

Fracture Caging to Control Induced Seismicity with Inspiration from the EGS Collab Project

Luke P. Frash¹, Jesse C. Hampton², Marte S. Gutierrez³, and The EGS Collab Team⁴

¹Los Alamos National Laboratory, PO Box 1663, Los Alamos, NM, 87545

²University of Wisconsin – Madison, Madison, WI

³Colorado School of Mines, Golden, CO

⁴Multiple affiliations

lfrash@lanl.gov

Keywords: Earthquake Control, Enhanced Geothermal Systems, Public Safety

ABSTRACT

In 2018, we introduced the concept of ‘fracture caging’ at the Stanford Geothermal Workshop. The concept involves drilling intelligent patterns of production wells around injection wells to improve EGS reservoir efficiency and to limit out-of-zone fracture growth. Experiments and modelling that validated this concept were inspired during the design phase of the eight-well EGS Collab Experiment 1 site at the Sanford Underground Research Facility (SURF). Recently, we discovered evidence that fracture caging could also offer a means to control earthquakes that would otherwise be caused by injection induced seismicity. Field examples of this effect from Hijiori, Pohang, and numerous injection dominated sites as well as laboratory examples from large block hydraulic stimulation and fluid circulation studies are presented. In this paper, we propose a mechanism linking fracture caging and reduced seismic risk and we elaborate on the potential of this mechanism to enable direct control of the risk of earthquakes generated by EGS sites. Scaled to large arrays of wells, this method appears to become increasingly feasible. While this fracture caging concept is relatively new, with sufficiently convincing validation, ‘fracture caging’ could help prevent the damaging induced seismic events from geothermal energy projects.

1. INTRODUCTION

Faults and fractures in the subsurface can provide high conductivity fluid pathways that could unlock deep unconventional geothermal resources for energy production (Tester et al., 2006). The current top candidate technology for electrical energy production from unconventional hot rock geothermal resources is commonly referred to as Enhanced Geothermal Systems (EGS; Brown et al., 2012; Hamm et al., 2019). At its core, this method relies on drilling both injection and production wells such that water can be supplied to the reservoir, heated in the subsurface, and then this harvested heat can be converted into electricity at a power plant on the surface. When combined with high-pressure fluid injection for fracture stimulation, this method could enable the creation of engineered productive reservoirs where the natural geothermal resources would otherwise exhibit insufficient natural water recharge or insufficient permeability for economic electrical energy production.

A key challenge facing EGS development is the risk of induced seismicity (Ellsworth, 2013; Giardini, 2009). In 2017, an injection induced Mw 5.4 earthquake at a geothermal energy plant struck Pohang (South Korea) causing an estimated \$52M of damage to the city and resulting in the shutdown of what could have been a 6.2 MW clean energy facility (Kim et al. 2018). Similar high profile events have caused disruption and/or damage in Alberta, Colorado, Landau, Basel, and Oklahoma (Evans, 1966; Kulish & Glanz, 2009; Hincks et al., 2018). Clearly, there is a need to address this risk of induced seismicity before the fear of earthquakes stops future geothermal energy development and this clean energy resource goes untapped while society heads towards a low-carbon future.

Current methods intended to reduce the risk of induced seismicity include detailed site investigations during site selection, advanced injection control strategies, and the rural placement of geothermal facilities where induced seismicity poses lesser risk to public safety and infrastructure. Site investigations are the first step in developing a geothermal energy resource. They are a crucial step for technical, social, and economic reasons. However, the inherent detection limitations and can fail to identify critical fault lineaments near the zone of injection (NRC, 1996) and the in-situ stress measurements for evaluating seismic slip tendency are prone to interpretation ambiguity and uncertainty (ASTM D4645, 2008). These types of deficiencies are linked to the first-ever documented case of induced seismicity at the Rocky Mountain Arsenal (Evans, 1966) and have also been attributed to some of the recent seismicity in Oklahoma (Keranen et al., 2013). The most common injection control strategy to manage induced seismicity risk is colloquially referred to as the ‘traffic light’ protocol (Ellsworth, 2013; Meier et al., 2015). This protocol is a set of pre-determined criteria that detail conditions required to continue injection (‘green’ condition), slow injection (‘yellow’), or stop/reverse injection (‘red’). The criteria typically include threshold limits of injection pressures and rates, seismic event counts, and maximum allowable event magnitudes. All of these traffic light protocol criteria are fundamentally reactionary and therefore offer no guarantee of preventing large seismic events. Instead, they are risk assessment based criteria decided using statistical analysis. Newer and more advanced injection control strategies for seismic mitigation methods include cyclic soft stimulation and limits on total injected volumes using empirical relationships between seismic event magnitudes and injected volume (Hofmann et al., 2018; McGarr, 2014). It is perhaps relevant to note that the current best-practices for mitigating induced seismicity were used during stimulation of the geothermal well in Pohang (South Korea) when the damaging Mw 5.4 earthquake was induced (Fig. 2) (Grigoli et al., 2018; Kim et al. 2018). If possible, direct control methods could be preferable over the statistical risk assessment and risk based control methods detailed thus far.

We submit that the new method of ‘fracture caging’ (Figure 1) could be used to directly control the maximum magnitude of seismic events induced at geothermal energy sites. This method entails drilling production wells so as to encage high-pressure fluids from injection wells within a targeted volume of naturally fractured or to be hydraulically fractured rock. For successful implementation, the pattern of wells for this cage can be designed to ensure that pressurized fractures from the injection well will intercept one or more of the production wells. These well intersections with fractures enable control of fluid flow through the reservoir that accounts for the discrete and localized nature of the fractures. With the production wells maintained at or below the in-situ reservoir pore pressure, these wells can act to inhibit hydraulic stimulation of out-of-zone fractures while also aiding management of the net pressure in the rock to better stabilize fractures and faults against seismic slip. In effect, this method builds on well-established conventional reservoir pressure management methods in a way that also takes into account the localized and highly conductive fractures that are so crucial to unconventional reservoir flow. Mechanisms for fracture caging to control maximum seismic magnitude are proposed with more detail in this paper.

