

## Conditions Required for Shear Stimulation in EGS

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### ABSTRACT

The mechanism of stimulation in Enhanced Geothermal Systems (EGS) is typically assumed to be induced slip on preexisting fractures (Pure Shear Stimulation, PSS). In oil and gas fracturing, the mechanism of stimulation is typically assumed to be opening and propagation of new fractures (Pure Opening Mode, POM). In this paper, we explore the possibility that stimulation in EGS sometimes occurs through a combination of propagation of new fractures and induced slip on preexisting fractures (Mixed-Mechanism Stimulation, MMS). Using a discrete fracture network model that couples fluid flow and fracture deformation in large, complex fracture networks, we show that there are many geological conditions that must be satisfied in order for PSS to be the mechanism of stimulation in the low matrix permeability settings typical for EGS. These conditions are (1) adequate storativity in closed natural fractures, (2) adequate initial transmissivity of natural fractures, (3) percolation of the natural fracture network, (4) natural fractures well oriented to slip in the local stress state, (5) natural fractures that experience enhanced transmissivity with slip, and (6) adequate stimulated transmissivity. These conditions have likely been met in some, but not all, historical EGS projects. We argue that in cases where these conditions are not met, the MMS mechanism is more likely than the PSS mechanism. We summarize some of the arguments that have been used to justify the PSS interpretation, and discuss how these arguments may not hold if the intact rock tensile strength is not negligible. We discuss techniques that might be used to diagnose stimulation mechanism from field data. Stimulation mechanism is discussed in the context of the EGS project at Fenton Hill, USA, and it is shown how evidence is consistent with the idea that substantial fracture opening and propagation occurred

during stimulation at that project. We conclude by discussing implications of stimulation mechanism for EGS modeling and design.

### 1. INTRODUCTION

#### 1.1 Overview

The mechanism of stimulation in Enhanced Geothermal Systems (EGS) is most often assumed to be induced slip on preexisting fractures (we refer to this mechanism as Pure Shear Stimulation, PSS) (Pine and Batchelor, 1984; Murphy and Fehler, 1986; Ito, 2003; Ito and Hayashi, 2003; Evans, 2005; Tester, 2007; Kohl and Mégel, 2007; Bruel, 2007; Dezayes et al., 2010; Cladouhos et al., 2011). During PSS (according to our definition), fracture opening (the walls come out of contact) does not occur, and the fluid pressure remains below the minimum principal stress.

In conventional oil and gas hydraulic fracture modeling, it is typically assumed that stimulation occurs through the opening and propagation of new fractures through the wellbore (we refer to this mechanism as Pure Opening Mode, POM) (Economides and Nolte, 2000; Adachi et al., 2007).

In hydraulic fracture modeling of shale gas stimulation, hybrid mechanisms are often used that assume that both new and preexisting fractures play a role in permeability generation. These hybrid mechanisms can be divided into two groups. If it is believed that propagating new fractures sometimes terminate against natural fractures, then branching networks of both new and preexisting fractures form (we refer to this mechanism as Mixed-Mechanism Stimulation MSS) (Damjanac et al., 2010; Weng et al., 2011; Wu et al., 2012). If it is believed that propagating fractures do not terminate against natural fractures, then a single, large, primary hydraulic fracture forms at each stage, and the primary fracture is surrounded by a region where fluid leaks off into

natural fractures that experience shear stimulation or open (we refer to this mechanism as Primary Fracturing with Shear Stimulation Leakoff, PFSSL) (Warpinski et al., 2001; Palmer et al., 2007; Rogers et al., 2010; Nagel et al., 2011).

In this paper, we explore the possibility that the mechanism of stimulation in many EGS projects may be MMS, not PSS. Using a discrete fracture network model that couples fluid flow with deformation, we show that there are many geological conditions that must be satisfied for PSS to be possible in the low matrix permeability settings typical for EGS. These conditions are (1) adequate storativity in closed natural fractures, (2) adequate initial transmissivity of natural fractures, (3) percolation of the natural fracture network, (4) natural fractures well oriented to slip in the local stress state, (5) natural fractures that experience enhanced transmissivity with slip, and (6) adequate stimulated transmissivity. Because these conditions may not always be satisfied, we do not believe PSS can always be assumed to be the mechanism of stimulation in EGS.

In this paper, Requirements (1), (2), and (3) are demonstrated using modeling. It should be clear, by definition, that Requirements (4) and (5) are needed for shear stimulation. Requirement (6), adequate stimulated transmissivity, was discussed in McClure and Horne (2012).

Practical experience at the recent Desert Peak EGS project demonstrated Requirement 6. Shear stimulation was performed by injecting for a long time at pressure less than the minimum principal stress. Subsequently, hydraulic fracturing (propagation of new fractures through the formation) was performed by injecting at a much higher rate (Benato et al., 2013). The formation permeability (after shear stimulation) was too low at Desert Peak to sustain the high injection rates used during the hydraulic stimulation, causing injection pressure to increase until it was high enough to propagate new fractures through the formation.

Evidence from historical EGS projects (in crystalline rock) shows that flow from the wellbore has almost always occurred from natural fractures, not newly formed fractures. This observation suggests that the POM and the PFSSL mechanisms were not the mechanism of stimulation at these projects.

According to our definition of MMS, it is not necessary to have new fractures form at the wellbore. However, according to our definition of MMS, natural fractures must open, and possibly new fractures may initiate off the natural fractures away from the wellbore and propagate through the formation.

