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Evaluation of hydraulic controls for leakage intervention in carbon storage reservoirs

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ABSTRACT

Assuring the storage security of geologically sequestered CO_2 is essential for proper project management and long-term emissions reductions. Storage security relies not only on comprehensive site characterization prior to injection and careful reservoir management, but also on having a suite of intervention and remediation strategies available to implement if leakage occurs. In this study sequential stages of intervention are analyzed and evaluated. The first step in halting leakage is likely to be stopping CO_2 injection in the vicinity of the leak (also termed passive remediation). Results indicate that while passive remediation can reduce the leakage rate by an order of magnitude, completely stopping leakage may often require implementation of additional measures. Additional measures evaluated here focus largely on hydraulic controls, whereby water is injected or produced in or above the CO_2 injection reservoir in order to terminate leakage. The degree of residual trapping determines the extent to which leakage is ultimately reduced. For example, water injection into the overlying aquifer directly above a fault was able to completely terminate leakage for as long as water injection continues. Remediation was even more effective when water injection above the fault was combined with reservoir fluid production. We also show that in addition to hydraulic control methods, extracting 15–25% of the injected CO_2 can lead to permanent leakage termination. The role of reservoir heterogeneity on remediation efficacy was also examined and found to reduce the total amount of CO_2 leaked compared to a homogeneous reservoir. Overall this study demonstrates that temporally limited, multi-stage intervention strategies such as hydraulic barriers can permanently stop CO_2 leakage from storage reservoirs into overlying aquifers.

1. Introduction

Carbon capture and sequestration (CCS) can aid in the reduction of global carbon emissions as energy systems around the world transition away from carbon intensive fuel sources. Despite the promise of CCS, it has been confined to a small fraction of large CO_2 emissions point sources around the world. While socioeconomic hurdles (e.g. global climate policy uncertainty, uncertain technology risks, public acceptance, and added costs of electricity generation with CO_2 capture) provide the largest barrier to widespread implementation of CCS, some questions remain about short and long-term storage security. Several mechanisms have the potential to compromise the security of supercritical CO_2 stored in deep saline aquifers or depleted oil and gas reservoirs (Benson and Cook, 2005; Friedmann and Nummedal, 2003; Celia et al., 2005; Nordbotten et al., 2004; Dockrill and Shipton, 2010). The two most likely pathways for leakage are through abandoned wells and fault or fracture zones. Due to the large uncertainty associated with characterizing the subsurface, these features could go undetected and thus provide potential fluid migration pathways from the storage reservoir to overlying aquifers or even to the earth's surface. To prepare for such an event, contingency plans are needed before implementing a large scale injection project.

When supercritical CO_2 is injected into deep saline formations there are usually two major driving mechanisms which try to force CO_2 from the reservoir into which it is injected. The first mechanism is the buoyancy force created by the density instability of a less dense CO_2 plume injected into a formation containing denser water and brine. The second mechanism is the pressure buildup in the reservoir resulting from the injection of CO_2. Carbon dioxide injection will typically increase the pore pressure in the storage reservoir relative to the pore pressure in overlying aquifer. Absent a high quality seal, this pressure gradient will drive fluid from the injection reservoir to the overlying aquifer.

Carbon dioxide is retained in the storage reservoir by four trapping mechanisms (Benson et al., 2005; Gunter et al., 2004).

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Nomenclature

S_i	initial gas saturation
S_{gr}	Corey curve gas residual trapping
S_{lr}	Corey curve water residual trapping
S_{nmax}	land trapping saturation coefficient
S_{trap}	trapped gas saturation

These mechanisms are structural, residual, dissolution, and mineral trapping. Structural trapping is provided by shale and other geologic materials that have very low permeability and very high capillary entry pressure. This trapping mechanism is key for preventing the buoyant rise of CO_2 from the storage reservoir. Residual trapping (also referred to as phase trapping) occurs as water imbibes into pore space occupied by CO_2, resulting in trapped ganglia of CO_2. The extent of this trapping mechanism is dependent on the initial CO_2 saturation and on the reservoir rock properties (Krevor et al., 2012, 2015). Dissolution (also known as solubility trapping) occurs when CO_2 dissolves in the resident reservoir brine, resulting in a fluid that is denser than the surrounding fluid. The solubility of CO_2 in water is around 5% at typical reservoir conditions—though this can vary significantly depending on groundwater salinity and chemistry (Gunter et al., 2004). Over geologic time this mechanism is thought to be able to permanently trap over 90% of injected CO_2 (McPherson and Cole, 2000). Finally, mineral trapping arises when dissolved CO_2 acts as a weak acid and reacts with minerals in the surrounding rock to form bicarbonate ions or carbonate ions (Gunter et al., 2004). These ions may then result in the formation of carbonate minerals, thereby permanently trapping the injected CO_2. The contribution of these trapping mechanisms is dependent not only on the physical and chemical characteristics of the storage system but also on the interplay between the trapping mechanisms. Doughty and Myer (2009) highlighted that structural trapping can hinder residual or dissolution trapping whereas if the plume is allowed to migrate further vertically and/or horizontally, this spreading will promote residual and dissolution trapping.

