NOTICE CONCERNING COPYRIGHT RESTRICTIONS

Injection Induced Seismicity and Geothermal Energy

Trenton Cladouhos[1], Susan Petty[1], Gillian Foulger[2], Bruce Julian[2] and Mike Fehler[3]

[1]AltaRock Energy, Inc, Seattle WA
[2] Foulger Consulting, Palo Alto CA
[3]EAPS, MIT, Cambridge, MA

Keywords

Geothermal, Engineered Geothermal Systems, EGS, induced seismicity, injection, hydroshearing, Soultz, The Geyser

ABSTRACT

Over the past few years injection-induced seismicity (*IIS*) has become an increasingly important issue that Earth scientists working in the geothermal, mining, petroleum and other industries must address. We present a brief review of the history of *IIS*, the importance of *IIS* to the growth of the geothermal energy industry, and suggest possible paths forward to managing the risks associated with *IIS*.

IIS occurs when the fluid pressure in a fault or fracture reaches a critical value above which the friction preventing fault slip is overcome. This concept was proposed in 1959, inadvertently demonstrated at the Rocky Mountain Arsenal in 1962, further tested at Rangely Oil field in 1969, and has been incorporated into continuous injection operations at Paradox Valley since 1996. EGS reservoir creation relies upon controlled *IIS* to create the high surface-area fracture paths necessary for sustainable and economic heat extraction. The lessons learned from past EGS projects, in particular at two projects along the Rhine Graben in Europe, are being used to refine the plans for future projects.

Background

Injection induced seismicity (*IIS*) is associated with changes in stress or fluid pressure in the Earth's crust which can accompany withdrawal or injection of fluids during oil and gas development, enhanced oil recovery, geothermal operations, and waste disposal in deep wells. The dynamic fault slip of *IIS* begins at a critical fluid pressure (P_c) which reduces the effective normal stress across a pre-existing fault plane (σ_{eff}) such that the critical or failure shear stress (τ_c) is exceeded. Assuming a constant depth of interest, that is

$$\sigma_{eff} = \sigma_n - P_c \tag{1}$$

$$\tau_c < \sigma_{eff}\, \mu \tag{2}$$

where, σ_n is the stress normal to the fault plane and μ is the coefficient of static friction on the fault plane. Hubbert and Rubey (1959) proposed equations (1) and (2) to explain the mechanics of overthrusts - "spectacular geological features along which large masses of rock are displaced great distances" – which they hypothesized would require naturally high fluid pressures in order to overcome the frictional resistance to fault movement.

For *IIS* the critical pressure is a combination of the initial or *in situ* pressure prior to injection, P_o, and the change in pressure applied, ΔP_c, necessary to cause slip,

$$P_c = P_o + \Delta P_c \tag{3}$$

Assuming a water table near the surface, P_o will be slightly less than hydrostatic, P_h. However, water tables in regions of geothermal resources can be quite deep, leading to underpressured ($P_o \ll P_h$) conditions. Overpressures or artesian conditions ($P_o > P_h$) may exist as well. In general, for *IIS* the critical pressure will be reached by filling a well with water and pumping,

$$P_c = P_h + P_{wp} - P_{fric} \tag{4}$$

where P_{wp} is the wellhead pressure and P_{fric} is the frictional flow losses down the wellbore and along fracture flow paths. We must also account for the possibility that in naturally underpressured regions ($P_o \ll P_h$), the critical pressure may be reached prior to completely filling the well with fluid and applying wellhead pressure:

$$P_c < P_h \tag{5}$$

ΔP_c will depend upon the tectonic environment of the well site. ΔP_c may be relatively small in rock masses already in or near a critical stress state, for example those rock masses that are either experiencing natural seismicity already or are aseismic with high stored deviatoric stress. Yet, ΔP_c cannot be precisely determined prior to injection. The actual maximum change in pressure or pressure buildup, ΔP_{max}, of an injection project will depend on the goals and plans of the injection and ability of the well engineers to monitor seismicity and control pressure. *IIS* may be the goal of fluid injection or just a (usually unwanted) side-effect.

Another type of injection has the goal of fracturing rock by exceeding its tensile strength. The fluid pressure needed is known as the breakdown or *fracture pressure* (P_f). In rock intervals with pre-existing fractures, the fracture pressure will typically exceed the critical pressure for shear ($P_f > P_c$). In fractured intervals, new tensile fractures may not form, instead fractures oriented perpendicular to the minimum stress (σ_h) may open when $P > \sigma_h$ is exceeded. Injection which causes tensile failure is generally known as *hydraulic fracturing* and although *IIS* may be a side-effect, tensile failure generally does not radiate significant seismic energy like shear failure does (Bame and Fehler, 1986; Ferrazzini et al., 1990). Cladouhos et al. (2009) proposed the term *hydroshearing*, to indicate injection where the ultimate goal is to cause shear failure and induced microseismicity. In general, hydroshearing treatments will be completed at lower pressures and larger volumes compared to typical hydraulic fracturing.

History of Injection Induced Seismicity

The industrial activities associated with *IIS* , withdrawal or injection of fluids, have occurred worldwide for decades, and scientific understanding of *IIS* and our ability to minimize the risk has increased in concert. Starting in the 1940's, oil and gas wells were hydraulically fractured with injected fluid to increase near-well permeability, and *IIS* was not considered to be a significant issue. Below, we review some salient points of four injection projects with well-studied *IIS*. For more details, the reader is referred to the excellent papers reviewed below. See Table 1 for a summary of the relevant quantitative parameters for each project.