Because PSS cannot occur unless several geological conditions are satisfied, it seems unlikely that PSS can occur in all cases. It seems unlikely that POM and PFSSL frequently occur in EGS (in crystalline rock) because new fractures have not commonly been

observed at the wellbore. Therefore, it seems likely that MMS occurs in some cases.

As discussed below, MMS is consistent with the interpretation of Brown (1989) from the Fenton Hill EGS project (also, Brown et al., 2012, page 74; Aki et al., 1982). At other EGS projects, such as the Soultz project, it appears likely that PSS is the appropriate interpretation (Evans et al., 2005).

In this paper, we summarize arguments made to argue in favor of the PSS mechanism. We discuss how these arguments may not hold if rock tensile strength is not negligible and if propagating tensile fractures sometimes terminate against natural fractures.

Based on the modeling results, methods are discussed that might be used in practice to diagnose whether the stimulation mechanism is PSS or MMS.

We conclude by discussing implications of stimulation mechanism for modeling, design, and analysis of EGS projects.

## 1.2 ARGUMENTS FOR PURE SHEAR STIMULATION

Evidence of the role of preexisting fractures comes from a variety of sources. In this section, we summarize some arguments that have been used to claim that EGS stimulation occurs solely due to induced slip on natural fractures.

In EGS projects in crystalline rock, wellbore observations demonstrate that during and after stimulation, fluid exits from the wellbore from preexisting fractures, not from newly formed tensile fractures. For example, this has been observed at projects in Fenton Hill, New Mexico, USA (Brown, 1989; page 69 of Brown 2012), Rosemanowes, UK (Moore and Pearson, 1989, section 3.4.3), Ogachi, Japan (Ito, 2003), Soultz-sous-Forêts, France (Evans, Genter, and Sausse, 2005; Dezayes et al. 2010), and Cooper Basin, Australia (Baisch et al., 2009).

In strong rock (common in EGS), the tensile strength of the intact rock may be significant enough that new tensile fractures do not form and propagate from the wellbore when the fluid pressure reaches the minimum principal stress. In this case, preexisting fractures (which are much weaker than intact rock) may open and propagate at a lower fluid pressure than would be needed to form new fractures at the wellbore. Brown (1989) argued that this happened at Fenton Hill.

Even though new fractures do not initiate at the wellbore, new fractures may initiate from open natural fractures in the formation away from the wellbore. We would classify such behavior as MMS.

We hypothesize that new fractures could initiate from open natural fractures (even if they do not form at the wellbore) because of the stress concentration that occurs at the transition between where the natural fracture has opened and where the natural fracture

remains closed. An opening natural fracture that is not oriented perpendicular to the minimum principal stress bears shear stress and experiences sliding as fluid pressure increases and eventually causes opening. The sliding may cause a concentration of tensile stress that result in initiation of a new tensile fracture from the fault. This is the process that causes “splay” fractures to form off faults in nature (Mutlu and Pollard, 2008).

Baumgärtner and Zoback (1983) described an experiment that provides an unambiguous example of fluid pressure elevating above the minimum principal stress and causing opening of natural fractures at the wellbore and not formation of new fractures at the wellbore. Packers were used to isolate and hydraulically fracture sections of open hole in crystalline rock. The minimum principal stress was vertical, and the vertical stress could be calculated by integrating the weight of the overburden. During many of the injections, injection pressure became constant with time, indicating fracture opening in the formation. In many of these cases, the fracture propagation pressure was significantly above the minimum principal stress (which was vertical and known with a reasonably high degree of accuracy). After shut-in, closure pressures were identified that were significantly above the minimum principal stress. In these cases, either natural fractures were opened or fractures oriented perpendicular to the minimum horizontal (intermediate principal) stress were formed. These results clearly demonstrate that in settings with hard rock, injection above the minimum principal stress can cause opening of natural fractures instead of formation of new fractures. Brown (1989) described the same process taking place at Fenton Hill. Cornet and Descroches (1990) described this process at Le Mayet.

Murphy and Fehler (1986) observed that the size of the region of microseismicity at the Fenton Hill project was much greater than the relocation uncertainty, indicating a volumetric region of shear stimulation. While it is certainly likely that there was a volumetric region where slip was induced on preexisting fractures, this could have happened whether or not preexisting fractures were opening or new fractures were propagating through the formation.

At Rosemanowes, the seismicity migrated downward from the wellbore during stimulation. Pine and Batchelor (1984) used a stress analysis to show that newly forming fractures should propagate upward, but induced slip on preexisting fractures could lead to downward propagation. Therefore, downward migration appears to be inconsistent with the idea that the natural fractures were opening. On the other hand, perhaps local heterogeneities in fracture density, fracture connectivity, and stress have a bigger effect on propagation than the overall, gradual trend in stress with depth. For example, as discussed later, Brown (1989) argued that natural fractures opened at Fenton Hill, and that anomalous observations of fracture

closure pressure could be explained by heterogeneity in natural fracture orientation, not large discontinuities in stress.

