ENGINE – **EN**hanced **G**eothermal **I**nnovative **N**etwork for **E**urope
Workshop 3, "Stimulation of reservoir and microseismicity"
Kartause Ittingen, Zürich, June 29 – July 1, 2006, Switzerland

Modelling geochemical effects of acid treatments and comparison with field observations at Soultz-sous-Forêts geothermal site.

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Abstract

Acid treatments have been successfully applied in many cases to increase or to recover geothermal wells production rates to commercial levels. Chemical stimulation techniques were originally developed to address similar problems in oil and gas production wells. The applicability of these stimulation techniques to a hot and fractured reservoir is less well known. High temperatures increase the acid-rock reaction rate. The development of Enhanced Geothermal Systems (EGS) depends on the creation of permeable and connected fractures. Acid stimulation jobs intend to clean (pre-existing) fractures by dissolving filling materials (secondary minerals or drilling mud) and mobilizing them for an efficient removal by flow transport. Recent acid treatments were performed on the EGS wells at Soultz-sous-Forêts (France). This 200°C and 5-km deep granitic reservoir contains fractures partially filled with secondary carbonates (calcite and dolomite). In order to dissolve these carbonates and to enhance the productivity around the wells, each of the three boreholes (GPK2, 3 and 4) were successively treated with various amounts of hydrochloric acid. The FRACHEM code, a Thermo-Hydraulic-Chemical coupled code, has been developed especially to forecast the evolution of the Soultz reservoir. Reactive transport modelling with FRACHEM code has been used to simulate acid injection and its impact on brine-rock interactions. Comparisons between FRACHEM simulations and field observations have been tested to forecast the impact of acid treatments on reservoir properties. The main goal is to simulate the effect of acid injection on permeability evolution in fractures at pressure and temperature conditions of the Soultz geothermal site.

Keywords: Enhanced Geothermal Systems ; chemical stimulation ; acid injection ; brine-rock interactions ; coupled modelling ; reactive transport ; Soultz-sous-Forêts.

1. Introduction

The Enhanced Geothermal Systems (EGS) are dedicated to the exploitation of the heat present in low productivity reservoirs. A geothermal resource is quite different from an oil or gas reservoir or even a ground water reservoir. In an oil reservoir, once the oil has been extracted, the reservoir is exhausted. By contrast, in a geothermal reservoir the water or steam originally present in the reservoir can be replaced by surrounding cooler water or re-injected fluid that is heated by the reservoir rock, becoming again available for production (O'Sullivan and McKibbin, 1993). Despite all the differences between hydrocarbon and geothermal reservoir, the techniques used for extraction of fluids are similar; as are the exploration techniques and reservoir management approaches. Techniques comparable to those used in the oil industry are employed to drill and complete well in the productive reservoir. In both cases formation damage should be minimized in order to optimize well performance. A well may encounter multiple, widely spaced, fracture zones, resulting in flow rates that are too low. Stimulation techniques have the potential to remediate such causes for low flow-rate wells. Different techniques can be used to enhance the fracture network but the main ones are hydraulic fracturation and chemical treatment. The present paper will be focused on the chemical stimulation of geothermal wells. This technology, developed for more than one century by oil industry for the stimulation of oil and gas wells, is also used in geothermal wells. After a reminding of the different chemical stimulations performed on the GPK4 well at Soultz-sous-Forêts, numerical simulations using FRACHEM code have been carried out to estimate the impact of the acidizing treatments on carbonates and reservoir properties.

2. Cleaning of geothermal wells

2.1 Well stimulation techniques

Resources exploitation of gas, oil and heat from deep reservoirs needs sometimes a permeability development around the production wells to ensure an efficient flow. The aim of this technology is to enhance the well productivity and to reduce the skin factor by removing near-wellbore damage and by dissolving scales in natural fractures. It consists to pump into the reservoir reactants such as strong acids (hydrochloric acid, HCl-HF mixture), organic acids (acetic acid, chloroacetic acid, formic acid, sulfamic acid) or chelatants (EDTA family). Besides the traditional acids, the chelatants are solutions used as formation cleanup and for stimulating wells especially in formations that may be damaged by strong acids (Frenier et al., 2001). They act as a solvent, increasing the water-wetting operations and dissolving (entirely or partially) some minerals containing Fe, Ca, Mg and Al.

These reactants can be pumped into the reservoir according to two procedures: below the fracturing flow rate and pressure of the reservoir (matrix acidizing) or above the fracturing flow rate and pressure (fracture acidizing). The main disadvantage of acid treatments is linked to the corrosion risk of the casing in particular with strong acids. Nevertheless, this risk can be reduced by addition of corrosion inhibitors or by using less-corrosive agents as chelatants, but their use increases the treatment cost.

Matrix acidizing

This process is performed below fracturing flow rate and pressure and is normally used for the removal of skin damage associated with work-over, well killing or injection fluids and also for to increasing formation permeability in undamaged wells.

The protocol of matrix acidizing has not really evolved since the beginning of the 1980's and is composed of three main steps: a preflush, with hydrochloric acid ; a mainflush with a hydrochloric – hydrofluoric acid mixture ; a postflush / overflush with soft HCl acid solutions or with KCl, NH_4Cl solutions and freshwater.

Treatment volumes, injection rates, acid placement techniques, acid system selection and evaluation of the results when stimulating geothermal wells, all follow the same criteria as for oil wells. The important difference is the formation temperature. High temperature reduces the efficiency of corrosion inhibitors (and increase their cost) as well as increasing the acid/rock reaction rate. The high acid rock reaction rate requires the use of a retarded acid system to ensure acid will not all be spent immediately next to the wellbore, but will penetrate deeper into the formation. Protecting the tubulars against corrosion is another serious challenge. This requires careful selection of acid fluids and inhibitors (Buijse et al., 2000), while cooling the well by injecting a large volume of water preflush may reduce the severity of the problem.

