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Methods for Selective Plugging of Geothermal 'Short Circuits'

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1. ABSTRACT

Rapidly cooled flow pathways, commonly referred to as short circuits, can pose significant problems in geothermal systems, decreasing production temperatures and reducing plant energy production and efficiency. The 2006 MIT report on the future of geothermal energy notes, for example, that one fracture in the Soultz system takes 70% of the total fluid flow through that reservoir and "this channeling, if left uncontrolled, will effectively reduce the useful recovered thermal energy of the entire reservoir." Clearly a method is needed to reduce flow through short-circuit pathways in which cooling fronts have reached, or nearly reached, the production well.

Temperature dependent 'plugging' agents have been proposed as one means of selectively reducing the permeability of prematurely cooled fracture flow paths. In the proposed method, compounds that are soluble or unstable at reservoir temperature, but solid and stable at slightly cooler temperature, or more viscous at lower temperature, would be injected into the cooled flow paths to reduce their permeability and thereby redistribute flow to more favorable flow paths. Several simulation studies have demonstrated how the emplaced material could effectively improve flow distribution and restore reservoir productivity. The heretofore unexplored problem with injection of temperature-dependent 'plugging' agents, however, is that it is difficult to emplace the material into cold flow paths without also doing so in the equally cooled upstream portion of the still 'hot' flow paths.

In this study, we examine delivery methods that might be used to emplace such permeability reducing agents, and some of the difficulties involved in different approaches. We focus on delivery methods that leverage differences in the temperature – travel-time histories between pathways, as we believe such methods offer the most effective means of selectively altering permeability. To demonstrate some of the complexities of selective permeability modification in fractures, we use a numerical model heat and mass transfer in a simple fracture system that models disparate cooling of two fractures, and the adjacent media. We conclude with a summary of the difficulties that must be overcome to make this method, or any such method, practical for industrial application.

2. INTRODUCTION

Worldwide, generation of electricity from geothermal energy currently relies almost entirely on exploitation of hydrothermal reservoirs, natural fractured convective systems that are relatively rare. As a consequence, the amount of electricity generated from geothermal sources is relatively small in comparison to the total electrical production from other resources. Engineered geothermal - , or 'hot dry rock', systems (EGS) offer as an alternative means of extracting heat energy from the Earth, using manmade, rather than natural, fracture systems. Such systems could exploit enormous reserves of heat energy stored at depths of 5 – 10 km. Estimates suggest that more than 2,000 times the total annual energy use of the United States could be supplied, using existing technology (Tester et al. 2006). However, exploitation of these energy reserves may require that effective means are available to mitigate the effects of rapidly cooled pathways through the developed fracture network.

3. BACKGROUND

Cold fluids may be injected into engineered geothermal systems (EGS) and conventional geothermal reservoirs to help extract heat from the subsurface or to maintain pressures within the reservoir (e.g., Rose et al., 2001). As these injected fluids move along fractures, they acquire heat from the rock matrix. As a consequence, a cold-fluid front migrating through each of the flow paths (Figure 1A) will eventually reach the production well and decrease the temperature of the produced fluids (thermal breakthrough). The migration of this front is faster in fractures with large aperture and in sets of closely spaced fractures. Breakthrough of cold water at the production well from such pathways can severely reduce energy production. As one example, the MIT report (2006) on the future of geothermal energy notes that one fracture in the Soultz system takes 70% of the total fluid flow through that reservoir and "this channeling, if left uncontrolled, will effectively reduce the useful recovered thermal energy of the entire reservoir." Clearly a method is needed to reduce flow through short-circuit pathways in which cooling fronts have reached, or nearly reached, production wells.

The goal of selective permeability reduction is to preferentially emplace some sort of treatment agent in those fast pathways that will disproportionately decrease their permeability, preferably without also doing so in the lower permeability paths (Figure 1B). This would reduce the flux through those prematurely cooled pathways, concentrate flow in the remaining fractures (Figure 1C), and thereby increase production well temperature. Ideally, this method would be applied after the available heat from those 'short circuit' pathways has been extracted, but before the associated cooling of those paths has reached the production well. SPR methods may thus depend on reactive tracers of cooling front propagation to determine when and how to effectively deploy them. In this paper we examine the delivery methods that might be employed to implement selective reduction of hydraulic conductivity.