A number of different remediation methods have been proposed to stop CO_2 leakage, many of which are currently used in ground water remediation and/or the oil and gas industry (Manceau et al., 2014). Proposed strategies generally belong to one of the following categories: (1) hydraulic controls and pressure management (Buscheck et al., 2012; Le Guénan and Rohmer, 2011; Réveillère et al., 2012; Zahasky and Benson, 2014a), (2) production and removal of injected CO_2 (Esposito and Benson, 2012), (3) biologically active barriers (Cunningham et al., 2009), and (4) sealants and other physical barriers (Ito et al., 2014). Hydraulic controls rely on altering the pore pressure in the overlying aquifer and storage reservoir by injecting water or producing reservoir fluid. By altering the pore pressure it is possible to counteract the mechanisms working to drive the CO_2 from the reservoir, resulting in leakage termination and in some cases leakage reversal (i.e. pushing CO_2 back into the storage reservoir). For clarity throughout this study, fluid in the reservoir and overlying aquifer fluid is termed "brine", and injected fluids are referred to as water.

In this study, simulation models are employed to evaluate the feasibility of slowing or stopping leakage of CO_2 through faults in the reservoir caprock by stopping injection and implementing hydraulic controls. We focus specifically on small, subseismic faults, which may be difficult to detect prior to injection (Gauthier and Lake, 1993; Pickering and Peacock, 1997). In this model, CO_2 is injected into a reservoir capped by an impermeable seal; above the seal is an aquifer. At some injection sites, this overlying aquifer may exist above the target caprock, at other sites it be considered an upper portion of the containment zone that is overlain by another and potentially more substantial seal. When the CO_2 is injected, the plume migrates along the bottom of the caprock and eventually reaches a permeable fault zone providing a pathway for CO_2 to leak from the storage reservoir into the overlying aquifer. To terminate leakage, a number of intervention methods are evaluated including CO_2 injection shut off, hydraulic controls such as water injection in the overlying aquifer above the fault and reservoir fluid production away from the CO_2 plume, and CO_2 extraction from the storage reservoir. To understand the influence that fault permeability has on the efficacy of different intervention methods both 10 mD and 100 mD fault scenarios are evaluated. Lower permeability faults have been analyzed previously and found to have negligible leakage rates and consequently were not considered here (Zahasky and Benson, 2014b). Similarly, higher permeability faults have also been studied, but leakage rates were not expected to be significantly higher than the cases studied here because the fault is no longer the leakage rate-limiting factor (Zahasky and Benson, 2014b).

Reservoir heterogeneity has the potential to create flow barriers, compartmentalization, and preferential flow pathways for injected CO_2 and thus may enhance or inhibit both leakage from the reservoir and the effectiveness of various remediation strategies. In order to test the influence of reservoir geology on the leakage rates of CO_2 and the ability of hydraulic controls to slow or stop leakage, a number of heterogeneous reservoir models are developed. Results from the homogeneous models are compared to results from heterogeneous models on the century timescale in order to understand the long-term leakage behavior resulting from various hydraulic barrier intervention strategies. In this section the influence of leakage detection is also evaluated by examining two different leakage scenarios. In the first scenario early leakage detection occurs; in the second scenario the leak is not detected until a significant amount of CO_2 has escaped from the storage reservoir. The analysis highlights the importance of monitoring and verification and how leakage detection influences the ability for hydraulic controls to terminate potential leakage.

It is important to emphasize that this is not meant to be an exhaustive study analyzing or optimizing the remediation of many different leakage scenarios and geologic environments, but is meant to demonstrate the feasibility of using hydraulic controls to slow or eliminate leakage relative to other remediation options. Detailed leakage response at specific storage sites will require analysis and simulation studies based on the site characterization and system conditions.

2. Methods and model development

2.1. Fault characterization

Geological faults and fractures are observed at spatial scales ranging from tectonic to thin sections. Here we focus on subseismic fault zones or fault zones that are below the resolution of most surface seismic surveys, which could easily go undetected during site characterization. While the subseismic threshold can vary based on fault properties and observation techniques, it is generally considered to include fault zones with displacements or offsets of less than 10–15 m (Gauthier and Lake, 1993; Kim and Sanderson, 2005; Pickering and Peacock, 1997). Based on this initial constraint of fault displacement, published correlations between fault displace and length (Cowie and Scholz, 1992; Elliott, 1976; Krantz, 1988; Walsh and Watterson, 1988; Peacock and Sanderson, 1991; Peacock, 1991; Muraoka and Kamata, 1983; Opheim and Gudmundsson, 1989; Kim and Sanderson, 2005), and fault displacement and fault width (Sperrevik et al., 2002; Hull, 1988; Evans, 1990; Knott et al., 1996),