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Fracture Performance Impairment and Mitigation Strategies

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ABSTRACT

Hydraulic fracturing is the key stimulation technology for sedimentary geothermal reservoirs. The technology is widely known from hydrocarbon exploitation. Nevertheless, for geothermal purposes it has to be adapted and further developed to reach high fluid production rates. Putting primary low-productive but widely spread aquifer structures in use for geothermal power generation is the main goal of an extensive research campaign in Germany.

Fracture characteristics and performance can be modelled by matching it to observed field data. The effectiveness of a fracture, concerning its stimulation potential, is highly depending on its long-term conductivity. The latter can be highly deteriorated by mechanical, hydraulic and chemical processes starting with fracture creation and being enhanced with the onset of production. Productivity impairment can be significantly decreased by a proper, site specific frac design. Therefore, the relevant damaging effects have to be qualified and quantified.

Stimulation experiments on a geothermal research well serve as case studies in this context. Furthermore, different hydraulic fracturing concepts are evaluated and compared in terms of their applicability and effectiveness in the investigated geologic environment. Insights gained can be transferred to geologically similar sites in order to increase the success of hydraulic fracturing operations and therefore the feasibility of the general reservoir development concept.

1. INTRODUCTION

For geothermal power generation in the North German Basin reservoirs have to be developed that are fluid bearing and show reservoir temperatures of at least 120°C. Consequently, because of an average prevailing geothermal gradient of 30°C/km in the Basin wells with a depth of more than 4 km are of interest. The reservoirs are low-enthalpy hydrothermal systems making high fluid production rates of more than 20 kg/s necessary for their economic exploitation (Hurter et al. 2002). Nevertheless, they are of high interest for a large-scale development because of their wide distribution throughout the basin. In the investigated geological setting the potential pay zones of primary concern are therefore Rotliegend sandstones (Huenges et al. 2002). Zones with decent permeability are known within these formations from intensive hydrocarbon exploration and exploitation. However, it has never been tried to explore the Rotliegend formations for geothermal heat or power production.

Therefore, a research project was initiated and a series of field experiments were conducted. The research well (E GrSk 3/90) is situated nearby Groß Schönebeck[1] (Germany) and drilled through a sequence of Rotliegend sediments consisting of silt-, sandstones and conglomerate into vulcanite layers. The initial productivity of the well was significant lower than it was expected from core measurements. Mainly inflow restrictions (near-wellbore damage) limited the fluid production. For this reason, multiple hydraulic proppant fracturing experiments have been conducted in two selected open hole intervals of the well. An open-hole-packer at the top and a sand-plug at the bottom of each interval were used as hydraulic barriers. Applying this configuration the intervals were fracture-treated placing about 11 tonnes of proppant (ceramic grains) and over 200 cubic meters of frac fluid (highly viscous gel) into the formation.

The objectives of the experiments were: 1) the verification of the technical feasibility of the multizonal open hole fracturing technology, 2) the creation of highly conductive flow paths to enhance the inflow performance, 3) the connection of productive reservoir zones to the well and 4) the decisive enhancement of the overall reservoir productivity.

Although technologically strongly related there are several main differences looking at exploitation strategies for low-enthalpy geothermal and hydrocarbon reservoirs:

1) High mass flow rates are required to achieve an acceptable energy efficiency when converting the thermal energy stored in the produced fluids into electricity by e.g. using binary cycles: 25 m³ of low-enthalpy geothermal fluid bear the same energy content as 1 m³ of crude oil.
2) A maximum inflow area has to be connected to the wellbore in order to achieve an efficient fluid production at high mass flow rates. The system efficiency is driven by the energy consumption for the artificial fluid lifting process, which is a function of reservoir productivity, pump efficiency and static fluid level in the well.
3) Stimulation treatment design has to aim at covering and creating as much net reservoir height (pay-zone) as possible. For hydraulic fracturing operations this means, unless not required due to technical reasons, no general need for fracture height containment. The hydraulic connection of additional pay zones is an explicit goal of any stimulation treatment. Nevertheless, a minimum initial productivity is required that gets enhanced by reservoir adapted stimulation treatments.

[1] Gauß-Krüger coordinates: RW 5406044,6; HW 5864387,2; height over NN: + 65,98 m

All of the listed demands implicate that the geothermal system has to be operated on a long term (> 20 a) and continuous (> 8000 h/a) scale. This is the key issue for all geothermal exploitation concepts (in Germany) aiming on feasibility.

2. KNOWLEDGE REVIEW AND TECHNOLOGY TRANSFER

So far stimulation of geothermal wells concentrated on acid treatments in carbonates (e.g. Tuscany, Italy) and large scale water-fracturing treatments (HDR/HWR) focused on high-enthalpy mainly crystalline reservoirs. The application of hydraulic proppant fracturing (HPF) to enhance the inflow performance of geothermal sedimentary reservoir rocks (matrix-type) has yet not been considered on a commercial basis. Though, research results on the latter technology exist from the Geothermal Reservoir Well Stimulation Program (GRWSP), conducted from 1979 to 1984 in the United States of America (Entingh 2000, Campbell et al. 1981, Morris et al. 1982). The research program led to two main conclusions relevant for the research work presented in this context: 1) HPF treatments *can* be successfully applied in sedimentary formations, *but* requiring a well with initial modest flow rate, 2) Open hole completions should be used in order to maximize the potential inflow area and mitigate further formation damage by completion work, 3) a suitable retrievable open hole packer should be used for zone selective stimulation treatments. The latter aspects were recommended but not tested yet.