Fracture acidizing

Also called acid fraccing, this technique is widely used for stimulating limestone and dolomite formations or formations presenting above 85 % acid solubility. It consists to inject first a viscous fluid at a rate higher than the reservoir matrix could accept leading to the cracking of the rock. Continued fluid injection increases the fracture's length and width and injected HCl acid reacts all along the fracture to create a flow channel that extends deep into the formation. The key to success is the penetration of reactive acid along the fracture. However, the treatment volumes for fracture acidizing are much larger than the matrix acidizing treatment, being as high as 12'000 – 25'000 l/m of open hole (Economides and Nolte, 1987).

Chemical mechanisms involved in acidizing

The preflush, performed most often with a HCl solution, has to allow the displacement of the formation brine and the removing of calcium and carbonate materials in the formation. Acid reacts rapidly with carbonate rocks when it reaches the grain surface according to reactions:

$$CaCO_3 + HCl \rightarrow Ca^{2+} + Cl^- + HCO_3^-$$

$$CaMg(CO_3)_2 + 2HCl \rightarrow Ca^{2+} + Mg^{2+} + 2Cl^- + 2HCO_3^-$$

By dissolving calcite and dolomite, acid may create wormholes (Crowe et al., 1992) and new pathways. If the reaction rate is too quick, acid is immediately consumed in the vicinity of the fracture, forming wormholes but preventing the aperture of new pathways and connection to other fractures.

The role of the preflush, by dissolving carbonates, also prevents their contact and their reaction with HF injected with the mainflush and therefore minimizes the risk of precipitation of calcium fluoride CaF_2, highly insoluble in water:

$CaCO_3 + 2\,HF \rightarrow CaF_2 + 2\,HCO_3^-$

During the mainflush, the HF acid reacts mainly with the associated minerals of sandstones (clays, feldspars and micas), rather than with quartz. The reaction rates of HF with clays or feldspars are 100 to 200 times faster than the one with quartz. It results from these reactions an enlargement and interconnections of the pores in the matrix, facilitating fluid flow. The risk of using HF acid is the strong affinity of Si and Al with F, which can cause the precipitation of silicium or aluminum complexes (SiF_6^{2-}, AlF^{2+}, AlF_2^+, AlF_3, AlF_4^-), then damaging the formation by plugging. This is why HCl is added to HF: hydrochloric acid keeps a low pH and prevents the formation of fluorosilicates, fluoroaluminates, and fluoride salts.

For the preflush operation in acidizing treatments, a solution of hydrochloric acid at a concentration of 10 to 15 % is most often used. For the mainflush, the mud acids generally range from 10% HCl – 5% HF to 12% HCl – 3% HF. Acidification of geothermal wells is not as frequent as of oil and gas wells, but the operations are borrowed from this industry.

Concerning the injected amounts, in the majority of the cases, the preflush volume was based on a dosing rate of 600 litres per metre of open hole (Malate et al., 1997; Barrios et al., 2002). The cleaning out of the geothermal wells needs about 900 litres per metre of target zone.

HCl and HF are two acids reacting quickly with carbonates and silicates. However, the objective of acid treatment is to increase porosity and permeability of the medium, deeply in the formation. Some retardants can be added to the mud acid to slow the reaction rate of acid with the minerals.

A key point is to inject a solution not containing HF explicitly but a compound able to generate HF at greater depth of penetration for a longer reaction time and a maximum dissolution of fines (Crowe et al., 1992). This retardant hydrolyzes in water when it enters in the reservoir to form HF according to the reaction:

$HBF_4 + H_2O \rightarrow HBF_3OH + HF$

Other retardant systems can be used as an emulsifier of the aqueous acid solutions in oil, the dissolving of the acids in a solvent (alcohol, gel…) or the injection of solutions of methyl acetate which hydrolyses slowly at very high temperatures to produce acetic acid.

Malate et al. (1998) also proposed an acid system applicable for moderate to deep penetrations. They used a phosphonic acid complex (HEDP) to hydrolyse NH_4HF_2 instead of HCl. HEDP has five hydrogens available that dissociate at different stochiometric conditions. Mixture of HEDP acid with NH_4HF_2 produces an ammonium phosphonate salt and HF.

2.2 Experiments of acid injection

The cleaning out of geothermal wells to increase their productivity after scaling deposits constitutes the main application of the acid treatments. This technique has been used extensively in some geothermal fields in the Philippines (Buning et al, 1995; Buning et al, 1997; Malate et al., 1997; Yglopaz et al., 1998; Malate et al., 1999, Jaime-Maldonado and Sánchez-Velasco, 2003, Amistoso et al., 2005), in El Salvador (Barrios et al., 2002) and in USA (Morris et al., 1984, Entingh, 1999). It presents interesting results, such as the well injectivity increasing by 2 to 12-folds according to the studied reservoirs (Table 1).

At the Larderello geothermal field (Italy), several stimulation methodologies have been used successfully by ENEL (Capetti, 2006). Among them, chemical stimulation operations were carried out by injection of acid mixtures. First, various laboratory tests were realised on reservoir rock samples to optimize the HCl/HF ratios and the effect on mineral dissolution. Field tests have shown impressive results on five deep wells for reservoir rocks composed of phyllites, hornfels and granites: the improvement of injectivity, respectively productivity ranged from a factor 4 to 12.

