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Super critical CO_2–methane relative permeability investigation

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ABSTRACT

This paper presents extensive laboratory results of unsteady state displacement of methane by super critical carbon dioxide SCO_2 in consolidated reservoir core plugs. The fluid flow of both phases is presented in terms of relative permeability using explicit methods. The main objective of this study was to investigate the feasibility of SCO_2 injection for enhanced gas recovery for a newly discovered gas field situated in the North West Shelf of Western Australia.

The core-flooding experiments of SCO_2–methane were carried out on three short plugs and one long vertical sample. The impacts of various parameters on the recovery efficiency and gas multiphase flow at pore scale were broadly studied. These parameters included pressure, temperature, composition, injection-rate, and permeability heterogeneity. Results indicated that the recovery factor at CO_2 breakthrough was a function of in situ gas composition, injection rate, and pore pressure. In contrast temperature, absolute permeability and core position factors only moderately affected the recovery factor.

A new power model has been developed for interpolating experimental gas–gas relative permeability data. This model can accurately account for subsequent gas compositional changes during the displacement process.

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1. Introduction

Conventionally, relative permeability is used to describe and model the multiphase flow of immiscible fluids through porous media. The analysis of such complex multiphase flow in porous media is normally presented in the form of Darcy-type equations. The extension of Darcy's law to include a phase relative permeability concept appears to have been first suggested by Muskat and Meres (1936) and co-workers Wyckoff and Botset (1936). Relative permeability of a phase is presented as a function of the fraction of pore volume that is occupied by the phase. At a given saturation, fluid flow in porous media can be the function of several macroscopic transport properties such as relative permeability, capillary pressure and dispersivity. Experimentally determined, these properties depend on fluid saturations, saturation history, fluid properties (viscosity, density and composition) and pore space morphology.

In the case of gas–gas displacement in porous media, researchers have interpreted the displacement front in terms of gas dispersion and molecular diffusion. This means that when the two gas phases are in contact in porous media, their interface will be a zone of miscibility ranging from one pure phase to the other. Hence the effects of the capillary force on the phase distribution are believed to be minimized because the gas phases cannot create a finite contact angle with the pore walls. Initially both phases, as injected, tend to saturate the larger pores, followed by smaller pores if the viscous force is great enough to overcome the capillary forces that are produced by the morphology of the porous media. As a result, recovery efficiency will not be affected by the phases' relative permeability.

The displacement of methane by super critical SCO_2 in a porous medium can be presented in terms of relative permeability, since an immiscible interface between SCO_2–methane is proved and documented in recent studies by Amin et al. (2010) and Sidiq and Amin (2010). In such systems relative permeability of the flowing phases will be influenced by the morphology and heterogeneity of the medium, whereas the wettability factor can only marginally effect the gasses' relative permeability because gasses are well acknowledged for being the most non-wetting phase.

Experimental results from this study indicated that methane recovery is profoundly influenced by injection rate, in situ gas composition and pore pressure. It is evident that inter facial tension (IFT) has a noticeable effect on the SCO_2–methane relative permeability curves, and hence the system does not reflect the relative permeability of an ideal gas. Apparently, SCO_2–methane's relative permeability behaves more like a near-miscible fluid. This contradicts conventional understanding of the subject, in that the IFT of a near miscible system is considered to have a minimal impact on the relative permeability

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curves (Delclaud et al., 1987; Kalaydjian et al., 1996). On the other hand, several researchers expected that the controlling parameter would be a ratio between the strength of the viscous forces relative to that of the capillary forces on the pore scale (Ameafule and Handy, 1982; Bardon and Longeron, 1980; Boom et al., 1995; Henderson et al., 1996; Leverett, 1941; Pope et al., 1998).

This paper focuses on experimentally determining the SCO_2–methane relative permeability from displacement tests conducted under various conditions. Pressures from 10.34 to 40.68 MPa, compositions from 0.1 to 0.75 mol% of SCO_2 in the in situ gas, and injection rates (velocities) from 1 to 10 cm/h (0.0166 to 0.166 cm/min) were investigated. Investigating different test conditions was to evaluate the effect of the intrinsic behavior of SCO_2 at super critical conditions on relative permeability.

The explicit methods used for generating the SCO_2–methane relative permeability curves were the JBN and Hassler methods. The relative permeability curves calculated from these methods were found to be comparable to one another. A straightforward model for calculating SCO_2–methane relative permeability was developed from the tests conducted on a consolidated core plugs and compared to both experimental data and the explicit results.

