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History matching of CO\textsubscript{2} core flooding CT scan saturation profiles with porosity dependent capillary pressure

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Abstract

This paper presents a numerical simulation study of a CO\textsubscript{2} core flooding test performed on a Tako sandstone sample, which measured 14.5 cm long and 3.68 cm in diameter. During the test, supercritical CO\textsubscript{2} (at 10 MPa and 40°C) was injected into one end of the horizontal core and a X-ray CT scanner (with a resolution of 0.35 mm x 0.35 mm) was employed to monitor and record changes in the fluid saturations at 70 sections evenly spaced along the core length to enable 3D mapping of the saturation profiles throughout the core during the course of CO\textsubscript{2} flooding and imbibition. Analysis of the mean saturation profiles along the core length (obtained by averaging the CT values over each cross-section) revealed a strong influence by the (mean) porosity distribution, though this influence became gradually less pronounced after CO\textsubscript{2} breakthrough. A 1D model of the core was first constructed to simulate the CO\textsubscript{2} injection process and in particular to history match the evolution of the CT scan CO\textsubscript{2} saturation profiles along the core length with time. It was found that a reasonably match could be achieved by using a porosity-dependent capillary pressure multiplier. The multiplier was also dependent on injection time (CO\textsubscript{2} saturation level). In order to match the saturation profiles, it needs to be gradually scaled down as more CO\textsubscript{2} is injected.

Keywords: Supercritical CO\textsubscript{2} core flooding, Tako sandstone, X-ray CT 3D mapping, history matching, CO\textsubscript{2} storage.

1. Introduction

Carbon capture and storage has been increasingly viewed as a promising technology to mitigate climate changes caused by global warming in short-to-medium terms, and as a potential means to bridge the transition from a fossil fuel-dominated to a low carbon energy world. Among the different main types of potential storage formations, namely saline aquifers, depleted hydrocarbon reservoirs and unminable coal seams, saline aquifers have by far the largest estimated CO\textsubscript{2} storage capacity worldwide. Three storage mechanisms in aquifers have been identified, in increasing order of time scale, hydrodynamic (or residual CO\textsubscript{2} saturation) trapping, solution trapping (dissolution in the formation water), and mineral trapping through geochemical reactions with formation fluids and rocks. A proper understanding of these mechanisms for a given storage site is important in order to improve public confidence in the long-term subsurface storage of CO\textsubscript{2}.

As CO\textsubscript{2} is injected into a storage formation, it tends to more upwards under its own buoyancy, as well as spread laterally driven by the pressure differential. The areal spread of a CO\textsubscript{2} plume away from its source over a given time period would to a large extent be controlled by the residual saturation trapping mechanism, through which, part of the free phase CO\textsubscript{2} becomes immobile. The residual gas saturation for a reservoir rock is usually measured in laboratory using core analysis techniques. Mulyadi et al [1] compared various core analysis techniques used for measuring residual gas saturation in water-driven gas reservoir. Recently computerised tomography (CT) has been increasingly used to visualise changes in-situ saturation distribution during a core flooding experiment for both enhanced oil recovery [2,3] and CO\textsubscript{2} storage [4].

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Yu et al. [2] conducted complete gas- and oil-injection cycles at the reservoir conditions of 20 MPa pressure and 100 °C temperature under X-ray CT monitoring to obtain oil and gas in-situ saturation condition at irreducible water saturation. Izgec et al. [4] reported a combined core flooding, under a confining pressure of 500 psi (3.45 MPa), and numerical modelling study, at both core and field-scale to investigate the important aspects of injection of sub-critical CO\textsubscript{2} in carbonate formations. CT scanning images taken during (some of) the tests were used to calibrate the core-scale numerical model. The carbonate core plugs used for CT imaging measured 7 cm in length and 3.81 cm in diameter. Laboratory core flooding tests on sandstone and carbonate core sample by Grigg and Svec [5] involved two types of displacement tests: gas injection to a residual brine saturation with respect to gas, followed by brine injection to a residual gas saturation with respect to brine.

More recently Ueda et al. [6] conducted laboratory supercritical CO\textsubscript{2} core flooding and follow-on imbibition tests on Tako and Berea sandstones. One of the objectives of the laboratory core flooding tests was to determine CO\textsubscript{2} residual saturation after the core has been subjected to continued brine injection to achieve a better understanding of this CO\textsubscript{2} trapping mechanism in sandstone aquifers. In two of the tests, X-ray CT scanning (at a resolution of 0.35mm x 0.35mm) was employed to monitor and record changes in the fluid saturations at 70 sections evenly spaced along the core length to enable 3D mapping of the saturation profiles throughout the core during the course of CO\textsubscript{2} flooding and imbibition. This paper focuses on the CO\textsubscript{2} flooding test performed on a Tako sandstone sample, which measured 14.5 cm long and 3.68 cm in diameter. A 1D model of the core plug was first constructed to simulate the CO\textsubscript{2} injection process and in particular to history match the time evolution of the longitudinal CT scan CO\textsubscript{2} saturation profiles.