In the field of EGS, few chemical treatments have been applied to stimulate reservoirs. In 1976, at the Fenton Hill Hot Dry Rock site (USA), 190’000 l of 1 N carbonate sodium base solution was injected to dissolve quartz from the formation and to reduce the impedance of the existing system. About 1’000 kg of silica were dissolved and removed from the reservoir but without impedance reduction. In 1988, a matrix acidizing was performed on the Fjällbacka reservoir (Sweden): major and minor fractures of the granitic reservoir were filled with calcite, chlorite and clay minerals. About 2'000 l of HCl-HF acid were injected in Fjb3 to leach fracture filling. Returning rock particles showed some efficiency of this acid injection (Wallroth et al., 1999). Several wells at Coso field, affected by calcium carbonate scaling, were treated by acid methods. A total of 30 wells were treated with HCl and 24 gave successful results (Evanoff et al., 1995).

Geothermal Fields	Number of treated wells	Injectivity Index (kg/s/bar)	Improvement factor
Bacman (Philippines)	2	0.68 → 3.01	4.4
		0.99 → 1.4	1.4
Leyte (Philippines)	3	3.01 → 5.84	1.9
		0.68 → 1.77	2.6
		1.52 → 10.8	7.1
Salak (Indonesia)	1	4.7 → 12.1	2.6
Larderello (Italy)	5	11 → 54	5
		4 → 25	7
		1.5 → 18	12
		-	4
		11 → 54	5
Berlín (El Salvador)	5	1.6 → 7.6	4.8
		1.4 → 8.6	6.1
		0.2 → 1.98	9.9
		0.9 → 3.4	3.8
		1.65 → 4.67	2.8
Beowawe (USA)	1	-	2.2
Coso (USA)	30	24 wells	successful

Table 1: Results of HCl-HF treatments for scaling removal and connectivity development

2.3 The case of the EGS reservoir at Soultz

The geothermal research program for the extraction of energy from a Hot Fractured Rock at the Soultz-sous-Forêts site began in 1987 (Hettkamp et al., 2004). The project aims to convert heat to electricity from a deep fractured and granitic reservoir. To extract the heat from the reservoir, three deviated wells have been drilled at a depth of 5'000 m and their bottoms are separated by 650 m. The fractured reservoir encountered at this depth presents a temperature of 200°C. One well (GPK3) is dedicated to injection of cold water in the granitic reservoir whereas the two others (GPK2 and GPK4), located on both sides of injector, are used to pump hot water.

Stimulation experiments and injection tests

Recently acid treatments were performed at Soultz-sous-Forêts (France). This deep granitic reservoir contains fractures partially filled with secondary carbonates (calcite and dolomite). In order to dissolve these carbonates and to enhance productivity around the wells, each of the three boreholes (GPK2, 3 and 4) were treated with different amounts of hydrochloric acid. If GPK2 and GPK3 have shown weak variations of their injectivity, GPK4 presented a real increase of its injectivity after the treatments.

GPK4 well

In February 2005, an acid injection was tested to improve the injectivity around GPK4 well. The experiment began on 22 February 2005 with an injectivity test of the well before soft acidification. It consisted of the injection of 4'500 m^3 of water at increasing flow rates (9 l/s, 18 l/s, 25 l/s) in 24-hour steps. The injection of water acidified by the addition of approximately 2 g/l of hydrochloric acid started on 2 March 2005 at a flow rate of 27 l/s. It lasted 2 days, followed by one day of injecting fresh water at much lower rates in decreasing steps. A total volume of 5'200 m^3 was injected; with a total weight of acid (HCl) of 11 tons. When the wellhead pressure was back to the value observed during the previous injectivity test, an identical test was repeated on 13 March 2003: injection of 4'500 m^3 of water in flow rate steps of 24 hours at 9 l/s, 18 l/s and 25 l/s.

In May 2006, new tests began with a test of the well injectivity before acidification. The acid treatment was performed in four stages :

- Injection of 2000 m^3 of cold water deoxygenized at 12 l/s, 22 l/s then finally at 28 l/s.

- A preflush of 25 m^3 HCl diluted at 15 % (3 tons) (with deoxygenized water) was pumped ahead of the HCl-HF acid mixture during 15 minutes at 22 l/s.

- A main flush consisted of the injection of 200 m^3 of Regular Mud Acid (RMA), (12 % hydrochloric (HCl)-3 % Hydrofluoric (HF) acid mixture treatment), with addition of a corrosion inhibitor, at a flow rate of 22 l/s during 2,5 hours.

- A postflush by injection of 2'000 m^3 cold water deoxygenized without inhibitor at a flow rate of 22 l/s then 28 l/s during 1 day.

When the wellhead pressure was back to a value identical to that observed in the previous injectivity test, a 3-day test identical to that of March 13, 2005 was repeated.

Results of acid stimulation treatments

Figure 1 shows the impact of the acidified water on the wellhead pressure during the first acid injection in GPK4 well. Despite the fact that the injection was performed in an over-pressurised reservoir, the injection pressure was decreasing during the last hours of the acidification test. Moreover, it is interesting to compare the data from two tests of water injection performed in the same conditions before (February 22, 2005) and after (March 13, 2005) the acid injection (Figure 1). Results (Gérard et al., 2005) show that after some 72 hours of water injection in the second test (24 hours at 9 l/s, 24 hours at 18l/s and 24 hours at 26 l/s), the GPK4 wellhead pressure was about 40 bars below the value observed in the same conditions before acidification. This represents a decrease of the apparent reservoir impedance seen from the wellhead by a factor ~1.5 (0.20 to 0.30 l/s/bar).