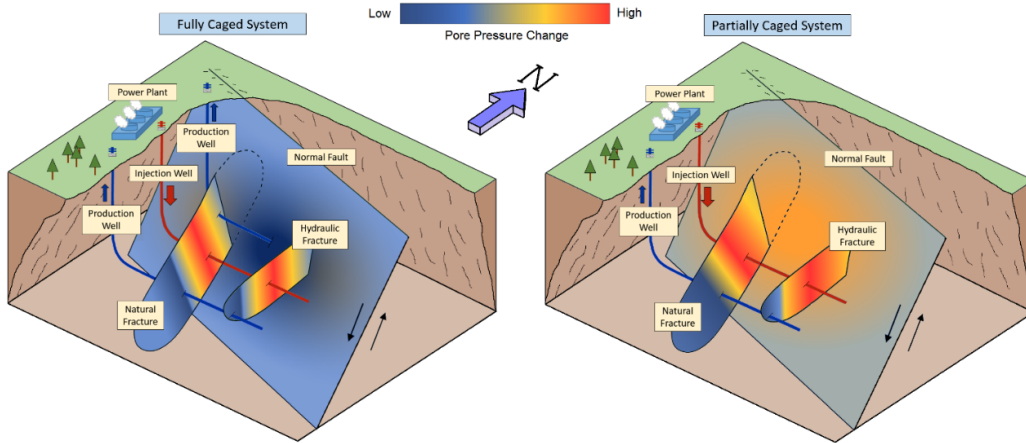


Figure 1: Fracture caging in an EGS application. If there is only one production well, the system is not fully caged and the nearby fault is at risk of seismic slip due to pressurization by injection. The addition of one more production well to the north of the injection well helps prevent over pressurization and stabilizes the fault and natural fractures against seismic slip.

As a newly proposed method, fracture caging is not currently considered in seismic risk and fracture fluid flow management strategies (Frash et al., 2018b). Our prior work demonstrated that four pre-drilled production wells around an injection well can halt propagation of a hydraulic fracture and can contain injected fluids within a targeted volume of rock (Frash et al., 2018a). This work also identified that fracture caging could be optimized to reduce the required number of production wells using statistical design or machine learning to make the method more successful (Frash et al., 2019a,b). In this study, we analyze past experiments across multiple scales that share some elements with the proposed fracture caging method. This analysis reveals that both seismic event magnitudes and the number of triggered seismic events can be limited when injection wells and adjacent production wells are simultaneously operated. However, this study also identifies a need for new models and experiments that are conducted with the intent of fracture caging to prove this new hypothesis and to address potential issues with scale-up or complex natural systems with leaky boundaries. In the following, we describe our data analysis methods and propose a mechanism for linking fracture caging and reduced seismicity. We also discuss upscaling potential.

2. METHODOLOGY

To investigate possible links between induced seismicity and caged fracture systems, we re-analyzed available data from laboratory and field experiments. A key basis for this analysis is derived from the work of McGarr (2014), Schultz et al. (2018), and Galis et al (2017) which indicated that cumulative injected volume shares a link with maximum induced earthquake magnitudes. In this study, we approximate the relationship proposed for maximum seismic event magnitude (M_o) as a function of cumulative injected volume (V_{inj}) from McGarr as:

$$M_o(\text{N-m}) = 3.0 \times 10^{10}(\text{Pa}) \times V_{inj}(\text{m}^3) \quad (1)$$

Along with presenting this function, we also acknowledge that this relationship is not the only, nor necessarily the best, for relating these two parameters. For example, Kim et al. (2018) noted that McGarr’s relationship under-predicts the earthquake magnitude that was observed at 5.4 Mw (1.41×10^{17} N-m) for Pohang, Korea. Also, there is the question of how to apply this relationship when fluid production is ongoing adjacent to the injection. In this case, one could use the net volume from the injected volume less the produced volume with the intention of accounting for the recovery of some fraction of the injected fluid. However, induced seismicity has also been observed when the injection and production volumes are equal, such as at Soultz-sous-Forêts (Cuenot et al., 2011). This observation at Soultz is an indicator that the net volume can be misrepresentative because additional corrections may be necessary to account for produced in-situ fluids separately from injected fluids and/or thermal effects. In other words, produced fluids can have a sources other than adjacent injection wells and the injection wells can therefore inject fluids out of a targeted zone even when the net

volume is zero or negative. In the case of Soutz, water chemistry and tracer analysis indicated that ~65% of the injected fluid volume was not being recovered by the production wells (Schill et al., 2017). High quality tracer data that can characterize this recovery behavior and quantify its change over time is atypical. In this study, we elect to present seismic data as a function of cumulative injected volume without attempting to correct for produced fluid volume. As it was, this parameter alone posed some challenges because measuring this parameter was not a goal in the prior experiments so unreported injections, sensor errors, and lost data all accumulate error in the cumulative injected volume.

At the EGS Collab project site (Kneafsey et al., 2019) at Sanford Underground Research Facility (SURF) in Lead, SD, a multi-well flow experiment is ongoing where high-resolution tracer, temperature, and microseismic monitoring is being conducted (Figure 2). This project which includes one injection well and concurrent produced fluid flow monitoring from seven adjacent wells was the inspiration for the exploring concept of ‘fracture caging’ and conducting the work in this study. As an ongoing project, the complete seismic data set is not yet available for presentation in this study. That said, qualitative observations from the microseismic monitoring system and flow monitoring during long-term circulation tests have indicated that a caged fracture system is likely to have been created in this experiment. This is evident in one part from reductions in the rates of seismicity over long term injection-production tests with respect to the initial stimulations and in another part by the long-term recovery of >90% of the injected fluid, both parts strongly indicate that the system is caged. We aim to report these results in greater detail via future publications.

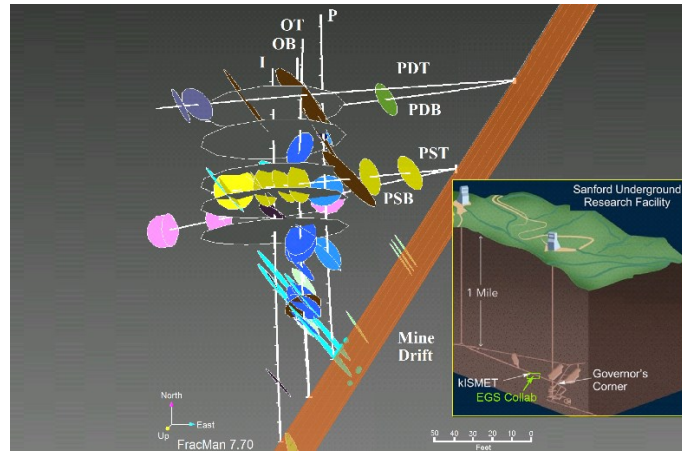


Figure 2: EGS Collab Project Experiment 1 test bed at SURF containing fracture flow within a network of eight wells. These include two wells that have been operated either an injector or producer at some point in time (I and P) and six other instrumented wells from which fluid flow is being recorded (OT, OB, PDT, PST, PDB, and PSB).