2. Experimental setup

The experimental design adopts the unsteady state procedure in which effluent production from the core sample was recorded during the course of the imposed displacement processes. The schematic drawing of the high pressure, high temperature experimental facility is shown in Fig. 1. Test fluids were stored in titanium accumulators that were connected to a variable-rate injection pump. These cells were kept outside the oven for safety reasons. However, the injected fluids were initially passed through stainless steel coils to heat them to reservoir temperatures before they entered the core sample. The lengths of the coils were precisely calculated using heat transfer coefficients of both coil material and injection fluids. The core holder, backpressure regulators and flow lines were housed inside a temperature-controlled, air-forced circulation oven. The simulated reservoir temperature was regulated by a high quality thermocouple. Pressure readings across the core sample were instantly recorded by high precision pressure transducers that were digitally synchronized to a laboratory PC. The composition of the produced gasses was monitored by gas analysers that were connected to the effluent flow line.

2.1. Core properties

All experiments were carried out on reservoir sandstone core plugs from a gas field in the North West Shelf of Western Australia. The characteristics of the cores utilized in the tests are shown in Table 1. The experimental program incorporated two sets of corefloods. One testing regime was conducted on the short core plugs with the aim of investigating the impact of permeability heterogeneity on the recovery efficiency. The other tests were conducted in a gravity stable mode, which involved injecting SCO_2 from the bottom of the core plug to displace the methane, used to explore the impact of in-situ gas composition, injection rate, pore-pressure and temperature on the recovery efficiency as well as to investigate the SCO_2 miscibility and gravity separation effects. All of the second series of experiments were carried out on the long core samples due to sufficient pore volumes and minimizing experimental artifacts.

2.2. Test fluids

Industrial methane and CO_2 gasses were supplied by British Oxygen Company (BOC) Australia. The brine was synthetically produced based on water analysis from the reservoir. The PVT properties of the fluids were calculated using the Equation of State (EOS).

3. SCO_2–methane phase behavior

Understanding the phase behavior of binary methane–CO_2 systems at reservoir conditions (high temperatures and pressures) plays a crucial role in describing the process by which CO_2 displaces methane at pore scale. It is known that CO_2 at a temperature of 304.15 K and pressure of 7.39 MPa reaches the critical condition. At low temperatures, below the critical point of CO_2, researchers have chiefly focused on hydrate formation from binary methane–CO_2 systems, because hydrate precipitation in gas plants is a common problem that can cause pipe-clogging. A substantial amount of literature can be found addressing hydrate formation for various systems. To the author's knowledge no prior attempt has been carried out to

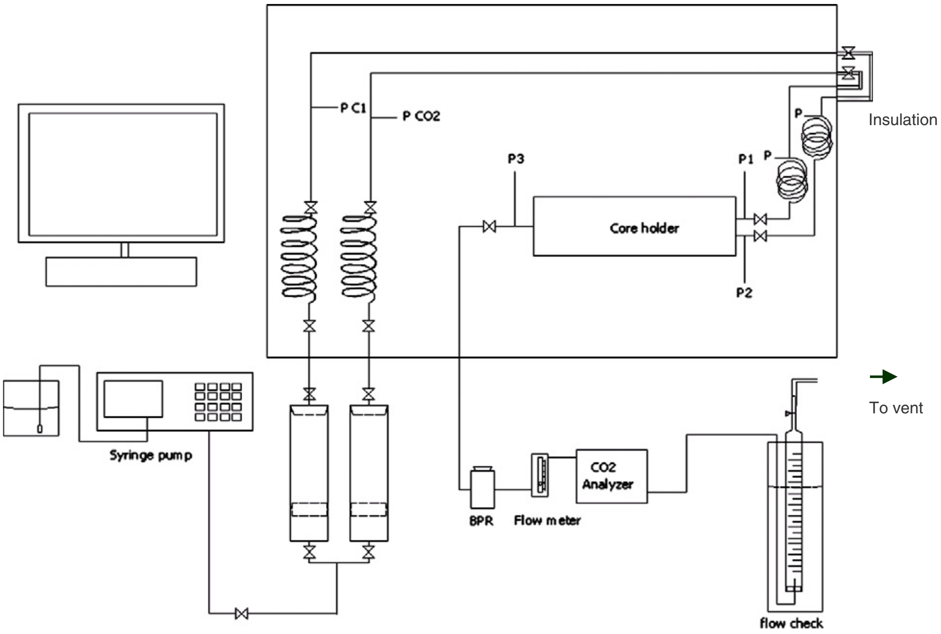

Fig. 1. HPHT schematic diagram of core flooding rig.

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