Figure 2 shows the impact of RMA acid job on the wellhead pressure by comparison before and after the second acid injection in GPK4 well. The repetition of the injectivity test showed that the difference in the over pressure values at the wellhead between the beginning of the test and the end were 16 bars. This represents a 35 % reduction of the wellhead pressure due to the acidification treatment. After some preliminary evaluation of downhole pressure changes, performed by Geowatt, this leads to a provisional estimate of GPK4 injectivity after chemical treatment of ~0.40 l/s/bar.

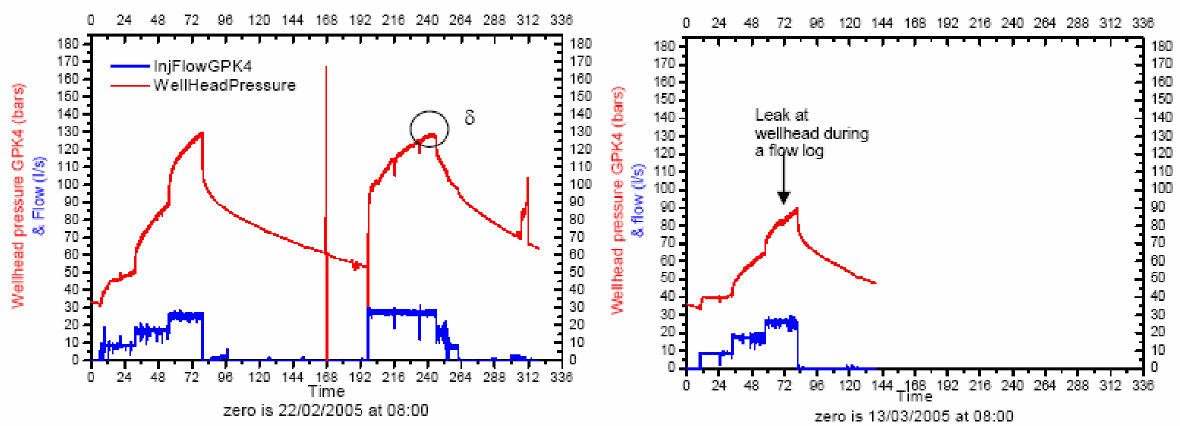

Figure 1: Impact of acidification test on GPK4; on the left, wellhead pressure before and during acidification injection, on the right, after acidification (Gérard et al, 2005).

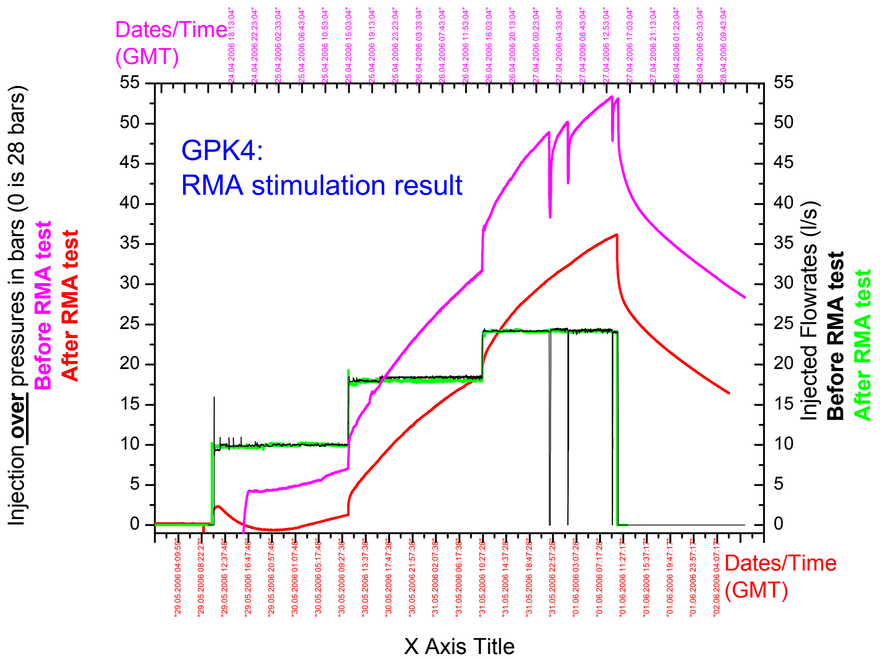

Figure 2: Impact of the RMA acidification test on the wellhead over pressure measured before and after the acidification test on GPK4 well (May 2006). (GEIE, 2006).

3. Modelling acidification impact on geothermal reservoir

The objective of the numerical simulation is to determine the impact of acid on the fracture minerals and on the reservoir properties.

3.1 Numerical modelling approach

To predict the impact of the acid treatment on the Soultz reservoir, the Thermo-Hydraulic and Chemical (THC) coupled code FRACHEM has been utilized. This THC code was built for the Soultz reservoir conditions. Instead of creating a totally new modelling programme, two existing codes, FRACTure and CHEMTOUGH2, have been combined in a new code called FRACHEM (Durst, 2002; Bächler, 2003; Rabemanana et al., 2003; André and Vuataz, 2005). FRACTure is a 3-D finite elements code and it determines thermal and hydraulic processes in fractured and porous rocks (Kohl and Hopkirk, 1995). CHEMTOUGH2 is a 3-D finite volumes code (White, 1995); it simulates the reactive transport and allows the variation of permeability according to chemical reactions occurring between fluid and rock of the reservoir. Considering the strong mineralization of brine and the high temperature of the reservoir, this last code has been modified by several implementations: thermodynamic model and computation of the activity coefficients of selected species in solution, kinetic model for dissolution and precipitation of minerals, as well as the relationship between porosity and permeability.

