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GEOTHERMAL WELL STIMULATION TREATMENTS

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The stimulation of geothermal wells presents some new and challenging problems. Formation temperatures in the 300-500°F range can be expected. The behavior of frac fluids and proppants at these temperatures in a hostile brine environment must be carefully evaluated before performance expectations can be determined. In order to avoid possible damage to the producing horizon of the formation, the high-temperature chemical compatibility between the in situ materials and the frac fluids, fluid additives, and proppants must be verified. Perhaps most significant of all, in geothermal wells the required techniques must be capable of bringing about the production of very large amounts of fluid. This necessity for high flow rates represents a significant departure from conventional oil field stimulation and demands the creation of fractures with very high flow conductivity or large fracture surface areas in the case of matrix permeability dominated formations.

Stimulation treatments have been conducted in formations which produce hot water as a result of both matrix permeability and from natural existing fracture systems. The following targets of opportunity are of particular interest:

- Wells that require additional drainage area because of insufficient formation permeability.
- Wells that did not intersect nearby major fracture systems.
- Wells that suffered man made damage during drilling or completion operations including mud or cement invasion.
- Wells that require periodic remedial treatment as a result of fluid production related damage.

Although numerous criteria have been established for the selection of candidate wells, the most significant is definite proof of a good producing reservoir. This data is normally obtained from offset well production.

Although sand is generally used as a proppant today and it has been the most widely used in the past, it is not strong enough to withstand the conditions in geothermal wells at elevated temperatures. Sand is definitely affected by temperature, particularly when tested in hot water or brine at various closure stresses. Figure 1 shows the effect of temperature on common frac sand (20/40 mesh). These results are short term results and only suggest the severity of long term field results.

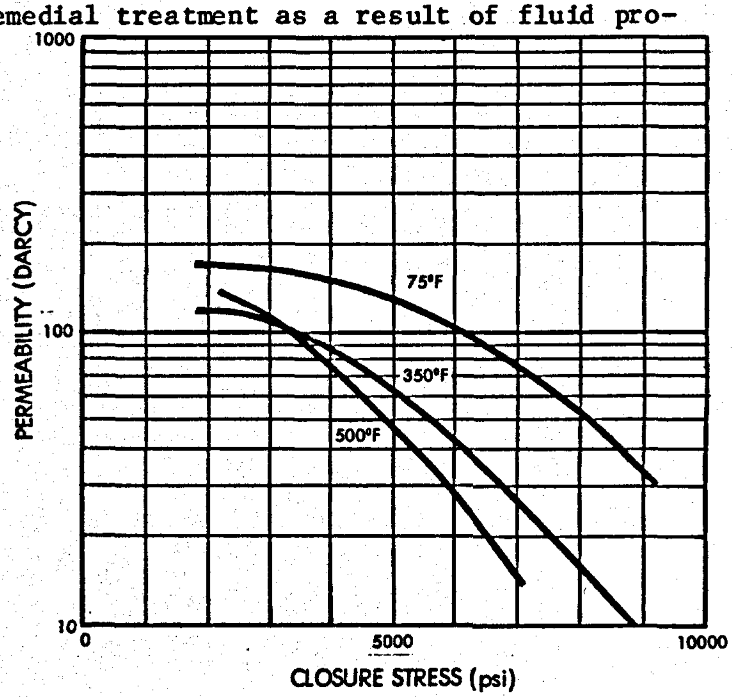

Figure 1. Temperature Effects on 20/40 Brady Texas Sand.

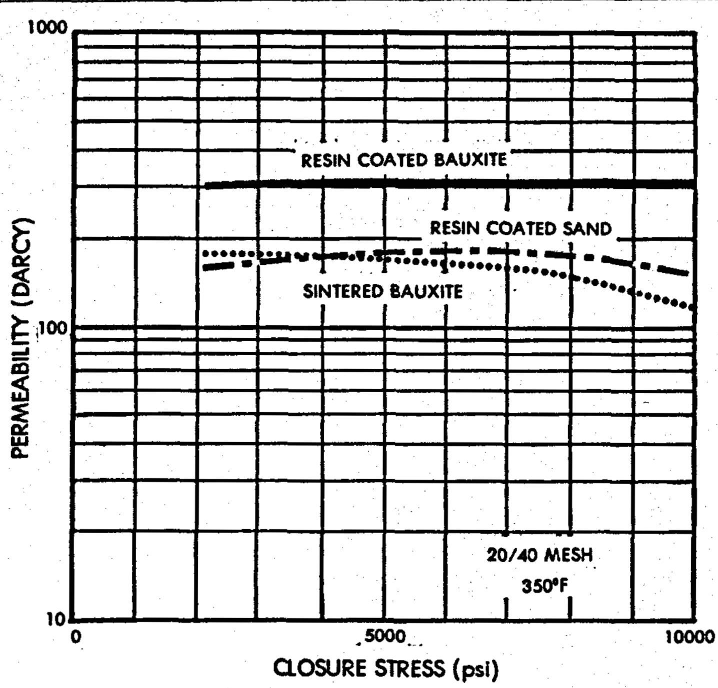

Figure 2. Permeability vs. Closure Stress for Temperature Insensitive Proppants.

There are several mechanisms that can destroy sand grains in the fracture. First, the sand is brittle and point-to-point loading can cause brittle failure. Second, sand is full of microfractures and faults which weaken the sand. Finally, when sand is stressed in a corrosive medium like hot water, stress corrosion cracking appears to destroy the sand at low closure stresses. High temperatures and high stresses combine to bring out the worst properties of sand.

The strongest proppant tested to date is Resin Coated Bauxite. It shows no temperature sensitivity or permeability decrease under load. The Resin Coated Sand is not temperature or load sensitive but does have a slightly lower permeability at any closure stress due to a slightly different distribution of particle sizes. Figure 2 shows the permeability of Resin Coated Bauxite and Resin Coated Sand under varying closure stress to 10,000 psi at 350°F. No temperature differences or sensitivities were found so tests at all temperatures gave the same results shown in Figure 2 within experimental scatter. One important point is that the resin coated materials are cohesive; therefore, once emplaced in the fracture flowback is reduced during production. Although slightly crushable, the Sintered Bauxite is much stronger than sand and effectively inert in hot brines. Figure 2 shows how Sintered Bauxite permeability behaves under increasing closure stress.

Under the Geothermal Reservoir Well Stimulation Program, two field experiments were performed at the Raft River KGRA in 1979. The first well stimulation experiment, performed on Well RRGP-4, used the "Kiel" dendritic fracturing process. A 200-foot vertical fracture was created at the wellbore. Post-stimulation production data indicate that Well RRGP-4 productivity was improved, but not to the hoped-for level of other wells in the field. The second well stimulation experiment, performed on Well RRGP-5, was a conventional massive hydraulic fracture treatment. A new vertical fracture of 140+ feet was created. Production tests suggested that the hydraulically created fracture intersected natural fractures very near the wellbore. Although the final well production rates were not as high as desired, the field experiments were technically successful in creating the artificial hydraulic fractures planned and have contributed significantly to the development of geothermal well stimulation technology.

The third and fourth field stimulation treatments under this program have just been completed in Republic Geothermal well 58-30 at East Mesa, CA. Preliminary flow test data indicates that the productivity was increased by a factor of 2.3 in the upper interval fracture stimulation treatment. The lower interval is currently being evaluated and the results from this treatment will be reported later.