Stimulation Experiments in Sedimentary, Low-Enthalpy Reservoirs for Geothermal Power Generation

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Abstract

Hydraulic stimulation experiments were conducted in a remediated Rotliegend-well situated in the eastern part of the North German Basin. The well is used as "Geothermal In-Situ Laboratory" and as a reference location for several ongoing research projects. The aim of the projects and experiments is the development of technologies to put primary low-productive aquifer structures in use for geothermal power generation.
The frac operations in 2002 were designed to enhance the inflow performance by connecting the well to productive reservoir zones. Two consecutive zones within the Rotliegend sandstones were selected. Here core measurements show the most promising petrophysical reservoir properties with respect to a productivity increase. The stimulation treatments were performed as hydraulic proppant fracturing operations. Proppants were used to support the fractures and to guarantee a long-term fracture aperture.
The treatment intervals are located in the open hole section of the well at depths between 4080 m and 4190 m and at temperatures of about 140°C. Therefore, technical demanding unprecedented conditions had to be managed.
An open-hole-packer at the top and a sandplug 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 (high-strength ceramic grains) and over 200 cubic meters of frac fluid (highly viscous gel) into the formation. The fracture treatments where conducted with two subsequent operations in each interval: A diagnostic treatment (datafrac) and the main treatment (mainfrac) with the proppant stages.
The frac operations were successful. Propped fractures were created in both intervals and the inflow behaviour of the reservoir was decisively enhanced. The effective pressures applied for fracture initiation and propagation were only slightly above the in-situ pore pressures.
Nevertheless, the stimulation ratio predicted by modelling could not be achieved. Multiple reasons could be identified that account for the mismatch. Probably chemical and mechanical processes during closure led to a reduced fracture conductivity. The insights gained from the experiments are important for future fracture treatment designs at the investigated site and at comparable locations.

Keywords

sedimentary reservoir rocks, hydraulic proppant fracturing, open hole treatment, fracture modelling

Introduction

For geothermal power generation in the North German Basin reservoirs have to be developed that are fluid bearing and show temperatures of at least 120°C. 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. Besides the target temperature a high production rate of more than 50 m³/h is necessary [6]. In the investigated geological setting the potential pay zones of primary concern are therefore Rotliegend sandstones [5]. Good permeable zones 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.

The investigated well Groß Schönebeck is drilled through the Rotliegend sandstones. The initial productivity of the well was significant lower than it was expected from core measurements. Mainly inflow restrictions (skin) limit the fluid production. For this reason, multiple hydraulic proppant fracturing experiments have been conducted at a depth of 4,2 km. Treatments were applied to selected intervals of the well's open hole section using an innovative hydraulic barrier system, consisting of an open hole packer assembly and a sand plug. The objectives of the experiments were: 1) the verification of the technical feasibility of the multizonal open hole fracturing technology, 2) the connection of productive reservoir zones to the well and 3) the decisive enhancement of the overall productivity of the well.

Experiments in the "In-Situ Geothermal Laboratory"

The former gas exploratory well Groß Schönebeck 3/90 was drilled in 1990. Because of insufficient gas discovery the well was closed immediately after drilling. In 2000 the well was selected to serve as "Geothermal In-Situ Laboratory" and therefore remediated and deepened to 4294 m (true vertical depth). The site is located northeast of Berlin (**Fig. 1**). The well develops a sequence of various geological formations, which are typical for the North German Basin. A series of 2370 m of Quaternary to Triassic sediments is followed by 1492 m of the Zechstein salinar [4]. The well has an open hole section of about 400 m that develops Rotliegend formations comprised of siltstones, about 100 m sandstones, conglomerates and 60 m of underlying volcanic rocks down to the final depth.