Knowing the high salinity of the brine of the Soultz system, The Pitzer formalism has been implemented in FRACHEM code to calculate the activity coefficients of selected chemical species; then, the precipitation/dissolution reactions of some minerals can be estimated. For the present time, the behaviour of eight minerals (calcite, dolomite, pyrite, quartz, amorphous silica, K-feldspars, albite and illite) is investigated. Detailed information on the determination of the reaction laws can be found in Durst (2002). At last, a supplementary module allows the determination of porosity and permeability variations linked with chemical processes occurring in the reservoir (André et al., 2005). The porosity variations are calculated and a combination of a fracture model and a grain model is used to determine the permeability evolution.

3.2 *Simulation setup*

Geometry

The same geometrical model as that presented in previous papers has been considered (André and Vuataz, 2005). The present application of FRACHEM is the modelling of a 2-D simplified model with a geometry close to the Soultz system. Injection and production wells are linked by fractured zones and surrounded by the impermeable granite matrix. The model is composed of 1250 fractured zones. Each fractured zone has an aperture of 0.1 m, a depth of 10 m, a porosity of 10%, and contains 200 fractures. This model allows an effective open thickness of about 125 m, while the mean openhole section of each well is about 600 m. Initially the temperature was set to the reservoir temperature of 200°C and the fractured zone contains the formation fluid.

One of these fractured zones is modelled with the assumption that the fluid exchange with the surrounding low permeability matrix is insignificant. Due to the symmetrical shape of the model, only the upper part of the fractured zone is considered in the simulation. The area is discretized into 222 2D elements (Figure 3).

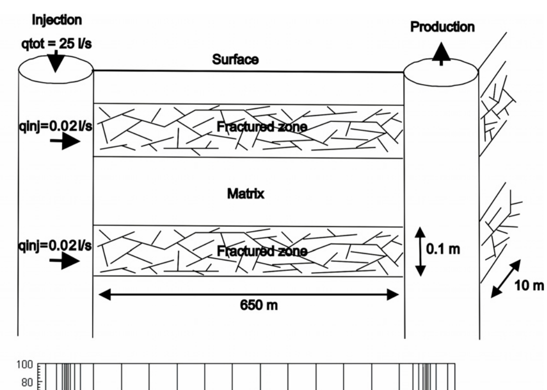

Figure 3: Simplified model and spatial discretization.

Considering a production rate of 25 l/s, the fluid was re-injected in each of the fractured zones at a rate of 2.10^{-2} l/s at a constant temperature of 65°C. During this simulation a constant overpressure of 8 MPa was assumed at the injection well and a hydrostatic pressure at the production well. Dirichlet boundary conditions were applied to the upper, left and right side of the model. The values of thermo-hydraulic parameters considered in the simulation are listed in Table 2.

Table 2: Thermo-hydraulic model parameters.

Parameters	Units	Fracture	Matrix	Fluid
Hydraulic conductivity	[m^2/Pa]	$7.4\ 10^{-8}$	10^{-15}	-
Thermal conductivity	[W/m.K]	2.9	3	0.6
Density	[kg/m^3]	-	2650	1000
Heat capacity	[J/kg.K]	-	1000	4200
Porosity	[%]	10	0	-

Rock composition

The mineralogical composition of Soultz granite given by Jacquot (2000) on GPK2 is assumed to be the same for the three wells (GPK2, GPK3 and GPK4) (Table 3). In the following simulations, the fluid is assumed to circulate within the hydrothermalised granite containing about 3.3 % of calcite and 0.8 % of dolomite.

Fluids composition

The fluid present in the formation is a NaCl brine with a pH of 4.9, a total dissolved solids of about 100 g/l and a temperature at the beginning of the simulation of 200 °C. The main characteristics of this fluid are given in Table 4.

The HCl solutions used to acidize the circulation fluid are highly diluted solutions (a fresh water) acidified to 2 g/l and to 15 g/l with concentrated HCl. These solutions are injected in the fractured zone at a temperature of 65 °C.

Table 3: Mean composition (in volume percent) of the different facies of granite in the Soultz reservoir (Jacquot, 2000).

Minerals	Healthy granite	Hydrothermalised granite	Vein of alteration
Quartz	**24.2**	**40.9**	**43.9**
K-Feldspar	**23.6**	**13.9**	
Plagioclases	**42.5**		
Illite		**24.6**	**40.2**
Smectite		**9.7**	**9.6**
Micas	**9.3**		
Calcite	**0.3**	**3.3**	**4.3**
Dolomite		**0.8**	**0.7**
Pyrite		**0.7**	**1.0**
Galena		**1.3**	**0.3**
Chlorite		**4.8**	

Table 4: Characteristics of the fluids used for the numerical simulations

Fluid		HCl solutions	Formation brine
Temperature (°C)		65	200
pH		1.3 to 0.4	4.9
Concentration (mg/kg)	Na^+	26.40	26400
	K^+	2.90	2870
	Ca^{2+}	4.75	6160
	Mg^{2+}	0.10	112
	Fe^{2+}	0.13	134
	SiO_2	0.36	364
	Cl^-	1455	54205
	SO_4^{2-}	0.07	63
	HCO_3^-	0.09	58

3.3 Simulation results of acid injections

We have been studying the impact of acid treatments on the Soultz reservoir properties near the injection well. The FRACHEM simulator is used to inject the adequate volume of acid in the model. The solutions are expected to circulate in a fractured zone composed of hydrothermally altered granite and their behaviour with respect to the minerals present in this granite is observed. When the desired volume is reached, the injection is stopped and the return to chemical equilibrium of the injected fluid is modelled. In the reservoir, a total pressure of 500 bars is assumed and the CO_2 partial pressure is fixed to 5 bars.