Rocky Mountain Arsenal – 1962-1966

In 1961, less than 10 miles from downtown Denver, a 3671 m deep well was drilled for the purpose of disposal of contaminated waste water. The well was cased through the sedimentary rocks of the Denver Basin and the bottom 21 m was left open in highly
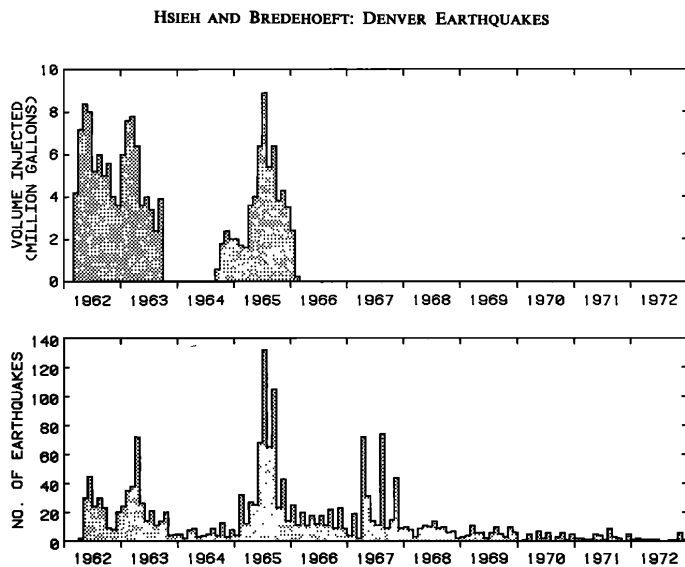
fractured Precambrian gneiss. Shortly after the injection program began in 1962, minor earthquakes were detected on a single local seismograph station. By 1967, over 1500 earthquakes had been detected within 8 km of the well, prompting the end of the waste disposal program in 1966 (Figure 1). *IIS* continued until 1972, six years after injection stopped including three earthquakes with magnitude greater than 5 in 1967 (Hsieh and Bredehoeft, 1981). Between 1966 and 1968, temporary seismic arrays were installed and the shape of the *IIS* zone was determined to be a 10x3 km ellipse with a major axis of N60°W. This zone can be interpreted as a subvertical NW trending, pre-existing fault or fracture zone (Healy et al., 1966; Hsieh and Bredehoeft, 1981).

Reservoir analysis of this early example of *IIS* confirmed the theory of Rubey and Hubbert (1959) on the fault-weakening effect

Table 1. Summary of parameters for injection projects discussed in text.

Project	Injection rates	Time Span	Est. press-ures (MPa)	Depth (km)	Deformation Modes on fractures	Rate of Detected Events*	Max M_L
RMA (1962-1967)	>6.3 L/s	4 years	$P_o = 26.9$ $\Delta P_c = 3.2$ $\Delta P_{max} \approx 16$	3.7	Shear, Opening	1 / day	5.3
Rangely (1969-1970)	Unk.	1 year	$P_o = 17$, $P_c = 25.7$ $P_{max} = 29.0$	~2	Shear	0.7 / day	3.1
Paradox Valley (7 tests) 1991-1994	9 – 25 L/s	438 days	$P_o = 43.6$ $\Delta P_c = 17$ $P_f = 70$	4.5	Shear, Opening, Acid dissolution, Tensile failure	Av. 1.5 / day Max 4 / day	--
Paradox Valley (Phase 1-2) 1996-2000	21.5 L/s	4 yrs at high rate	$P_{wh} = 34.5$ $P_{max} = 82$	4.5	Shear, Opening, Tensile failure, Thermal?	2.1 / day	4.3
Paradox Valley (3-4)2000-2003	14.5 L/s	3 yrs at low rate	$P_{wh} = 30.3$	4.5		0.3 / day	2.8
Geysers (2003-2010) in ~40 wells	~2000 L/s	7 yrs w/ current supply	$P_c << P_h$	2-3	Shear, Thermal	3/day $M_L > 1.5$	4.6
Soultz: GPK2	50 L/s	5.9 d	$P_{wp} = 14.5$	5	Shear	122/day $M_L > 1.0$	2.5
Soultz: GPK3	50 L/s briefly 90L/s	10.6 d	$P_{wp} = 16$	5	Shear	23/day $M_L > 1.0$	2.9
Soultz: GPK4	45 L/s	7.4 d	$P_{wp} = 17,14$	5	Shear	17/day $M_L > 1.0$	2.7
Basel	55 L/s	6 d	$P_{wp} = 29.6$ $\Delta P_c < 11$ $\Delta P_{max} = 17$	5	Shear, on conjugate sets in cataclastic zone	400/day $M_L > -1.0$	3.4
Newberry (planned)	<50 L/s	Max 21 d	$\Delta P_{max} < 15$	3	Shear		

HSIEH AND BREDEHOEFT: DENVER EARTHQUAKES

Figure 1. Comparison of fluid injected and the frequency of earthquakes at the Rocky Mountain Arsenal. Upper graph shows monthly volume of fluid waste injected in the disposal well. Lower graph shows number of earthquakes per month. After Hsieh and Bredehoeft (1981) and Evans (1966).

* <1% of detected events are typically felt. In addition, comparing event rates should be done with great caution due to network sensitivities, reporting thresholds, and the different volumes over which the seismicity is occurring.

of high fluid pressures and set the foundation for further studies of IIS (Healy et al., 1968; Hsieh and Bredehoeft, 1981; Zoback and Healy, 1984). The critical fluid pressure change, ΔP_c, was determined to be just 3.2 MPa or 325 m of hydraulic head. This was based on the observation that it took 6 years for the reservoir pressure to diffuse, drop below P_c and *IIS* to cease. Eventually the water table in the cased well settled at 923 m below the surface, indicating an underpressured aquifer in the fractured basement.

During the injection program, downhole pressures sometimes reached as high as 43 MPa (ΔP_{max}= 16). Examination of pressure records at the start of shut-in periods during the injection program indicated that above a downhole pressure of ~38 MPa hydraulic fracturing had occurred.

According to Hsieh and Bredehoeft (1981) most seismologists of the day agreed that the earthquakes were of tectonic origin – they resulted from the sudden release of tectonic strain energy stored in the gneiss. The release of the stored energy was triggered by the increase in fluid pressure from the injection program resulting in a ten year earthquake swarm. Since then it has become clearer that seismically quiet intraplate crust may often been under a compressive stress state and have stored strain energy that can be released by fluid injection, but would otherwise remain stored (i.e. Zoback and Zoback, 1980; Zoback et al., 1989).