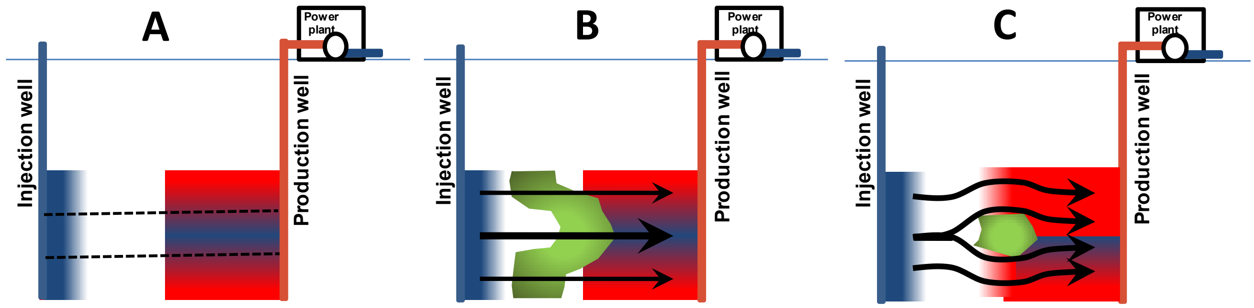

Figure 1. Schematic diagrams illustrating temperature distribution in a fractured reservoir comprised of three fracture zones where colder fluid (blue) is being injected and hot fluids (red) are being produced. Panel A shows that upper and lower fracture zones are cooled only near the injection well while the cooling front in the middle zone has progressed almost to the production well. Panel B illustrates behavior of permeability modification agents immediately after addition to the injection well to obstruct short circuit pathways. Panel C illustrates conditions after temperature-dependent kinetics have triggered SPR in the path with extensive cooling.

4. PREVIOUS WORK

While several investigations have examined selective permeability reduction in geothermal systems, most of those studies have focused on the effects of successful delivery of some permeability-modifying agent, and not the difficulties of the delivery itself. Ezzedine (2012), for example, provides a detailed modeling study of the long-term effect of a hypothesized selective permeability reduction emplacement, but appears not to have included study of the delivery method. Application of selective sealing methods to geothermal systems are generally focused on diversion agents that temporarily seal fractures during the stimulation process to allow hydrofracturing of additional zones (e.g., Petty et al. 2011, Rose 2010). AltaRock Energy, Inc. (Petty et al. 2011), for example, uses a temporary permeability modification agent to alter the pressure distribution in a borehole during stimulation of a geothermal well, injecting a solid particle diverter agent that temporarily reduces permeability of some fractures in order to promote pressurization, and stimulation, of others. The diverter material has a temperature-dependent degradation rate, and is designed to degrade relatively quickly after emplacement, but its use as a means of redistributing flow after a long period of plant operation has not been suggested. Introduction of such an agent into an injection well after substantial cooling has occurred could potentially block all flowpaths, because the injection point is the coldest location in the system.

Methods of modifying fracture permeability via precipitation or dissolution chemistry have been more heavily explored in the oil and gas recovery literature, particularly in the context of enhanced oil recovery (EOR). In that industry, relative permeability modification (RPM) or disproportionate permeability reduction (DPR) is applied to reduce permeability to water flow to a greater extent than to oil or gas flow (Seright 2006). In a discussion of methods for altering the swept region in a petroleum reservoir, Reis (1994) reviews several methods by which permeability may be selectively reduced to improve enhanced oil recovery. Perhaps the simplest of the available methods is the injection of solids with particle size selected so that the material may enter wider aperture fractures that have cooled faster than other, smaller aperture, fractures. The particles enter the fractures and travel some distance before bridging, and thus forming an aggregation point for following particles, the collection of which acts to reduce fracture permeability. While this has the advantage of simplicity, the method requires that the fast pathway have greater aperture at the injection point. In reality, a preferentially cooled path can result from a large-aperture section with small aperture entrance/exit points if sufficient fracture width exists to provide the same overall transmissivity in those areas.