Laboratory data for multi-well hydraulic fracturing and fluid circulation experiments was derived from our prior work. This work, conducted at Colorado School of Mines from 2010 to 2014, used a custom heated true-triaxial apparatus that included a real-time microseismic monitoring system (Figure 3). This equipment was used to hydraulically fracture and flow fluids through specimens of granite, shale, and concrete that contained one or more wells. The specimens for these experiments measured 300 mm × 300 mm × 300 mm and the wellbores were nominally 5.6 to 10 mm diameter with lengths of 150 to 270 mm. Maximum applied stresses were up to 13.3 MPa with independent control along the x , y , and z axes. Boreholes were drilled under active confinement stresses and at heated conditions, when heat was applied, using an orientable drill press that could drill through the steel walls of the apparatus.

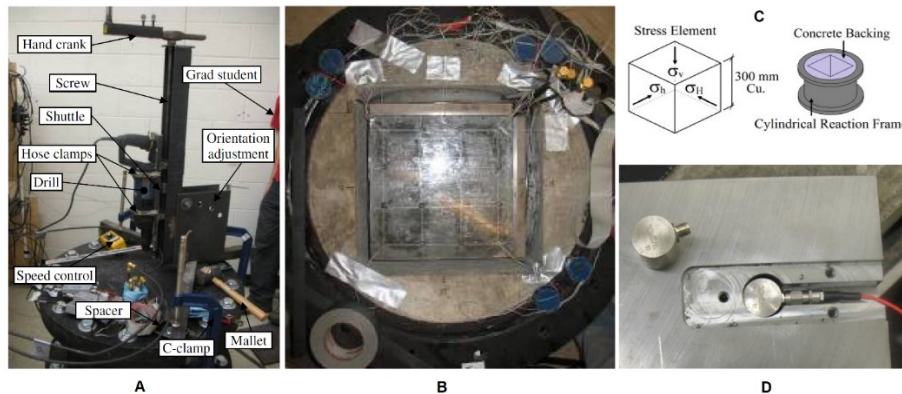


Figure 3: True triaxial apparatus having the ability to (A) drill boreholes at any location and any orientation under confined stress conditions, (B) record microseismic and electrical self-potential voltage fields, (C) independently control vertical, minimum horizontal, and maximum horizontal stresses, and (D) optimally position acoustic sensors for quality microseismic data.

Relevant to this study, these laboratory experiments recorded micro-seismic event magnitudes and event counts and then subsequently mapped hydraulically stimulated fractures after the experiment was complete (e.g., Figure 4b). One experiment using this true-triaxial apparatus was conducted in cement for which a five-well fracture caging well design was implemented (Frash et al., 2018a). This experiment was successfully able to contain the injected fluid within the borehole cage as indicated by >90% recovery of injected fluids from an otherwise dry rock. However, two unreliable acoustic sensors caused the recorded microseismic data for this particular experiment to be unreliable for this study. A separate unconfined acrylic block experiment with a five-well fracture cage was also completed without microseismic monitoring (Figure 4a). This acrylic experiment demonstrated that a cage can halt the propagation of a high-pressure hydraulic fracture but did not include microseismic monitoring (Frash et al., 2018b). Earlier, five granite experiments provided experiment microseismic data for hydraulic stimulation and fluid circulation with systems having one or more well (Frash et al., 2015a,b; 2019b). These experiments provided paired cumulative injected volume and microseismic data that is now relevant to investigating fracture caging. However, tracer studies were not conducted and the borehole geometries in these experiments were not designed for fracture caging. Despite this, the limited extent of these laboratory specimens at 300 mm size and the drained outer boundary of these specimens causes these examples to be ‘perfectly caged’ with respect to a contained seismically active volume of rock. Our subsequent analysis here focuses on the experiments having microseismic data.

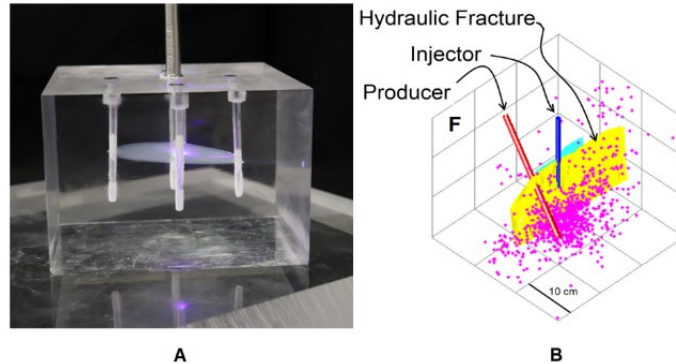


Figure 4: Laboratory examples of fracture caging. (A) Four production wells encaging an injection well was able to halt hydraulic fracture propagation through acrylic. (B) A production well to the left of the injection well was able to hinder hydraulic fracture growth in its direction while the same fracture propagated to the edge of the specimen in the opposite direction.

Field data from reports on the Hot Dry Rock Geothermal Power Project in Hijiori, Japan (GERD, 1989, 1991, 1993, 1994, 1995, 1996, & 1997) was also available for our analysis, courtesy of Norio Yanagisawa (e.g., Figure 5). This field project included injection with concurrent production using as many as four wells (SKG-2, HDR-1, HDR-2a, and HDR-3) at depths up to 2300 m. To analyze this data, we estimated the cumulative injected volume for the site over the years from 1989 to 1996 and paired this data with available microseismic event counts and magnitudes. With particular relevance to fracture caging, there was one notable experiment during the 1991 circulation tests that was referred to as an “(acoustic emission) AE promotion test”. This experiment was motivated by concern that the microseismic monitoring system had failed because of a lack of recorded seismic events despite significant injected volumes. In this test, the injection rate was increased by a factor of three in a successful attempt to stimulate fresh new microseismic events. This particular test is significant because concurrent injection and production was part of the 1991 circulation tests and the recovery rate for injected fluid hit its peak during this time at ~77%. This high injected fluid recovery and the low seismicity even with the large injected volumes is a likely indicator of a caged fracture system, or at least a partially caged fracture system.