Moment tensor analysis from seismicity at EGS projects has typically indicated dominant shearing mode deformation. However, a lack of significant tensile source mechanisms during stimulation should not be taken as evidence that fracture opening is not taking place. Opening mode deformation tends to occur aseismically (slowly) because fracture extension reduces fracture fluid pressure, inhibiting further extension. Slow deformation is aseismic because the subsurface must move rapidly to cause a seismic event. As a result, tensile events during hydraulic fracturing, if they occur at all, are very low magnitude, high frequency, and difficult to detect. Some modelers have hypothesized about mechanisms that could theoretically cause opening mode seismic events, but these mechanisms require very specialized and have not been clearly verified (Aki et al., 1977; Sammis and Julian, 1987).

## 2. METHODOLOGY

In this section, we demonstrate that there are several geological conditions that must be present for PSS to occur. Simulations were performed using CFRAC, a recently developed simulation tool that fully couples fluid flow with the stresses induced by fracture deformation in large, complex discrete fracture networks (McClure, 2012).

The full details of the computational model are summarized in Chapter 2 of McClure (2012). Darcy's law is assumed in the fractures. Non-linear relationships are used for the relationship between fracture stress, fluid pressure, opening displacement, sliding displacement, fracture transmissivity, and void aperture (Willis-Richards et al, 1996). Sliding leads to an increase of fracture transmissivity. Fractures may be closed (walls in contact) or open (walls out of contact), and appropriate stress boundary conditions are applied depending on this condition. Fractures are allowed to slide or open. Newly forming fractures can form and propagate, but the locations at which these newly forming fractures can form must be specified in advance. The model assumes single phase liquid water (no proppant), isothermal flow in the fractures and zero flow in the matrix around the fractures. Stresses induced by fracture deformation are calculated with the boundary element method assuming homogeneous, isotropic, linear elastic deformation. The simulations are two-dimensional, and should be interpreted as showing vertical fractures sliding horizontally, viewed from above. The Olson (2004) adjustment is used to approximate the effect of a finite formation height on the induced stresses (so that the calculations were pseudo-3D instead of either plane strain or plane stress).

Six conditions were identified as being necessary for PSS to be possible in a low matrix permeability setting (typical for EGS). They are: (1) adequate storativity

in closed natural fractures, (2) adequate initial transmissivity of natural fractures, (3) percolation of the natural fracture network, (4) natural fractures well oriented to slip in the local stress state, (5) natural fractures that experience enhanced transmissivity with slip, and (6) adequate stimulated transmissivity.

To summarize these conditions, PSS requires the formation to be capable of accepting fluid at the specified injection rate without experiencing excessive buildup of pressure. Excessive fluid pressure buildup could cause new fractures to form and propagate through the formation. Alternatively, excessive fluid pressure buildup could cause natural fractures to open (walls come out of contact). If either occurred, then the stimulation mechanism would no longer be PSS. In this discussion, we have assumed that the matrix permeability is very low (typical for EGS) and that the initial fracture transmissivity is very low.

The modeling described in this paper is focused on demonstrating conditions (1), (2), and (3). By definition, it should be obvious that PSS requires the presence of natural fractures that are well oriented to slip (Requirement 4) and that the slip must cause increase in transmissivity (Requirement 5). Furthermore, the transmissivity of the shear stimulated fractures must be high enough to prevent excessive fluid pressure buildup (Requirement 6), a topic discussed in McClure and Horne (2012).

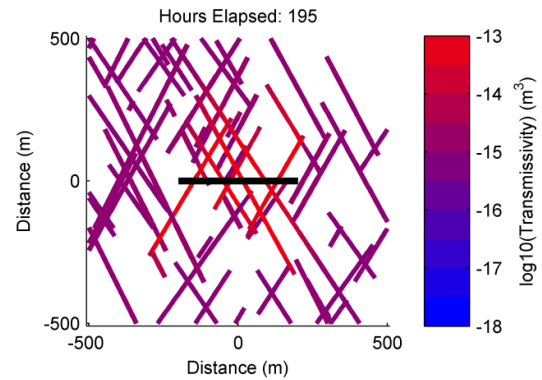
Five simulations were performed. The simulations are described in greater detail in Chapter 3 of McClure (2012). In Simulations A and B, injection was carried out at 30 kg/s, 60 kg/s, and 90 kg/s for one hour each, followed by 24 hours of shut-in, and then several days of producing fluid back from the reservoir. In Simulation C, injection was performed at 30 kg/s for only a few minutes. In Simulations D and E, injection was carried out at a constant pressure, set to be less than the minimum principal stress, for one week. The injection pressure exceeded the least principal stress in only one simulation, Simulation B, and in this simulation a single, linear, newly forming fracture propagated through the formation. All other fractures in the simulations were natural fractures that were assumed to exist at the beginning of the simulations.

Table 1 gives the baseline settings for all simulations, and Table 2 gives the specific settings that varied between the different simulations. The definitions of the variables used in Tables 1 and 2 are given in McClure (2012).