Several authors have proposed EOR methods involving temperature-dependent effects. The work most relevant to geothermal problems appears to be that of Acock and Reis (1994) and Reis (1994) who considered the thermally induced precipitation as a means of improving oil recovery during water flood operations. They suggested that treatment solutions injected through preheated thief zones could cause cooling-induced precipitation of a variety of chemicals, including potassium carbonate and sodium borate. The pretreatment heating is used to allow subsequent flow to create variation in temperatures along different flowpaths, where greater flow would cause greater cooling. The resulting mineral precipitation in the colder paths would then improve sweep efficiency of water used to displace hydrocarbons. In a geothermal system, the reservoir is naturally preheated, so no artificial ‘preheating’ is necessary. The drawback with this approach for application to a geothermal system, however, is that essentially all flowpaths are cold near an injection well, so that cooling-induced precipitation would block low-permeability paths as well as preferential ‘fast’ paths.

Sharp (1989) described a more complex temperature-dependent treatment method for improving reservoir sweep efficiency in secondary and tertiary oil recovery operations. That method involves injection of a material at a temperature higher than its melting point, which would then cool and solidify in the reservoir. Prior to injection of the treatment agent, the well region is preheated via high temperature fluid injection. This allows the injected material to pass through the cool region immediately surrounding the well and penetrate to distances at which there exist substantial differences in the degree of cooling. After injection, the well is shut in for a period that allows the material to cool and solidify. The borehole region is then reheated via a conductive heating process which theoretically would only remove the solidified material from the cooled portion of the smaller pathways cooling would not extend far from the well in those pathways. A problem with this method in application to geothermal systems is that the cooling front in virtually all useful flowpaths - after any substantial period of plant operation - would likely extend well beyond the characteristic length for conduction for a reasonable treatment period. The characteristic length for heat conduction in rock, for a heating period of 1 month, for example, is approximately 3 m, so conductive reheating would release solidified material from fractures only to that distance. In contrast, for fractures with flow rates designed for a 30-year plant life, the (1/e)-fold cooling distance is approximately 125 m after 10 yrs.

Complex methods involving precipitation of solids by chemical reaction have also been proposed. Precipitation of solids may be effected by introduction of two solutions with a time-dependent, as well as temperature-dependent reaction rate. Richardson (1971) and Richardson and Scheuerman (1973) proposed a treatment method involving injection of an aqueous solution containing two agents: (1) a dissolved salt of a metal that precipitates as a gelatinous, hydrous, or hydrated metal oxide or hydroxide at a pH higher than that of the solution and (2) a dissolved material that reacts within the solution to, over time, raise the pH to that needed to cause precipitation of the first agent. Torrest and Huang (1987) showed that gelation time of a hydrated aluminum oxide gel could be controlled by pH adjustment and that conductivity reductions of up to 98% could be achieved. In these approaches, the goal is to delay formation of a precipitate until the reactants are transported to a location where treatment is desired. Inclusion of a temperature dependence in treatment reaction would seem most beneficial if the region requiring treatment is warmer than other regions, as few reactions have the reverse Arrhenius behavior that would promote reaction in colder regions.

Finally, multi-stage treatments have been proposed that involve multiple chemical agents injected at different times. Hower and Ramos (1956), for example, described a two-stage treatment designed to reduce permeability of thief zones in EOR. A first injection includes a chemical agent that is preferentially adsorbed to the rock surface. A water spacer is then injected to reduce adsorbed concentrations near the well and then a second solution is injected that reacts chemically with the adsorbed compound to forma a water-insoluble, gelatinous precipitate. Needham et al. (1974) and described a similar method involving more stages, involving injections of (1) a sorbing polymer solution, (2) an aluminum citrate solution, in which the aluminum ions are retained in the adsorbed polymer, (3) a second polymer injection, and , finally (4) a brine solution. Permeability reduction was effected by crosslinking of the second polymer cycle with aluminum ions and reduction factors of 3 to 4,170 were obtained in treatments in sandstone.

Complex mixtures of polymeric solids, or gels, while not actually modifying permeability, effectively alter hydraulic conductivity by increasing the fluid viscosity. If gels can be placed in such a way as to sufficiently reduce hydraulic conductivity that the effect is maintained for sufficient time, they might provide the ‘plugging’ action necessary to favorably redistribute flow. Considerations for gel injections include controlling the time for gelation to occur, which is influenced by temperature, pH and metal content of the gel. Reis (1994) notes that methods that result in water-insoluble gelatinous precipitates are more effective than methods producing crystalline materials.

