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# Natural Fractures, Mechanical Properties, and *In Situ* Stress in the Planning and Execution of the Desert Peak EGS Experiment

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## Introduction

An integrated study of fluid flow, natural fractures, stress, and rock mechanical properties has been conducted in Desert Peak well 27-15 as the basis for a stimulation protocol to develop an Enhanced Geothermal System (EGS) through hydraulic stimulation. Stimulation of this well was initiated in August of this year (2010), and the analysis is being updated as new data is accumulated and analyzed by an extensive multi-disciplinary team of industry and academic partners (see partial list in acknowledgments and references). Conditions during stimulation are being monitored via a combination of real-time down-hole pressure monitoring, micro-earthquake activity via a local seismic network, and episodic down-hole TPS measurements, tracer tests, and pressure transient tests.

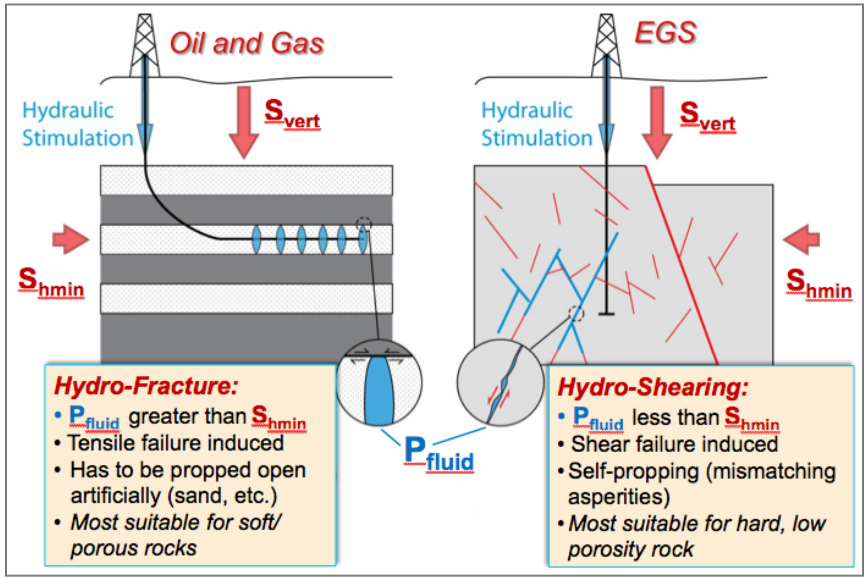


Figure 1: (left) Conceptual model for massive hydraulic fracturing exploiting layered sediments with contrasting mechanical properties and stress conditions in conjunction with directional drilling. (right) Conceptual model for use of low fluid pressure and pumping rates to induce shearing within natural fractures to enhance permeability, analogous to some natural systems such as Dixie Valley (Barton et al., 1998; Hickman et al., 1998, 2000) the Coso Geothermal Field (Davatzes and Hickman, 2005, 2010), and low porosity-crystalline rocks (Barton, 1995; Ito and Zoback, 2000; Townend and Zoback, 2000).

By analogy to case studies of natural hydrothermal systems (Figure 1), the goal of this EGS hydraulic stimulation is to artificially induce shear slip and dilatation along pre-existing fractures by injecting fluids at low pressures (preferably below the least principal stress), thereby enhancing formation permeability in hot but impermeable rock. This approach provides a mechanism to maintain fracture permeability through self-propping due to mismatch of rough surfaces in cases in which artificial proppants may not be suitable. The large volume, low-pressure injection also seeks to develop an extensive and tortuous reservoir well away from the borehole that is characterized by large surface area. Exploitation of existing fault networks provides a potential mechanism to keep the stimulation deep in cases where lithologic layering may be insufficient to provide vertical confinement in normal and strike slip stress regimes. Thus, characterization of the geometrical, mechanical, and hydrologic properties of natural fractures in relation to the *in-situ* state of stress is critical to stimulation planning and evaluation for EGS projects underway at Desert Peak, Nevada (Zemach et al., 2009, Stacey et al, 2010), and elsewhere (see MIT, 2006).