On the other hand, hydraulic proppant fracturing is a standard technology in hydrocarbon industry and has been commercially applied to stimulate oil and gas wells since over 30 years so far. In 2001 more than 60% of the oil and more than 85% of the gas wells are completed with fracture treatments (Economides et al. 2002). Since the 1950's the term water-fracturing in hydrocarbon industry stands for an application that uses a low-viscosity frac fluid with a low concentration of proppants added in order to create long fractures as primary fluid conduits in a very low permeable, dry gas reservoirs connecting productive reservoir zones aloof from the wellbore (Mayerhofer et al. 1998) The proppants are added in order to guarantee a fracture tie-back to the well under drawdown conditions.

Conventional HPF treatments use high-viscosity frac fluids (polymer based gels) and large amounts of proppants to create highly conductive flow paths in a porous, permeable rock matrix that, depending on the permeability contrast created and the fracture penetration into the reservoir, enhance the radial inflow behaviour of the well 8McGuire et al. 1960). The rheology and chemistry of the frac fluid and the type and properties of proppant are adapted to the treated formation. Thus, a wide range of formations – in terms of permeability - can be treated using this technology (Cleary 1994). Usually, zonal isolation is realized by running the treatments in cased and perforated intervals with packers or plugs as static or temporary barrier systems.

Consequently, the experiments in this context aim at bridging a technology gap by investigating the feasibility of multizonal open hole HPF treatments for the stimulation of geothermal wells.

3. EXPERIMENTS IN THE "IN-SITU GEOTHERMAL LABORATORY"

The primary goal of the field experiments at the site is the geothermal technology development with focus on stimulation concepts.

The open hole completion (3874-4294m true vertical depth) guarantees a maximum inflow area that would allow a commingled production from all the potentially productive reservoir zones in order to achieve a high productivity level. Furthermore, a continuous, unaltered monitoring and borehole logging before, during and after the treatments was possible due to the direct contact to the reservoir rock.

The stimulation experiments were focused on the Rotliegend sandstones for which core measurements indicated permeability values up to 200 mD. For geothermal means this still is considered low permeable. Two intervals were selected for stimulation as potential pay zones: 4130 – 4190 m and 4078 - 4118 m respectively.

Matrix treatments were ruled out because of two reasons: 1) the zones showed impaired inflow behaviour prior to stimulation probably due to formation damage as consequence of the drilling operations, therefore a damaged zone of unknown lateral extent had to be effectively by-passed, 2) the pay zones are represented by clastic sediments without carbonate cements; an acidizing job would have at best restored the natural porosity and permeability but not created new flow paths that were needed to enhance the inflow performance decisively. Even the application of hydrofluoric acids (mud acids) was not an option regarding the risk of destabilizing the wellbore due to matrix disintegration besides environmental and economic issues.

The stimulation concept involved the application of a retrievable hydraulic barrier system to independently and successively treat the two intervals in the open hole section of the well (**fig. 1**).

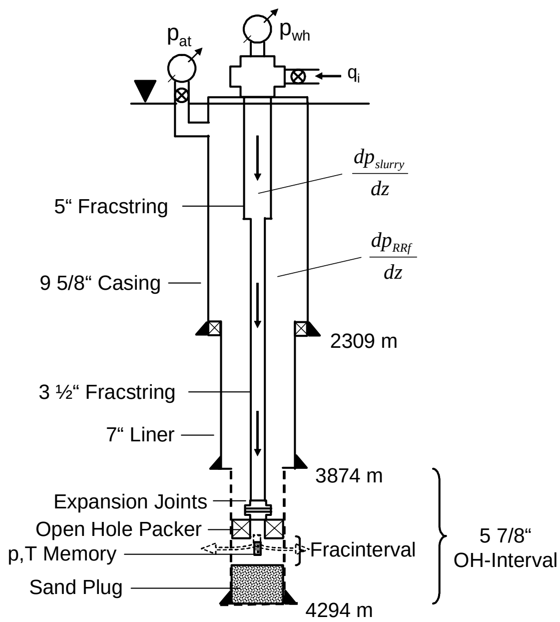

Figure 1: Schematic of the frac treatment set-up in the well E GrSk 3/90

The annulus between frac string and casing was filled with saline fluid and remained open to the atmosphere. During the treatments the fluid level (annulus pressure) was monitored at the wellhead and stayed constant. In each interval a diagnostic treatment (datafrac) was conducted prior to the mainfrac with proppants. The datafrac was designed as a step-rate pure fluid treatment with downhole *p*,*T*-recording. The volume and type (linear, low-pH gel) of the fluid system was equivalent to the mainfrac. The term linear in this context stands for the viscoelastic behaviour of the fluid. The viscosity increases linearly with the polymer concentration. With the datafrac the main hydraulic (leak-off coefficient/permeability) and rock mechanical (fracture closure pressure) parameters could be determined, including minimum hydraulic height and volume of the created fracture by *p*,*T*-logging and history matching the pressure response. The diagnostic measures are necessary for an adequate mainfrac design and secure job executions (Cipolla et al. 2000).