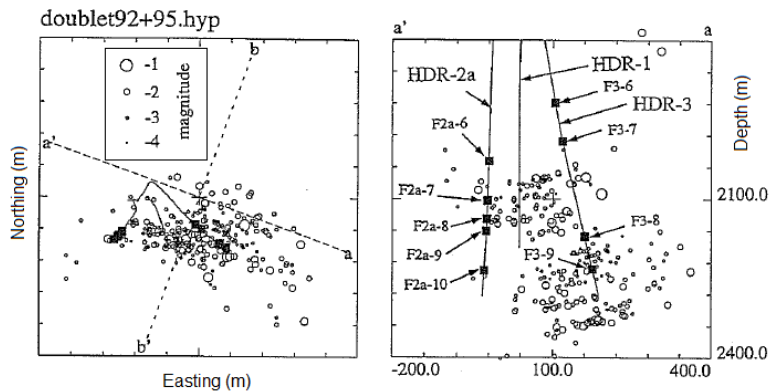


Figure 5: Microseismic data from Hijiori Hot Dry Rock Geothermal Project (GERD, 1996) showing data from the 1995 circulation experiment at 2200 m depth. Water was injected into HDR-1 at up to 57 kg/s and produced from HDR-3 and

HDR-2a. This system is partially caged as evident from the production wells recovering only ~16% to ~77% of the injected fluid during multi-well circulation tests. Full caging could perhaps aim for >90% recovery.

3. FRACTURE CAGING MECHANISM

In the introduction and methods sections, we presented some statements pertaining to the mechanism by which fracture caging can limit induced seismicity. Here we now directly focus on our proposed mechanism for this process that draws from three key phenomena.

First, we call on Mohr-Coulomb shear slip theory which is ubiquitous for interface, fracture, and fault slip analysis. We also acknowledge that other, perhaps better, friction models are available, such as rate-state friction parameters, but the principle of interest here is that changing the pore pressure in a fracture that is subject to in-situ shear stress can destabilize the fracture and cause it to slip (Figure 6). This slip event could be directly caused by pressure increase and the resulting effective stress decrease (Ellsworth, 2013), as illustrated, or by pressure decrease changing local stresses via poro-mechanical interactions (Grasso and Wittlinger, 1990; Segall et al., 1994). Thus, a good target for preventing uncontained slip could be to minimize the volume of fractured seismogenic rock that is subjected to pore pressure change from injection and production activities.

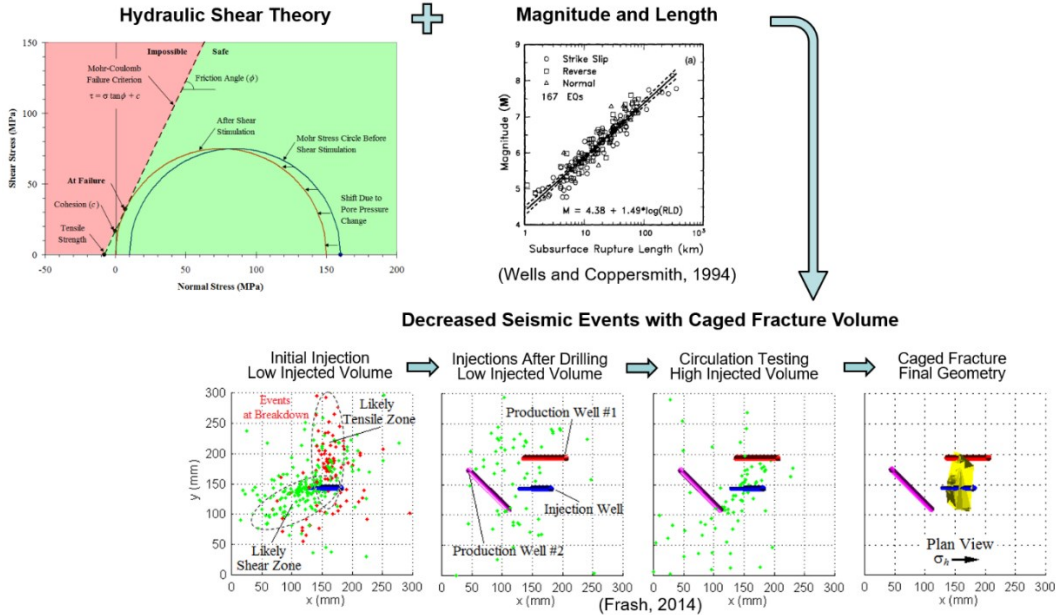


Figure 6: Shear failure can cause slip on natural fractures when the pore pressure in a fractured rock is altered by geothermal water injection and production. If these slip events are large enough, they can create felt earthquakes or even damaging earthquakes. However, in caged systems, the pressurized length of fractures can be limited by design and thereby the maximum number and magnitude of induced earthquakes can be reduced, even if significant volumes of fluid are injected.

Second, Galis et al. (2017) presented useful insight regarding slip being constrained to limited portions of large fractures when pore pressure changes are limited in extent. By extension, if the lengths or areas of fractures that are subjected to pressure alteration from injection or production is limited by strategically placed wells, then it is reasonable to expect that the slip lengths would also be limited.

Third, strong empirical evidence is available that links earthquake magnitude (Wells and Coppersmith, 1994) to subsurface rupture length (i.e., slip length). Therefore, limiting slip lengths and shear displacement magnitudes would also limit the maximum induced seismic event magnitudes. By a similar notion, there exists a maximum amount of shear displacement that can be incurred for a fracture of a fixed length (Schultz et al., 2008). Thus, once the local segments slip, the potential for future seismicity from these segments will decrease. This would result in decreasing numbers of locally generated seismic events over time. Simply put, after the small seismic slips occur inside a fracture cage, the potential for future slip in this cage will be reduced.

Combining these three phenomena, reveals a mechanism by which fracture caging could limit seismicity. That is, a cage of production wells around injection wells contain pore pressure changes to a limited volume of fractured rock and thereby limit both the maximum induced seismic event magnitudes and the number of seismic events over time. This effect requires a balance between injection and production rates to contain pressure alterations to within a targeted volume of rock through strategic placement of wells. By this mechanism, the spacing of the wells becomes an important parameter where closer spacing could result in reduced seismic event magnitudes through more tightly constrained induced rupture lengths. For best effect, as much injected fluid as possible must be recovered by the adjacent production wells, perhaps targeting >90% recovery by volume as indicated by conservative tracer tests. This is because, the balance between injection and production volumes offers a means to regulate reservoir and fracture pore pressure changes, but it is also important that the source of the produced fluid is the injected fluid, more so than in-situ fluids. If injected fluid is permitted to leak off into the far field, the earthquake limiting effect cannot be expected.

