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Design of Carbon Dioxide Storage in Oilfields

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Abstract

We extend our study of the design of carbon dioxide, CO₂, storage in aquifers (Qi *et al.*, 2007) to oilfields. We demonstrate that pore-scale capillary trapping is an effective and rapid mechanism to render the CO₂ immobile in oil reservoirs. We construct analytical solutions to the transport equations, accounting for relative permeability hysteresis. We use this to design an injection strategy where CO₂ and brine are injected simultaneously followed by chase brine injection. We study field-scale oil production and CO₂ storage using a streamline-based simulator that captures dissolution, dispersion, gravity and rate-limited reactions in three dimensions. While injecting at the optimum WAG ratio gives the fastest oil recovery, this allows CO₂ to channel through the reservoir leading to rapid CO₂ breakthrough and extensive recycling of the gas. We propose to inject more water than optimum. This allows CO₂ to remain in the reservoir, increases the field life and leads to improved storage of CO₂ as a trapped phase. A short period of chase brine injection at the end of the process traps most of the remaining CO₂.

Introduction

Carbon Capture and Storage (CCS), the collection of CO₂ from industrial sources and its injection underground, could contribute significantly to reductions in atmospheric emissions of greenhouse gases (IPCC, 2005). Possible sites for injection include coalbeds, deep saline aquifers, and depleted oil and gas reservoirs. Although aquifers have the greatest storage potential, injecting CO₂ into depleted oil and gas reservoirs can provide additional hydrocarbon production and improved storage security.

The principal concern with CO₂ storage is its long-term fate: can it be guaranteed that the CO₂ will remain underground for hundreds to thousands of years? Since oil and gas has been trapped for geological time in hydrocarbon reservoirs, they should all contain impermeable seals preventing escape. However, the top seal could leak, have gaps or be penetrated by wells through which CO₂ could migrate to the surface (Bruant *et al.*, 2002). Dissolution in water and reaction with rock could also contribute to safe CO₂ storage, but both are slow processes taking thousands to billions of years (Ennis-King and Paterson, 2005; Hesse *et al.*, 2006; Xu *et al.*, 2003). Capillary trapping (residual non-wetting phase trapping) has been recognized as the most rapid method to immobilize CO₂ with time scales in the order of years to decades (Ennis-King and Paterson, 2002; Kumar *et al.*, 2005; Obi and Blunt, 2006; Juanes *et al.*, 2006; Taku Ide *et al.*, 2007; Ghomian *et al.*, 2008). Our previous study on the design of CO₂ storage in aquifers (Qi *et al.*, 2007) has recommended an injection strategy in which CO₂ and brine are injected simultaneously followed by chase brine injection to render more than 85% of injected CO₂ immobile in a very short period.

In the oil industry, CO₂ flooding has been used worldwide as a tertiary Enhanced Oil Recovery (EOR) mechanism for more than 30 years, particularly for reservoirs with pressures above the minimum miscibility pressure (MMP) where miscible displacement would occur. The ideal reservoirs for miscible CO₂ flooding usually have oil densities ranging from 29° to 48° API (882–788 kg/m³) and reservoir depths from 760m to 3700m below the surface (Taber *et al.*, 1997).

CO₂ flooding has the disadvantage that the unfavorable mobility ratio between the oil and CO₂ can result in early CO₂ breakthrough because of channeling of CO₂ through the reservoir fluids. Water alternate gas (WAG) injection can be successfully applied to improve the sweep efficiency and delay early CO₂ breakthrough (Lake, 1989). However, CO₂ flooding EOR projects have been designed to minimize the amount of CO₂ injected to recover the oil, since the CO₂ costs money to transport and inject, while for CCS, injection needs to maximize both CO₂ storage and oil recovery. It has been recommended by other researchers that the fluids be injected at the optimal WAG ratio, the injection gas composition be adjusted to reach the MMP, while the well type and completions are designed to maximize both oil recovery and CO₂ storage (Jessen, *et al.*, 2004; Kovscek and Cakici, 2004; Malik and Islam, 2000).