5. PROPOSED SELECTIVE PERMEABILITY ALTERATION METHODS

Reservoir influences

In this study, we examine delivery methods that could, through temperature differences, or flow behavior, selectively reduce the permeability of preferentially cooled pathways in a natural or engineered geothermal system. Understanding the velocity, flux, and temperature distribution in fractures in a geothermal system is thus essential to evaluating the potential for successfully deploying SPR. Those factors define the conditions that produce premature cooling, and rapid cooling is not limited to the shortest paths nor even the fastest flow paths, so the term ‘short circuits’ can be misleading. Second, treatment methods that rely on some form of temperature-dependent reaction or ‘triggering’ should be quantitatively related to the relative positions of cold fronts within different flow paths.

We demonstrate how cooling may progress in a fractured system using calculations based on the Gringarten (1975) solution for heat flow in parallel fractures of uniform spacing. We consider sets of fractures of varying fracture aperture, interfracture spacing, and fluid velocity, the primary controls on cooling behavior. While the discussion thus focuses on comparison of cooling in different fractures, similar comparisons could be made for different flow paths within the same fracture, where preferential flow occurs along fracture paths with greater aperture.

If we assume that volumetric fluid flow, Q, through each fracture in a reservoir consisting of rectangular fractures each subject to the same pressure drop, then the fluid flux per unit aperture thickness and height, q, length, L, and aperture, b, can be determined from the cubic law for fracture flow,

$$q = \left(\frac{\rho g}{\mu} \frac{b^2}{12} \frac{\Delta p}{L} \right)$$

where ρ is fluid density, g is gravity, μ is dynamic viscosity, and Δp is the total pressure drop across the system. For a system of fractures of uniform height and length, but different aperture, the volumetric fluid flux per unit cross sectional area is proportional to the square of the aperture. However heat extraction is a function of the fluid flow per unit height and the rate of cooling a fracture is therefore proportional to the cube of the aperture. Thus, for a single fracture that has variable fracture aperture pathways, the fracture path with greater aperture will show a greater extent of thermal breakthrough with time that that of the lesser aperture. Similarly, for two fractures of varying apertures, the fracture with the larger aperture will show faster thermal breakthrough.

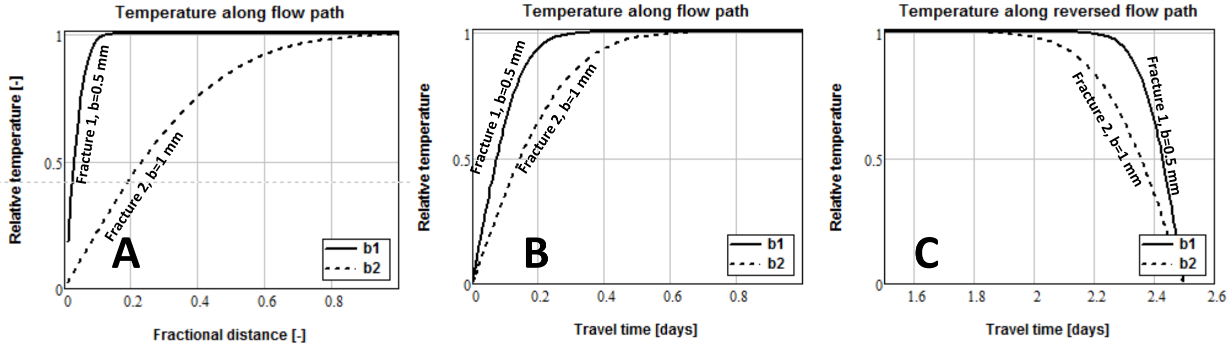

Figure 2. Relative temperature ([T – Tinj]/[Tres – Tinj]) vs. fractional distance along flow path (A) and vs. travel time (B and C) for a 0.5-mm and 1.0-mm fracture, where the velocity in the narrower fracture is 200 m day^{-1}. Temperatures reflect thermal evolution over a ~10-year period.