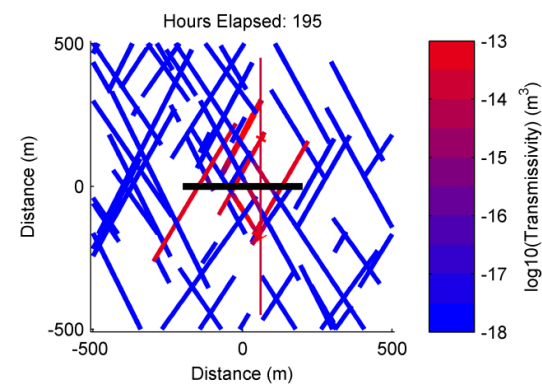
### 3. RESULTS

Figures 1-5 show the final distribution of fracture transmissivities in the fracture networks for Simulations A-E. The thick black lines in the centers of the figures represent the wellbores. Figures 6 and 7 show the injection rates and pressure during and shortly after injection for Simulations A and

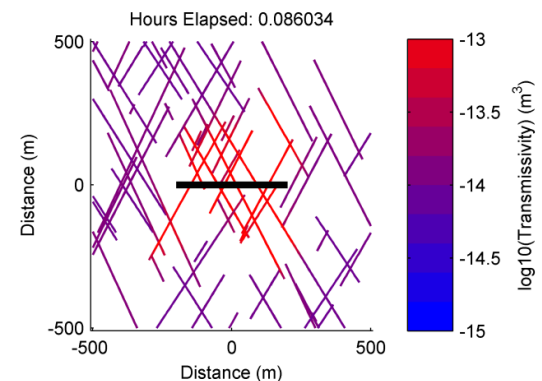
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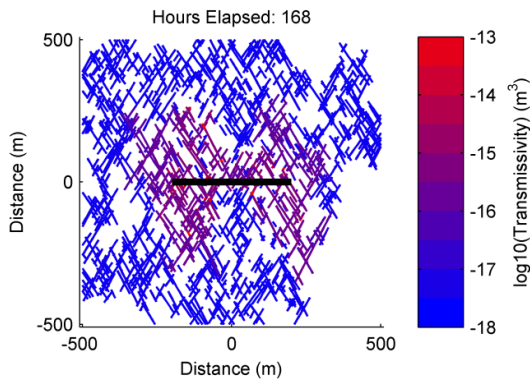
**Figure 1: Final transmissivity distribution for Simulation A.**



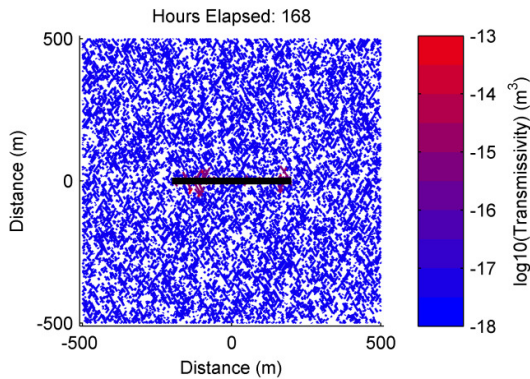
**Figure 2: Final transmissivity distribution for Simulation B.**



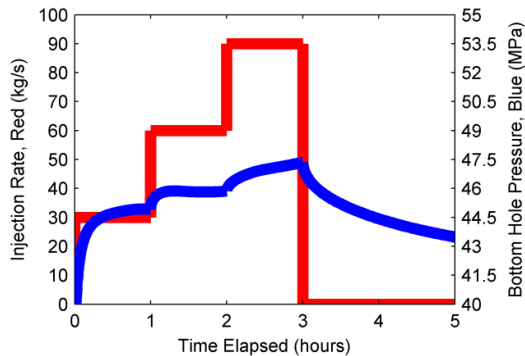
**Figure 3: Final transmissivity distribution for Simulation C.**



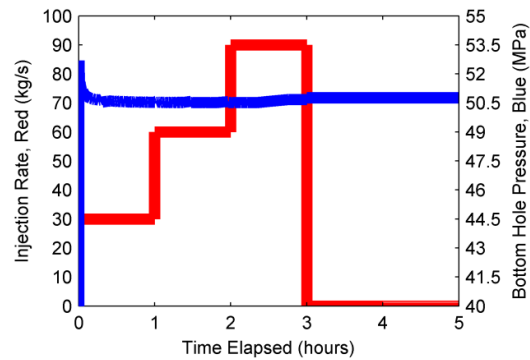
**Figure 4: Final transmissivity distribution for Simulation D.**



**Figure 5: Final transmissivity distribution for Simulation E.**



**Figure 6: Injection pressure and rate for the first five hours of Simulation A.**



**Figure 7: Injection pressure and rate for the first five hours of Simulation B.**

Simulation A had large faults with intermediate initial transmissivity and high storativity. These faults are similar to the large, thick faults described by Genter et al. (2000) at Soultz. Simulation B was identical to Simulation A, except that the initial fracture transmissivity was extremely low. Simulation C was identical to Simulation A except that the fracture storativity was much lower than in Simulation A.

Simulations D and E used somewhat different settings than Simulations A, B, and C. Simulations D and E were identical to each other except for the natural fracture networks. The wellbores in Simulations D and E intersected roughly the same number of natural fractures, and the fractures had similar orientation distributions. Therefore, on the basis of wellbore imaging logs alone, the networks in Simulations D and E would be indistinguishable. The difference was that the network in Simulation D had a smaller number of longer fractures, and Simulation E had a larger number of shorter fractures.

## 4. DISCUSSION

### 4.1 Simulation Results

Simulation A is an example of PSS. The natural fractures remained closed for the entire injection, and Figure 6 shows that the injection pressure never exceeded the minimum principal stress (50 MPa).

Comparison between Simulations A and B demonstrate the importance of adequate fracture transmissivity (Requirement 2).