Rangely –1967-1974

The RMA discovery led to speculation that the natural earthquake cycle might be controllable by *IIS*. This hypothesis was tested at the Rangely Oil Field near Vernal, Utah, which had been on waterflood for secondary oil recovery since 1957. The experiment is described thoroughly by Raleigh et al. (1976). To begin, a seismic network of 14 stations was installed and a calibration shot detonated in an injection well to determine seismic velocities and station corrections. From October 1969 to November 1970 bottom-hole pressures in four wells open in the Weber Sandstone at a depth of two kilometers were raised from 23.5 to 27.5 MPa. During that time period, 367 seismic events occurred within 1 km of the wells; the largest of which had a magnitude of 3.1 (Figure 2). Analysis of the event focal mechanisms and locations suggested that the *IIS* was occurring as right-lateral slip in a 1 km wide zone near the tip of a modest (~6 km long), vertical fault; consistent with the known tectonic stress field in the region. A critical pressure, P_c, of 25.7 MPa was determined, compared to a virgin reservoir pressure, P_o, of 17 MPa. After the wells were shut-in and back-flowed, the seismic activity near the wells dropped to 1 event/month.

The success of the experiment led the authors to propose a scheme in which the fluid pressures in wells along the San Andreas Fault could be alternately increased and decreased in order to relieve the shear stress along the fault and prevent great earthquakes (Raleigh et al., 1976).

Paradox Valley - 1991-2004

The Paradox Valley unit (PVU) is a U.S. Bureau of Reclamation facility that extracts aquifer brine from shallow wells and re-injects the brine at high pressure into a single deep well. The purpose of the PVU is to reduce salt water seeps into the Dolores River and thus improve the quality of the Colorado River into which it runs. The PVU has been operating continuously since 1996.
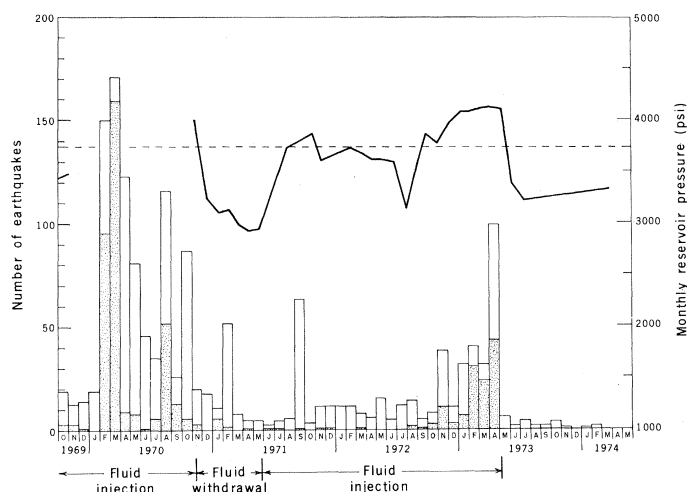
Figure 2. Frequency of earthquakes at Rangely. Stippled barbs indicate earthquakes within 1 km of experimental wells. The clear areas indicate all others. Pressure history in well Fee 69 is shown by the heavy line; predicted critical pressure is shown by the dashed line (after Raleigh et al., 1976).

Ake et al. (2005) describe the facilities of the PVU and analyze 15 years of *IIS*. The Paradox Valley Seismic Network (PVSN) was installed in 1985. It consists of 15 surface stations in two roughly concentric rings around the injection well. The PVSN can detect events down to M_L = -0.5 and reliably locate events down to M_L = 0.5. The 4900 m deep injection well targets the Leadville Limestone, which is a highly-fractured, very-tight dolomitic limestone. The well was sited to optimize fluid migration into and along inactive northeast dipping, Laramide-age faults of the Wray Mesa.

In six years of pre-test seismic monitoring no events were detected within 10+ km of the proposed injection site. The first injection test in 1991 was 14 days long at an average rate of 9 L/s. The downhole pressure reached ~64 MPa on the third day, and the first seismic event was recorded on the fifth day. The authors used this observation to estimate that ΔP_c=17 MPa. In all, 20 events were detected in Test 1 (3.3/day). Following an acid job in 1993,
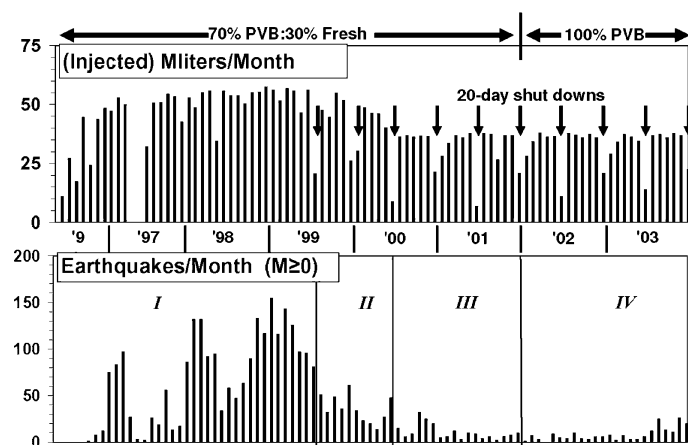
Figure 3. Four phases of continuous pumping (1996-2003) superimposed on monthly injected volumes and induced seismic events per month versus time. PVB designates Paradox Valley Brine, the extract fluid from the local aquifer (from Ake et al., 2005).

a 41-day injection test reached 25 liters per second (L/s), and the seismicity rate peaked at 4 events/day.

Continuous injection began in 1996 at 21.5 L/s and reservoir volume growth stabilized by mid 1999 at 20-30 km^3. After three felt events (M_L 3.5, 3.6 and 4.3) in 1999 and 2000, changes were made to the injectate makeup, and the injection rate was eventually reduced to 14.25 L/s with a corresponding drop in average wellhead pressure, P_{wp}, from 33.8 to 30.3 MPa. The reduced injection rate had the desired effect on *IIS*, and the detected event rate dropped from ~2.7 events/day down to ~0.3 events/day (Figure 3) and resulted in no additional events with $M_L>3.0$ from 2000 to 2003. From 1996 to 2003, 99.9% of the 4000 surface recorded events had $M_L<2.0$ and only 15 events were felt.

Our own analysis of the data from after the second injection test through both phases of continuous injection (Ake et al., 2005) shows a remarkable linear relationship with $R^2=96\%$ of

$$S_R = 0.27\ I_R - 3.1 \qquad\qquad (6)$$

where I_R is the injection rate in L/s, and S_R is the seismicity rate in events/day. This fit has a zero seismic event intercept of 11.3 L/s, indicating that it might be possible, as occurred in Test 4 at 10.3 L/s, to inject with no *IIS* (but other PVU brine disposal requirements would then be unmet).