As an example, we consider the thermal evolution of two 500-m long fractures, one with an aperture of 0.5 mm and another with double that aperture. In each fracture, interfracture spacing is sufficient that there is no overlap in the cooling fronts propagating away from the fracture faces into the rock. If the fluid velocity in the 0.5-mm aperture fracture is 200 m day^{-1}, then by equation (2) the permeability in the larger fracture is four times greater, and its transmissivity 8 times greater. Because the pressure drop is assumed to be the same for each fracture, the velocity in the 1-mm fracture is four times that of the smaller fracture. Thus, the temperature evolved in these fractures after ~8 years (arbitrarily selected to illustrate fracture cooling prior to thermal breakthrough at the production well), is shown as a function of normalized distance along the flow path in Figure 2A. The cooling front in the wider aperture has progressed further than in the narrower fracture, to the point that thermal breakthrough effects from this fracture would just be evident in the production temperature. To alter the permeability of the colder fracture via a chemical reaction that takes advantage of temperature differences, however, we must consider the temperatures that would be encountered as a function of time after injection, which is different than plotted in Figure 2A because of the differences in velocities between the two paths. When velocity is accounted for, via a plot of temperature vs. travel time (Figure 2B), the differences are less pronounced, but still significant.

The above discussion illustrates how fractures with different aperture can develop different temperature – travel time histories. Similar effects can be caused by differences in interfracture spacing, even where the aperture is the same. For sets of fractures, cooling fronts progressing from adjacent fractures into the rock will overlap after some time of operation that is inversely proportional to the spacing. Using the 1-mm fracture and flow characteristics of the above example, Figure 3 illustrates the effect of a 4-fold and 8-fold decrease in fracture spacing from an initial value equal to twice the characteristic length for heat conduction in the rock. In this case, aperture and, therefore, velocities are unchanged, so travel time is equivalent to flow-path distance. As with the reduced aperture example, the cooling front for the more closely spaced fractures has advanced significantly further toward the extraction well than for the 100-m spacing, but in this case the shape of the cooling front is also different. With changes only in aperture, the injection temperature is preserved only very close to the injection well, and temperatures rise in a smooth curve all the way to the far end of the fracture. With decreasing space between fractures, the amount of interference between them increases, and cooling increasingly proceeds as a distinct front, with the injection temperature preserved for a greater distance away injection.

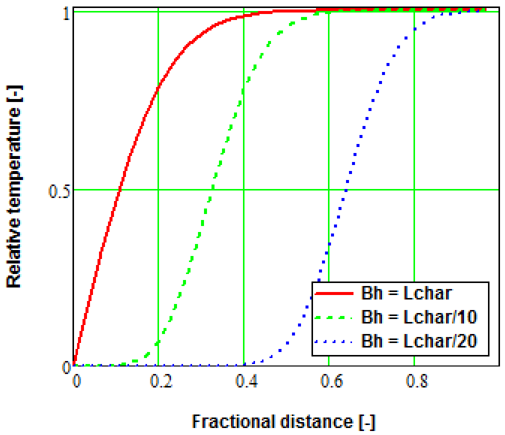

Figure 3. Temperature vs. travel time for three sets of 0.38-mm fractures with interfracture spacing specified in the legends. Fracture flow velocity = 500 m day^{-1}. Relative temperatures reflect thermal evolution over an ~8-year period.

Selective Permeability Reduction Delivery Methods

While numerous materials appear to have the desired effect of reducing the hydraulic conductivity of a fracture, practical application of such treatments is not without difficulty, and substantial problems exist in delivery of the desired treatment even in purely theoretical considerations. First, while different temperature-time histories may develop along different flow paths, temperatures near the injection point are cold in all paths, so simple temperature-dependent plugging would effectively seal all fractures at the injection point. Another difficulty may arise with delivery methods that depend on differences in fracture aperture to selectively reduce flow through cold pathways. As described above, premature cooling can also result from tightly spaced collections of small-aperture fractures. In that case, a method relying on fracture aperture, such as solid particle size exclusion, or methods relying on travel-time vs temperature differences would likely fail. Finally, methods that rely on altering the temperature of the rock during the treatment will likely require multiple pore volumes to be effective, and thus require longer treatment periods than is desirable, or practical. The problem of reducing permeability in rapidly cooled flow paths in a geothermal system differs from the EOR problem in that the timescale involved in the cooling period may be quite different than that involved in the treatment. That is, while it may take years, and many pore volumes, to cool preferentially cooled paths to the point that mitigation is needed, duration for the treatment period should be, if possible, much shorter, on the order of days to weeks. In an EOR situation, in contrast, the mass removal from high-flow pathways may occur quite quickly. Thus, the distance that treatments must penetrate in EOR is more similar to the distance over which the problem exists that would be the case in a geothermal system.