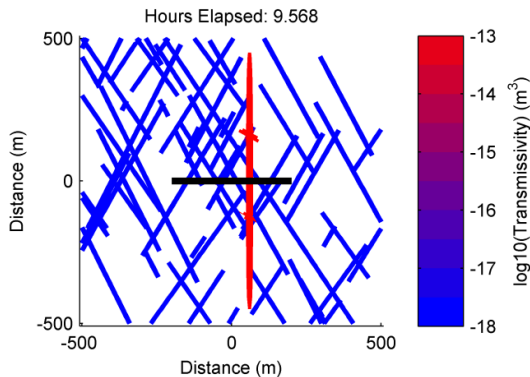
In Simulation B, the initial transmissivity was too low to allow the natural fractures to slip at the beginning of injection. In Section 3.4.2.2 of McClure (2012), a mechanism called “crack-like shear stimulation” (CSS) is described that accounts for the interaction of induced stresses, fluid flow, and transmissivity enhancement and explains how shear stimulation may propagate rapidly down natural fractures at a rate independent of the initial fracture transmissivity. With this mechanism, it could be possible for stimulation to propagate rapidly through a formation, even if the initial transmissivity is very low.



However, the CSS process cannot begin until slip has initiated for the first time on a fault. The initiation of slip depends on fluid flow into the fault at the initial transmissivity.

If the initial transmissivity is too low, fluid pressure will quickly build up at the beginning of injection (carried out at constant rate), causing the formation of a new opening mode fracture before the CSS process has initiated. This is what happened in Simulation B. Figure 7 shows that the injection pressure was above 50 MPa, the minimum principal stress, for the entire duration of the simulation.

Figure 8 shows the distribution of fracture transmissivity after 9.568 hours, more than 6.5 hours after the end of injection. Almost all of the injected fluid went into the newly formed fracture and did not leak off for many hours after the end of injection. After a significant duration of time, fluid was able to seep out into the natural fractures, initiate the CSS process, and allow a significant amount of fluid to leak off into the natural fractures (Figures 2 and 8).



**Figure 8: Transmissivity distribution after 9.568 hours during Simulation B.**

In Simulation A,  $E_0$  (the void aperture of the fracture at zero effective normal stress) was 5 cm. In Simulation C,  $E_0$  was 0.5 mm. As a result, the fractures in Simulation A were capable of storing a much greater amount of fluid than the fractures in Simulation C.

This difference in void aperture was designed to mimic the difference in storativity between cracks and fault zones. At some EGS projects, such as Soultz, flow has been localized into porous, highly fracture fault zones up to 10 m thick (Genter et al., 2000). At other EGS projects, such as Ogachi and Rosemanowes, the natural fractures have been no thicker than cracks, with apertures no greater than a few millimeters (Ito, 2003; Randall et al., 1990; Whittle, 1989; Pearson et al., 1989; Richards et al., 1991; review in Chapter 5 of McClure, 2012). Laboratory experiments of cracks in granite have reported apertures less than one millimeter (Barton et al., 1985; Lee and Cho, 2002; Esaki et al., 1999).

Because the matrix permeability in EGS projects is typically very low and the duration of injection is relatively short, we can assume that only a limited amount of fluid is able to bleed off into the matrix. Therefore, all the injected fluid must be stored in the fracture network. If fracture walls come out of contact, fractures may have quite significant storativity, but if fracture walls remain in contact, the storativity of the fractures is limited by their closed void aperture (as noted by Pearson, 1981). In the case of thick fault zones, the close aperture may be large, but for thin cracks, it could be very small.

Closed fractures may be able to store a large amount of fluid if they are very closely spaced, but in EGS projects, wellbore logs have typically reported that flowing fractures are widely spaced (Richards et al., 1994; Ito and Kaieda, 2002; page 533 of Brown et al., 2012; Miyairi and Sorimachi, 1996; Wyborn et al., 2005; Baria et al., 2004; Evans, Genter, and Sausse, 2005; Dezayes et al., 2010).

Therefore, it is unclear how closed fractures could possibly store the volumes of fluid injected during stimulation (1000's of  $m^3$ ) in cases where only thin cracks are present.

Figure 3 demonstrates the consequences of having fractures with high transmissivity but low storativity. The low storativity caused the hydraulic diffusivity of the fractures to be extremely high (diffusivity is transmissivity divided by storativity). As a result, shear stimulation was able to propagate hundreds of meters from the wellbore in only five minutes. This is clearly an unrealistic behavior that has never occurred at an actual EGS project. If it had ever occurred, it would have been visible as an exceptionally rapid spreading of microseismicity.

This result suggests that in settings with very low matrix permeability and only thin fractures (such as Ogachi and Rosemanowes), it may not be reasonable to assume that all the injected fluid is stored in closed fractures. The alternative is that the injected fluid could be stored in open fractures, but that would imply the MMS mechanism, not PSS.

Comparison between Simulations D and E shows the importance of fracture network percolation. In this context, the term percolation refers to the presence of continuous pathways for flow through the reservoir that pass only through connected fractures. Without percolation, flow over long distances must involve flow in the matrix, which would be a major obstruction if the matrix is very impermeable.

Unfortunately, it is not possible to use wellbore observations alone (such as wellbore imaging logs) to assess unambiguously whether the natural fracture network is percolating. For example, the wellbores in Simulations D and E intersect roughly the same number of fractures with the same orientations. Yet the network in Simulation D percolates, and the network in Simulation E does not.