The completion type guarantees a maximum inflow area that would allow a commingled production from each productive reservoir

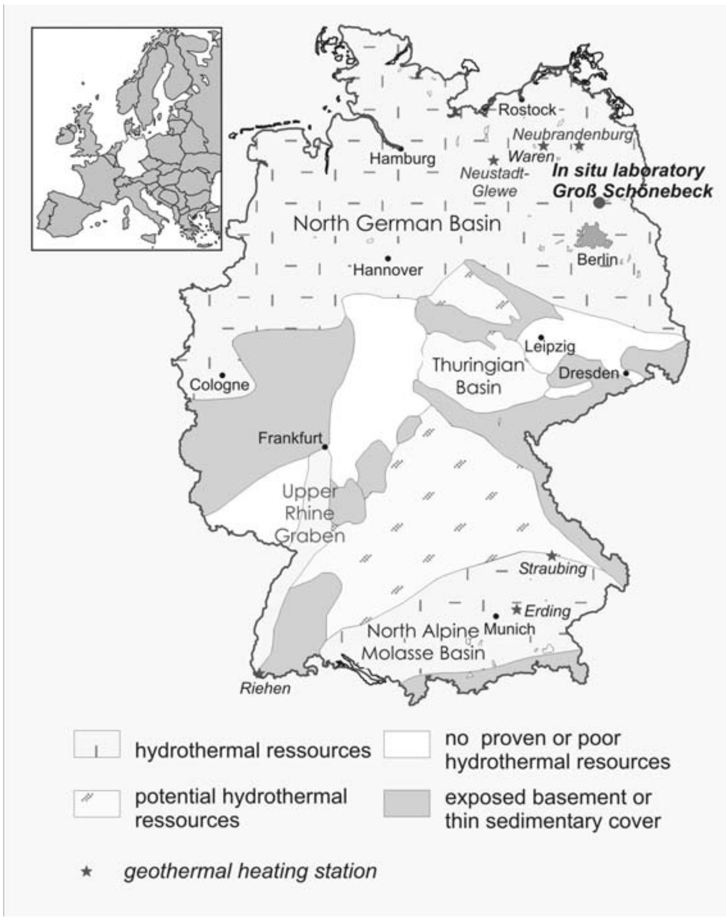

Fig. 1: *Location of the "In-Situ Geothermal Laboratory" Groß Schönebeck in the remediated Rotliegend gas exploratory well E GrSk 3/90 [4]*

zone in order to achieve the desired productivity values for an efficient high rate fluid production. Furthermore, a continuous, unaltered monitoring and borehole logging before, during and after the treatments is possible due to the direct contact to the reservoir rock.

The stimulation experiments were focused on the Rotliegend sandstones for which core measurements indicated promising petrophysical properties. Two intervals were selected: 4130 – 4190 m and 4078 - 4118 m, respectively. The 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. 2**). The annulus between frac string and casing was filled with saline fluid and remained open to 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. Therefore, the main hydraulic and rock mechanical parameters could be determined, including hydraulic height and volume of the created fracture by p,T-logging and history matching the pressure response.

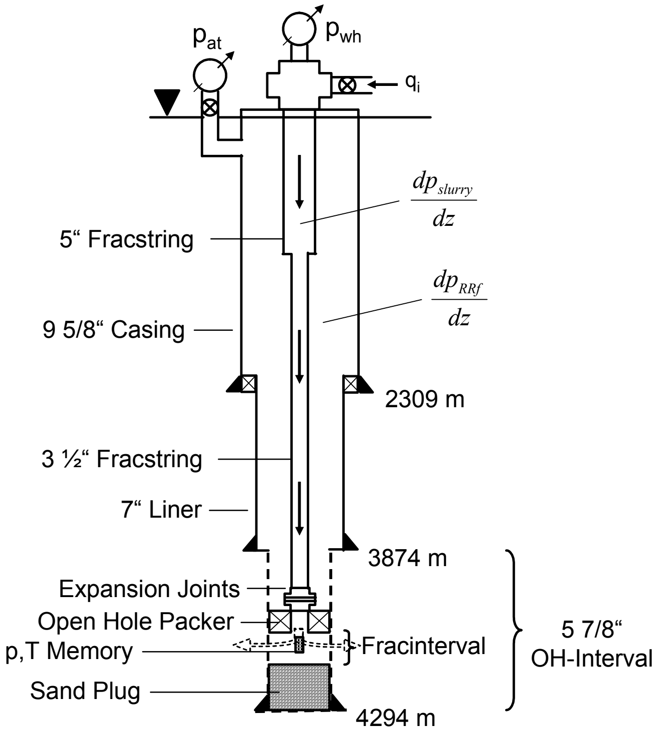

Fig. 2: Schematic of the frac treatment set-up in the well E GrSk 3/90.

