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Effect of CO_2–brine–rock interaction on fracture mechanical properties of CO_2 reservoirs and seals

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ABSTRACT

The effect of CO_2–water–rock interactions on fracture mechanical properties of reservoir and seal rocks due to injection of CO_2 in the subsurface may impact long-term (10^2–10^4 yr) storage security. At the Crystal Geyser and Salt Wash field sites near Green River, Utah, sandstone of the Salt Wash Member of the Morrison Formation and Mancos Shale have undergone chemical alteration associated with flow of CO_2-bearing water under natural conditions over geologic time scales of 10^3–10^5 yrs. To quantify the effects of these diagenetic changes on rock fracture mechanical properties we conducted opening-mode fracture mechanics tests using the double torsion method on a suite of CO_2-altered and unaltered siliciclastic samples. We show that dissolution of hematite and carbonate cement in Entrada Sandstone by CO_2-rich brine lowers fracture toughness by nearly 40% relative to adjacent, unaltered samples from the same unit. In contrast, precipitation of calcite pore cement in a sandstone of the Salt Wash Member of the Morrison Formation, attributed to CO_2 degassing during upward fluid flow along the Little Grand Wash Fault, results in a 100–700% increase in fracture toughness. Similarly, precipitation of carbonate mineral cements and replacement of matrix measurably strengthens Mancos Shale, considered a regional top seal. Subcritical fracture growth index (SCI) which quantifies reaction-assisted subcritical fracture propagation is also affected by CO_2-related alteration. Based on previous numerical simulations of fracture network growth with varying fracture mechanical parameters, we find that the measured variations in fracture mechanical properties qualitatively match observed differences in opening-mode fracture distributions along the fault, with short, non-connected fractures in CO_2-bleached rock, long, throughgoing fractures in calcite-cemented shale, and short, closely spaced, interconnected fracture networks in highly altered rock directly adjacent to fault conduits. Our fracture mechanics tests demonstrate that fracture mechanical properties of reservoir and seal rock can change as a result of chemical CO_2–brine–rock interaction. These chemical interactions may favor or inhibit subcritical fracture growth processes and thus reservoir and seal flow properties. In regions of CO_2-related mineral dissolution, subcritical fracture growth may reduce seal integrity over time scales beyond those of active injection and reservoir monitoring, thus negatively affecting seal integrity over the expected design lifetime of a CO_2 reservoir.

1. Introduction

Successful implementation of carbon storage in subsurface reservoirs will require physics-based approaches to assess leakage risk of CO_2 or CO_2-laden brine to the surface or into overlying aquifers (Benson et al., 2005; IEAGHG, 2011). In contrast to CO_2 injection into producing hydrocarbon reservoirs where the net increase in pore fluid pressure after CO_2 injection may remain small, CO_2 injection into brine aquifers may result in a significant net increase in pore fluid pressure (Benson et al., 2005). This increase in pore fluid pressure will result in a decrease in effective stress that favors the reactivation of faults and fractures, or the formation of new fractures, providing preferred flow conduits in the reservoir and potential leakage pathways of CO_2 or CO_2-charged brine through overlying sealing units (Rutqvist et al., 2008; IEAGHG, 2011).

Fracture processes of reservoirs and sealing units could potentially be aided by chemical fluid–rock interactions. Chemically assisted fracture growth is well documented in laboratory experiments, and considered an important mechanism for natural fracture growth under diagenetic subsurface conditions (Atkinson,

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1982; Eichhubl and Aydin, 2003; Hangx et al., 2010; Plümper et al., 2012; Brantut et al., 2013). The injection of supercritical CO_2 into brine aquifers and subsequent dissolution of CO_2 have been shown to significantly shift subsurface geochemical environments away from chemical equilibrium (DePaolo and Cole, 2013). These changes in formation water chemistry have the potential to cause irreversible chemical reactions between CO_2-laden brine and reservoir and seal rocks (Benson et al., 2005; DePaolo and Cole, 2013; Kaszuba et al., 2013). This has been demonstrated in field-scale projects such as the Cranfield, Mississippi CO_2 sequestration site (Lu et al., 2012), and the Rangeley, Colorado oil field where geochemical monitoring of produced water and analyses of core after CO_2 flooding indicates dissolution of sulfate, carbonate, and Fe-bearing phases (Bowker and Shuler, 1991). Changes in pore water composition associated with CO_2 injection may thus aid chemically-assisted subcritical fracture growth in reservoir and seal rocks even in the absence of significant pore fluid overpressure, potentially creating or enhancing fracture-controlled leakage pathways across top seals.

In addition to aiding fracture growth, changes in subsurface geochemical environment may also irreversibly alter bulk geomechanical properties of reservoir and seal rock through dissolution and precipitation of mineral phases and cements that can either mechanically weaken or strengthen or rock. While rock mineral composition is accepted to provide a first-order control on fracture mechanical properties (Atkinson, 1982), the effects of diagenetic changes in the amount, composition, and morphology of detrital grains and pore mineral cement on fracture mechanical properties have not been generally documented or appreciated, with exception of the work by Rijken (2005). We posit that chemical reactions and their effects on fracture mechanical properties should be considered in CO_2 sequestration models of reservoir and seals, especially those that simulate reservoir performance over long time scales ($>10^2$–10^4 yrs). So far, changes in fracture mechanical properties in response to CO_2–brine–rock interaction have not been systematically investigated.