The average downhole pressure in 2003 at the lower injection rate, 79.3 MPa, is sufficient to open pre-existing fractures (σ_h=69.6 MPa) and cause tensile failure (P_f=70 MPa). However, this tensile failure occurs at the well bore. Due to the high frictional losses in flowing fractures, the pressure dissipates rapidly away from the well. Thus while, in the region near the well, fractures may be held open by the fluid pressure, in the regions experiencing *IIS*, the pressure would likely be less that 70 MPa.

Finally, Ake et al. (2005) note that seismically illuminated faults and fractures can accommodate only a few percent of injectate. Therefore, numerous small fractures must open to provide the remaining ~97% additional storage. This ratio may also be relevant to Engineered Geothermal Systems that are discussed in the next section.

The Geysers - 1960-2010

The Geysers Geothermal Field (GGF) is one of the most seismically active producing geothermal fields in the world. The GGF is large, geologically and operationally diverse, has been actively produced for 50 years, and is in an active tectonic region. Thus, it is likely that seismicity at the GGF has many contributing causes in addition to changes in fluid pressure, including stress changes due to tectonic, thermal and poro-elastic forces. Scientific studies have shown a correlation between , the field-wide annual fluid injection volume and *ISS* rate at The Geysers (Smith et al., 2000; Stark et al. 2005; Greensfelder et al., 2008). This relationship is shown in Figure 4; compare the number of events with $M_L>1.5$ (blue curve) and the injection volume (green curve). The $M_L>1.5$ *IIS* rate tracks the increases in injection volume due to new supply pipelines finished in 1998 and 2003. In fact, similar to the Paradox Valley relation shown in equation (7), Greensfelder et al. (2008) suggested a simple linear relation between the injection rate in multiple wells on the NCPA lease in the southeast Geysers, I_R and the seismicity rate, S_R with $R^2=65\%$ of

$$S_R = 0.0007\ I_R - 0.035 \qquad\qquad (7)$$

However, the relationship between injection and *ISS* rates does not extend to $M_L>3.0$ events. Since 1985, 13 to 32 of these events occur per year with no upward trend despite the doubling of injected fluid (Figure 4). Currently about 1000 events with $M_L>1.5$ and approximately 20 events with $M_L>3.0$ occur in the GGF every year. During 50 years of production and 40 years of injection, there have been 22 events with M_L between 4.0 and 4.6, the largest occurring in 1982 when injection was more modest than today. If there is any water table at the GGF, it lies below the steam reservoir (2-3 km); therefore, the reservoir itself is severely underpressured ($P_o<<P_h$) and pre-existing fractures fail in shear before well bores are filled with water. Assuming that most GGF seismicity is *IIS* implies that the reservoir pressure currently exceeds the critical value, P_c.

Geysers Annual Steam Production, Water Injection and Seismicity, 1960 - 2006
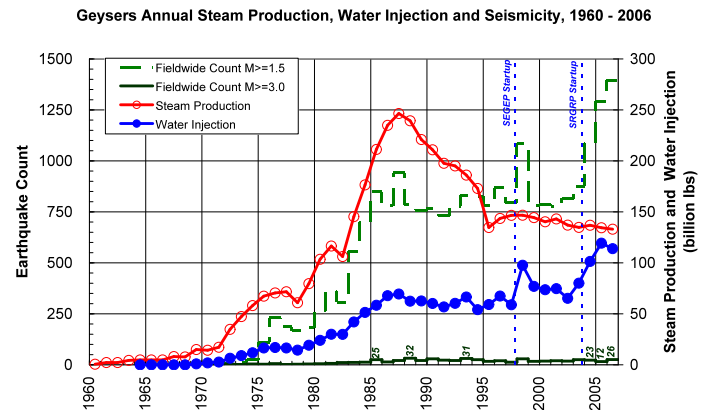
Figure 4. The steam reservoir at The Geysers has no natural recharge and production has been declining since 1987. Water injection has slowed the decline considerably; microseismicity (M<3.0) has increased. (Stark et al., 2005).

EGS and IIS

Engineered Geothermal Systems (EGS) have the potential to expand the availability of clean renewable, baseload energy beyond conventional geothermal areas. An EGS reservoir is created by injecting large volumes of cold water into hot, low-permeability rock to induce seismic slip and enhance the permeability of pre-existing fractures. Compared to the examples discussed above, *IIS* needs to be much more carefully controlled in order to achieve the goal of creating an economic EGS reservoir. The flowing fractures in an EGS reservoir form a heat exchanger at depth and, like a radiator, should contain many, high-surface-area channels and no paths that short circuit the heat exchange surfaces. Thus, the fluid pressures during EGS reservoir creation must be greater than the critical pressure to create hydroshearing (P_c) but less than the breakdown pressure associated with typical hydraulic fracturing (P_f). It also means that large faults and open fracture zones should be avoided, as they will also create short circuits. Most EGS-related *IIS* will be detected only by sensitive, local seismometers designed to monitor reservoir growth; however, some of the seismic events may reach magnitudes of 2-3.

EGS projects have been carried out at Fenton Hill in New Mexico, Ogachi and Hijiori in Japan, Landau, Soultz, and Basel

in Europe's Rhine Graben, and Cooper Basin in South Australia. Majer et al (2007) provides a more complete review of *IIS* associated with EGS projects. Below we briefly discuss the results at two of these sites.

Soultz- 1987-2010

Over two decades of research and development in EGS has been carried out at Soultz-sous-Forêts, France, resulting in a pilot program that currently includes a 200° C EGS reservoir, an injector, two producers, two downhole pumps and a 1.5 MWe binary power plant (Genter et al., 2009). A great deal has been written on the Soultz EGS project; here we summarize the relationship between the hydraulic stimulation (hydroshearing) and *IIS* from an extensive body of literature (Baria et al, 2005; Baria et al, 2006; Dorbath et al., 2009; Genter et al., 2009 and many others).