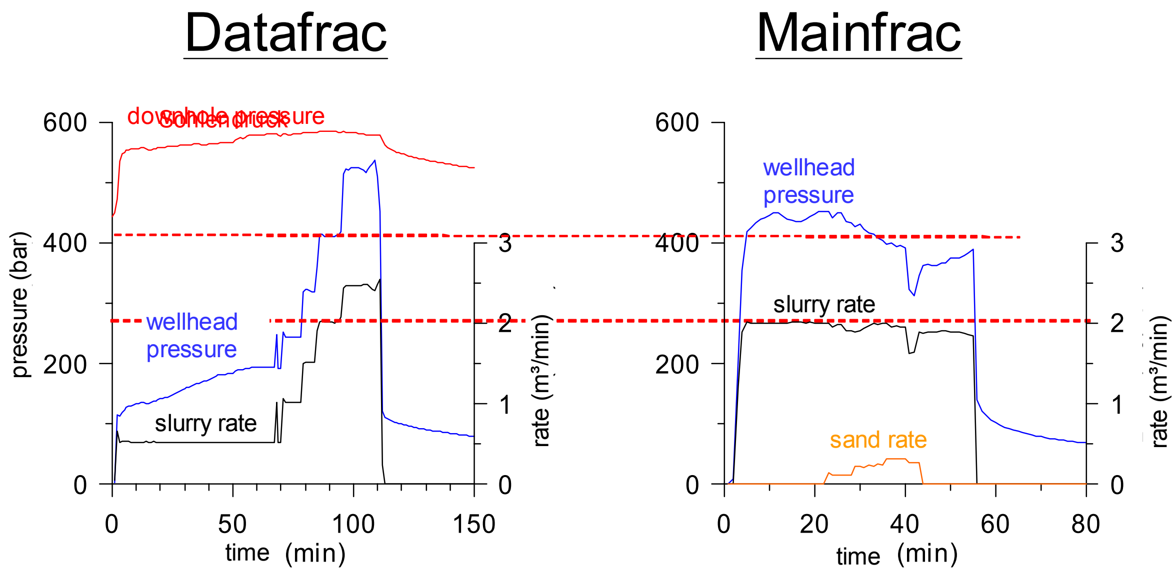

Fig. 3: Pressure and rates for the frac treatment in the interval 4130-4190m. Determination of maximum wellhead pressure and slurry rates (frictional losses) for the mainfrac treatment by applying a step-rate test (datafrac)

This was necessary for an adequate mainfrac design and secure job executions (**Fig. 3**). In terms of the applied proppant fracturing treatments in the open hole section difficult and partly unprecedented circumstances had to be managed. The high temperature and the open hole conditions mean a high risk for a packer operation. Especially fracture height growth had to be limited and bypassing the packer with proppants had to be avoided. This situation resulted in a less-aggressive frac design.

Results and discussions

Hydraulic propped fractures were created with treatments in both intervals placing more than 11 tonnes of proppants and 200 m³ frac fluid into the formations. Before and after the stimulation production tests (nitrogen lift) were performed. In Fig. 4 the pressure responses and flow rates are shown for both tests.