The consequence of percolation is seen in the spreading of stimulation in Simulations D and E. Injection was performed at constant pressure below the minimum principal stress (and so new fractures could not form). In Simulation D, the stimulation propagated a significant distance from the wellbore because long distance pathways for flow existed through the fracture network. In Simulation E, long distance pathways for flow did not exist (because the network was not percolating), and shear stimulation was isolated to the near wellbore region. In Simulation E, if injection had been performed at constant rate, the injection pressure would have been forced to increase until the minimum principal stress was reached, and a newly forming fracture would have formed and propagated through the formation.

#### 4.2 Fenton Hill as a Possible Example of Mixed-Mechanism Stimulation

A review of the literature on the Fenton Hill EGS project shows that all evidence is consistent with a Mixed-Mechanism hypothesis.

At the Fenton Hill EGS project, there were not thick, high storativity fault zones like at some EGS projects such as Soultz (Genter et al., 2000). Therefore, the Fenton Hill reservoir did not satisfy Requirement (1) for Pure Shear Stimulation, adequate storativity of the natural fracture network. On that basis alone, we might suspect that the stimulation at Fenton Hill was not Pure Shear Stimulation.

Investigators at Fenton Hill were aware that the low storativity of the natural fractures made Pure Shear Stimulation unlikely. According to Pearson (1981), “the speed with which seismicity migrated [during injection] suggests ... some sort of high permeability or low impedance path ... A hydraulic fracture or a network of self-propped shear fractures can easily explain this observation. The connection between the wells is probably a hydraulic fracture opened in tension rather than a large self-propped fracture ... A tensile fracture explains the ability of the reservoir to store large amounts of water better than a shear fracture because the width of a fracture that opens in tension can increase to accommodate increasing volumes of water, while the width of a self-propped shear fracture is largely determined by the size of the mismatched irregularities.”

Albright et al. (1980) noted that selective attenuation of shear waves occurred when fluid pressure exceeded the minimum principal stress, apparently indicating that fractures were opening. Aki et al. (1982) described a variety of active and passive seismic experiments carried out at Fenton Hill. They concluded that the reservoir consisted of discrete, open, planar vertical cracks. Based on the attenuation, they proposed that there were multiple vertical cracks with spacing of a few meters. Years later, experiments were carried out in the oil and gas industry where wells were cored across regions of hydraulic fracturing. In these experiments, multiple

stranded, closely spaced fractures were typically encountered, just as Aki et al. (1982) suggested was present at Fenton Hill (Warpinski et al., 1993; Fast et al., 1994; Hopkins et al., 1998).

House et al. (1985) found that first motions were consistent with shear slippage and not tensile fracturing. However, this does not prove that tensile fracturing did not occur, because tensile fracturing does not typically cause seismicity.

Therefore, there is good evidence that fracture “opening” occurred at Fenton Hill. There are two important remaining questions – (1) were the open fractures in the formation newly formed or were they jacked open natural fractures and (2) if there were propagating fractures, did they initiate at the wellbore?

Ideally, high quality wellbore imaging logs would have been run in the wells before and after stimulation (as was done at Soultz, for example, Evans et al., 2005). This would at least verify whether new fractures were observed at the wellbore, but would not prove whether or not new fractures formed away from the wellbore (which could only be proven unambiguously by coring through microseismic cloud, see Warpinski et al., 1993; Fast et al., 1994; Hopkins et al., 1998). Unfortunately, televiewer technology of the time was rather low quality, and difficult to interpret (Burns, 1986), and so such data is only partially available. Coring was occasionally performed for limited distances – around 3 m – but this was sporadic and less common in the deeper parts of the reservoir (page 60 of Brown et al., 2012).

Despite these challenges in data collection, Brown et al. (2012) argued opening of natural fractures – not creation of new fractures occurred in the Fenton Hill reservoir: “Via the injection well, fluid pressure is used to open a multiply interconnected array of pre-existing but resealed joints within the rock mass” (page 30 of Brown et al., 2012) and “in all ... injection tests involving pressurization of a significant interval of borehole, it would be found that the applied hydraulic pressure was opening existing joints rather than fracturing unflawed rock” (page 69, Brown et al., 2012). In our opinion, without direct observation (using a wellbore imaging log) of the wellbore before and after stimulation, this statement by Brown et al. (2012) cannot be confirmed unambiguously. However, Brown (1989) and Brown et al. (2012) provided evidence that opening of joints, not formation of new fractures occurred in at least some cases (at the wellbore), and we summarize here.

During minifrac and other injection tests at Fenton Hill, fracture “breakdown” was not observed (Kelkar et al., 1986; pages 15 and 67 of Brown et al., 2012). This is cited as evidence that preexisting fractures were opened by injection rather than creation of new fractures. Impression packers used to isolate the zones of injection showed evidence of natural joints that had opened, but no evidence of newly formed fractures at the wellbore (pages 14, 68-70 of Brown et al., 2012).

