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Use of low- and high-IFT fluid systems in experimental and numerical modelling of systems that mimic CO_2 storage in deep saline formations

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A B S T R A C T

Storage of CO_2 in deep saline formations is currently the most promising option for mitigating the impact of climatic changes. Therefore, it is important to understand flow processes and distribution of forces acting on injected CO_2. To demonstrate the influence of gravitational, viscous, and capillary forces on the flow of CO_2, special experiments were designed. Laboratory experiments and numerical simulations were performed, where fluid representing CO_2 was injected into a 2D porous medium saturated with fluid representing brine. Two sets of fluids characterised by different interfacial tension (IFT) were tested. Results demonstrate that at increasing injection rate viscous forces become stronger, leading to a higher total displacement of brine. Such performance is preferred at field scale, since it facilitates dissolution and residual trapping of CO_2. Gravity effects were more pronounced in cases with low injection rates and high permeability and are demonstrated by lower volumes of the in-situ fluid displacement. Therefore, reservoirs giving low influence of gravity forces are more suitable for CO_2 storage. The high-IFT fluid system had an IFT corresponding to the value of CO_2–brine systems at possible reservoir conditions. However, the fluid flow in the laboratory model was dominated by capillary forces. This kind of behaviour is less likely to be observed at field scale as it is a result of the much smaller volume of porous system used in the laboratory compared to the volume at the field scale. The low-IFT fluid system resembled better field scale flow behaviour. The laboratory experiments were also modelled using a numerical reservoir simulation software. While modelling of observations from high-IFT system was challenging, simulations for low-IFT displacements showed accurate reflection of experiments.

1. Introduction

Since the late 19th century, the Earth's surface temperature has increased and the evidence on climate change has grown substantially (Stocker et al., 2013). The main cause of climate change is attributed to deforestation and increase in anthropogenic emissions of CO_2 and other greenhouse gases in the atmosphere originating from fossil fuel combustion. Since the start of the industrial revolution in the mid-18th century mankind has produced approximately 337 billion metric tonnes of CO_2 and half of this amount has been emitted since the mid-1970s (Boden et al., 2010). Currently CO_2 emissions from fossil fuels are approximately 8.4 billion metric tonnes (Gtonnes) per year (Boden et al., 2010). As the emissions of CO_2 are predicted to increase in the future (IPCC, 2007) it is important to find efficient methods of limiting its release to the atmosphere.

Storage of CO_2 in deep geological formations is one of the measures for mitigating the impact of climatic changes (IPCC, 2005). Currently the most promising option for geological CO_2 storage is thought to be deep saline formations, due to their large, immediately available capacity (IPCC, 2005). Saline formations are sedimentary rock saturated with brine which is not suitable either for human consumption or for agriculture (e.g. IPCC, 2005). Global storage capacity in saline aquifers was estimated to be in the range of 1000–10,000 Gtonnes (IPCC, 2005; IEA-GHG, 2008). This could mean that all CO_2 produced in this century (assuming current yearly levels) could be stored underground if the capacity of the saline aquifers would be efficiently used and storage sites would prove to be safe.

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Nomenclature

A	cross-section surface area, m^2
a, b, c, d	empirical constants in relative permeability calculations
d_b	glass-bead diameter, m or μm
Δp	pressure drop, Pa
$\Delta\rho$	density difference of the fluids, kg/m^3
g	acceleration of gravity, m/s^2
γ	interfacial tension, IFT, mN/m
h	distance between model's inlet and top outlet, m
k	permeability, m^2 or mD or D
k_{rnw}	non-wetting phase relative permeability
k_{rw}	wetting phase relative permeability
L	glass-bead pack length, m
μ	fluid viscosity, Pa s
N_C	capillary number
P	pressure, bar
P_c	capillary pressure, bar
PV	pore volume fraction
ϕ	porosity
q	flow rate, m^3/s
R_{CG}	capillary to gravity forces ratio
R_{VG}	viscous to gravity forces ratio
ρ_{nw}	density of non-wetting phase, kg/m^3
ρ_w	density of wetting phase, kg/m^3
S_{nwr}	non-wetting phase residual saturation
S_w	wetting phase saturation
S_w^*	effective wetting phase saturation
S_{wi}	wetting phase irreducible saturation
u	Darcy's flow velocity, m/s

Every potential geological storage site considered for use in carbon capture and storage (CCS) must be carefully investigated and the flow processes taking place within such reservoirs must be understood. The characteristics of flows that occur when CO_2 is injected into a deep geological formation control how much CO_2 can be effectively injected and stored within the formation. Understanding of processes that take place within a saline formation during and after CO_2 injection is essential in order to select a suitable storage site. Flow regimes that occur when CO_2 is injected into a geological formation control how much CO_2 can be stored in the formation. Therefore, selection of a geological storage site for CO_2 must be preceded by an accurate understanding of the flow processes that take place within the reservoir during and after injection.