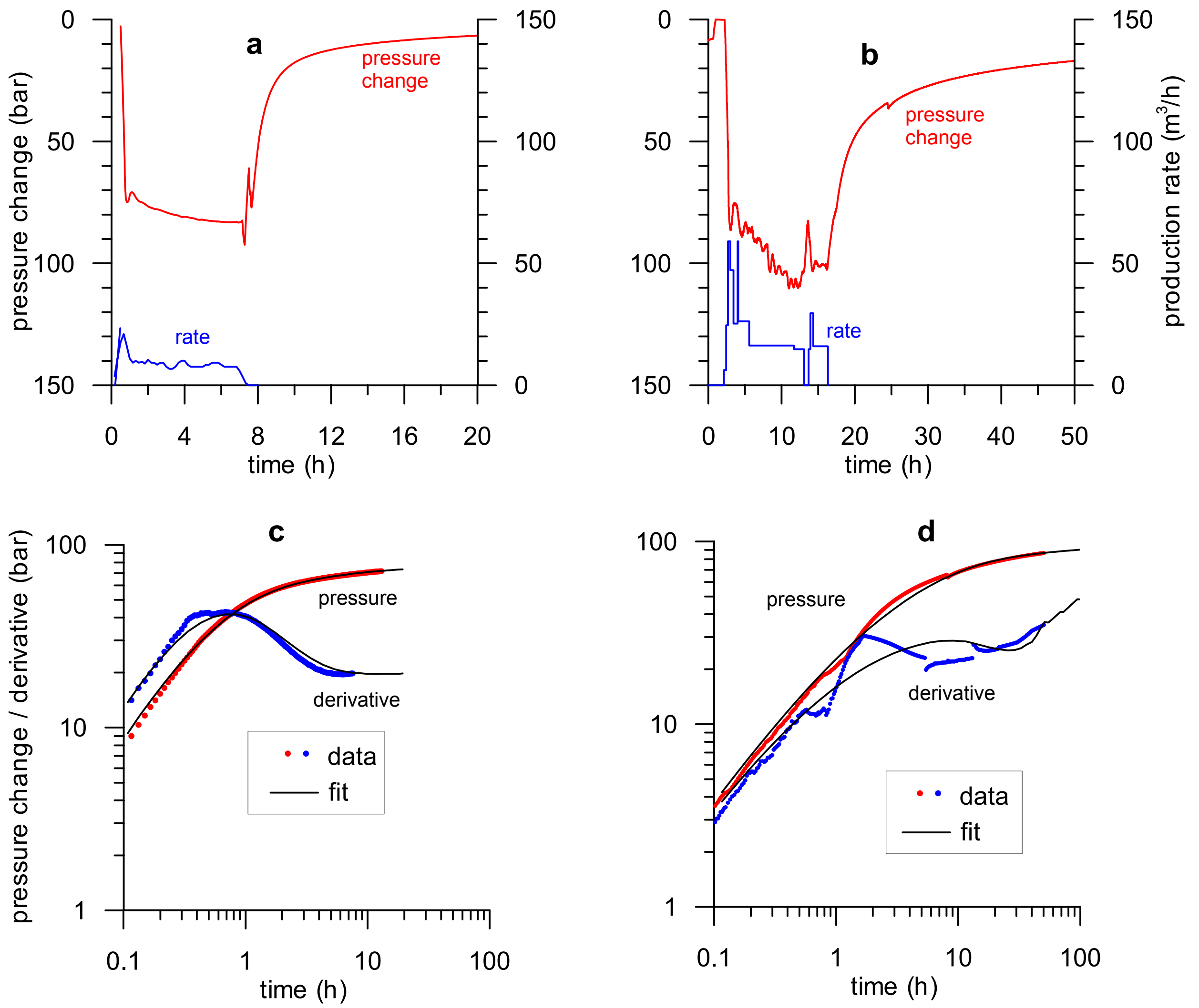

__Fig. 4__: Pressure change and production rate for the lift test before stimulation (a) and after stimulation (b). Diagram c (d) shows the log-log-plot for the buildup periods before (after) stimulation. In c and d the fit curves are obtained assuming a radial composite model. (c): The following important parameters were obtained by nonliear regression: Before stimulation (c): Skin = -1.0; After stimulation (d): Skin = -4.9. The transmissivity of the inner zone is in the range of (0.5 - 1.1)E-13 m^3 and the transmissivity in the outer zone is in the range of 1 - 7E-14 m^3. According to the assumed composite model the transition between inner and outer zone occurs at a radial distance between 30 and 80 m.