The EGS project at Soultz started at GPK1, a shallower, cooler well and has progressed to three deep wells with BHT of 200°C: an injector, GPK3, and two producers, GPK2 and GPK4. The wells are drilled from the same pad, and penetrate approximately 1400 m of sediments before reaching fractured Paleozoic granites. The wells deviate from vertical at ~2500 m, such that the wells align with the maximum horizontal stress direction (N170°E). At depth, GPK3 is between the other two with ~700 m well spacing (Genter et al, 2009). The wells are cased between the surface and 4500 m with approximately 500 m of open-hole at the bottom. The seismic network at Soultz consists of two arrays. The first is a surface array of 9 permanent stations plus up to 14 temporary stations. The second is an array of four (4) accelerometers at depths greater than 1500 m, so that they are deployed in the granite itself. The down hole array, which is only operated during stimulation or circulation, returned locatable events at about 2-3x the rate as the surface array in the GPK2 and GPK3 stimulations and 24x in the GPK4 stimulation (Dorbath et al., 2009).

Each of the wells was hydraulically stimulated after drilling. Although the stimulation designs for each well were similar, the results of each stimulation and the characteristics of the associated *IIS* were quite different.

Well GPK2 was stimulated in 2000 for six days with a maximum flow rate of 50 L/s and a well head pressure of 14 MPa.
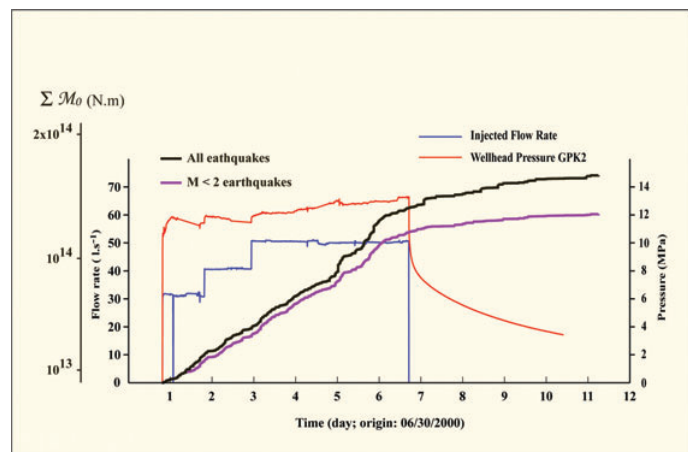
Figure 5. The 2000 stimulation of GPK2 hydraulic parameters; pressure (red) and flow rate (blue). Cumulative seismic moment: all earthquakes (black), and M<2 earthquakes (violet) from Dorbath et al. (2009).

Figure 5 is a synoptic figure of this stimulation; it shows flow rate, well head pressure, and rate of seismicity. Dorbath et al (2009) present this information-rich figure for the stimulation of each well. A huge amount of microseismic events were generated when GPK2 was stimulated; 14000 events were located by the downhole array and 7215 events by the surface array of which 718 events had $M_L > 1$. The largest event was a M_L 2.5. The b-value, a measure of the size distribution of the seismicity, was 1.23, which is slightly higher than for most tectonic regions and indicates relatively few large events and numerous small events. The relatively high b-value and character of the *IIS* cloud indicate that a dense network of medium sized fractures were stimulated. The injectivity of GPK2 increased 20-fold from a low initial value of 0.2 to 4.4 L s^{-1} MPa^{-1} (Dorbath et al, 2009).

Well GPK 3 was stimulated in 2003 for 10.6 days at a standard flow rate of 50 L/s (with pulses of a few hours up to 90 L/s) and a well head pressure of 16 MPa (with 19 MPa spikes at the high rate). Despite 1.5x the volume and ~2x the duration, fewer microseismic events were generated than at GPK2; 8345 events were located by the downhole array and 3253 events by the surface array of which 240 events had $M_L > 1$. The largest event, a $M_L=2.9$, was the largest at Soultz to date, which occurred three days after the stimulation. The b-value for the GPK3 *IIS* was 0.94, which is closer to a tectonic value and indicates relatively more large events. The low b-value and character of the *IIS* cloud, indicates hydroshearing occurred along one large structure (Dorbath et al, 2009). This conclusion was confirmed by borehole image and flow logs which show a large scale fault at a depth of 4770 m, which took 70% of flow in GPK3 (Baria et al, 2005; Genter et al, 2009). The injectivity of GPK3 was relatively high after drilling, 3.5L s^{-1} MPa^{-1}, and did not significantly improve after stimulation (Tischner and Teza 2005).

GPK4 was stimulated in 2004 and 2005. In the first stage, a continuous flow rate of only 30 L/s was achieved at a well head pressure of 17 MPa. After 3.5 days of stimulation, a PTF sonde in GPK4 quit working, and the casing was found to have collapsed above the tool (Baria et al 2006). GPK4 hydraulic stimulation resumed for an additional four days in 2005 at flow rates of 30 and 45 l/s and well head pressures from 14 to 18 MPa. GPK4 stimulation produced a large amount of locatable events on the downhole array (32,288) but the fewest locatable events on the surface array; 1341 located, 128 $M_L > 1$. The largest event was a $M_L=2.7$, which started the activity in the second stage after a full day of stimulation with no events. The character of the *IIS* indicates that the stimulated zone in GPK4 is a single zone like that in GPK2. After the hydraulic stimulation, an acid stimulation was also performed; 6000 m^3 of water with 30 m^3 of 30% HCl was injected (Portier et al., 2009). The injectivity of GPK4, which started very low at <0.15 L s^{-1} MPa^{-1}, had improved to 2.5 L s^{-1} MPa^{-1} after the acid job (Baria et al 2006).
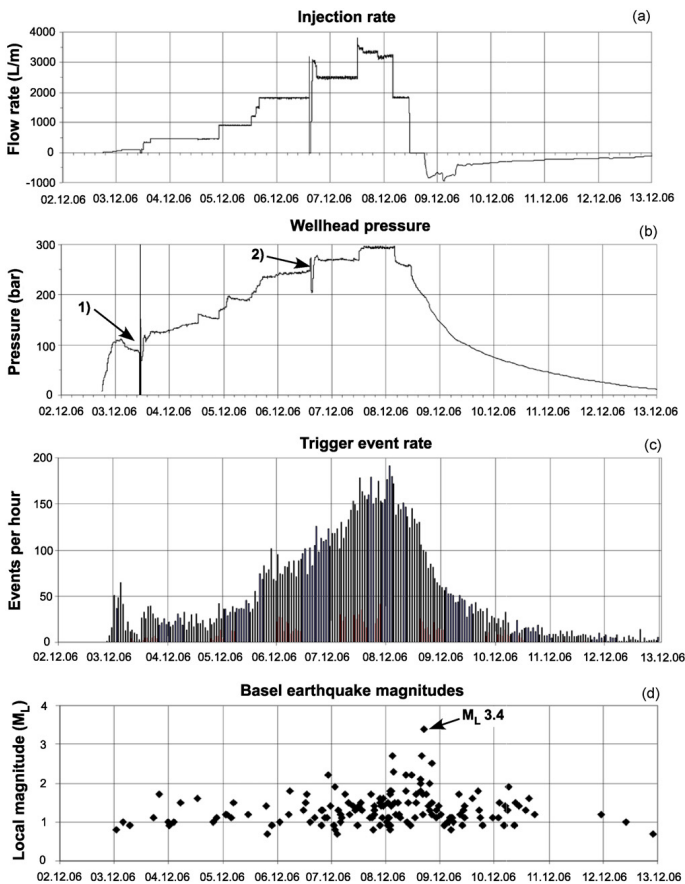
The stimulation results at the three Soultz wells demonstrate that *IIS* characteristics (maximum magnitude, b-Value, and event rate) and stimulation efficacy (improvement of injectivity and reservoir volume) seem to be a function of the characteristics of the preexisting natural fractures and faults in the well bore. To maximize the effectiveness of hydroshearing, stimulation plans need to account for the features encountered by the well.