This study addresses the effect of CO_2–brine–rock interaction on fracture mechanical properties by testing the fracture mechanical properties of reservoir and sealing lithologies that are naturally altered by CO_2-charged brines over geologic time scales. Samples were collected from the Crystal Geyser and Salt Wash Graben field sites near the town of Green River in eastern Utah (Fig. 1) where natural CO_2 leakage has altered sandstone, siltstone, and shale over time scales of 10^4–10^5 yrs (Burnside et al., 2013; Frery et al., 2015). These tests are intended as proxies for the fracture mechanical properties of reservoir and seal rock that have undergone similar water–rock interactions in CO_2 reservoirs after long-term exposure ($>10^2$–10^4 yrs) to CO_2-charged brine. Specifically, we test whether CO_2–brine–rock interactions have made rock more prone or less prone to fracture growth.

Using double torsion tests, we measured two parameters, mode-I, or opening-mode fracture toughness K_{IC} and the velocity exponent n or subcritical fracture propagation index (SCI) for subcritical opening-mode fracture growth. Subcritical fracture describes generally slow chemically-assisted fracture growth at loading stresses below those required for purely mechanical fracture growth. Higher SCI values imply faster growth under subcritical conditions. We selected opening-mode fracture mechanical tests because they provide a direct measure of the combined effects of chemical and mechanical processes associated with fracture propagation and the formation of hydraulically conductive fault and fracture networks. Subcritical fracture growth is likely to be relevant for time-dependent failure under chemically reactive conditions (Brantut et al., 2013) including those expected in the vicinity of CO_2 injection sites. The effect of aqueous chemical environment on crack behavior has also been shown to be significant (Atkinson and Meredith, 1981; Atkinson, 1982; Hangx et al., 2010), however this study primarily focuses on the end-product of CO_2-related alteration as one simple case of chemo-mechanical behavior.

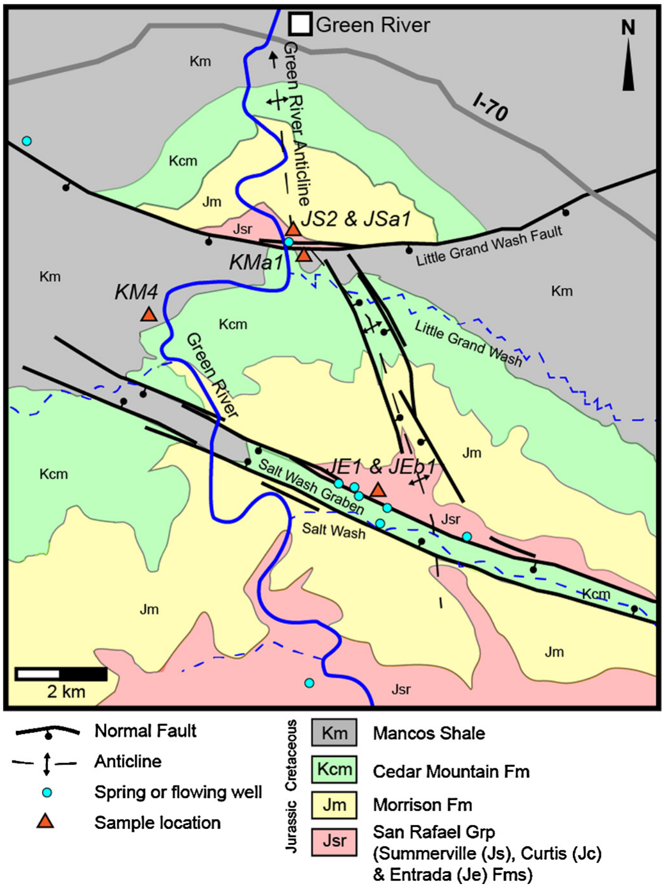

Fig. 1. Simplified geologic map of the Crystal Geyser and Salt Wash field sites near Green River, Utah with sample locations noted. Geology based on Doelling (2002), spring and well locations from Heath et al. (2009).

1.1. Geologic background

The Crystal Geyser and Salt Wash field sites, including the Little Grand Wash Fault and Salt Wash Graben has been the focus of numerous studies over the past decade as a CO_2 sequestration analog (e.g. Heath et al., 2009; Wilkinson et al., 2009; Wigley et al., 2012; Kampman et al., 2014b; Frery et al., 2015). Crystal Geyser is a cold-water, CO_2-driven geyser that has erupted periodically through an abandoned well bore since being drilled as an oil exploration well in the 1930s (Baer and Rigby, 1978). Crystal Geyser and a series of travertine mounds which represent fossil CO_2 springs are located along the Little Grand Wash Fault, which is an E-W striking normal fault that cuts the gently northward plunging Green River Anticline located few kilometers south of the town of Green River, Utah (Fig. 1). The fault has a maximum offset of approximately 250 m (Dockrill and Shipton, 2010; Urquhart, 2011) and exposes a series of Jurassic through Cretaceous-aged siliciclastic rocks, including sandstone, siltstone, and shale. A similar natural CO_2 system with several active and numerous fossil springs and geysers is also found 10 km to the south along faults in Salt Wash Graben (Dockrill and Shipton, 2010). We collected samples from outcrop for fracture mechanics testing from the following rock units, listed stratigraphically youngest to oldest, and from top seal to reservoir: