fracture length of several hundred meters and it can be assumed that the fracture area covers some 100,000 m^2.

3.2.3 Frac-tests in the Kalkarenit formation (horizon for re-injection)

Although the Kalkarenit formation is in principle accessible via the outer annulus (13 3/8'') of the well, it was unclear, if injection of water was feasible since the annulus was filled with a viscous mud and the internal yield strength of the outer casing is as low as 150 bar. For testing, the 7" production casing of the well was directly connected to the respective annulus by a high pressure line. Fluid from the pressurized frac in the Detfurth-Sandstone formation was carefully bleeded off into the annulus using an adjustable choke. Flow rate, pressures and temperatures were recorded. It turned out that brine could be injected into the Kalkarenit formation at sufficient high flow rates at a pressure of approximately 110 bar. However, a minimum pressure of approximately 80 bar is needed even for the injection of low flow rates. This indicates that a fracture was initiated in the formation accessed by the outer annulus.

As the depth of the flow exit was not clear due to the completion of the well (Fig. 2), a temperature log was recorded. Prior to logging, 110 m³ of cold fresh water (7 °C) were injected into the outer annulus to induce a temperature anomaly that allows identification of the flow zone. A comparison of the log with the temperature log acquired before the tests clearly reveals, that the water is entering the formation above a depth of approximately 1200 m (Fig. 5). This is in agreement with the final depth of the 13 3/8" casing and reveals that the casing is undamaged and that no flow exit exists below the Kalkarenit. It is therefore proven, that the Kalkarenit formation is the re-injection horizon.

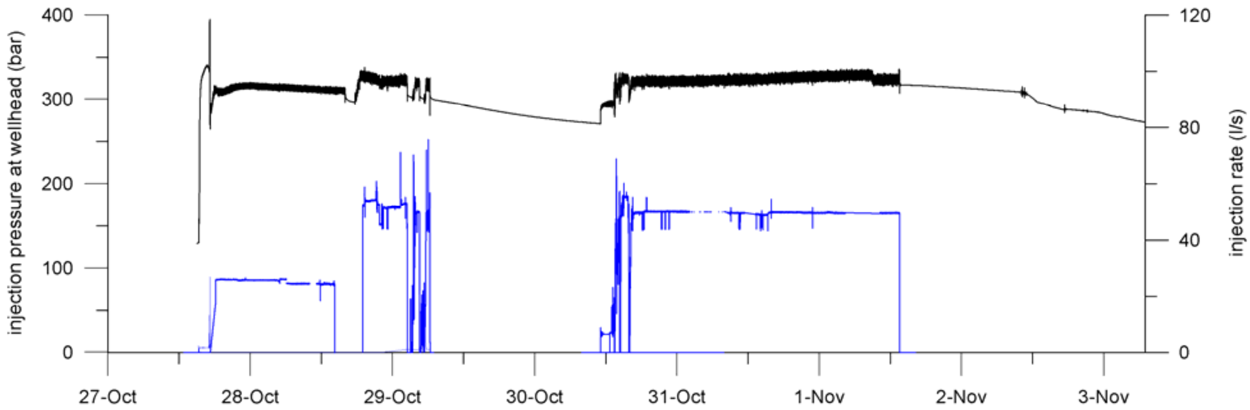

Figure 4: Injection pressure at wellhead (black curve) and injection rate (blue curve) recorded during a waterfrac-test in the Detfurth Sandstone formation.

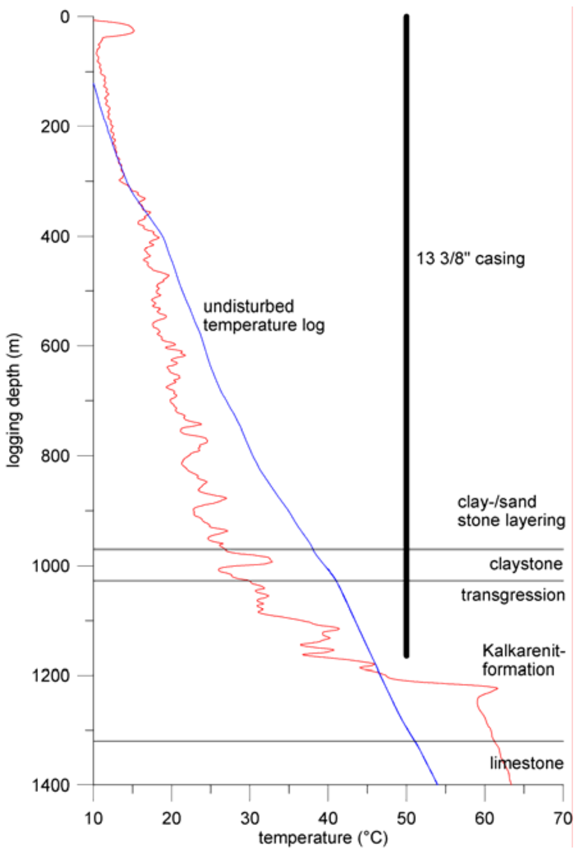

Figure 5: Temperature log to identify the zone, where fluid enters the re-injection horizon (red line). The blue line gives an undisturbed temperature profile. Below 1200 m, temperatures are increased relative to the undisturbed log, due to a preceding production test.

