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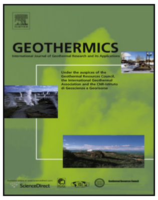

Environmentally friendly, rheoreversible, hydraulic-fracturing fluids for enhanced geothermal systems

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ABSTRACT

Cost-effective creation of high-permeability reservoirs inside deep crystalline bedrock is the primary challenge for the feasibility of enhanced geothermal systems (EGS). Current reservoir stimulation entails adverse environmental impacts and substantial economic costs due to the utilization of large volumes of water "doped" with chemicals including rheology modifiers, scale and corrosion inhibitors, biocides, friction reducers among others where, typically, little or no information of composition and toxicity is disclosed. An environmentally benign, CO_2-activated, rheoreversible fracturing fluid has recently been developed that significantly enhances rock permeability at effective stress considerably lower than current technology based on laboratory-scale tests. In the present work we evaluate the potential of this novel fracturing fluid for application at geothermal sites under different chemical and geomechanical conditions, by performing laboratory-scale fracturing experiments with different rock sources under different confining pressures, temperatures, and pH environments. The results demonstrate that CO_2-reactive aqueous solutions of environmentally amenable polyallylamine (PAA) represent a highly versatile fracturing fluid technology. This fracturing fluid consistently and reproducibly creates/propagates fracture networks through highly impermeable crystalline rock from Coso EGS and Newberry EGS sites at significantly lower effective stress as compared to conventional fracturing fluids. In addition, permeability was significantly enhanced (several orders of magnitude). This was evident in all laboratory-scale experiments, including variable rock source/type, operation pressure and temperature (over the entire range for EGS applications), as well as over a wide range of formation-water pH values. This effective, versatile, and environmentally-friendly fracturing fluid technology represents a significant advancement compared to industrially available fracturing fluids for cost-effective and competitive geothermal energy production.

1. Introduction

Enhanced geothermal systems (EGS) are considered a promising alternative for energy production for the United States and worldwide (Blackwell et al., 2006; Duffield et al., 2003). With its negligible CO_2 emissions, EGS can help to mitigate climate change. However, this renewable energy alternative faces challenges. To our knowledge, no prior EGS project has sustained production at rates greater than 50% of what is needed for economic viability (Duffield et al., 2003). The primary limitation for commercial EGS is the lacking of suitable technologies to cost-effectively create high-permeability reservoirs from impermeable crystalline rock within the 900–4000 m depth in a temperature range of 150–400 °C (Duffield et al., 2003; Pruess, 2006).

Recent advances in hydraulic fracturing techniques and horizontal drilling represent a key driver for EGS and subsurface energy development. As conventionally recoverable resources decline, hydraulic fracturing in unconventional oil and gas exploitation has been implemented in over 52,000 oil and gas wells across the U.S. (Kargbo et al., 2010; Kerr, 2010; Tester, 2006). However, the fracturing fluids used in the oil and gas industry are problematic for EGS. First, the macropolymers developed to modify fluid rheology

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in oil/gas standard hydraulic fracturing may not be applicable at geothermal temperature ranges (150–400 °C) due to their thermal decay (Garcia-Ochoa et al., 2000; Jang et al., 2005; Wang et al., 1995). Second, these macropolymers are difficult to remove from the formation after fracture creation. The so called "fracture skin", which is the residue of injected polymers and drilling mud not removed during fracture cleanup, limits effectiveness of hydraulic fracturing, because it decreases flow rates and heat transfer in EGS. There is also increasing concern over induced seismicity potential and how it may be associated with reservoir stimulation practices (Tester, 2006; Scotchman, 2014). In addition, the most challenging issue is the large volumes of water used and wastewater generated during hydraulic fracturing that must be treated and disposed of. Finally, the contamination of soil and drinking water resources have raised both environmental and economic concerns (Scotchman, 2014). Thus, to address these issues and advance the economic viability of EGS, the development of effective and environment-friendly hydraulic fracturing fluids is needed.

We recently developed a new fracturing fluid that can mediate a stimulated expansion and provide a controllable increase of hydraulic pressure to aid in fracturing processes (Jung et al., 2015). Triggered by reaction with CO_2, this novel fracturing fluid [poly(allylamine) aqueous solution, referred as PAA hereafter] can undergo chemically-induced reactions to form a hydrogel with concomitant large and rapid volume expansion and viscosity increase (Fig. S1 in Supporting information) (Jung et al., 2015). We reported that in the presence of CO_2 under 135 atm and 190 °C (the maximum temperature and pressure attained by the instrument), the viscosity of PAA solution was 15 cP, as compared a 1–2 cP on the control experiment under identical conditions (Jung et al., 2015). Although a comprehensive study on the fracturing mechanism is planned and will be the subject of a coming publication, the authors believe that the volume expansion would generate a significantly increased mechanical stress in the confined environments of the fracture networks propagating fractures at effective stress significantly lower than currently used methods.