The high temperature and the open hole conditions pose a high risk for packer operations in general. Especially fracture height growth had to be limited in order to avoid a by-pass of the packer with proppant-laden fluids that would lead to a screen-out in the annulus.

The lack of experience with this situation made a less aggressive (sub optimum) frac design necessary, meaning smaller volumes, lower proppant concentrations and lower pumping rates. Therefore, treatment pressures and consequently achievable dynamic and final fracture dimensions were limited from the start. The packer consisted of two metal anchor sections preventing the vertical movement of the element under loading conditions in both directions. A short rubber element served as the hydraulic seal of the annulus between frac string and borehole wall. The type of the chosen elastomer as well as the geometry of the sealing section allowed the packer application in the high temperature environment. To account for axial movement of the frac string during the treatment three expansion joints each 1,5 m long were installed above the packer element. Additionally the whole frac string was fed off by about 40 metric tonnes. The annulus stayed open to atmosphere to monitor the tightness of the packer and to avoid fluid loss and/or fracture the formation above the packer seat.

3.1 Results and discussions

The fracture treatments where conducted with two subsequent operations in each interval: A diagnostic treatment (datafrac) - to determine the relevant in-situ hydro-mechanical reservoir and fracture parameters - and the main treatment (mainfrac) with the proppant stages (Legarth 2003).

<u>3.1.1 Mechanical Rock Response</u>

The fracture closure pressures (p_c) in the two intervals were determined by analysing the pressure decline curve of the datafracs. The term "closure pressure" is defined as the pressure equal to and counteracting the minimum principal rock stress perpendicular to the fracture planes. Together with the permeability profile it is the single most important parameter in order to design and model hydraulic fracturing treatments. The p_c will always be equal to or less than the breakdown pressure (fracture initiation) and always less than the fracture extension pressure. An upper bound of the p_c is the Instantaneous Shut-In Pressure (ISIP). With progressing shut-in time the pressure decline approaches a linear relation with the square root of time. Fracture closure is identified as inflection point on the decline curve where the slope changes. Different time functions are used to plot the pressure depending on the type of frac fluid used. Most commonly the G-Function (Nolte 1982) is applied. The latter is derived based on the mass balance and fluid leak-off from the fracture, under the ideal assumption of fixed fracture surface area (Weng et al. 2002). An inclination change is caused by changes of the stiffness (lower compressibility) and a variation of the leak-off behaviour (from bilinear to pseudo radial flow) of the system when the created fracture closes. When the fracture walls start contacting, as the fracture approaches closure, the fracture still bears a residual conductivity due to the roughness of the wall's surfaces. With decreasing pressure the effective stress on the fracture planes increases and the conductivity is reduced due to width reduction. The consolidation process can in practice result in a smooth transition of the pressure slope, masking the actual closure event (Weng et al. 2002).

The p_c represents a global value determined from large-scale fracturing experiments, valid for the fractured zone, where a significant net fracturing pressure share has to be accounted for. Therefore it can not be directly compared with individual values of $\sigma_{h\ min}$ (local value) determined via small-scale micro-fracturing (Economides et al. 1998) or laboratory data. It is rather the average of the minimum principal stress of the zone covered by the created fracture(s).

At least for the lower interval treated, it was found that with 8,4 MPa the effective closure stress ranges only slightly above the in situ pore pressure. The second interval showed a significantly higher closure stress value. The presence of inter-layered clay (higher anisotropy) and clearly lower permeability account for the initially higher stress state (**fig. 2**).

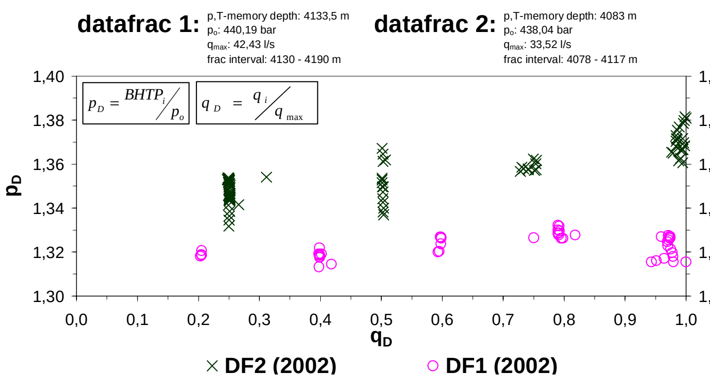

Figure 2: Downhole pressure vs. rate plot of both Datafrac treatments. The crossplot with dimensionless variables allows a direct comparison of the in-situ pressure conditions during the treatment. The upshifting of the treatment pressures in the second interval can be explained by diverse stress and tortuosity conditions.