We acknowledge that additional investigation is needed to identify and validate links between fracture caging well spacing and induced seismic event magnitudes. Also, the conditions required for these links need to be identified. An investigation such as this would require a focused effort that includes fracture caging the design process. As a placeholder function, we hypothesize that the link between maximum seismic event magnitude in a caged system (M_{oc}) and nominal well spacing (S) could take the following form:

$$M_{oc}(N-m) = aS(m)^b \quad (2)$$

Where, the constants can be estimated at $a \approx 8.22 \times 10^8$ and $b \approx 2.235$ by combining the moment-magnitude scaling relationship from Hanks and Kanamori (1978) with the subsurface rupture-length and magnitude relationship from Wells and Coppersmith (1994). In this combination, we substitute well spacing (S) for the subsurface rupture length (L_{RLD}) based on the assumption that an effective fracture cage is established where pore pressure change beyond the cage's nominal well spacing is negligible.

$$M_w = \log_{10}(M_o(N-m)) - 9.05/1.5 \quad (3)$$

$$M_w = 4.38 + 1.49 \times \log_{10}(L_{RLD}(\text{km})) \quad (4)$$

Note that cumulative injected volume (V_{inj}) is not in the proposed relationship of Eq. (2). This is in direct contrast with Eq. (1) and stems from the assumption of a caged system where the system is in balance with the produced fluids being sourced from the injected fluids. High recovery of the injected fluid (e.g., >90%) via the production wells offers a means to verify this balance. Also, fracture caging will limit seismicity even with very large or infinite cumulative injected volumes.

Natural rock complexity poses a potentially critical challenge to fracture caging. Natural rock heterogeneity and unknown hydraulically conductive fractures could cause flow to bypass production wells and then render these bypassed wells ineffective for limiting the volume of seismically active rock. Victims of chance, stress heterogeneity and choke points in fracture fluid flow could similarly render some production wells ineffective. Effective fracture caging designs would take these complications and the uncertainty of the subsurface environment into account. Through field and experimental evidence, we demonstrate that fracture caging can be effective even in natural rock that is home to this complexity.

4. FRACTURE CAGING TO LIMIT SEISMICITY

Here we present evidence from laboratory experiments and field data that compares injection dominated systems to multi-well injection-production systems that are similar to fracture caged systems. These similar systems were used because relevant data from systems that were designed to investigate or apply fracture caging are not yet available. From this analysis, we will show that there is promising potential for fracture caging to limit induced seismicity risk.

To begin, we re-examine the microseismic data from a two-well granite block hydraulic fracturing and water circulation experiment (Frash et al., 2015a). In this experiment sequence (Figure 7), a small ~0.8 mL initial injection was performed into a central vertical well and the densest part of the resulting microseismic cloud was selected as a target for drilling a subsequent oriented production well. It was expected and later confirmed that this densely seismic region was most likely to contain the stimulated hydraulic fracture. Next, an extensive series of new injections and circulation tests were performed, totaling at >1000 mL cumulative volume, with the production well free to flow at atmospheric pressure. The outer boundary of the specimen was also free to flow at atmospheric pressure.

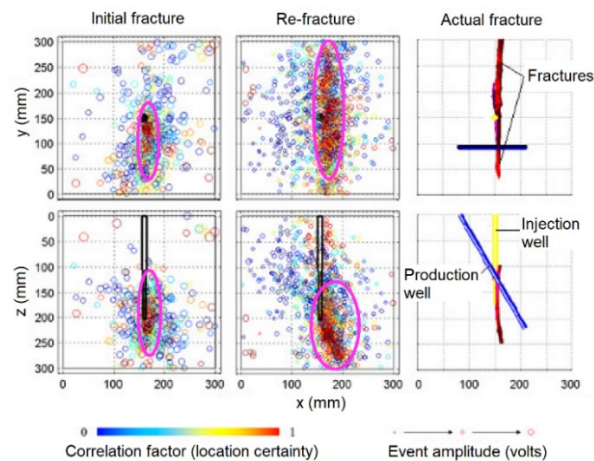


Figure 7: Mapped microseismic cloud and actual hydraulic fracture geometry observed after injection and water circulation through a granite block at true-triaxial stress conditions. Minimum principal stress was along the x-direction. Magenta ellipses highlight the dense zones of microseismic activity. Note the shift from fracture propagation in the positive y- to negative y-direction indicated by the seismic hypocenters after the production well was drilled between the initial fracture and the re-fracture sequences. Also note that the fracture did not reach the positive y-face of the specimen.

The microseismic cloud and the actual observed fracture geometry (Figure 7) both indicate that the production well had the effect of inhibiting fracture growth beyond this well in the positive y -direction. This could be attributed to fracture caging. It is important to note that the propagation direction of the fracture appeared to switch after the production well was drilled and that the fracture was not contained against growth in the negative y -direction by a second production well. A second production well would have been required for a more complete fracture cage inside of the block. The seismic data here only shows the initial injections that used less than ~ 5.0 mL of cumulative water volume. The late time seismic data after ~ 5.0 mL of water was injected is not shown because there were not many events to plot, despite the large >1000 mL of water ultimately injected.

Stronger fracture and seismicity containment trends were observed in a granite block experiment that included two production wells drilled after the first hydraulic fracture stimulation that used ~ 5.0 mL (Figure 6). Seismic data from this experiment indicated stimulation of a natural fracture shear zone and a tensile dominated zone. A production well was drilled into each of these zones but most fluid was produced from the tensile zone production well #1. Here, the late time seismic data is shown even though the number of seismic events was low relative to the high cumulative injected volume of >5800 mL. This three-well system represents an effective fracture caged system despite the experiment not being designed for caging. A key difference here is that we expect a fracture caging design to function best with the production wells drilled prior to injection. In the field, drilling production wells before injection would be intended to avoid a Pohang-type event, which may have been caused by pressurization of a large slip-critical fault (Kim et al., 2018).

Next, we investigate cumulative number of seismic events as a function of the cumulative injected volume. To assure comparability, these events were recorded using a constant detection threshold for each example. We investigate data from the above three-well experiment and the Hijiori EGS project (Figure 8). Both of these experiments show a clear trend of decreasing seismic activity as the injection continues over time. Here, it is pertinent to note the logarithmic scaling of injected fluid volume and the plateaus in the cumulative seismic events. The vast majority of seismic activity, both in the laboratory and the field, was observed during the first injection stages when the production wells were not yet flowing or were not yet drilled. In the Hijiori data, there are significant bumps in seismic activity after 1992 which coincide with increasing injection rates, stimulation of a deeper zone in the reservoir, and a reduction in the number of active production wells. Seismic activity was at its lowest in 1991 when water injection was continued for a long duration at a modest rate of $10 \text{ m}^3/\text{min}$. It was this low seismic activity that inspired the successful ‘AE promotion test’ with a factor of three injection rate increase, as described in the methodology section. From this test, and confirmed by our laboratory observations, it is possible to renew seismic activity in fracture caged systems by injecting more aggressively, even at later times.