Basel – 2008

In 2006, a deep well was drilled for the purpose of creating an EGS reservoir as part of the Deep Heat Mining (DHM) project at Basel, Switzerland. The well passes into crystalline basement at 2507 m, reaches TD of 5000m and a BHT of 190°C, a well geology similar to the Soultz project. The 371 m open-hole section at the bottom has a fracture spacing of 3-5 m and contains two major clay-rich cataclastic fracture zones, indicating that significant fault slip had occurred at this location in the past (Haring et al, 2008). A normal fault in the hills just south of Basel is thought to be responsible for an earthquake that destroyed much of Basel in 1356 (Meghraoui et al., 2009).

A seismic network consisting of six down-hole three-component geophones was installed to monitor the *IIS*. Since the project was located in a major city, a seismic response procedure, adapted from the "Traffic Light System" proposed by Bommer et al. (2006), was developed to monitor and control *IIS*. Three independent parameters were chosen; public response (phone calls), local magnitudes (M_L), and peak ground velocity (PGV). Thresholds were set for each parameter, with an appropriate response at the well site predetermined for each threshold (Dyer et al, 2008; Haring et al, 2008).

The well Basel-1 was hydraulically stimulated in December 2006 starting with a flow rate of 1.7 L/s, enough to increase the well head pressure (W_{wp}) to 11 MPa and initiate *IIS*. Over six days the flow rate was increased to a maximum flow rate of 55 L/s and a well head pressure of 29.6 MPa or a downhole pressure of 74 MPa (Figure 6). No hydrofracturing tests were performed in Basel-1 prior to stimulation; however, since there was no hydraulic evidence of tensile fracturing at the shoe during the massive stimulation, it is assumed that $\sigma_h > 74$ MPa (Figure 7).
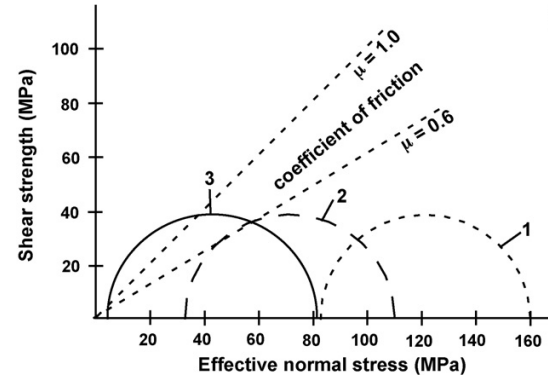
Figure 7. Mohr diagram illustrating the effect of increasing pore pressure in weak rock. Circle 1 is total stress, Circle 2 is effective stress at hydrostatic conditions, and Circle 3 is effective stress at maximum overpressure conditions during hydraulic stimulation (Haring et al., 2008).

During the six days of stimulation 11,200 events were detected and 2400 located. At 3:06 am December 8th, a $M_L = 2.6$ event occurred, so the rate was reduced to 30 L/s, a response more precautionary than required by the safeguard procedure (which would have allowed continued pumping at 55 L/s). Later that morning additional $M_L > 2$ events occurred and the injection was stopped completely and the well shut-in. However, the same afternoon 2.7 M_L and 3.4 M_L events required that the well be bled off. *IIS* continued after bleed off, including three $M_L > 3.0$ events in the following two months (Haring et al, 2008).

The felt intensity of the M_L 3.4 event appears to have been very strong compared to other induced and natural events of this low magnitude (Baisch et al, 2009). The peak ground velocity was 0.9 cm/s and the Modified Mercali Intensity reported by the public was IV or V (light or moderate shaking perceived). Despite the exceptional human alarm, Haring et al (2007) reports that "[t]he still ongoing investigations have found only minor damages so far. The great majority of reported damages are small cracks in plasterwork , often of disputable age. There are no claims of injury and no structural damage has been detected."

A report on the long-term seismic risk of the DHM project commissioned by the Canton government (Baisch et al., 2009) concluded that "from a seismic risk perspective, the location of Basel is unfavourable for the exploitation of a deep geothermal reservoir in the crystalline basement. Other locations in Switzerland may offer a significantly lower risk."

Theory and Models

In concert with the field experiences of *IIS* such as those described above, theory and models of *IIS* have significantly progressed. For example, Shapiro et al. (2007) and Shapiro and Dinske (2009) provide a theoretical basis for *IIS* rates, size distributions and volume growth. The theory begins with the simple

Figure 6. Data on the hydraulic stimulation of well Basel-1. History of (a) injection rates, (b) wellhead pressures, (c) trigger event rates and (d) Basel earthquake magnitude as determined by Swiss Seismological Survey (SED). From Haring et al., (2008).

relation between the IIS triggering front as a function of time, r(t), and a hydraulic diffusivity, D:

$$r(t) = \sqrt{4\pi Dt} \qquad (8)$$

Figure 8 shows the fit of Equation (8) for *r-t* data for Basel. From the starting point of Equation (8), additional factors such as non-linear diffusion effects, pumping rates, critical pressure, tectonic b-values, and tectonic potential are included. The final equations are tested against data from EGS projects (Ogachi, Cooper Basin, and Basel) and hydraulic fracturing injection into tight gas reservoirs (Cotton Valley sandstones and Barnett Shale). The data for these five projects can be well-explained by the theory.