3.3 Intermittent Production test

From the slow pressure decay during the shut-in following the frac-test in the Detfurth sandstone, it became clear, that the pressure decline would last for several months.

In order to accelerate the pressure release and to investigate the transport- and storage properties of the fracture created in the Detfurth sandstone as a function of pressure, an intermittent venting test was performed. During this test the borehole was periodically vented and shut in for 12 hours at a time. This procedure was repeated daily for more than two weeks. In doing so, a total volume of 7,000 m³ of brine was produced from the frac in the Detfurth Sandstone formation and re-injected into the Kalkarenit formation. Throughout the test, “circulation” was driven by the high pressure in the Detfurth frac. At the end of the test, pressure was lowered by more than 100 bar. The test yields the following results:

- Despite a pressure release of more than 100 bar, the frac retains a high hydraulic conductivity (transmissivity). A self-propping mechanism similar to the one assumed for crystalline rock seems to provide an enduring fracture width (Jung & Weidler, 2000).

- Temperatures of the produced fluid exceeded 90°C at the well head few days after beginning of the test and reached more than 100°C toward the end of the test. A memory sonde, placed some 20 m above the production zone (perforated zone in Detfurth formation) recorded temperatures in excess of 120°C. This is quite remarkable, as 11,000 m³ of fresh water with a temperature of approximately 10°C were injected during frac test into that zone only a few days before the production test.

These observations are important for the further development of extraction of geothermal energy from tight sediments. They demonstrate that the water frac technique that has successfully been introduced for the treatment of crystalline rock, can also be applied in sedimentary rock.

3.3 Cyclic Tests

The positive results from the intermittent production tests drew the attention to another concept that may be practicable for providing heat energy. It consists of a cyclic injection of cool water into the frac and production of the water from the frac after a period of heating-up in the fracture. To test the feasibility of the concept, respective tests with daily and weekly cycles were performed in January and February 2004. Planning and accomplishment of the tests, i.e. length of injection, shut-in and production period, fluid volumes injected and produced, obeyed the necessities of a practical operation. For the daily cycle about 400 m³ of water was injected in the hours before midnight and the well was then shut-in for the rest of the night, followed by a 14 h production period during the day.

For the weekly cycle, approximately 2,500 m³ of water were injected at the beginning of the weekend and the well was then shut-in until early Monday morning (Fig. 6). On the following five weekdays, water was produced from the frac for 15 hours per day in the daytime and was re-injected in the Kalkarenit without cooling. In the realistic scenario energy could then be extracted from the hot water and the re-injected water would still have temperatures in the order of 60 °C to 70 °C.

In contrast to that realistic scenario, here cold water with a temperature of 10°C was used for injection. Despite these unfavourable conditions, produced temperatures amounted to 80°C for the daily cycle and even 90°C for the weekly cycle. A memory sonde recorded temperatures of approx. 110°C downhole (depth: 3770 m) in the vicinity of the production zone, indicating that with the usage of thermally isolated production strings wellhead temperatures could exceed 100°C. The average thermal power for the weekly cycle is estimated to approximately 0,5 MW_{th}, assuming a cooling of 25 °C.