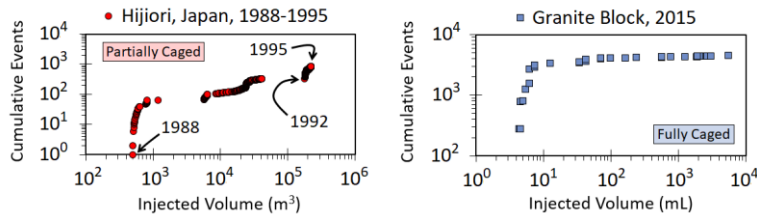


Figure 8: Multi-well and fracture caged systems could be linked to reduced seismic activity over the long term. In the case of perfectly caged laboratory experiments and the partially caged field example of Hijiori, it is apparent that the rate of occurrence of seismic events can decrease over time even as injected water volumes increase by orders of magnitude. Hypocenter locations of seismic events and fracture propagation in the granite were partially contained after drilling the production well between the initial hydraulic fracture and the later re-fracture #1.

Comparing the granite block laboratory experiment and the Hijiori field experiment, seismicity was less limited in the ‘partially caged’ Hijiori case. This could be attributed to the 20%-70% fluid loss during circulation experiments and a well layout that was not designed to exploit fracture caging. In contrast, the granite block is a ‘perfect cage’ or ‘fully caged’ due to the finite size of the specimen, not just the two production wells alone. It would be interesting to see field results from a system designed for fracture caging.

An important and key value of fracture caging could be the potential for this method to limit maximum induced seismic magnitudes (Figure 9). To investigate this, we compare injection dominated site data having ‘no cage’ to Hijiori with its ‘partial cage’ and laboratory experiments that were ‘fully caged’. Injection dominated site data is reproduced from McGarr (2014) which includes oil and gas wells, geothermal wells, waste water disposal wells, and research wells. With reference to the maxima line from Eq. (1), it appears that caging effects could be responsible for the reduction in maximum induced seismic magnitudes. For example, the peak magnitudes at the partially caged Hijiori site were significantly lower than the peaks with comparable cumulative injected volumes at the injection dominated sites without caging. Also, the laboratory experiment data indicates increases to seismic magnitudes initially, as the fracture grows with low injected volumes, but these magnitudes then diminish to lower values as injection continues and the caging effect sets in, preventing the hydraulic stimulation of rock further afield. Reference lines are included showing the seismic magnitudes as a function of well spacing (Eq. 2) that are set at the nominal injection-to-production well spacing in the laboratory (~ 150 mm), at EGS Collab (~ 15 m), and at Hijiori (~ 120 m). We suspect that the well spacing is a controlling factor for the maximum induced seismic event magnitudes in these examples. This of course neglects critically stressed scenarios where only small perturbations are needed to trigger large events, but these scenarios are expected to be rare (Galis et al., 2017). If our proposition of well spacing limiting the seismic event magnitudes is true, fracture caging could offer a direct means to limit the seismicity at an injection site.

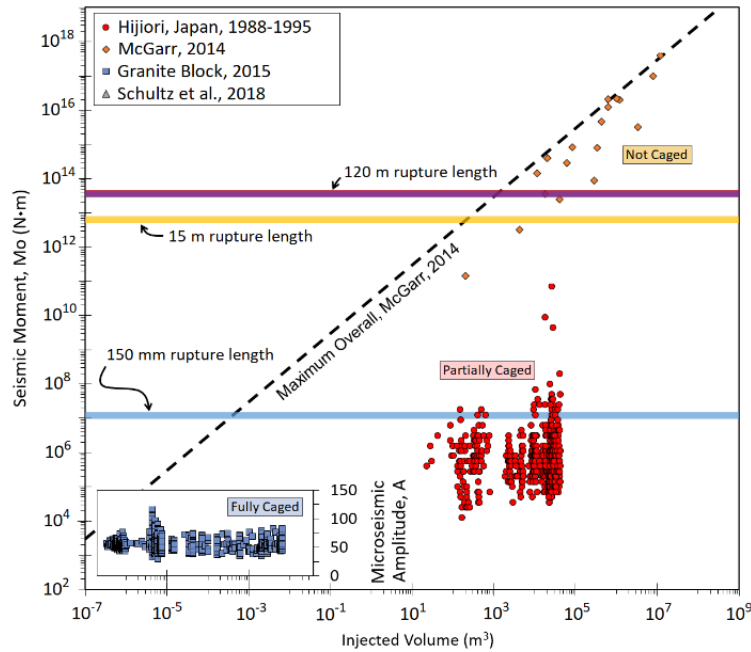


Figure 9: Multi-well and fracture caged systems also exhibit a link to reduced seismic event magnitudes as a function of cumulative injection volume. By comparison, injection dominated systems that are not paired with concurrent fluid production have been shown capable of triggering large magnitude seismic events, for which empirical relations have been proposed linking injected volume to maximum seismic magnitude (McGarr, 2014).

5. UPSCALLING

Economically, it is not trivial to ask operators to drill three or more wells to implement a new method such as fracture caging. This hesitation understandably stems from the current conventional model of EGS requiring only two wells, the thought that sufficient site characterization can predict a stimulation's results despite the inherent uncertainties in the subsurface, and the knowledge that drilling operations are typically the most expensive task in geothermal site development (Tester et al., 2006; Hamm et al., 2019). Naturally, it is of interest to start a new site's development conservatively by investing the minimum amount necessary to prove viability. However, considering the potential benefits of fracture caging and the historical cases of induced seismicity such as at Pohang, conserving cost by drilling fewer wells could come with a significant risk of even higher costs from damaging earthquakes. The lost circulation of cold injected fluids adding to reservoir cooling but not production is also a factor that could be considered in uncaged systems. Addressing the intricacies of engineering decision making for site design is beyond the scope of this paper. That said, we do here propose a scale-up concept that could be a factor in site development where fracture caging is intended to be exploited, by design. Specifically, we propose large patterns of wells in order to enable development of large resources in a more efficient manner (e.g., Figure 10). If large patterns are used, the ratio of injectors to producers could approach the 1:1 ratio of the conventional EGS model while maintaining the seismicity control offered by fracture caging. If combined with directional drilling, the benefits of horizontal wells could also be exploited, possibly to a similar effect as for the shale-gas revolution. Based on this concept, we suggest that the conservative action is not to make a development as small as possible, but rather the opposite. Drilling more wells at one time also invokes cost-saving through less obvious mechanisms such as increased drill-crew experience and efficiency owing to site-specific learning that overcomes drilling challenges and enables follow-on wells to be drilled with better economy. Also, there is potential for cost saving by reducing the number of drill rig mobilizations with respect to the number of wells drilled. Oil and gas experience offers a good guide to the benefits of these combined effects and the need for appropriate capital investment in order to ensure the success of a drilling project.