We suggest a number of delivery methods that may be used for SPR and roughly distinguish these by whether they involve only forward flow through the system or some combination of forward and reverse flow. Size exclusion methods are perhaps the most obvious option for forward-flow SPR, if it can be demonstrated that the degree of permeability reduction is not simply proportional to the aperture of the fractures encountered. Because forward-flow injections (i.e. operational flow regime is maintained) will encounter cold water in the upstream portion of all paths, temperature dependent SPR methods will likely also require some kinetic effect that will delay the desired reaction until the reactants escape the low-temperature zone (as illustrated in Figure 1) in the warm paths but not in the cold paths. An obvious disadvantage of this approach is that it requires a reaction that occurs preferentially in colder temperature water, but is also delayed during transport through the coldest portion of its flow path. Reactions with inverse temperature dependence are unusual, but do occur in complex reaction mechanisms. As the simplest case, consider a forward reaction that is exothermic. As temperature increases, the reaction shifts toward the left, by LeChatelier's principle, so that the reverse, endothermic, reaction may dominate at high temperature.

Alternative treatment scenarios, that may be difficult operationally but have several advantages, involve temporary reversal of flow between the wells, with injection into the 'production' well for a period shorter than that needed to complete pore volume displacement in the smaller fractures. Assuming that preferential cooling results from differences in fracture aperture, an injection in the reverse direction would flow faster in fractures with wider aperture. Any SPR method that preferentially reduces flow in colder paths could work in this scenario, as reverse flowing injectate would first encounter cold temperatures in the faster flow paths. In that case, a variety of SPR methods might be used successfully. This includes materials with suitable phase change temperature or that dissolve at higher temperature, particles with a tendency to aggregate at colder temperature, fluids with temperature-dependent viscosity, or reactions with inverse Arrhenius temperature dependence.

Finally, a more complex treatment scenario, may involve a combination of forward and reverse injections. Reis's (1994) summary of SPR methods applied for EOR suggests that methods that create a gel precipitate are most effective at reducing permeability. Because Arrehenius kinetics produce faster reaction rates at higher temperatures, it might be difficult to find materials that would precipitate preferentially at lower temperature. A two-stage injection method, similar to those proposed for EOR, might provide a solution. In this scenario, a sorbing compound would first be injected in the forward flow direction, with the aim of extending the chemical front slightly more than one half a pore volume into the larger fractures. A second compound, designed to form a precipitate upon reaction with the sorbed compound, would then be injected in the reverse direction. Because velocities are higher in the wider aperture pathways, the reactants should intersect first in those paths. While this method is disadvantageous in its complexity, it has the advantage of not requiring temperature dependent reaction.

6. NUMERICAL SIMULATION EXAMPLE

To enable further testing of various SPR delivery methods, we have begun developing numerical simulations aimed at designing suitable laboratory experiments. As a simple example that illustrates some of the difficulties of delivery, we describe numerical simulation of a method involving reverse injection of a material with temperature dependent viscosity. The SPR agent in this scenario is an aqueous solution of Polyethylene Glycol 3350-$MgSO_4$ (PEG 3350), with temperature-dependent and concentration-dependent viscosity as illustrated in Figure 4. In the example given, we consider flow in a 2-D domain into two 500-m fractures, one with 0.5-mm aperture and one with 1-mm aperture, as illustrated in Figure 6. Injection- and initial reservoir temperature are 10°C and 60°C, respectively. In the experiment, scaled to the laboratory with respect to temperature, but using reservoir scales for time and length, we cool the system with flow into a channel that connects the fractures at the left end and apply constant pressure in the channel at the far end. Inputs and outputs of the modeling domain, and its temperature distribution after 8 years of injection at a flow rate of 1.04E-5 m^2 s^{-1}, are shown as **Error! Reference source not found.**.

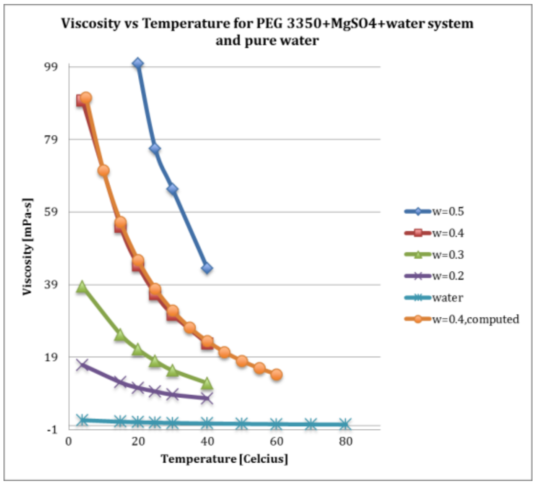

Figure 4. Viscosity as a function of temperature, at different concentrations (mg/mg) of a solution of PEG 3350 and $MgSO_4$.

A temperature-distance plot (Figure 8) after the 8-yr cooling period illustrates how much further has progressed the cold front in the wider aperture fracture. Immediately following that period, we simulate injection of the polymer solution into the production 'well,' at a concentration of 40%, by reversing the location of the pressure and injection points. Because hundreds of pore volumes are required to cool the rock (pore volume ≈ 1 day) and the treatment injection is on the order of one pore volume, temperature remains constant during the treatment. In this example, where the pore volumes are known a priori, the treatment injection has the desired effect of complete penetration of the large-aperture fracture, but only partial penetration of the smaller fracture (**Figure 6**). This has the desired effect of increasing the viscosity of the fluid in the large fracture more than in the smaller fracture. Figure 7 shows the fluid viscosity, normalized to the temperature-dependent viscosity of pure water, in the two fractures at the end of the treatment period, and after a return to normal flow direction, at approximately the same pressure gradient as in the initial operating period.

In this example, although the treatment agent is distributed in a potentially suitable manner, the viscosity effect is completely reversible, and when the normal flow direction is reestablished, the treatment agent is rapidly pushed back out of the system (Figure 7). In this situation, two additional effects are needed to produce the desired SPR. First the viscosity effect would have to be irreversible, either through time-dependent delay of reaction of a multiple reactant injection or via a multiple-stage injection employing a sorbing compound as a first reactant. Second, to remove the resulting gel/precipitate from the smaller fracture, the precipitated SPR would also have undergo thermal degradation.

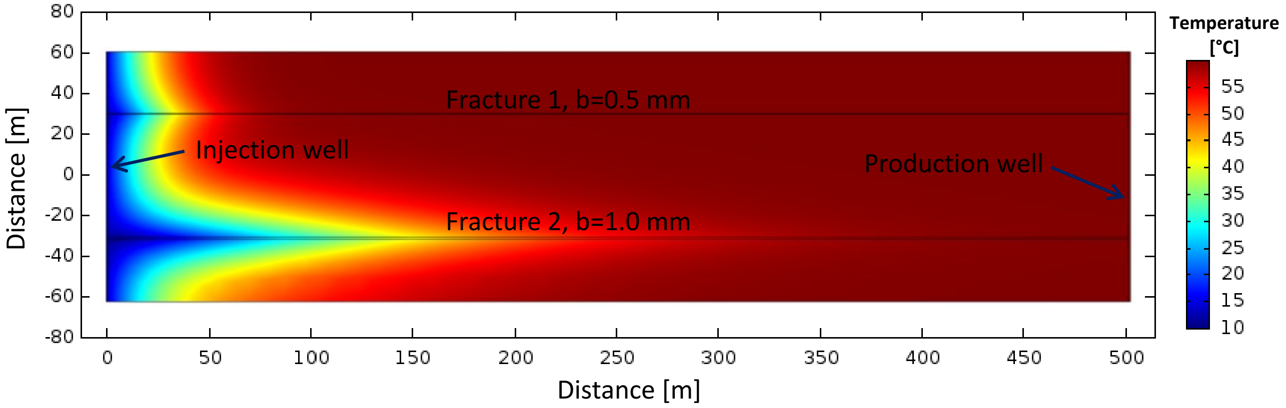

Figure 5. Details of model domain, under operating mode and temperature distribution in the model domain after 8 years injection.

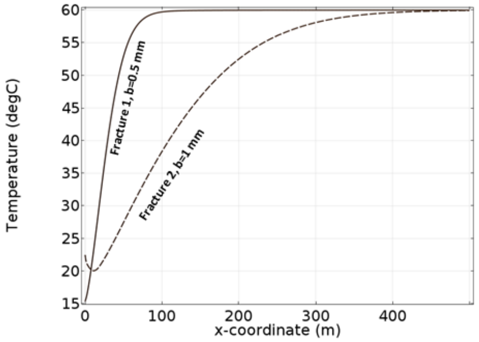

Figure 8. Temperature in fractures of different aperture after 8 years of water injection.