Additionally and according to Biot's theory (stress is a function of pore pressure), the stress state in the second (upper) interval might have been altered due to a large-scale change in pore pressure as a consequence of the treatment of the lower interval in advance. As the two intervals are spatially very close to each other and no natural hydraulic barrier is present in the reservoir an interaction in terms of a pressure diffusion process seems very likely. The identified stress gradients dp_c/dz in the two intervals (lower: 12,7 MPa/km and upper: 14,3 MPa/km respectively) compare very well with stress values determined by Lempp et al.

(1999) and Röckel et al. (2003) for comparable sub-salinar clastic reservoir rocks in the North German Basin. Although the closure stresses could be matched by the subsequent fracture modelling process, further diagnostic treatments such as "Pump-In Flow-Back" and Hydraulic Impedance Testing (Holzhausen et al. 1985) should be applied to verify the results found by pressure decline analysis. The latter delivers representative values of dp_c/dz only for pure fluid treatments and requires knowledge about the in situ fluid properties (viscosity, leak-off coefficient, density).

With the two most important parameters: closure stress gradient (pressure decline analysis) and permeability of the pay zone (primary production testing) and surrounding layers the fracturing process could be modelled **(fig. 3)**.

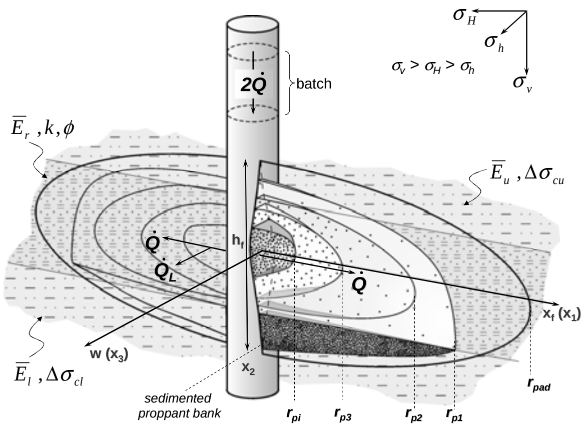

Figure. 3: Schematic picture of the three dimensional fracture model with its most important influencing parameters: Q - flow rate, sigma – stress magnitude, E – Youngs Modulus, k – permeability and the fracture dimensions: w – width, xf – half length, hf – height, r – fluid penetration radii (Legarth 2003)

A three dimensional fracture simulator (FRACPRO™) was used to retrieve the fracture dimensions by matching the modelled with the observed net treatment pressures (**fig. 4**).

The net pressure is defined as the pressure in the main-body of the fracture, free of tortuosity (here: near-wellbore frictional pressure losses caused by the curved path the fluid takes from the wellbore into the main-body of the fracture), controlling the extension and dimension of the fracture. In case of little tortuosity a fracture modelling can be achieved by matching bottomhole pressures instead of net pressures.

A reasonable pressure match of the real-data always “only” represents one plausible solution for the fracturing process and fracture geometry in reality. A good idea of the in-situ fracture dimensions is most important in order to setup the subsequent production schedule and – as real-time modelling with the applied simulator becomes possible – to optimize frac and treatment design on site. Due to technical problems the in situ pressure recording of second mainfrac was distorted. Only the treatment in the lower interval delivered reliable, interpretable data.

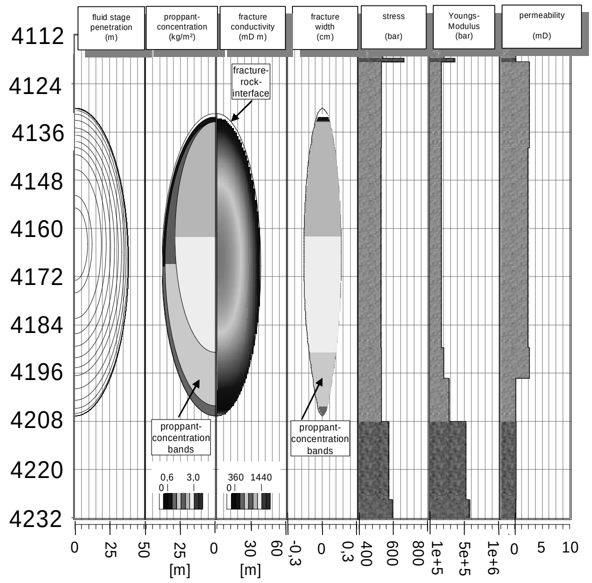

Figure. 4: vertical profile of the frac dimensions from three dimensional modelling and reservoir properties in first frac interval 4190 m – 4130 m TVD; (profiles: fluid stages, proppant concentration in fracture ca. 1,9 kg/m², fracture conductivity 300 – 500 mDm, propped half-length ca. 32 m, fracture height ca. 72 m, max. width at wellbore ca. 0,16 cm, stress, Youngs Modulus, permeability)

3.1.2 Transient production analysis

Hydraulic propped fractures were created with treatments in both intervals. Before and after stimulation production tests (nitrogen lift) were performed to determine the stimulation effect. From an interpretation of the transient production periods a significant increase in productivity is evident. Considering a production time of 10 hours in both tests the productivity increases from 1,2 to 2,1 m³/h MPa, that means by a factor of about 1,8 (Legarth 2003). To characterize changes in the hydraulic system the build-up periods have been analysed. Before stimulation the peak in the derivative indicates a significant skin. After stimulation almost no peak is observed indicating the reduction of skin. The pseudo stabilized level of the derivative is almost constant in both cases. Thus, the transmissibility of the production zones remained unchanged (Tischner et al. 2002).

