Advances in Water Resources 62 (2013) 442–453

Contents lists available at SciVerse ScienceDirect

Advances in Water Resources

journal homepage: www.elsevier.com/locate/advwatres

Experimental and numerical study on supercritical CO_2/brine transport in a fractured rock: Implications of mass transfer, capillary pressure and storage capacity

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ARTICLE INFO

Article history:
Available online 1 April 2013

Keywords:
Carbon dioxide
Fracture
Migration
CO_2 transfer
Injectivity
Storage capacity

ABSTRACT

This study presents the impact of fractures on CO_2 transport, capillary pressure and storage capacity by conducting both experimental and numerical studies. A series of laboratory experiment tests was designed with both a homogeneous and a fractured core under CO_2 storage conditions. The experimental results reveal a piston-like brine displacement with gravity override effects in the homogeneous core regardless of CO_2 injection rates. In the fractured core, however, two distinctive types of brine displacements were observed; one showing brine displacement only in the fracture whereas the other shows brine displacement both in the fracture and matrix with different rates, which were dependent on the magnitude of the pressure build-up in the matrix. The injectivity in the fractured core was twice of the homogeneous core, while the amount of calculated CO_2 in the homogeneous core was over 1.5 times greater than the fractured core. Salt precipitation, which is likely to occur near injection wells, was observed in the experiments; X-ray images enabled the observation of salt-precipitation during CO_2-flooding tests. Finally, numerical simulations predict free-phase CO_2 transfer between fracture and matrix in a fracture-matrix system. Pressure gradients between the fracture and matrix enforced CO_2 to transfer from the fracture into matrix at the front of the CO_2 plume, whereas, the reversal of pressure gradients at the rear zone of the CO_2 plume reversed the transfer process. The variation of CO_2 saturation within the fracture was caused by fracture aperture variations, and local variations of fracture permeability control the free-phase CO_2 transfer between the fracture and matrix.

1. Introduction

Carbon capture and storage (CCS) is a promising technology for mitigating CO_2 emissions into the atmosphere [1–3]. Suitable geological formations for CCS include saline aquifers, coal seams, and depleted oil/gas reservoirs. Among these options, deep saline sedimentary units are promising storage locations, owing to their high storage capacities [4]. A number of field-demonstration projects at various scales are being performed around the world in order to understand the physicochemical characteristics of CO_2 in reservoirs and to evaluate the feasibility of CO_2 storage for mitigating global climate change [5].

In addition to field-oriented projects, a number of studies have used laboratory experiments to investigate the behavior of supercritical CO_2 ($scCO_2$) under reservoir conditions using either Berea sandstone or formation cores into which CO_2 is currently injected. These studies focused on measuring relative permeabilities [6,7], interfacial tension [8,9], and capillary pressures [10–12], as these are important factors controlling the behavior of two-phase fluids and residual CO_2 trapping mechanism in porous media.

A successful CCS program should guarantee safe and reliable long-term storage of injected CO_2. Among various risks and concerns, CO_2 leakage through naturally preserved fracture/fault system could raise the risk of acidification of drinking water resources [13,14], potential asphyxiation hazards [15,16], and creation of eruptive discharge of CO_2 and brine [17,18].

Densely fractured natural reservoirs are rarely considered as suitable candidates due to issues related to safe and secure long-term storage [19]. Nevertheless, assessment of CO_2 storage processes including fluid migration in a storage medium with fractures is critical, as fractures occur in nearly all geological settings and play a major role in hydrocarbon migration as well as entrapment [20,21].

Single-phase fluid flow behavior through fractured rocks has long been a subject of interest, and the classical cubic law has been

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http://dx.doi.org/10.1016/j.advwatres.2013.03.007

applied and evaluated [21–23]. Many experiments have pointed out this law as being an inadequate description of flow, but an alternative model for flow in fractures has yet to be generally accepted [21].

Two-phase flow in fractured rocks is much more complex due to dynamic interactions among the capillary, buoyancy, and viscous forces. Furthermore, the geometry of the fracture-matrix systems can result in complex flow patterns. Studies have been conducted to assess the efficiency during miscible CO_2 injection in fractured oil reservoirs using experimental and simulation results [24], and the influence of matrix diffusion on the trapping mechanisms relevant for the long-term fate of $scCO_2$ injected into fissured rocks [19]. Although $scCO_2$ transport in the fracture-matrix system is an important issue, $scCO_2$ migration process in a saline formation that contains fractures has not been assessed. Further investigations in this area will advance the current understanding.

In the present study, we designed a laboratory experiment and numerical model for two-phase ($scCO_2$/brine) core-flooding tests under reservoir conditions to understand the migration behavior of $scCO_2$ in both a homogeneous and a fractured core. Experimental investigations and numerical simulations were interactively conducted to assess: (1) the fluid migration behavior in both fractured and unfractured core, (2) the injectivity, capillary pressure and storage capacity, (3) the free-phase $scCO_2$ transfer between fracture and matrix, and (4) the impact of the fracture aperture and its hydraulic characteristics. All the laboratory experiments and numerical simulations were conducted under assumed storage conditions of 10 MPa and 40 °C, keeping CO_2 in its supercritical state. The pressure and temperature conditions chosen in this study are of the cold and shallow reservoir [25,26].