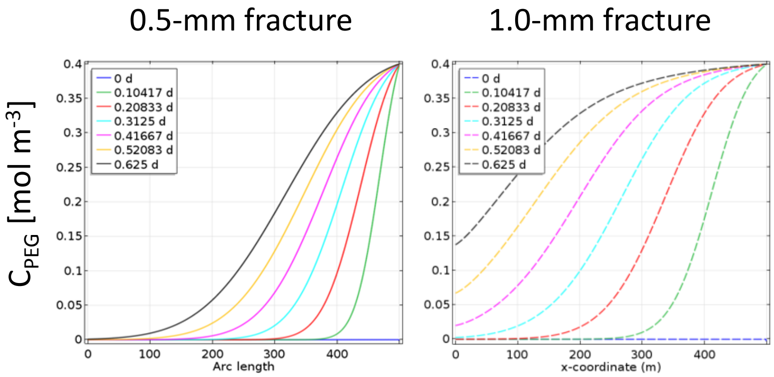

Figure 6. Concentration of treatment agent in the two fractures during the reverse-flow injection phase, illustrating greater penetration of injection in the larger fracture.

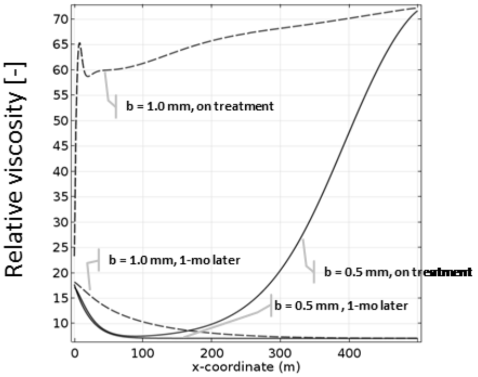

Figure 7. Relative viscosity (normalized to temperature-dependent viscosity of pure water), immediately after treatment and soon after reestablishment of forward flow.

7. CONCLUSIONS

The importance of finding methods to cope with short circuiting was emphasized in the MIT report on The Future of Geothermal Energy (Tester et al. 2006), which states “short circuiting, the development of preferred pathways in stimulated reservoirs, is one of the major problems for EGS economics.” This study directly addresses this need by describing methods that could selectively modify flow in rapidly cooling fractures. Successful development of a solution to this problem would have substantial beneficial impacts on the geothermal industry, by decreasing water requirements, increasing the energy produced per unit mass of water extracted, and potentially decreasing the risk of induced seismicity.

While previous studies have investigated methods of modifying fracture permeability via precipitation or dissolution chemistry, this discussion is, to our knowledge, the first that focuses on the problems of delivery of SPR materials to the desired location. The most closely related work appears to be that of Acock and Reis (1994), in the EOR literature, who reviewed a wide variety of methods of reducing the permeability of water flood thief zones, and proposed thermally induced precipitation as a new means of accomplishing that goal. Application of selective sealing methods to geothermal systems are generally focused on diversion agents that temporarily seal fractures during the stimulation process to allow hydrofracturing of additional zones (e.g., Petty et al. 2011, Rose 2010). Selective permeability reduction, which may be critical for long-term sustainability of constructed reservoirs, appears to have been explored only little in geothermal studies.

A review of relevant literature and preliminary modeling results suggests that there are considerable advantages to methods that incorporate a reverse-flow injection in a multi-stage treatment method, in which a treatment solution is pumped backwards, from production well to injection well, through the reservoir. The primary advantage of this approach is that the treatment solution will encounter cooler temperatures in the short circuit pathways before it encounters cooler temperatures in the thermally productive pathways. If the injected solution contains reactants that yield a flow restriction upon cooling, its effect would be stronger in the wider aperture pathways with higher velocity flow. By limiting the period of the reverse flow operation so that the plugging solution does not reach the cool end of the thermally productive pathways, these restrictions will develop only in the undesired ‘short circuit’ pathways, thereby improving and extending reservoir productivity. If that effect is not be limited to the lower-temperature portion of fracture paths, the desired reaction product would also have to be subject to thermal degradation, to remove it from the penetrated portion of the low-permeability fractures. The difficulties of such schemes are obvious, but the heterogeneous nature of the subsurface means that they would be useful in virtually any geothermal system, and could provide substantial cost advantage over other methods of mitigating the effect of premature cooling of ‘short circuits’.

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