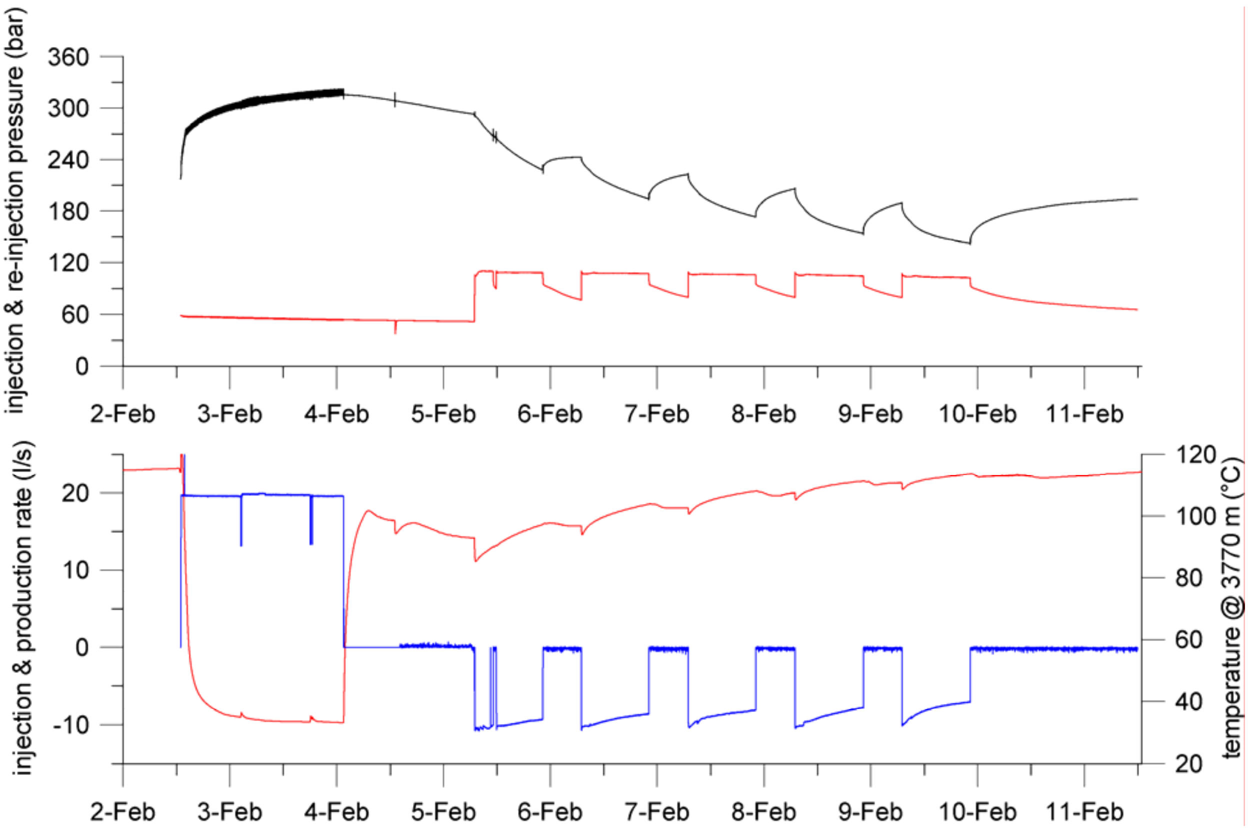

Figure 6: Wellhead pressure for injection (black line) and re-injection (red line) (top), injection and production rates and temperature measured at a depth of 3770 m (red curve) (bottom).

During the weekly cycle, a general decrease of the wellhead pressure is observed with ongoing time. Analysis of the hydraulic data indicates that this decrease is accompanied by a slight decrease in effective fracture length and transmissivity. Numerical simulations are currently prepared to investigate the thermal long term behaviour of such a system during operation.

3.3 Connecting the Solling Sandstone Formation to the Well

The Solling Sandstone Formation has a thickness of approximately 20 m and a porosity of 11% is determined from log analysis. The rock is assumed to be fully water saturated. In February 2004 the well was perforated in the depth of the Solling formation to enhance the productivity of the well. A flowmeter log carried out directly after the perforation revealed that the major fraction of the produced brine originated from the Solling formation. The production rate however, decayed substantially during a long term production test. During the test more than 7,100 m³ of brine were produced and re-injected in the Kalkarenit formation. As no further flowmeter log was done, the temporal development of the relative contributions of the two formations to the production rate is unknown. Analysis of the wellhead pressure data however, reveals that the pressure can be matched assuming a model where a finite conductivity fracture embedded in a porous-permeable matrix intersects the well. For later stages of the production test therefore the contribution of the Solling Sandstone formation to the produced volume may diminish. The results show a decrease of fracture area compared to results obtained for the Detfurth formation, indicating a closing of the fracture with lower fluid pressure. Absolute fracture conductivity is still high though, and the same order of magnitude is obtained than for the previous test.

Numerical modelling using the software FracPro (by ResNet) clearly indicates, that due to the high porosity, a successful stimulation operation of the Solling Sandstone would require very high flow rates. Therefore the formation was not treated. The modelling also indicates that the frac propagated from the Detfurth Sandstone formation is most likely connected to the Solling Sandstone formation.

4. GEOPHYSICAL FRAC MONITORING

To monitor the fracture propagation during the stimulations and to detect effects of the water injection, a comprehensive geophysical monitoring program was realized.