2. Laboratory experiments

A CO_2-flooding system comprising of a fluid-injection system, a core-holder system, a confining- and back-pressure control system, and an X-ray scanning system was assembled for this study (Fig. 1). The fluid injection system included a 4-cylinder dual fluid-pumping system (Chandler Engineering, model Quizix Q5000-10K), which controlled fluid flow rate and pore pressure in the system, combined with a 1-liter piston accumulator for CO_2. The core-holder system (Coretest Systems Inc., model 24″ composite coreholder) was constructed of graphite composite with titanium endplates, with multiple spiral grooves on the inlet face end-plug so that fluid injection would be evenly distributed onto the face of the core. An integrated heating system with temperature-monitoring thermocouples allowed temperature control during the tests.

The confining-pressure controller (Coretest Systems Inc., model PCI-112) generated and maintained a constant confining pressure, while the back-pressure regulator (Coretest Systems Inc., model DBPR-005) controlled flow to maintain pore pressure. Line-pressure measurements were performed at both upstream and downstream ends of the core with pressure transducers (Quartzdyne, model DSB301-10-C85). The X-ray scanning system consists of an X-ray tube (Varian Medical Systems, model NDI-160-20) and a detector (Sens-Tech, model XDAS-V2). The detector board has two arrays of 128 channels each, corresponding to 256 detectors with a detector pitch of 0.4 mm. The data output is in 16 bit format. The scanning system produced two-dimensional (2D) images for measuring CO_2 saturation along the core.

Twin samples of Berea sandstone cores with 20% porosity and 1.7×10^{-13} m^2 permeability were used in the experiments. The Berea sandstone is composed mostly of quartz and includes small percentage of feldspar and iron clays. The cores were prepared to 150 mm length and 38 mm diameter, and the pore volume (PV) of the samples was 34 ml. The cores were then fired at a temperature of 700 °C to stabilize clay minerals, thereby reducing clay swelling and the migration of fine grains during the CO_2-flooding [7,27]. One of the samples was cut longitudinally through the center of the core to generate a single artificial fracture (Fig. 1). The other core represented the homogeneous core. These two cores were wrapped with heat shrink Teflon tube followed by aluminum foil and another Teflon tube before mounting in the core holder.

During the test, the downstream pressure was maintained at 10 MPa, and the temperature was set at 40 °C to replicate hypothetical 1 km subsurface environment. The brine was synthesized

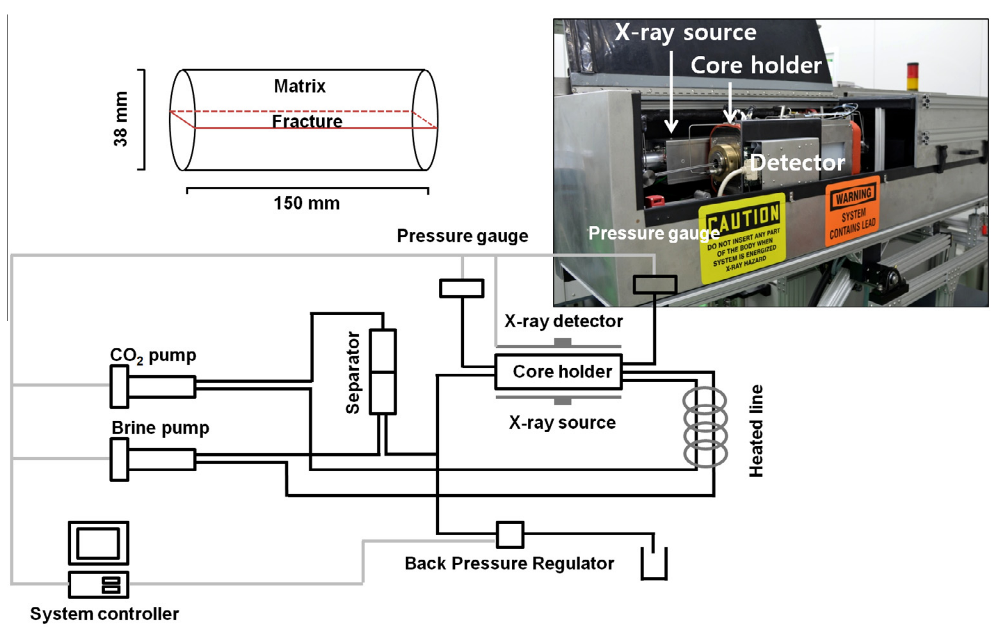

Fig. 1. Schematic of the core-flooding experimental setup. The system consists of core holder, high-pressure syringe pumps, thermal controller, back pressure regulator, and X-ray scanner. One of the twin sandstone cores was cut longitudinally through the center of the core to generate a single artificial fracture. Tests were conducted at $P = 10$ MPa and $T = 40$ °C.