7. CONCLUSIONS

In this study, we presented field and laboratory evidence that fracture caging could offer a means to limit both the number of seismic events and the magnitude of seismic events when deployed for enhanced geothermal systems (EGS). We also proposed a mechanism by which fracture caging could limit seismicity by limiting the volume of rock subjected to pore pressure changes during geothermal fluid circulation operations. In this mechanism, drilling production wells around injection wells contains pore pressure changes to a targeted volume or rock which thereby limits induced seismic slip to this within this volume. Limiting the dimensions of this targeted volume via a nominal spacing between wells could offer a means to control the maximum induced seismic event magnitudes. A key challenge for fracture caging is posed by uncertain fracture locations and natural rock heterogeneity that could cause injected fluid to not be recovered by the production wells, even if the injection and production flow rates are equal. However, it may be possible to address this challenge by using intelligent patterns of wells combined with tracer tests and microseismic monitoring to confirm whether or not a caged system has been successfully created. Next, considering scale-up potential, it may be that fracture casing is best suited for large field development where the ratio of injection wells to production wells could be made more economic through large arrays of wells.

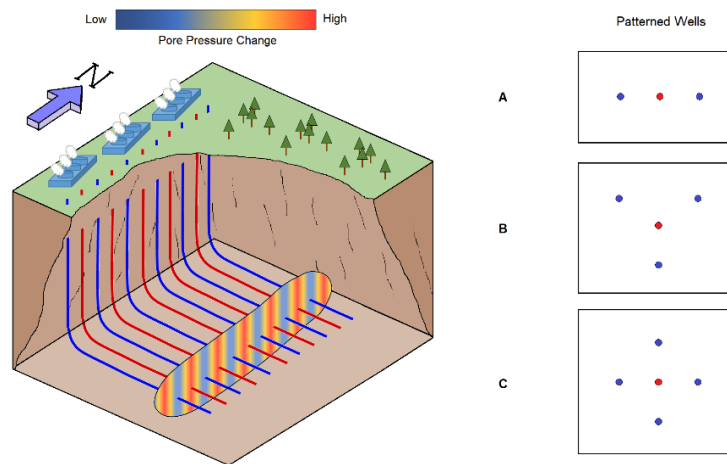


Figure 10: Upscaling fracture caging for large EGS deployments via patterns of injection and production wells could help improve the economy of this method for geothermal energy production with seismicity control. In particular, patterns can move the ratio of injection to production wells closer to a ratio of 1:1 while simultaneously increasing total output.

ACKNOWLEDGEMENTS

This work is supported by Department of Energy (DOE) Basic Energy Sciences under FWP LANLE3W1. The EGS Collab work in this study is supported by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE), Geothermal Technologies Office (GTO) under Contract No. DE-AC52-06NA25396 with Los Alamos National Laboratory, led by Contract No. DEAC02-05CH11231 with Lawrence Berkeley National Laboratory. Research supporting this work took place in whole or in part at the Sanford Underground Research Facility in Lead, South Dakota. The assistance of the Sanford Underground Research Facility and its personnel in providing physical access and general logistical and technical support is gratefully acknowledged. We thank Yanagisawa, N. for his contribution of acoustic emission data from the Geothermal Power Project at Hijiori, Japan. We wish to recognize EGS Collab Team members for providing motivation and feedback. LA-UR-20-20707.

EGS Collab Team: J. Ajo-Franklin, T. Baumgartner, K. Beckers, D. Blankenship, A. Bonneville, L. Boyd, S. Brown, J.A. Burghardt, C. Chai, Y. Chen, B. Chi, K. Condon, P.J. Cook, D. Crandall, P.F. Dobson, T. Doe, C.A. Doughty, D. Elsworth, J. Feldman, Z. Feng, A. Foris, L.P. Frash, Z. Frone, P. Fu, K. Gao, A. Ghassemi, Y. Guglielmi, B. Haimson, A. Hawkins, J. Heise, M. Horn, R.N. Horne, J. Horner, M. Hu, H. Huang, L. Huang, K.J. Im, M. Ingraham, E. Jafarov, R.S. Jayne, S.E. Johnson, T.C. Johnson, B. Johnston, K. Kim, D.K. King, T. Kneafsey, H. Knox, J. Knox, D. Kumar, M. Lee, K. Li, Z. Li, M. Maceira, P. Mackey, N. Makedonska, E. Mattson, M.W. McClure, J. McLennan, C. Medler, R.J. Mellors, E. Metcalfe, J. Moore, C.E. Morency, J.P. Morris, S. Nakagawa, G. Neupane, G. Newman, A. Nieto, C.M. Oldenburg, T. Paronish, R. Pawar, P. Petrov, B. Pietzyk, R. Podgorney, Y. Polsky, J. Pope, S. Porse, J.C. Primo, C. Reimers, B.Q. Roberts, M. Robertson, W. Roggenthen, J. Rutqvist, D. Rynders, M. Schoenball, P. Schwering, V. Sesetty, C.S. Sherman, A. Singh, M.M. Smith, H. Sone, E.L. Sonnenthal, F.A. Soom, P. Sprinkle, C.E. Strickland, J. Su, D. Templeton, J.N. Thomle, C. Ulrich, N. Uzunlar, A. Vachaparampil, C.A. Valladao, W. Vandermeer, G. Vandine, D. Vardiman, V.R. Vermeul, J.L. Wagoner, H.F. Wang, J. Weers, N. Welch, J. White, M.D. White, P. Winterfeld, T. Wood, S. Workman, H. Wu, Y.S. Wu, E.C. Yildirim, Y. Zhang, Y.Q. Zhang, Q. Zhou, M.D. Zoback

REFERENCES

- ASTM D4645-08. Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method. In: *Annual Book of ASTM Standards*. West Conshohocken, PA: ASTM International, (2008).
- Brown, D.W., Duchane, D.V., Heiken, G., & Hrisco, V.T. *Mining the Earth's Heat: Hot Dry Rock Geothermal Energy*, Springer (2012).
- Cuenot, N., Michel, F., Catherine, D., & Marco, C. Induced microseismic activity during recent circulation tests at the EGS site of Soultz-sous-Forêts (France). *Proceedings, Thirty-Sixth Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 31 - February 2 (2011).
- Ellsworth, W. L. Injection-induced earthquakes. *Science* **341**, 1225942 (2013).
- Evans, D. M. The Denver area earthquakes and the Rocky Mountain Arsenal disposal well. *The Mountain Geologist* **3**, 23-36 (1966).
- Frash, L. P., Arora, K., Gan, Y., Lu, M., Gutierrez, M., Fu, P., Morris, J. Hampton, J., & EGS Collab Team. Laboratory validation of fracture caging for hydraulic fracture control. *Proceedings, 52nd US Rock Mechanics / Geomechanics Symposium*, Seattle, Washington, USA, June 17–20 (2018a).
- Frash, L. P., Fu, P., & Morris, J., EGS Collab Team. Fracture Caging: Can We Control the Extent of a Hydraulic Fracture Stimulated Zone? *Proceedings, 43rd Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, February 12-14 (2018b).