4.1 Monitoring of Microseismicity

To monitor microseismicity induced during stimulations (Phillips et al., 2002), a seismic network was installed. It consists of eight stations installed on two circles with a radius of 800 m and 1600 m respectively, centred around the well position at depth and a surface array of 60 geophones (Buness and Druivenga, 2004) (Fig. 5). Prior to the installation of the network, numerical investigations were conducted to optimize the geometry of the network to achieve the best resolution. At each of the stations, an about 100 m deep well was drilled and 3-component 4.5 Hz geophones were installed permanently at the bottom of these wells. Additionally a 3-component 1 Hz seismometer was placed at each station. Data acquisition was secured by EDL and PDAS systems operating at 500 Hz and 200 Hz sampling rate respectively. Data were read-out twice a day and were subsequently transferred to a contractor, that promptly analysed the data on-site with respect to the occurrence of microseismicity. A velocity model for the region around the well was calibrated using the seismic signals that evolved from the ignition of the perforator guns.

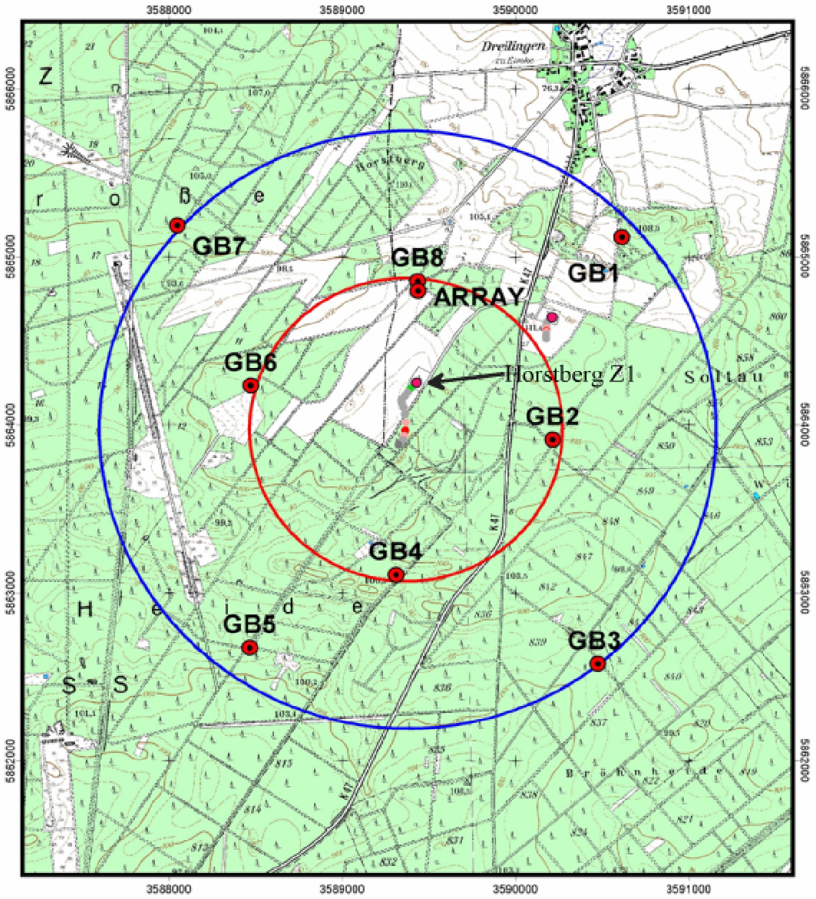

Figure 7: Locations of the seismic stations (red symbols) and the array relative to the well Horstberg Z1. The surface location of the well is indicated by the arrow, the well trajectory is indicated by a grey path.

Though the network operated without problems, recordings of some of the stations were temporarily disturbed by noise generated by the vibration of the high pressure pumps, detonations on an adjacent military test site and crossing of trains. Apart from short periods with a high noise level the network was sensitive enough to detect signals whose energy was in the order of those generated by the perforator guns. Using the energy of the explosives and assuming a seismic efficiency between 0.001 and 0.0001 the detection level M_L of the seismic network was estimated to about $-0.5 < M_L < 0$ (M_L: Magnitude).

In contrast to water frac tests in crystalline rock, where several thousands or tens of thousands microseismic events were detected and located with networks of comparable sensitivity (e.g. Audigane et al., 2002) here, only 11 events were detected. A reliable source location could not be inferred for any of these events.