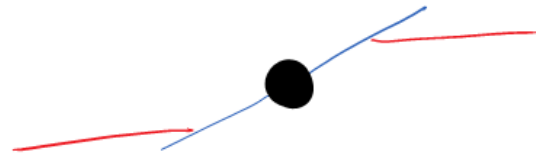
Brown (1989) noted that at depths below 3230 m, estimates of ISIP or closure pressure (Kelkar et al., 1986) were in the range of 30 MPa above hydrostatic, but in the depth range of 2900-3230 m, tests indicated ISIP or closure pressure closer to 10 MPa above hydrostatic. The original stress profile of Kelkar et al. (1986) assumed that these closure pressures and ISIPs represented the minimum principal stress and suggested that there was a large discontinuity in minimum principal stress around 3230 m. Brown (1989) proposed that the lower values were truly representative of the minimum principal stress. Brown (1989) argued that the pressure required to form a new fracture at the wellbore was high and that injection was causing opening of natural fractures rather than creation of new fractures. According to that argument, the ISIP and closure pressure measured at the wellbore were equal to the normal stress of whichever natural fractures happened to intersect the wellbore in that interval. Brown (1989) argued that the discontinuity at 3230 m was in fracture orientation rather than stress value: above 3230 m, there were subvertical natural fractures oriented nearly perpendicular to the minimum principal stress, but below that depth, there were only natural fractures oriented at an angle to the minimum principal stress. This is the mechanism that caused the observations of Baumgärtner and Zoback (1983), as discussed above.

According to the proposed stress profile of Brown (1989), the ratio of vertical to minimum horizontal principal stress would be nearly 2.0, a rather large value that would require a coefficient of friction around 0.9 to allow frictional stability at hydrostatic pressure. This value may seem high, but similar ratios of maximum and minimum principal stress have been estimated at other EGS projects in deep granite (Pine and Batchelor, 1984; Evans, 2005).

A rather unique experiment described on pages 74-75 of Brown et al. (2012) supports the idea that natural fractures were being opened at the wellbore at Fenton Hill. On several occasions, minifrac experiments had been performed, where a relatively small volume of water was injected into a short section of open hole isolated between packers. In each case, a breakdown pressure was not observed, but injection pressure abruptly leveled out at a particular pressure, apparently indicating fracture opening. Open flow-back, it was observed that less than half the injected fluid was recovered. Three theories were offered: (1) fluid leaked off into the granite matrix around the fractures (though it was known to have very low permeability), (2) fluid leaked off into some permeable fractures in the formation (though it was known the bulk permeability of the formation was very low), or (3) that the part of the fracture near the wellbore was preferentially closing, hydraulically isolating the rest of the open fracture from the wellbore.

Figure 9 shows how preferential fracture closing near the wellbore could be explained by the opening of a

natural fracture, and then the subsequent formation and propagation of a newly formed fracture. The black dot is the wellbore. The blue line is an open natural fracture, and the red line is a newly forming fracture.



**Figure 9: Schematic of a natural fracture (blue) opening with newly forming fractures (red) propagating away from it.**

The new fractures form perpendicular to the minimum principal stress. The natural fracture closes at a higher fluid pressure than the newly formed fracture. Therefore, the natural fracture could close, hydraulically isolating the fluid in the (still open) new fractures from the wellbore.

To distinguish between the competing hypotheses, the investigators at Fenton Hill performed injection into one of the zones using a viscous gel and sand proppant (page 74 of Brown et al., 2012). With subsequent venting, 98% of the injected fluid was recovered. This result confirms the third theory- that the joints were “snapping shut” near the wellbore. The proppant held the fracture open near the wellbore, preventing closure.

Without reliable results from wellbore imaging logs (which are not available), we do not feel that we can unambiguously confirm the hypothesis of Brown (1989) that the discontinuity in ISIP and closure pressure corresponded with a discontinuity in fracture orientation and was caused by opening of natural fractures, not creation of new fractures. However, several lines of evidence given by Brown et al. (2012) and Brown (1989) suggest that this is the best interpretation.

#### 4.3 Diagnosis of Stimulation Mechanism

Techniques are needed that can be used to diagnose stimulation mechanism in the field, particularly to distinguish between MMS and PSS. A full discussion of this issue is found in Chapter 3 of McClure (2012).

A major distinguishing factor between MMS and PSS is whether the injection pressure reaches the minimum principal stress. If the downhole fluid pressure reaches or exceeds the minimum principal stress, then fracture opening is likely to occur, and new fractures may propagate through the formation (even if new fractures are not observed at the wellbore). If the natural fracture network contains only crack-like fractures with low storativity, then it is likely that the formation does not have the storativity to contain all the injected fluid without opening. In this case, MMS is likely to occur. In the case of low storativity cracks,



it is theoretically possible that the fluid pressure could remain at or above the minimum principal stress after shut-in (which is what happened in Simulation B). \

These methods require that the minimum principal stress is known with good precision. Unfortunately, estimating the least principal stress is more challenging in very low permeability matrix settings. For example, the primary assumption of a leakoff test, that fluid will leak off from newly formed fractures into the formation, is not valid in very low matrix permeability. Simulation B demonstrates that pressure may remain above the minimum principal stress after shut-in if leakoff into the formation is limited. Observing pressure while producing fluid back after shut-in could be more diagnostic. If fractures are open in the formation, they may close during production, which may cause relatively discrete discontinuities in the derivative of the pressure decline.

Section 3.4.7 of McClure (2012) contains additional discussion of the difficulties in estimating the least principal stress in low matrix permeability settings.

The best way to diagnose stimulation mechanism would be to core a well through the stimulated region of another well that was previously stimulated. This would allow it to be unambiguously determined whether new fractures were forming in the formation. This would be expensive, but not without precedent. Such experiments have been performed for hydraulic fracturing for oil and gas (Warpinski et al., 1993; Fast et al., 1994; Hopkins et al., 1998; Mahrer, 1999). A main result from these studies has been that newly created fracture networks are much more complex than had been previously believed (Mahrer, 1999).