The increase of productivity results from a skin reduction due to creation of artificial fractures. In contrast to the expectations no additional high permeable zones were connected to the wellbore.

No hydraulic signatures of fractures (slope of ½ or ¼) could be observed in the log-log-plot after stimulation. Probably less conductive or short fractures were created and the hydraulic characteristics of the fractures are masked by the large wellbore storage. To fit the pressure response of the well an inhomogeneous reservoir must be assumed. As an example good matches are obtained by using a composite model with two consecutive zones with radial decreasing transmissibility (Tischner et al. 2002).

4. FRACTURE PERFORMANCE ANALYSIS

The stimulation effect of hydraulic fracturing in a porous-permeable matrix is estimated by analytical modelling. The applied model [8] is valid for a fracture half lengths < 0,5 times the reservoir drainage radius. The stimulation ratio

(FOI) is plotted versus the dimensionless fracture conductivity (F_{CD}) – a measure for the created permeability contrast between fracture and matrix - revealing the sensitivity of specific fracture parameters as conductivity ($k_f w$) and half length (x_f) (**fig. 5**).

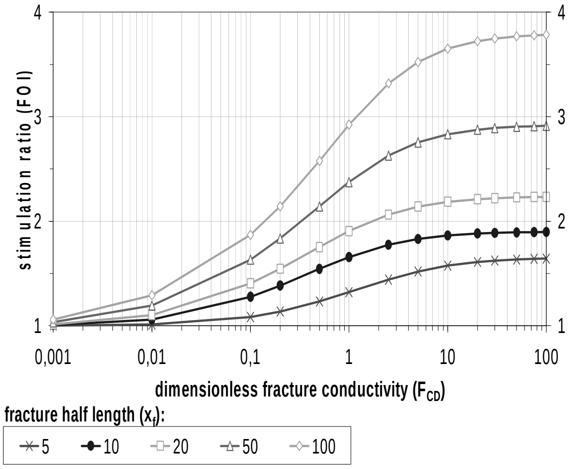

Figure 5: Stimulation ratio of a vertical fracture with variable conductivity and half length in a porous-permeable matrix under pseudo-steady, radial inflow conditions (with ln(re/rw) = 8,75)

The most important conclusion drawn from this analysis is that:

1) stimulation ratios are individual values and have to be determined for each reservoir/fracture setting
2) stimulation ratios increase with increasing F_{CD} reaching a half length dependent maximum.
3) For high values of F_{CD} – that can also result from low matrix permeability (k) - an increase in stimulation ratio can only be achieved by increasing the fracture length (fracture dimensions) which is strongly bound by the technical and economical feasibility.

The initial reservoir productivity ($PI_{pre-frac}$) gets multiplied by the calculated FOI revealing the post-frac productivity ($PI_{post-frac}$). In the given case (see transient production analysis) $PI_{post-frac}$ remained insufficient with respect to the predefined objectives. Simulating the fracture performance (with FRACPRO™) according to the modelled fracture dimensions (**fig. 5**) values for the FOI between 7 and 8 were expected. The reason for the mismatch between the observed (FOI = 1,8) and modelled (FOI = 7-8) can be explained by re-modelling the fracture performance taking various hydraulic and mechanical effects more into account (Legarth 2003).

4.1 Non-Darcy Flow Effects

The developed reservoir is situated below the Gas Water Contact (GWC) with large lateral, stratiform extensions. Measurements on cores showed clear evidence for the presence of pay zone porosities between 5 % and 15 % and transmissibilities of several Darcy-Meter (Legarth 2003). Therefore, a poor reservoir is unlikely to account alone for the lack in productivity described beforehand (chapter: transient production analysis). Obviously multiple frac dominated effects cause the main lack in productivity increase.