In recent years numerous analytical and numerical studies have been undertaken that concern site characterisation for CO_2 injection/storage and describe the simultaneous flow of CO_2 and brine in subsurface formations (e.g. Nordbotten et al., 2005; Taku Ide et al., 2007; Wood et al., 2008; Kopp et al., 2009). However, experimental data that shed light on the nature of the drainage process which applies to CO_2 injection has been less frequently reported. Fluid flow in the parameter range appropriate for CO_2 storage in saline aquifers has been studied in both 2D (Hele-Shaw-like) and cylindrical models filled with glass-beads (e.g. Cinar et al., 2009; Islam et al., 2013). In addition, pore-scale micro-models (e.g. Chapman et al., 2013), sand-packs (e.g. Pentland et al., 2010; Al Mansoori et al., 2010) and consolidated rocks (e.g. Berg et al., 2013) were used to study various aspects of fluid behaviour in the porous media with respect to CO_2 storage.

Systems with immiscible fluids, characterised by high interfacial tension (IFT), were commonly used in order to model flow patterns under CO_2 injection. Such experimental set-up provides information on the behaviour of fluid displacement in addition to the data which can be used in numerical simulations. Furthermore, experimental procedures can be successfully employed in order to verify results of analytical and numerical studies. The main advantage of these experiments is the possibility to visually assess the behaviour of the fluids in the model.

CO_2 and brine are immiscible at reservoir conditions and they form a high-IFT fluid system where CO_2–brine IFT falls between 20 and 56 mN/m (Bennion and Bachu, 2006; Chiquet et al., 2007). Therefore, the high-IFT system is usually a first choice when one tries to mimic CO_2 and brine interaction. Past work on fluid flow in high-IFT systems often demonstrated by the means of Hele-Shaw cell (e.g. Saffman and Taylor, 1958; Homsy, 1987; Løvoll et al., 2005; Duan and Wojtanowicz, 2007) indicates that the most visible feature is the pronounced fingering of injected fluid which dominates the flow. At lower IFT, however, it is possible to observe a more stable and uniform displacement front in addition to finer, viscous fingering. Further, as demonstrated previously (Cinar et al., 2006; Asghari and Torabi, 2008; Islam et al., 2013), it is problematic to simulate accurately laboratory-scale high-IFT experiments in commercial fluid flow simulators. Nevertheless, in this work, we present an approach for simulating a high-IFT system that resembles the effects observed in the experiments. In addition to the high-IFT system, a low-IFT system was investigated in order to observe the finer details of fluid flow behaviour on a smaller scale. Furthermore, it has been demonstrated that the low-IFT system is more suitable for simulations at the laboratory scale.

Additionally, the paper presents findings obtained during experimental examination of the flow processes that normally take place within a saline formation during CO_2 injection. In the procedures, CO_2 is represented by a model fluid injected into a model system of saline aquifer. Influence of low- and high-IFT fluid systems on the flow patterns is demonstrated along with results of the numerical simulations from modelling of the laboratory experiments.

2. Material and methods

Quasi two-dimensional experiments were performed in a synthetic porous medium initially filled with a water-rich phase. The model was made of two vertical glass plates with space between them packed with glass-beads. Models used in the experiments represented homogeneous porous media where the glass-bead size controlled their permeability. Two sets of fluids with different IFT were used in the experiments.

In the field applications, CO_2 is normally injected at the bottom of the geological formation. Even in a supercritical state, it is less dense than in-situ brine, and it tends to migrate up, towards the top of formation. In such a case, gravity forces will cause instabilities in the displacement front. Additionally, high viscosity difference between fluids at the reservoir conditions indicates the instability caused by the viscosity difference. Therefore gravity and viscous unstable floods were most suitable to experimentally model CO_2 injection into brine-filled formations. Experiments were designed in a way that demonstrate the influence of gravitational, viscous and capillary forces on the vertical flow of CO_2. Further, experiments were modelled by means of ECLIPSE 100, a commercial numerical reservoir simulation software.