## Summary of Stimulation Criteria and Design

Planning for the stimulation was developed on the basis of the borehole conditions, a number of local geologic criteria applicable to the immediate borehole environment, and large-scale reservoir structure and hydrology. The local geologic criteria include: (1) the stimulation interval is below the zone of smectite alteration overlying the geothermal reservoir because smectite-filled fractures are not prone to dilation and related permeability enhancement during slip (Davatzes and Hickman, 2009, Lutz et al., 2009, Hickman and Davatzes, 2010) and their accessibility to stimulation fluids is uncertain; (2) the interval exhibits high formation temperatures and is below any shallow conductively heated, low temperature cap (see temperature profile in Robertson-Tait *et al.*, 2004); (3) the interval intersects highly stressed, slightly permeable natural fractures well oriented for frictional shear failure; and (4) the mechanical properties of rocks in the interval are such that they would be susceptible to “self-propping” dilatation and permeability enhancement during fluid injection and shearing (Brown, 1987; Teufel, 1987; Willis-Richards, 1996; Lutz et al., 2010a, b).

## Stress and Geomechanical Model

Hydraulic stimulation is now being applied to units comprised of rhyolite tuffs and metamorphosed mudstones between ~3000 to ~3500 ft MD at temperatures of 180-195° C (Stacey et al., 2010). Temperature-Pressure-Spinner Flow-meter (TPS) logs indicate that the well is located in hot, but low permeability rock outside the existing resource. Active injectors are located approximately 0.5 km to the SSW and the nearest active producer is approximately 1 km to the SSW of well 27-15.