At first non-Darcy flow effects (NDF) (Forchheimer 1901) have to be considered. The occurrence of non-Darcy flow effects leads to a reduction of the effective transmissibility as a result of turbulence in the flow channels. They begin to appear at a Reynolds Number (N_{Re}) above 1 (NDF criterion) considering a bent tube model (Li et al. 2001): The higher the N_{Re} the smaller the remaining transmissibility (Gidley 1990). The magnitudes of the NDF were calculated for a fluid production rate of up to 25 m³/h (observed during the casing lift tests), the geometry of the well and the reservoir and frac model described in this context. Even for high rates the N_{Re} stays small for flow in the matrix compared to the N_{Re} in the frac. At the specified rate the corresponding N_{Re} reaches values, depending on the given model, far below 1 for flow in the matrix and orders of magnitudes higher (clearly above 1) in the vertically oriented, proppant filled bi-wing frac as primary flow path in the system. In the given case and for rates between 25 and 100 m³/h the N_{RE} reaches the following values: $5x10^{-3}$ up to $2x10^{-2}$ in the matrix (here: average grain diameter 5 µm) and between $6x10^{1}$ and $3x10^{2}$ in the frac, respectively. Thus, it is obviously important to account for NDF when analysing transient production tests in low permeability reservoirs where the inflow is dominated by linear and bi-linear flow through the frac in the early- and mid-time region. For long production times – depending on the individual reservoir properties – pseudo radial inflow conditions will prevail in the reservoir. The matrix will take its share in the production. Independent of the regime, NDF cannot be neglected for flow within the frac. This is even valid if the frac itself is only sharing very little in the entire flow due to the flow channel diameter relationship (matrix vs. frac ~ 1:100). Using the approach of Gidley (1990) the dimensionless fracture conductivity (Eq. 1) calculated can be corrected for non-Darcy flow effects (Eq. 2).

$$F_{CD} = \frac{k_f \cdot w}{x_f \cdot k} \qquad \text{(Eq. 1)}$$

$$F_{CD}^{*} = \frac{F_{CD}}{1 + N_{RE}} \qquad \text{(Eq. 2)}$$

F_{CD}^{*} represents the corrected dimensionless fracture conductivity. The F_{CD} is expressing the created contrast between frac and formation permeability. An optimum frac design is reached at a value of 1,6 for the F_{CD} (Economides et al. 2002).

Fig. 6 and **fig. 7** reveal that already for very small proppant diameters the N_{Re} exceeds the NDF criterion. As a consequence, the corresponding F_{CD}^{*} is diminished and the inflow enhancement strongly deteriorated. **Fig. 6** presents the values of F_{CD} and F_{CD}* for the modelled frac (**fig. 4**) showing a potential severe reduction of fracture conductivity as a result of NDF.

This leads to the following conclusion with respect to NDF:

Given that the reservoir characteristics remain unchanged the flow conditions will be strongly improved in case one or a combination of the following are provided:

- higher remaining fracture widths and heights,
- larger fracture height vs. length relationship,
- larger proppant diameter,
- less heterogeneous proppant pack (smaller grain size range),
- smaller production rates

All of the above aid in either increasing the inflow area or decreasing the fluid velocity per flow channel that leads to a direct reduction of NDF. The height vs. length relationship aspect is rather critical because it is hardly to influence. It strongly depends on the fracture compliance. Ideally, the fracture should be very short and at the same time covering the whole pay-zone in height. An aggressive tip screen-out design might lead to that geometry but at the same time bear a high risk of treatment failure. The simplest fracture geometry to assume for design purposes (no compliance) is the radial or "penny-shaped" frac with $x_f = ½ h_f$.

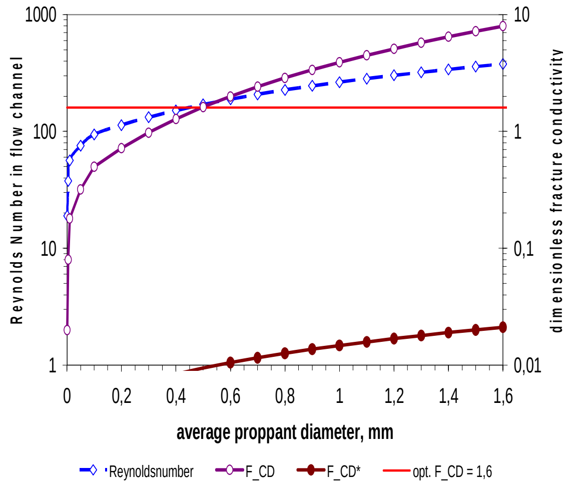

Figure 6: Deterioration of the fracture performance by non-Darcy flow effects; fracture geometry taken from Fig. 5; flow rate: 15 m³/h; the flow channel geometries are calculated considering a dense spherical pack of grains (proppants) in a bi-wing frac; the NDF criterion is reached for a grain size above 0,5 mm; FCD* is far below the design optimum of 1,6; model parameters: k = 2 mD, h_f = 72 m, x_f = 32 m, w = 0,0016 m

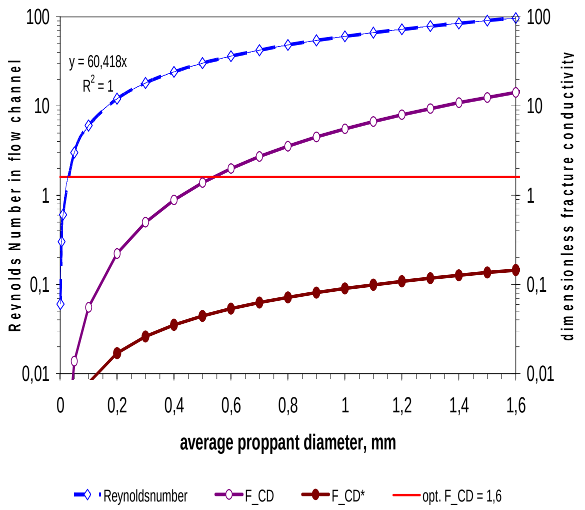

Figure 7: Deterioration of the inflow performance by non-Darcy flow effects in a proppant filled fracture (bi-wing) at a flow rate of 15 m³/h; the flow channel geometries are calculated considering a dense spherical pack; model parameters: k = 2 mD, h_f = 72 m, x_f = 32 m, w = 0,005 m