The goal of the present study is to demonstrate the versatility of this novel fracturing fluid for fracture creation/propagation under different EGS-relevant conditions. Specifically, this work: (1) conducted hydraulic fracturing experiments on rock cores collected from two EGS sites at different pressure, temperatures, and formation fluid pH, (2) characterized the fracture networks and determine overall permeability and (3) performed computational fluid dynamics modeling on two representative EGS rock cores to evaluate the spatial distribution of the fracture networks and compute individual fractures permeabilities as well as bulk post-fracturing permeability. This work provides qualitative and quantitative basis for the potential application of our new fracturing technology in EGS operations to advance sustainable EGS-based energy production.

2. Materials and methods

2.1. Chemicals and rock samples

Poly(allylamine) solution (average MW ~17,000, 20 wt% in H_2O) was obtained from Sigma–Aldrich. This polymer solution was diluted with deionized water (DIW) for 20 times and the diluted solutions were used for hydraulic fracturing experiments as described below. In some experiments, pH 7 and pH 10 buffer solution (Sigma–Aldrich) was used for sample preparation to characterize the effect of reservoir fluid pH on the ability of the PAA-based fracturing fluid to create/propagate fractures.

There were two rock cores used in this work. One was collected from the Coso geothermal field in California at depth of ~490 m. Coso Rock samples consisted of Mesozoic diorite metamorphosed to greenschist facies. The second rock cores were obtained from Newberry Crater, Oregon, at depth 706 m. These samples consist of siliceous volcanic rocks formed from massive to very vesicular lava flows, pumice, lahars, vitrophyre, cinders, lithic tuff, and interflow breccia. These raw sample materials were cut into small cylindrical rock cores (1.59 cm diameter and 5.08 cm length) and a centered hole (0.32 cm diameter and 2.54 cm deep) was drilled from the top of the cylinder. The top and bottom of the cores were polished to ensure the sealing with an O-ring (see Section 2.2).

2.2. Hydraulic fracturing experiments

Laboratory-scale hydraulic fracturing experiments were performed using the rock cores prepared from rock samples collected from the aforementioned two field sites. A schematic diagram for the hydraulic fracturing experimental setup is shown in Fig. 1. Each rock core was placed in a state-of-the-art cradle designed to expose the entire sample to the desired confining pressure while isolating the central hole drilled to introduce the fracturing fluid (Fig. S2).

Stainless steel tubing (0.16 cm OD) was introduced 0.5 cm into the hole leaving an internal dead volume of ~200 μL in the rock core. Teflon O-ring was used on the top of the cradle to ensure sealing of the connections and avoid any communication between the external fluid (water) used to apply the desired confining pressure and the internal dead volume in the rock core during the course of the fracturing experiment. The rock core in the cradle was then connected to the head of a high pressure vessel (High Pressure Equipment Company, Erie, PA), and the cradle was introduced to the pressure vessel. A 3-way valve was used to deliver polymer solution and CO_2. The temperature of the reactor was controlled with heating tape, a thermocouple, and a temperature controller. After the target temperature was reached, water was injected into the pressure vessel using a syringe pump to increase confining pressure. The confining pressure was first increased to 68 atm, immediately followed by introduction of 200 μL of 1 wt% PAA solution and 68 atm of CO_2 inside the core sample via the three-way valve. Then, the confining pressure and rock core pressure were increased in 3.4 atm (50 psi) intervals until the target pressure was achieved. Subsequently, the rock core internal pressure was gradually increased in intervals of 1 atm with the fracturing fluid while maintaining the confining pressure constant, until an increase in the confining pressure was observed. This pressure equilibration indicates communication between the internal and external fluids as a result of fracture formation/propagation. The pressure difference between the applied fracturing fluid pressure required for rock core fracturing and the confining pressure is defined as "effective pressure" or "effective stress." After pressure equalization was observed, the system was cooled to room temperature and the pressure was released before the pressure vessel was opened and the rock core retrieved. For comparison, control fracturing experiments using DIW/CO_2 were also performed at identical experimental conditions. The rock cores retrieved from the high pressure vessel after fracturing experiments were subjected to a series of tests to examine the formation and distribution of fractures as described below. Hydraulic fracturing experiments were performed at 150 °C and 250 atm as well as at 300 °C and 330 atm with 1 wt% PAA solution to evaluate the fracturing fluid technology at low and high EGS temperature and pressure limits. In addition, we also conducted the fracking experiments with PAA solution prepared in pH 7 and 10 buffer solutions to test the effect of reservoir fluid pH on the effectiveness of the fracturing fluid to enhance permeability. Experiments at pH 7 and pH 10 were conducted at 300 °C and 333 atm with rock from the Coso site.