The lower level of microseismicity in the sediments compared to granite may be explained by the fact that the sandstones and claystones are less brittle than granite or by the fact that the principal stress components at our site are very similar so that the shear stresses and accordingly the stress drop resulting from rupture are very low. Of course installing the geophones in deep wells would give a better chance to detect more seismic events This however involves a drastic increase in costs. The experiences gained within the project are highly relevant for the oil- and gas industry in the Northern German Basin since they have lively interest in seismic monitoring of stimulation operations (Henke et al., 2003).

4.2 Monitoring of Self-Potential

Before, during and after the stimulation tests the electric self potential was continuously monitored in order to investigate whether the fluid injection has an effect on the self potential measured at the surface. Such a correlation between fluid injection in a deep well and changes of the self potential has been observed by Marquis et al. (2002) for stimulation operations at the European HDR test site Soultz-sous-Forêts, France.

In the vicinity of the Horstberg site, 49 copper-copper-sulphate sondes were installed on two perpendicular profiles with a spacing of 100 m. It was possible to acquire data for 90% of the total duration of the tests. The gaps in the data records are caused by maintenance work routinely done every day. In order to eliminate magneto-telluric effects the earth magnetic field was recorded at two reference stations. During the stimulation tests several geomagnetic storms occurred. These storms had a significant influence on the self potential data and impeded the analysis (Grinat et al., 2004).

4.3 Monitoring of Surface-Deformation

For the monitoring of deformations caused by frac operations tiltmeters are routinely used by the oil- and gas-industry (Poe and Economides, 2000). An array of wells in the vicinity of the treated well is required to install the tiltmeters, however.

As an alternative, the use of high sensitive tiltmeters installed near the surface has been investigated as a method to monitor deformation induced by the fracture propagation (Wood, 1979). At the Horstberg test site four tiltmeters were installed near the surface (3 m depth) on a profile, perpendicular to the expected direction of fracture propagation and were operated for several weeks. The tiltmeter data recorded during the water-frac tests in the Volpriehausen Sandstone conspicuously contain signals, which correlate with the injection periods. A detailed correlation of the tiltmeter signatures with pumping parameters (injection rate, pressure) will be performed soon.

5. CONCLUSION AND OUTLOOK

The experiments performed in the well Horstberg Z1 reveal that in sedimentary rock large scale fractures can be created by employing the water-frac technology successfully apllied in crystalline rock in several Hot-Dry-Rock projects. Recordings of pressure during the injection and shut-in periods of the water-frac tests indicate that the induced fracs are tensile cracks. They also indicate an unusual high magnitude of the minimum horizontal rock stress component S_h for the site. For the Detfurth Sandstone formation it is estimated that $S_h \approx 0.7 \cdot S_V$ and for the Volpriehausen Sandstone formation $S_h \approx 0.85 \cdot S_V$, with S_V being the vertical stress component. Differences in the three principle stresses and shear stresses are therefore low. This may serve to explain the low number of microseismic events detected.

From the slow pressure decay during the shut-in period of the water-frac tests in the Detfurth Sandstone an extremely large storage capacity of the fracture of approx. 100 m³/bar can be estimated indicating a fracture surface area of at least several hundred thousand m^2. The large fracture or at least the part of the fracture within the sandstone layer of the perforation interval retained a remarkable fracture width after releasing the pressure from the frac extension pressure (330 bar) to about 200 bar. This allowed flow rates of more than 25 m³/h to be vented from the fracture at a drawdown of less than 40 bar. Long term extrapolations of the venting flow rate however showed that the desired flow rate of 25 m³/h can not be maintained over a prolonged time period since the production and reinjection horizon (at 1200 m depth) do not communicate and the overall yield of the formation accessed by the fracture is too low.

For this reason an alternative cyclic test scheme (huff-puff) was investigated consisting of a cold water injection period, a warm-up period and a venting period. Cycles were experimentally performed on a daily and weekly basis. First results were promising and indicate that this concept may be a suitable means for heat production from tight sedimentary rock formations and may also be a solution for heating the GEOZENTRUM Hannover. Investigation of the thermal long-term behaviour is subject of numerical simulations.

6. OUTLOOK

One of the key questions, when transferring the water frac technology to sediments is, if the residual fracture width after pressure release is permanent or diminishes with time. To investigate this question, a further venting test will be performed in summer 2004.

Numerical modelling of fracture propagation during the stimulation using the software FracPro and hydraulic observations indicate that the fracture initiated in the Detfurth Sandstone formation propagated up to the Solling Sandstone formation. This opens up the perspective for a circulation test between the Detfurth and the Solling Sandstone formation. This test requires the installation of a production string with a packer to separate the perforation intervals of the two formations. The experiment is currently designed and will be performed in Autumn 2004.

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