The production rate resembles the main design parameter but is set by overall production requirements in order to guarantee an economic energy conversion (q > 20 kg/s). The only possibility would be in this case to realize a multi-well scenario with a commingled production, splitting up the required flow rate over the number of producers. As the wells generally represent the highest share of the overall investments in geothermal exploitation this can only be a solution for low-drilling-cost locations (e.g. shallow reservoirs).

Thus, the fracture dimensions are the remaining primary design parameters that can be varied according to treatment set-up:

- fracture widths and heights increase with net treatment pressure
- fracture width increase by tip-screen out design (fracture inflation)

Still, the parameters are not arbitrarily adjustable. Realistic conditions have to be assumed. An effective proppant pack (multi-layering) is reached when achieving about 10 kg/m² (2 lb/ft²) proppant concentration in the fracture (at a bulk density of ordinary high strength proppants of about 2000 kg/m³ this results in a fracture width of 5 mm). Keeping the proppant concentration constant the proppant pack strength decreases with increasing grain size. This behaviour is inversely proportional to the individual grain strength. Nevertheless, more fines are generated when proppant packs with larger grains are exposed to high effective stresses (due to decreasing contact area). Nevertheless, pumping an average grain diameter of 1 mm is realistic considering modern proppant technology. A proppant pack optimization towards larger grain sizes can even be further achieved if considering that in geothermal wells the drawdown (proportional to the effective stress) is anyway strongly limited by production efficiency criteria (energy demand of artificial lift). The result for such a re-designed frac is given in **fig. 7**. Nevertheless, it can be analysed that even for a strongly improved frac geometry the F_{CD}* remains below the design criterion due to NDF.

The mentioned aspects yet neglect the long-term behaviour of the propped frac under drawdown conditions. Additional measures such as proppant flow-back control and slurry under-displacement have to be taken into account for a broader design needed in the actual field case.

4.2 Proppant Pack Damage

Secondly, mechanical and size effects are discussed as additional causes for missing the designed productivity goal. The first assumption is a frac creation without properly connecting productive zones to the well (Tischner et al. 2002). This can be caused by either a frac that is too short and does not by-pass a damaged zone as already identified by transient production analysis. Or a frac with appropriate length but low conductivity was created so that the intended permeability contrasts to the matrix were not achieved. Of course, a combination of both scenarios is also possible. Another explanation is a frac with initial proper dimensions, but with a conductivity that was deteriorated as a consequence of proppant crushing, embedment and proppant flow-back events that occurred during drawdown (choked fracture, fracture-face skin effect). Other possible reasons for the phenomena such as proppant convection and lacking tie-back, multiple fracture as well as out of pay zone growth are referred to in other cases (Cleary et al. 1992, Berghofer 1998, Aud et al. 1999). Finally, the assumptions need to be individually checked for plausibility. This was done by including the effects in a fracture and reservoir model and trying to establish an adequate pressure match (fracture performance modelling). It turned out that the observed behaviour could only be adequately explained by either a severe post-treatment conductivity reduction (~ 90%) or a missing tie-back of the frac to the well (Legarth 2003).

Proppant crushing and embedment due to increasing effective stresses during drawdown lead to a reduction in fracture width and thus can cause that reduction of fracture conductivity (**fig. 8**).

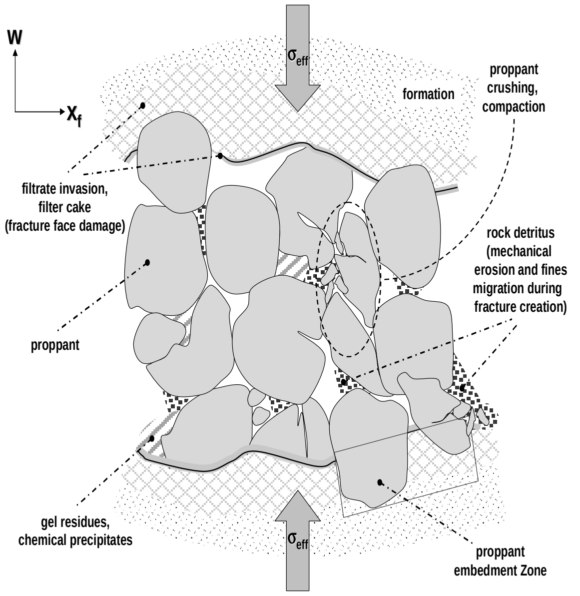

Figure 8: Schematic picture of potential secondary effects in a hydraulic fracture and its direct environment leading to a performance impairment and gross productivity decrease. The effects and impairment are aggravated with decreasing proppant concentration and increasing effective stress on the fracture walls

Theoretically the proppants get crushed or embedded in the rock matrix depending on the relationship between their mechanical strength and that of the rock (Sato et al. 1998). Together with chemical fluid-rock interactions and reactions (filtrate invasion, salt precipitates, fines movement) this is believed to account for a significant fracture-face skin effect. The Latter leads to a permeability reduction of the fracture-rock interface and thus to an impairment of the overall inflow performance. Presently, a mayor research focus of the authors listed covers the quantification of the described effects.