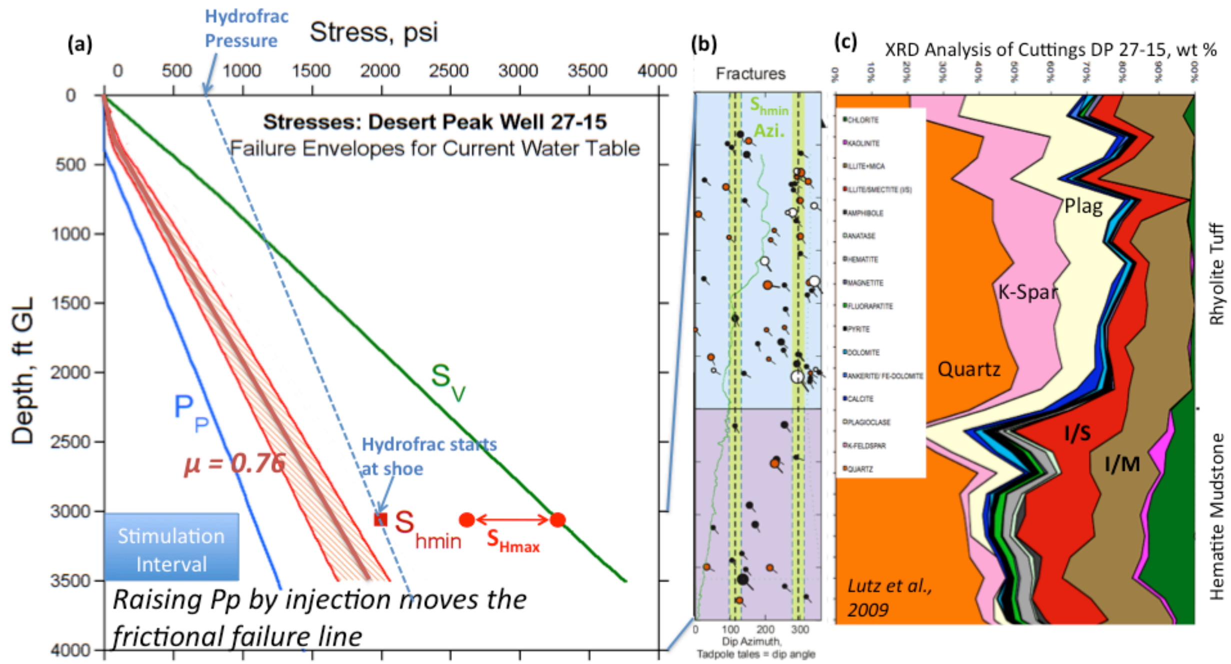


Figure 2: (a) Stress model for Well 27-15 from Hickman and Davatzes (2010), including envelope for normal faulting frictional failure along cohesionless fractures for coefficients of friction, μ, ranging from 0.6 to 1.0.. Fluid pressure in the formation, Pp, is assumed to be in static equilibrium with shut-in pressure logs. The magnitude of the least horizontal stress, $S_{hmin}$, was obtained from a mini-hydraulic fracturing test, the vertical stress, $S_V$, was calculated for the appropriate rock densities, and bounds on the maximum horizontal stress, $S_{Hmax}$, are from local tectonic considerations. (b) Orientation of $S_{hmin}$ from borehole failure and the dip azimuth and dip angle of natural fractures in the stimulation interval at 3000-3500 ft, with dip azimuth indicated by position of dots and dip angle by angle of the tail from horizontal. For comparison, surface normal faults dip approximately 65° in a 310° direction. (c) Variation in the depth distribution of minerals in the stimulation interval (modified from Lutz et al., 2010).

Borehole image logs reveal drilling induced tensile fractures indicating the minimum horizontal principal compressive stress, $S_{hmin}$, is oriented 114 ± 17° (Figure 2). Mapping of natural fractures in these images suggests that numerous fractures in the stimulation interval are optimally oriented for normal faulting, consistent with young normal faults mapped at the surface (Faulds and Garside, 2003). Several of these fractures are associated with slight temperature perturbations that are indicative of their ability to take fluid during hydraulic stimulation, but insufficient to host a natural hydrothermal system. A mini-hydraulic fracturing measurement of the magnitude of $S_{hmin}$ was conducted at the top of the intended stimulation interval and indicates that the magnitude of $S_{hmin}$ is 1995 ±

60 psi, which is ~0.61 of the calculated vertical (overburden) stress at this depth (Figure 2a) (Hickman and Davatzes, 2010). This $S_{hmin}$ magnitude is higher than expected for critically stressed, optimally normal faults assuming a typical range of Byerlee friction (Figure 2a) or the measured friction in representative core samples from a nearby well (Lutz et al., 2010).

However, frictional failure analyses of fractures using the measured fracture orientations (Davartzes and Hickman, 2009), stresses (Hickman and Davatzes, 2010) and coefficients of friction (Lutz et al., 2010) indicate frictional failure should begin at wellhead pressures as low as 200 psi, with a significant fraction of the natural fractures observed in the stimulation interval having sheared by 600 psi wellhead pressure. This is far below the anticipated wellhead pressure for hydrofrac propagation of about 750 psi, as indicated in Figure 2.

A number of observations by Lutz et al. (2010) suggest that rocks within the well 27-15 stimulation interval should be amenable to shear-enhanced stimulation. X-ray computed tomography of triaxially deformed samples of comparable lithology to those in the stimulation interval from a nearby well reveal areas of porosity primarily developed due to dilatation along the slip surface. Scanning electron images overlain on a laser scan of the slip surface topography from these samples reveals discontinuous generation of gouge due to abrasion accompanying fault slip, but confirms that asperities survive to provide the bridging necessary to prop the shear fracture open. In addition, comparison of pre- and post-test permeability suggests an up to twenty-time increase in permeability accompanying fracture formation and slip.

Previous studies in normal faulting and strike-slip faulting stress environments show that shear fracture formation during hydraulic stimulation tends to be aligned in the direction of $S_{Hmax}$, even at injection pressures considerably less than the least principal stress (Willis-Richards et al., 1996; Heffer, 2002; Rahman et al., 2002). Similarly, the microseismic clouds produced during hydraulic stimulation of Soultz-sous-Forêts, France, geothermal wells GPK2, GPK3 and GPK4 at pressures less than the least principal stress were also aligned in the direction of $S_{Hmax}$ (e.g., Schindler et al., 2008; Valley and Evans, 2007). Thus, in the case of well 27-15, we expect the enhanced permeability zone to be created during EGS hydraulic stimulation to grow preferentially parallel to $S_{Hmax}$, in a SSW direction toward nearby injection and production wells, or to the NNE, toward an undeveloped part of the field. This expectation is consistent with tracer tests by Rose et al. (2009), which reveal potential pathways between nearby injectors and the main reservoir to the south, which could be intersected and enhanced by hydraulic stimulation in well 27-15.

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