Frash, Hampton, Gutierrez, and EGS Collab Team

- Frash, L. P., Gutierrez, M., Hampton, J., & Hood, J. Laboratory simulation of binary and triple well EGS in large granite blocks using AE events for drilling guidance. *Geothermics*, **55**, 1-15 (2015a).
- Frash, L. P., Gutierrez, M., & Hampton, J. Laboratory-scale-model testing of well stimulation by use of mechanical-impulse hydraulic fracturing. *Society of Petroleum Engineers Journal*, **20** (2015b).
- Frash, L.P., Gutierrez, M., Tutuncu, A., Hood, J., & Mokhtari, M. True-triaxial hydraulic fracturing of Niobrara carbonate rock as an analogue for complex oil and gas reservoir stimulation. *Proceedings*, 49th U.S. Rock Mechanics/Geomechanics Symposium, San Francisco, CA (2015c).
- Frash, L. P., Hampton, J., Gutierrez, M., Tutuncu, A., Carey, J. W., Hood, J., Mokhtari, M., Huang, H., & Mattson, E. Patterns in complex hydraulic fractures observed by true- triaxial experiments and implications for proppant placement and stimulated reservoir volumes. *Journal of Petroleum Exploration and Production Technology* (2019b).
- Frash, L. P., Morris, J. P., & EGS Collab Team. Stochastic prediction of multi-well fracture connectivity and application to EGS Collab experiment 2. *Proceedings*, 53rd US Rock Mechanics/Geomechanics Symposium, New York, New York, June 23–26 (2019a).
- Galis, M., Ampuero, J. P., Mai, M., & Cappa, F. Induced seismicity provides insight into why earthquake ruptures stop. *Science Advances* **3**, ecap7528, (2017).
- GERD: Summary of Hot Dry Rock Geothermal Power Project in Japan. *Japan Geothermal Energy Department* (1989, 1991, 1993, 1994, 1995, 1996, & 1997).
- Giardini, D. Geothermal quake risks must be faced. *Nature* **462**, 848-849 (2009).
- Grasso, J. R. & Wittlinger, G. 10 years of seismic monitoring over a gas field area. *Bulletin of the Seismological Society of America* **80**, 450-473 (1990).
- Hamm, S., Hass, E., Winick, J., Tasca, C., Albayrak, F., Augustine, C., Boyd, L., Eugeni, E., Thomas, H., Reinhardt, T., Richard, C., Segneri, B., Snyder, N., Wall, A., & Williams, T. GeoVision: Harnessing the heat beneath our feet. *US Department of Energy*, (2019).
- Hanks, T.C., and Kanamori, H. A Moment Magnitude Scale. *Journal of Geophysical Research* **84**, B5 (1979).
- Hincks, T., Aspinall, W., Cooke, R., & Gernon, T. Oklahoma’s induced seismicity strongly linked to wastewater injection depth. *Science* **359**, 1251-1255 (2018).
- Keranen, K. M., Savage, H. M., Abers, G. A., & Cochran, E. S. Potentially induced earthquakes in Oklahoma, USA: Links between wastewater injection and the 2011 Mw 5.7 earthquake sequence. *Geology* **41**, 699-702 (2013).
- Kim, K-H., Ree, J-H., Kim, Y., Kim, S., Kang, S. Y., & Seo, W. Assessing whether the 2017 Mw 5.4 Pohang earthquake in South Korea was an induced event. *Science* **360**, 1007-1009 (2018).
- Kneafsey, T.J., et al. EGS Collab Project: status, tests, and data. *Proceedings*, 53rd US Rock Mechanics/Geomechanics Symposium, Brooklyn, NY (2019).
- Kulish, N., and Glanz, J. German geothermal project leads to second thoughts after the earth rumbles. *The New York Times* (2009).
- McGarr, A. Maximum magnitude earthquakes induced by fluid injection, *J. Geophys. Res. Solid Earth*, **119**, (2014), 1008-1019.
- Meier, P. M., Rodriguez, A. A., & Bethmann, F. Lessons learned from Basel: New EGS projects in Switzerland using multistage stimulation and a probabilistic traffic light system for the reduction of seismic risk. *Proceedings*, World Geothermal Congress, Melbourne, Australia, April 19-25 (2015).
- National Research Council. *Rock Fractures and Fluid Flow: Contemporary Understanding and Applications*. Washington, DC: The National Academies Press, (1996).
- Segall, P., Grasso, J. R., & Mossop, A. Poroelastic stressing and induced seismicity near the Lacq gas field, southwestern France. *Journal of Geophysical Research: Solid Earth*, **99**, 15423-15438 (1994).
- Schill, E., Genter, A., & Cuenot, N., & Kohl, T. Hydraulic performance history at the Soultz EGS reservoirs from stimulation and long-term circulation tests. *Geothermics*, **70**, 110-124 (2017).
- Schultz, R., Atkinson, G., Eaton, G. W., Gu, Y. J., & Kao, H. Hydraulic fracturing volume is associated with induced earthquake productivity in the Duvernay play. *Science*, **359**, 304-308 (2018).
- Schultz, R. A., Soliva, R., Fossen, H., Okubo, C. H., & Reeves, D. M. (2008). Dependence of displacement–length scaling relations for fractures and deformation bands on the volumetric changes across them. *Journal of Structural Geology*, **30**, 1405–1411.
- Tester, J. W., Anderson, B. J., Batchelor, A. S., Blackwell, D. D., DiPippo, R., Drake, E. M., Garnish, J. D., Livesay, B., Moore, M. C., Nichols, K., Petty, S., Toksoez, M. N., & Veatch, R. W. J. The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century. Massachusetts Institute of Technology: Idaho Falls, ID, USA, *US Department of Energy*, (2006).