There have also been recent advances on stochastic fracture models (e.g. Willis-Richards et al.,1996; Jing et al., 2000). Computer models based on this work will allow hydroshearing plans to be simulated on a modeled volume populated with geologically realistic fractures. Based on reasonable assumptions about the rock mass, hydroshearing scenarios can be tested to predict which fractures will shear, and help predict the size and shape of the EGS reservoir likely to be created.

Southeast Geysers EGS Demo Project
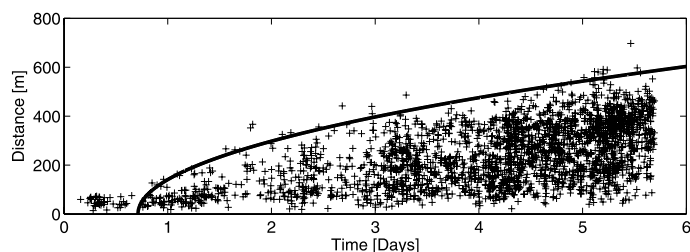
Figure 8. Injection pressure, flow rate and an r-t plot of the corresponding fluid injection microseismicity at a geothermal borehole in Basel region of Switzerland. The data are courtesy of U. Schanz and M.O Haring. Curve is Equation (7) with D= 0.06 m²/s. From Shapiro et al., (2009).

In early 2009, AltaRock planned and commenced a DOE-funded project in the southeast Geysers, California, with the objective of creating an EGS reservoir in intrusive rock below the currently producing steam reservoir (Cladouhos et al., 1999).

The AltaRock project began without DOE funding in August of 2008. After an initial meeting with the BLM and state and county regulators, AltaRock staff and contracted expert seismologists assessed the risk of hazardous *IIS*. After receiving an award from the DOE in October, 2008, DOE agreed to follow the requirements of the BLM in their efforts to comply with NEPA for the grant. The induced seismicity hazards study, completed in November of 2008, which was incorporated into the Environmental Assessment (EA) for the project, concluded that the EGS project would not significantly impact the already high rate of seismicity or cause events as large or larger than those already occurring. To monitor seismicity around the project, AltaRock installed a network of eight state-of-the-art, three-component borehole accelerometers to monitor the stimulation. Additionally, a strong ground motion seismometer was installed in the nearby community of Anderson Springs. The BLM issued a Finding of No Significant Impact (FONSI) for The Geysers EGS project in June of 2009 with pro-

tocols for monitoring and mitigating *IIS* during the project. The DOE requires that any EGS projects with federal funding comply with protocols established by the International Energy Agency (IEA) that include a maximum threshold for shaking recorded on a strong motion seismometer in the nearest community.

Adverse publicity linking the Geysers project to the DHM project in Basel resulted in separation of the DOE NEPA compliance from the BLM effort. The DOE asked for further review of the seismicity anticipated from the stimulation. Drilling difficulties in the soft, wet serpentinite caprock at the project site resulted in suspension of the workover effort and eventual release of the rig. At the end of 2009, AltaRock ceased all work on the project. To date, no direct EGS-related activities have occurred in the southeast Geysers. Despite this setback, the DOE went on to fund three new EGS projects in the fall of 2009.

Conclusion and Plans for Future EGS Projects

The successes and lessons learned from past injection and EGS projects suggest the following principles for a successful EGS project:

Cultural Setting

The RMA disposal well and the DHM injection well were too close to major cities for the public's comfort. The risk of damage to buildings and infrastructure was deemed too great. For now, EGS will be best performed away from urban areas. Even in more sparsely populated areas, the local population and media must be well-educated about the project, so that there are no surprises if an event large enough to be felt does occur.

Geological and Tectonic Setting

The disposal well at the RMA, Soultz GPK3, and Basel-1, all injected fluid directly into large faults zone or weak zones. These zones seem to be more susceptible to larger seismic events, and it is difficult to significantly improve the already high levels of productivity/injectivity of these zones (i.e. GPK3). Thus, when possible, known structures in the well bore should be avoided and the injection focused to a different depth in the injection well.

The existing seismic hazards and background seismicity need to be studied at the project onset. If faults capable of damaging earthquakes are found in the region, appropriate buffers and exclusions zones to prevent interaction with these faults should be defined.

Seismic Network and Monitoring

Initially, the *IIS* Rocky Mountain Arsenal near Denver was recorded on a single seismometer. Projects since have confirmed the importance of a microseismic array (MSA) in order to collect data on the background seismicity and monitor the growth and size distribution of project *IIS*. The MSA is also key to determining the onset of microseismicity and providing feedback to operators on the effect of flow rates and well head pressures on *IIS* (e.g. Figures 3, 4, 5, and 6).

In order to monitor the impact of IIS on the local community, a strong motion seismometer (SMS) should be installed in the nearest local community. The potential for heightened human perception of EGS *IIS* also needs to be part of any public outreach plans. Despite the overall disappointment at the DHM project, the

modified "Traffic Light System" employed was successful at preventing *IIS* magnitudes from reaching damaging magnitudes.

References

Ake, J. K. Mahrer, D. O'Connell, and L. Block, 2005, Deep-Injection and Closely Monitored Induced Seismicity at Paradox Valley, Colorado, Bulletin of the Seismological Society of America, Vol. 95, No. 2, pp. 664–683.

Baria, R., S. Michelet, J. Baumgärtner, B. Dyer, J. Nicholls, T. Hettkamp, D.Teza, N. Soma, H. Asanuma, J. Garnish and T. Megel, 2005, Creation and Mapping of 5000 m deep HDR/HFR Reservoir to Produce Electricity Proceedings World Geothermal Congress 2005, Antalya, Turkey, 24-29 April 2005.

Baisch S., D.Carbon, U. Dannwolf, B. Delacou,, M. Devaux, F. Dunand. R. Jung, M. Koller, C. Martin, M. Sartori, R. Secanell, and R. Vörös, 2009, Deep Heat Mining Basel – Seismic Risk Analysis, downloaded from Basel-Stadt website on April 25, 2010: http://www.wsu.bs.ch/ serianex_teil_1_english.pdf.