#### 4.4 Consequences of Stimulation Mechanism

Computational models of stimulation in EGS are typically designed with the stimulation mechanism assumed in advance. It is critical to determine the stimulation mechanism in order to confirm the usefulness of these models. The process of matching field data is non-unique, especially when very complex models are used. It could be possible to build a model with a completely incorrect assumption about stimulation mechanism and nevertheless match field data. This danger underscores the critical importance of correctly diagnosing and understanding stimulation mechanism.

It is possible that one stimulation mechanism or another has properties that are more favorable for economic EGS development. It is likely that the optimal stimulation design is different depending on the stimulation mechanism. Perhaps different mechanisms may have relative advantages and disadvantages, and it may not be obvious which mechanism is ideal for EGS development. Understanding these issues could lead to significant improvement in EGS stimulation design. If a project is intended to exploit a particular stimulation mechanism, it could be intentionally located in a place

that has the geological conditions that are favorable for that mechanism.

## 5. CONCLUSION

Most EGS models assume that stimulation occurs primarily from induced slip on preexisting fractures (Pure Shear Stimulation, PSS). In this paper, we argue that in some EGS projects, stimulation may occur through a mixture of opening and sliding of preexisting fractures and propagation of new fractures (Mixed-Mechanism Stimulation, MMS).

It was demonstrated that there are several geological conditions that must be satisfied for PSS to be possible in a particular formation. These conditions cannot always be assumed to be present. Therefore, in many cases, the stimulation mechanism may not be PSS. PSS is more likely in geological settings with thick, spatially extensive preexisting faults that are well oriented for slip and have the ability to experience enhanced transmissivity from slip (for example, at Soultz). MMS is more likely in geological settings with thin, smaller (less likely to percolate) fractures, especially if they are mineralized shut and have low initial transmissivity (examples are Rosemanowes and Ogachi).

The most common justification for the PSS mechanism is that newly formed fractures are not typically observed at the wellbore in EGS projects in crystalline rock. However, if intact rock tensile strength is not negligible, then the fluid pressure may exceed the minimum principal stress and cause opening of preexisting natural fractures without initiating a new fracture at the wellbore.

Stimulation mechanism has important consequences for EGS modeling and design. Stimulation mechanism is one of the fundamental assumptions of a stimulation model. Optimal stimulation designs might be tailored for stimulation mechanism. If it was determined that a particular stimulation mechanism was more favorable for economic deployment of EGS, projects could intentionally be developed in settings with geological conditions that encourage that mechanism.

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## TABLES

**TABLE 1: SIMULATION PARAMETERS USED IN SIMULATIONS A-E. VARIABLE DEFINITIONS ARE GIVEN IN MCCLURE (2012).**

$h$	$100\text{ m}$
$G$	$15\text{ GPa}$
$\nu_p$	$0.25$
$\eta_{\text{targ}}$	$0.5\text{ MPa}$
$S_0$	$0.5\text{ MPa}$
$S_{0,\text{open}}$	$0.5\text{ MPa}$
$K_{hf}$	$0.01\text{ MPa}^{-1}$
$K_{l,\text{crit}}$	$1.0\text{ MPa}\cdot\text{m}^{1/2}$
$K_{l,\text{crit}hf}$	$3.0\text{ MPa}\cdot\text{m}^{1/2}$
$P_{\text{init}}$	$35\text{ MPa}$
$\sigma_{xx}$	$50\text{ MPa}$
$\sigma_{xy}$	$0$
$\sigma_{yy}$	$75\text{ MPa}$
$mechtol$	$.003\text{ MPa}$
$itertol$	$0.01\text{ MPa}$
<i>Pseudo-3D adjustment (Olson, 2004)</i>	<i>Used</i>
$\eta$	$3\text{ MPa}/(\text{m/s})$
$\mu_f$	$0.6$
$\sigma_{n,\text{Eref}}$	$20\text{ MPa}$
$\sigma_{n,\text{eref}}$	$20\text{ MPa}$
$\phi_{\text{Edil}}$	$0^\circ$
$\phi_{\text{edil}}$	$2.5^\circ$
$T_{hf,\text{fac}}$	$10^{-9}\text{ m}^2$
<i>Strain Penalty</i>	<i>Not used</i>

<i>Method</i>	
<i>cstress</i>	<i>Turned off</i>
<i>Adaptive domain adjustment</i>	<i>Not used</i>
<i>BEM method</i>	<i>Hmmvp</i>
$\epsilon_{\text{tol}}$	$10^{-6}$
<i>Transmissivity updating</i>	<i>Implicit</i>
<i>Friction</i>	<i>Constant coefficient of friction</i>

**Table 2: Specific differences between Simulations A-E. Variable definitions are given in McClure (2012).**

	A	B	C	D	E
$E_0$	$5\text{ cm}$	$5\text{ cm}$	$0.5\text{ mm}$	$0.2\text{ mm}$	$0.2\text{ mm}$
$e_0$	$0.2\text{ mm}$	$0.01\text{ mm}$	$0.5\text{ mm}$	$0.03\text{ mm}$	$0.03\text{ mm}$
$D_{e,\text{eff},m_{ax}}$	$2\text{ cm}$	$2\text{ cm}$	$2\text{ cm}$	$1\text{ mm}$	$1\text{ mm}$