As rock is an anisotropic, inhomogeneous medium, especially when naturally fractured, both effects are likely to occur at different parts of the fracture-rock-interface.

The lower the concentration of proppants in the fracture the more severe these effects occur (Sato et al. 1998). Especially considering partial monolayer proppants (**fig. 9**) the stress concentration on one grain is maximised (punctual loading). The three-dimensional modelling of the conducted fracture treatments showed maximum post-job proppant concentration of only about 1,9 kg/m². This value is slightly above the monolayer criterion stated by Sato et al. (1998) and consequently does represent a sub-dimensioned packed frac in this reservoir.

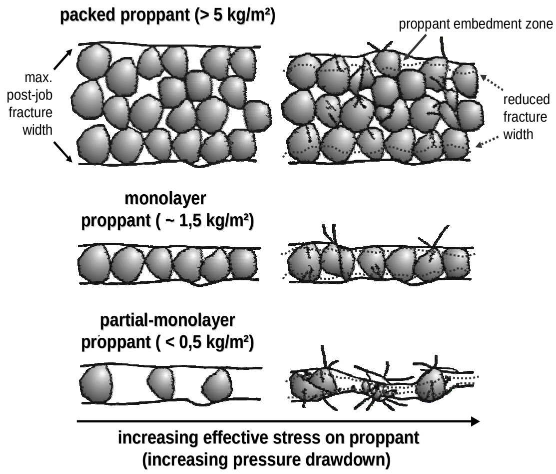

Figure 9: Potential post-job proppant pack damage due to proppant crushing and embedment for different proppant concentrations with increasing effective stresses during drawdown

Therefore, the conductivity of the frac is strongly limited and potentially inflow restrictions are not completely by-passed. Additionally, proppant flow-back occurred during the production tests that further diminishes the proppant concentration in the vicinity of the wellbore. Leaving the fracture end insufficiently (partial-monolayer) or unpropped can results in partial closure of the frac and further production impairment.

Finally, the described reasons for an observed inflow performance impairment (less productivity increase as expected) caused by hydraulic and mechanical effects would have not been necessarily less without the use of proppants. The risk of fracture closure and a hydraulic decoupling, especially in the near-wellbore region, is even enhanced. Effective (highly conductive and sustainable) self-propping mechanisms are yet not proven for sedimentary geothermal reservoirs.

5. CONCLUSIONS

The open hole hydraulic proppant fracture treatments were successful: The technical feasibility of the fracturing concept was proven, propped fractures were created and the inflow performance of the well was enhanced.

Though, the anticipated stimulation ratio and post-frac productivity could not be achieved. Probably the fracs were sub-dimensioned and do not properly connect existing productive reservoir zones to the well. The main reason for the insufficient fracture dimensions is the initial, moderate fracture design that was risk reduction orientated. For an effective productivity enhancement additional hydraulic proppant fracture treatments in the Rotliegend sandstones with increased proppant loading are necessary in order to create long-term conductive fractures. Moreover, post-frac production tests have to be performed moderately at lower depressions to mitigate additional proppant pack damage and high fracture-face skin effects resulting in fracture conductivity reduction and severe productivity impairment.

Non-Darcy flow effects deteriorate the achievable well productivity by reducing the effective fracture conductivity. This can in parts be avoided by adapting the fracture treatment concept and design as described.

Furthermore, the treatment analysis due to low effective fracture closure and net pressure shows overall favourable conditions for fracturing in the potential pay zone. Further hydraulic tests should be conducted in order to verify the findings.

At this stage the key question whether the target zones also represent pay zones cannot be fully answered. What can definitely be stated is that the stimulation potential of the Rotliegend sandstone reservoir is not yet exhausted, maximum achievable productivity values are not yet reached. This maximum can be individually defined and is limited depending on reservoir properties and the technical and economic feasibility. In any case, especially when thinking of a concept transfer to other but geologic similar locations, the applied technology is not a self runner. Even considering an optimum stimulation design, at least moderate initial reservoir productivity is required (> 10 m^3/h MPa) to reach an efficient and economic fluid production. This is due to the fact that the stimulation effect (Fold Of Increase in production) of such treatments in the given geologic environment is bound between a level of approximately 2 to 4. Thus, the site dependency and the need for an adequate exploration are increased.

The hydraulic connection of further productive zones - in vertical and lateral direction from the investigated potential sedimentary pay zones – yields an increase of the overall transmissibility (*kh*) and can compensate lower primary productivity values. Considering a commingled production the efficiency goal could still be reached.

Therefore, further efforts have to be attempted that integrate the obtained insights and consider additional technologic advancement.

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