Concerning the acid solution used in the simulations, it should be noted that, for the time being, the code is not able to make the difference between the type of injected acid. It means that FRACHEM does not make the difference between hydrochloric and hydrofluoric acids. In this condition, the injection of an acid solution and the acid concentration are fixed by the H^+ concentration and by the total volume injected. Concentrated solutions are characterised by low pH solutions.

At last, it should be noted that the code calculates phases equilibrium between fluid and rock without taking into account the specific reaction rate of acid on carbonates. We suppose here that the reaction between acid and carbonates is instantaneous which is not a real disadvantage considering the high reactivity of HCl with carbonates and in particular with calcite.

Soft acidification

The duration of the numerical simulation was determined in order to simulate the real amount of acid injected in GPK4 in February 2005. The interpretation presented here are given for HCl injection of 60 hours at a flow rate of 25 l/s and at a concentration of 2g/l, equivalent to the 11 tons of HCl injected in GPK4 in February 2005.

The action of acid on carbonates has been investigated. Results show that acid solution dissolves carbonates in the first metres of the fractured zone. Around GPK4 (60 hours injection), the injected amount of HCl affects the first 3.5 metres around the injection well (Figure 4). Due to the respective reaction rate of each mineral, it should be noted that dolomite has dissolution rates two orders of magnitude smaller than calcite (Figure 5). Comparatively to a normal brine injection, after 60 h, the acid injection involves an increase of dissolved calcite and dolomite.

HCl acidification has a weak impact on other minerals: it only decreases the precipitation rate of K-feldspar, albite, illite and amorphous silica (Figure 6). Finally, quartz is not affected by this type of acidification (Figure 6).

All these dissolution processes cause an increase of about 2.0 % of rock porosity in the short interval of 0.5 m around the injection well and 0.1 % in the interval 0.5-1.5 m. This estimation of the reservoir changes is linked to the choice of the porosity model used in FRACHEM, namely the double fracture and grain model.

In conclusion, we can suppose that the volume of injected acid in the first soft acidizing test on GPK4 had only an impact on the first 4 metres around the injection well. With these rather small acid amounts, the impact on the reservoir properties seems to be limited, although the porosity increases in the close vicinity of the wells due to carbonates dissolution.

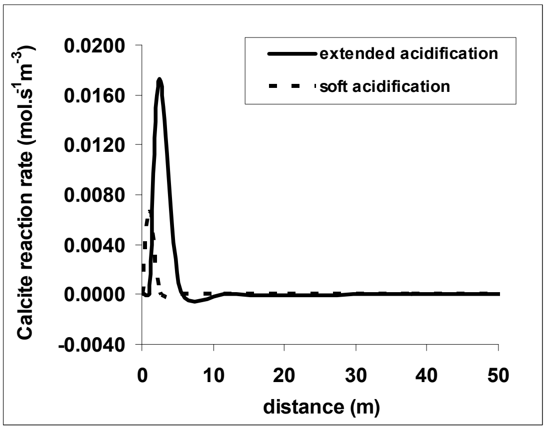

Figure 4: Variation of calcite reaction rate after acid injection.

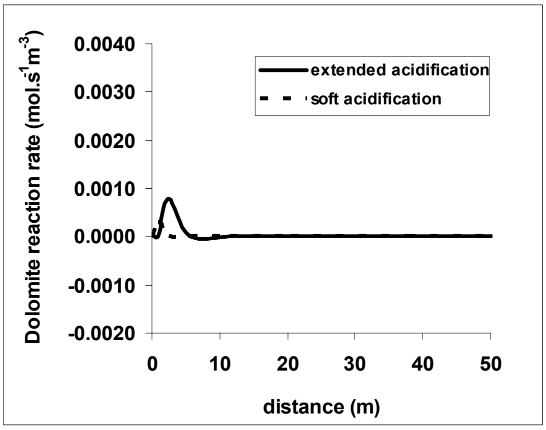

Figure 5: Variation of dolomite reaction rate after acid injection.

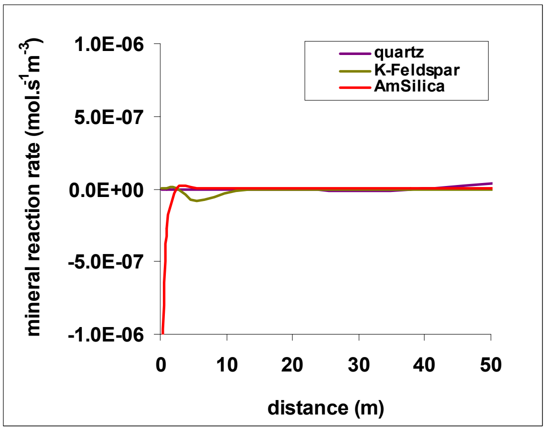

Figure 6: Variations of quartz, K-Feldspar and amorphous silica reaction rate after soft acid injection.

Influence of injection flow

The chemical stimulation of an EGS reservoir is effective if the acid can reach fractures distant from the injection well. In order to simulate this process, the flow was doubled meaning that the acid solution, at a concentration of 2 g/l, was pumped at 50 l/s. In these conditions, the 11 tons of acid are injected in 30 hours, compared to the 60 hours of the previous simulation. We observed that doubling the flow allows a farther transport of acid within the fracture. Less calcite is dissolved near the well but the impact of acid is visible up to 7.5 metres (Table 5). The same phenomenon applies to dolomite. Dissolution rate of this mineral is two orders of magnitude smaller than calcite. Consequently the impact of acid is still active beyond 15 metres along the fracture.