Transient production analysis. 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 m^3/h MPa, that means by a factor of about 1.8. 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.

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 transmissivity (**Fig. 4**).

Fracture Performance Analysis. The post-frac productivity remains insufficient with respect to the predefined objectives. Modelling the created frac dimensions by net-pressure matching and simulating the according fracture performance values for the stimulation factor (FOI) between 7 and 8 were expected. The mismatch between the observed (FOI = 1,8) and modelled (FOI = 7-8) results can be explained by re-modelling the fracture performance taking various effects into account.

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 [7]. Therefore, a limited reservoir is unlikely to account for this behaviour. Obviously multiple frac dominated effects cause the lack in productivity increase. In this context, the first assumption is a frac creation without properly connecting productive zones to the well [9]. 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. Other possible reasons for the phenomena such as proppant convection and lacking tie-back, multiple fracture growth as well as out of pay zone growth are referred to in other cases [1, 2, 3]. 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 or a missing tie-back of the frac to the well [7].

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. 6**). Theoretically the proppants get crushed or embedded in the rock matrix depending on the relationship between their mechanical strength and that of the rock. 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. Especially considering partial monolayer proppants: Then 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 (**Fig. 5**).

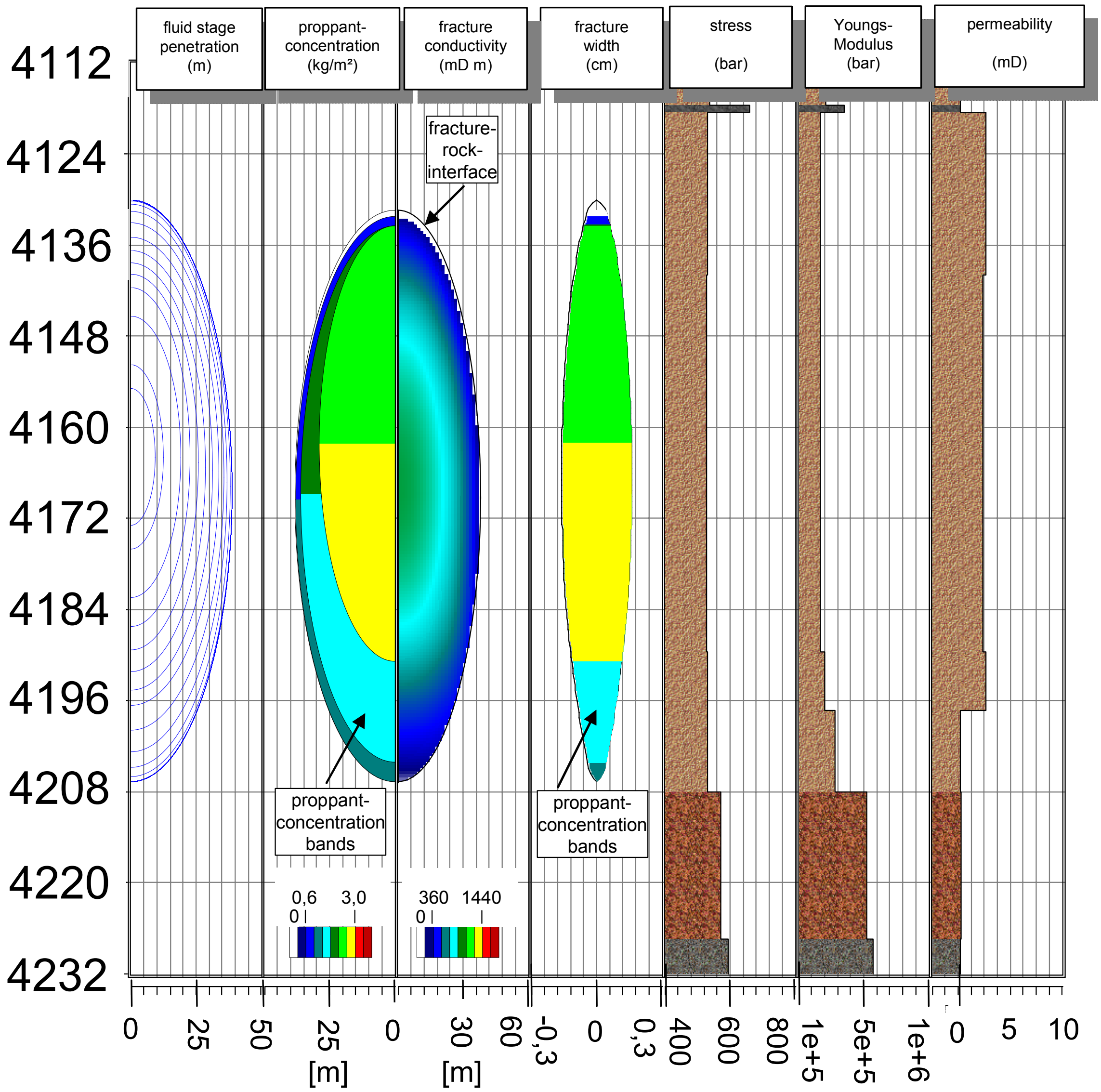

***Fig. 5:** Frac dimensions from three dimensional fracture modelling (fracture properties: proppant concentration ca. 1,9 kg/m²; conductivity 300 – 500 mDm; half-length ca. 32 m; height: ca. 72 m; max. width: ca. 0,16 cm); first frac interval 4190 m – 4130 m [7]*

This value is slightly above the monolayer criterion [8] (**Fig. 6**) and consequently does represent a sub-dimensioned packed frac in this reservoir. 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.

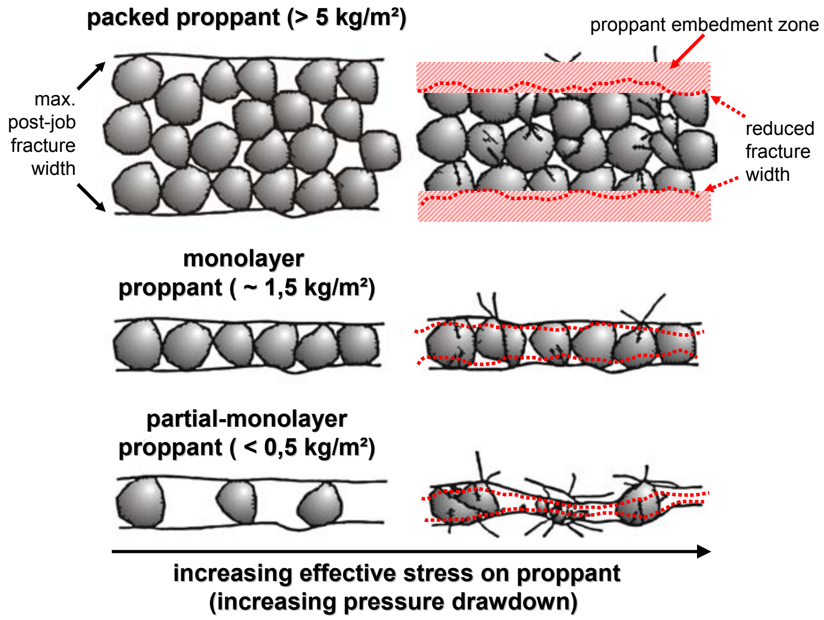

Fig. 6: *Potential post-job proppant pack damage due to proppant crushing and embedment for different proppant concentrations with increasing effective stresses during drawdown; proppant pack classifications after Sato et al. [8].*

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 productivitiy 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 resulting in fracture conductivity reduction and production impairment.
Thus, the stimulation potential of the Rotliegend sandstone reservoir is not yet depleted, maximum productivity values are not yet reached. Therefore, further efforts have to be attempted that integrate the obtained insights and consider additional technologic advancement.

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