Bame, D. and M. Fehler, Observations of long period earthquakes accompanying hydraulic fracturing, *Geophys*. *Res*. *Letters* 13, 149-152, 1986.

Baria, R., R.Jung, T.Tischner, J.Nicholls, S.Michelet, B.Sanjuan, N.Soma, H.Asanuma, B.Dyer and J.Garnish, 2006, Creation of an HDR Reservoir at 5000 m Depth at the European HDR Project. PROCEEDINGS, Thirty-First Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 30-February 1, 2006.

Bommer, J.J., S. Oates, , J.M., Cepeda, C., Lindholm, J., Bird, R., Torres, G., Marroquin, and J., Rivas, 2006. Control of hazard due to seismicity induced by a hot fractured rock geothermal project. Eng. Geol. 83, 287–306.

Cladouhos, T., S. Petty, B. Larson, J. Iovenitti, B. Livesay, and R. Baria., 2009, Toward More Efficient Heat Mining: A Planned Enhanced Geothermal System Demonstration Project, GRC *Transactions*, Vol. 33, pp.165-170.

Dorbath, L., N. Cuenot, A. Genter, and M. Frogneux, (2009), "Seismic response of the fractured and faulted granite to massive water injection at 5 km depth at Soultz-sous-Forêts (France)," *Geophysical Journal International* 177, no. 2 (May 1, 2009): 653-675.

Evans, D. M., The Denver area earthquakes and the Rocky Mountain Arsenal disposal well, Mt. Geol., 3(1), 23-36, 1966.

Ferrazzini, V., B. Chouet, M. Fehler, and K. Aki, Quantitative analysis of long-period events recorded during hydraulic fracturing experiments at Fenton Hill, New Mexico, *J. Geophys*. *Res*. 95, 21871-21884, 1990.

Genter A., D. Fritsch, N. Cuenot, J. Baumgartner, J-J. Graff, 2009, Overview of the Current Activities of the European EGS Soultz Project: from Exploration to Electricity Production, Proceedings, Thirty-Fourth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, February 9-11, 2009.

Greensfelder, R., T.T. Cladouhos and A. Jupe, 2008, Induced Seismicity Report, Engineered Geothermal System Demonstration Project Northern California Power Agency, The Geysers, CA, Internal report to AltaRock. (Appendix B).

Haring, M., S. Ulich, F. Ladner, and B. Dyer, 2008, Characterisation of the Basel 1 enhanced geothermal system. Geothermics Vol. 37, Issue 5, pp. 469-495.

Häring,M.O., F.Ladner, U. Schanz, and T. Spillmann (2007) Deep Heat Mining Preliminary Results. Downloaded from Geothermal Explorers website on April 25, 2010: http://www.geothermal.ch/fileadmin/ docs/ downloads/dhm_egc300507.pdf

Healy, J. H., W. W. Rubey, D. T. Griggs, and C. B. Raleigh (1968). The Denver earthquakes, *Science* 161**,** 1301–1310.

Hseih, P. A., and J. S. Bredehoeft (1981). A reservoir analysis of the Denver earthquakes—a case study of induced seismicity, *J. Geophy. Res*. 86, 903–920.

Hubbert, M. K. and Rubey, W.W., 1959, "Mechanics of fluid-filled porous solids and its application to overthrust faulting, [Part] 1 of Role of fluid pressure in mechanics of overthrust faulting." *Geological Society of America Bulletin* 70.2 (1959): 115-166.

Jing Z., Willis-Richards J., Watanabe K., Hashida T. (2000). A three-dimensional stochastic rock mechanics model of engineered geothermal systems in fractured crystalline rock. Journal Geophysical Research V105, B10, pp23663-23679.

Majer E.L., Baria, R., Stark, M., Oates, S., Bommer, J., Smith, B., and Asamuma, H. 2007. Induced seismicity associated with Enhanced Geothermal Systems, *Geothermics* v 36, 185-222.

Meghraoui, M., B. Delouis, M. Ferry, D. Giardini, P. Huggenberger, I. Spottke and M. Granet1, 2009, Active Normal Faulting in the Upper Rhine Graben and Paleoseismic Identification of the 1356 Basel Earthquake, Sceince V. 293, 2070-2073.

Portier, S., F.-D. Vuataz, P.Nami, B. Sanjuan, and A. Gérard, 2009, Chemical stimulation techniques for geothermal wells: experiments on the three-well EGS system at Soultz-sous-Forêts, France, Geothermics 38 (2009) 349–359.

Raleigh, C.B., J. H. Healy, J. D. Bredehoeft, 1976, An Experiment in Earthquake Control at Rangely, Colorado Source: Science, New Series, Vol. 191, No. 4233 (Mar. 26, 1976), pp. 1230-1237

Shapiro, S., C. Dinske and J. Kummerow, J., 2007. Probability of a given-magnitude earthquake induced by fluid injection. *Geophysical Research Letters* V34, L14312.

Shapiro, S. A., and C. Dinske (2009), Scaling of seismicity induced by nonlinear fluid-rock interaction, J. Geophys. Res.,114, B09307, doi:10.1029/2008JB006145.

Smith, B., J. Beall, and M. Stark, 2000. Induced seismicity in the SE Geysers Field, California, USA, *Proceeding World Geothermal Congress 2000*, Kyushu – Tohoku, Japan, May28-June10, 2000.

Stark, M.A., W.T. Box Jr., J.J. Beall, K.P. Goyal, A.S. Pingol, 2005. The Santa Rosa-Geysers Recharge Project, Geysers Geothermal Field, California. GRC Transactions, 29, 145-150.

Tischner, T. and D. Teza, 2005. Hydraulic characterization of the deep wells in Soultz after stimulation, in *Proceedings of the EHDRA Scientific Conference*, Soultz-sous-For^ets, France, 17–18 March, 6pp.

Willis Richards J., K. Watanabe and H. Hashida H. (1996). Progress toward a stochastic rock mechanics model of engineered geothermal systems. *J. Geophy. Res*. 101, B8, pp17481-17496.

Zoback, M.L., M.D. Zoback, and 26 others. Global patterns of tectonic stress. (1989): Nature 341.6240291-298.

Zoback, M. D., and M. L. Zoback (1980). State of stress in the conterminous United States, *J. Geophy. Res*. 85, 6113–6156.