Table 5: Variation of the proportion of carbonates around the injection well according to variable transport flow

Distance from injection well (m)	Injection at 25 $L.s^{-1}$		Injection at 50 $L.s^{-1}$	
	Calcite (%)	Dolomite (%)	Calcite (%)	Dolomite (%)
0 0.5	- 19.70	- 5.73	- 18.80	- 6.00
0.5 1.5	- 1.40	- 0.12	- 1.02	- 0.10
1.5 3.5	- 0.15	- 0.15	- 0.37	- 0.06
3.5 7.5	0	- 0.10	- 0.10	- 0.05
7.5 15	0	0	0	- 0.05

Extended acidification

In May 2006, GPK4 well was stimulated by injecting 98 tons of HCl during a period of 2.5 hours. This second acidizing treatment used hydrochloric acid at a concentration of 12 % and hydrofluoric acid at a concentration of 3 %. After this injection, the acid is displaced within the formation by injecting about 2'000 m^3 of fresh water. The results showed a decrease of the injection pressure in the vicinity of the injection well, as the calcite was dissolved and progressively carried away. The response of the model to the acid addition has been examined.

Influence of high acid concentration

Knowing that the code is not able to make the difference between the type of injected acid, a numerical simulation was carried out to investigate the impact of this acid injection at a concentration of 15 g/l. This simulation was performed with fresh water. Its pH was lowered to 0.4, whereas the injection rate within the fractured zone was maintained to 2.10^{-2} l/s. Therefore, the flow was fixed at 25 l/s and the duration of the injection was 70 hours. The total amount of injected acid is equal to 98 tons. The results indicate that calcite is as usual, the most affected mineral by the acid injection. Respectively to the extended acidification, the increase of acid concentration seems to augment the dissolution processes in the first meter around the injection well, and the impact of acid is also noticeable farther in the formation (Figures 4, 5 and Table 6). The porosity increases mainly in the vicinity of the injection well of about 4.5 % (Figure 7) instead of the 2.0 % estimated with a soft acidification. This increase of porosity is expressed by an injectivity rise in the zones affected by acidizing treatment.

In conclusion, the extended acidification amplifies the amount of dissolved calcite of about 70 % around the injection well. We can also suppose that the volume of injected acid in the second test on GPK4 had an impact on the first 10 metres around the injection well. The simulation results were consistent with those of the experiment. The additional H^+ ions significantly modify the calcite reaction rate around the injection well. The additional acid reaction leads to significantly drop the pressure around the injection well (Figure 8). This brine acidification implies a decrease of about 4 bars near the injection well, corresponding to a reduction of about 5 % of the pressure in 70 hours. This result is linked to the enhanced dissolution of calcite within the fractured zone. As the reservoir permeability and porosity are controlled by the occurrence of mineral precipitation and dissolution, this stronger calcite dissolution implies an improvement of the reservoir properties, namely the hydraulic impedance of the injection well.

Table 6: Variation of the amounts of carbonates and quartz near the injection well according to the amount of acid injected.

Amounts of minerals (kg)	Calcite	Dolomite	Quartz
Soft acidification	-15.4	-13.8	+0.0207
Extended acidification	-145	-35.6	+0.0129

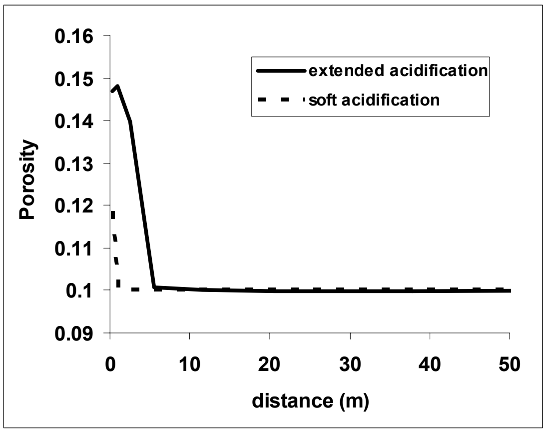

Figure 7: Porosity variation at different distance from the injection well after acid injection.

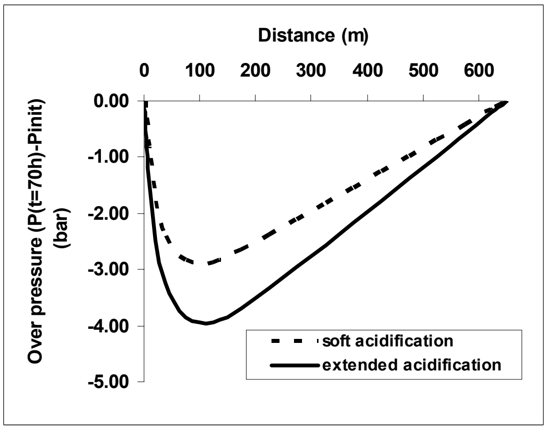

Figure 8: Variation of the pressure at different distance from the injection well after acid injection.

3.4 New improvements of the simulation

In order to improve simulation of the acidification processes, some new results of acid injections simulations using FRACHEM code are presented here. Porosity evolution resulting of acid injection has been observed according to three main parameters:

- acid concentration, varying from 2 to 15 g/l of HCl.

- flow imposed to the system, ranging from 10 to 50 l/s.

- duration of acid injection / circulation fluid in the fractured zone, reaching 0.5 to 10 days.

For a limited acid injection (10 l/s at 2 g/l), acid effect on dissolved carbonates and on penetration within the reservoir is very restricted. At this flow, a real impact on reservoir properties is only obtained for extended injections of many days and for high acid concentrations. After an injection of 10 days of a solution at 15 g/l, all carbonates are dissolved in the first 0.5 metres around the injection well but only 65 % in the range 0.5 – 1.5 m. The relative weak effect of a small flow is shown here.

Nevertheless, for the other simulations at this flow, it seems that acid concentrations of about 7 to 15 g/l could have a positive impact up to 7.5 metres away from the injection well, and for a relatively limited injection time (5 days).

Injected acid reacts of course with carbonates (calcite and dolomite). According to mineralogical data, these compounds represent more or less 5 % of the hydrothermally altered granite. From this proportion and in case of a massive acid injection, all carbonates can be dissolved by acid solution leading to a porosity of about 0.15.

Obviously, the best results are obtained for long-term injections of high-concentration acid solutions. In these conditions, the impact radius can reach 15 metres around the injection well. Considering these conditions (for example 15 g/l and 50 l/s), it should be noted that the important amount of injected acid is able to dissolve carbonates (calcite + dolomite) up to 7 metres from the injection well, even for very limited injection times (2.5 days), (Figure 9).

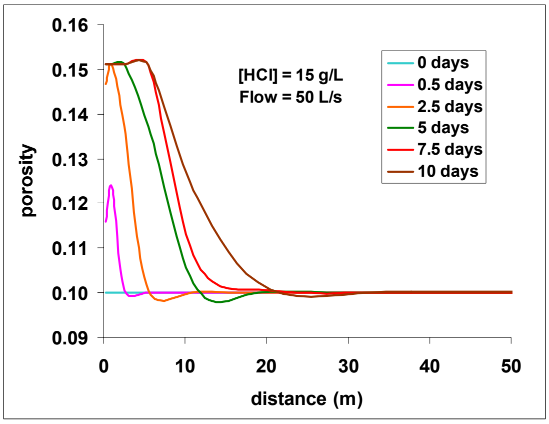

Figure 9: Porosity evolution of the fractured zone according to acid concentration and time of acid circulation and for a flow in the fractured zone of 50 L/s.

Finally, the increase of acid concentration involves an augmentation of dissolution processes but always in the first 5 metres around the injection well. Due to the high reactivity of HCl, the rock volume affected by acid is relatively small. An increase of the flow should allow a better dispersion of acid within the formation. The increase of the acid injection pressure to simulate a fracture acidizing allows a farther acid transport trough the fractures (Figure 10).

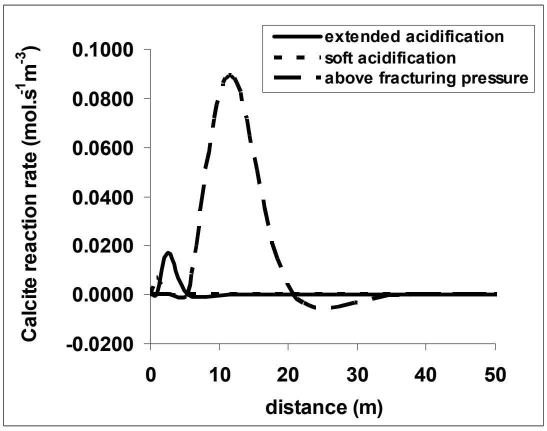

Figure 10: Variation of calcite reaction rate after acid injection below and above fracturing pressure.

4. Conclusions

Recent acid treatments have been successfully performed in geothermal granitic reservoirs such as at Soultz and encouraging results were obtained on GPK4 well.

Some numerical simulations using FRACHEM code were performed to better understand the acid behaviour within the reservoir. Considering the geometrical model used for the simulations and the different assumptions about fluid and rock compositions, some estimations have been proposed.

Simulations result indicate that carbonates are the most dissolved minerals by hydrochloric acid.

For GPK4 well, the first acid injection lasted 3 days at a concentration of 2 g/l (about 11 tons of acid injected in the reservoir). According to the simulation of this test, the amount of acid is just sufficient to dissolve half of the carbonates initially present in the range of 0 – 0.5 metres. Farther in the fracture, the impact is quasi nil.

Simulation of extended acid injection performed in May 2006 (about 98 tons of acid injected in the reservoir) seem to show a significant dissolution of carbonates around the injection well. The increase of acid concentration augments the reactivity in the vicinity of the injection well and enhances the porosity.

Nevertheless, the high reactivity and a weak flow prevent the penetration of acid in the far field between the wells. This high reactivity also involves the risk of creating wormholes, able to increase the porosity but not always the permeability of the fractured medium.

Finally, we have demonstrated that acid injection can play a significant role in the development of porosity around injection wells. It was shown that HCl acid has the possibility to react with carbonates, dissolving them and opening new pores within the reservoir. The positive effect of acid injection on porosity is proportional to the amount of injected acid.

Looking for commercial production rates of the wells, other chemical stimulation techniques should be considered, such as fracture acidizing, more complex acid compounds and chemical retardants. These types of acid jobs should have a more pronounced effect on the fracture network of the far field and eventually connect injection to production wells.

Acknowledgements

The authors thank the State Secretariat for Education and Research and the Swiss Federal Office of Energy for funding this project (OFES-N° 03.04.60). The authors are also grateful to André Gérard of the GEIE at Soultz and Thomas Kohl of GEOWATT AG (Zürich) for their scientific support.

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