2. Laboratory CO\textsubscript{2} core flooding test with simultaneous CT scanning

The Tako sandstone core used for the flooding test had an average porosity of 0.27 and a pore volume of 41.61 cm\textsuperscript{3}. The air permeability measured 55.42 mD (1 mD = 10\textsuperscript{-15} m\textsuperscript{2}) at 400 psi (2.76 MPa) confining pressure, reducing to 9.7 mD as the confining pressure was increased to 13.79 MPa. Pose size distribution analysis by mercury injection of one of the Tako sandstone cores, which had a porosity of 0.277, revealed that the pore volume mainly resided in the pores with radius ranging from 1,000 to 10,000 Angstrom (Figure 1). The average pore radius of the sample was 6868.9 Angstrom. Fine resolution (0.35mm x 0.35mm) CT scanning was performed at an interval of about 2 mm along the core length, giving rising to a total of 70 cross-sectional images covering the entire core. In addition, CT image along the core length was also taken. CT scanning of dry and water-saturated core showed that it had a heterogeneous porosity distribution in the cross-sections perpendicular as well as parallel to the core length axis (Figure 2a and b), with the porosity ranging from 0.14 to 0.34. There were close to 100 x 100 saturation data on each image in Figure 2a.

During drainage phase of the flooding test, supercritical CO\textsubscript{2} (at 10 MPa and 40°C) totalling 24 PV was injected into one end of the horizontal core. The injection rate was increased from an initial 0.1 cc/min to 4.5 cc/min through several steps (Figure 3). CO\textsubscript{2} breakthrough was observed after the injection of approximately 0.42 pore volume (PV) of CO\textsubscript{2}. Pressure drops across the core, as well as the injection and effluent rates, were recorded throughout the test. Figures 3 illustrates graphically the time evolution of the phase saturation throughout the core over the CO\textsubscript{2} injection period.

![Figure 1. Tako sandstone core pore size distribution (after Ueda et al. [6]).](image-url)
Figure 2. CT images showing porosity distribution within a) cross-sections at 1-cm interval over the core length; b) longitudinal cross-section (after Ueda et al. [6]); c) computed mean porosity at the imaged cross-sections from the digital CT data.

Figure 3. CT images of snapshot phase saturation distribution showing the migration of CO$_2$ at different stages of CO$_2$ flooding: the caption underneath each image giving the cumulative injected CO$_2$ volume (expressed as multiples of the pore volume of the sandstone) and the spot injection rate (after Ueda et al. [6]).
3. Numerical simulation of CO₂ core flooding

3.1. Profiles of CT porosity and CO₂ saturation evolution

As stated, there are multiple sets of 100 x 100 x 70 phase saturation, as well as one set of porosity, values generated by CT scanning. As a first step of data analysis, mean porosity and CO₂ saturation profiles along the core length were generated from the CT data. This was achieved by averaging the 100 x 100 CT porosity/phase saturation values at each of the 70 cross-sections and plotting them against its spatial position along the core. The resulting porosity profile is shown in Figure 2c. The mean porosity is seen to vary along the core length, reaching a peak of 0.284 at approximately 6 cm from the injection end. The lowest porosity, at 0.246, was found close to the outlet. The evolution of the mean CO₂ saturation profile is plotted in Figure 4. The following observations can be made:

- The CT saturation data indicated that the sandstone core was not fully saturated with water at the start of CO₂ injection (0 PV). Rather it appeared to contain a residual (air) gas phase with an average saturation of roughly 3.5%.
- Gas saturation increased steadily with CO₂ injection, reaching a mean level of ~0.4 after 13.4 PV of CO₂ had been injected.
- CO₂ breakthrough occurred when roughly 0.5 PV of CO₂ was injected.
- Closely following the trend of the mean porosity profile, the mean gas saturation profiles showed the build-up of a peak at around half way along the core length, which became gradually less pronounced after CO₂ breakthrough.

![Figure 4. Mean gas saturation profiles computed from the CT data.](image)

3.2. Construction of a 1D model

In an attempt to simulate the CO₂ flooding process and in particular history match the time evolution of the CO₂ saturation profiles, a 1D model of the core with 24 uniform gridblocks was first constructed. The porosity of each gridblock was obtained by averaging 3 consecutive mean CT porosity values, except the last gridblock at the outlet, which was assigned the same value as the 23rd gridblock. An exponential relationship was then used to derive permeability, constrained by an overall core permeability of 9.7 mD, which was the permeability to gas measured at a confining pressure of 13.8 MPa. The corresponding permeability to water would be somewhat lower. The resulting grid permeability ranged from 3.6 to 39.5 mD, with a harmonic mean of 9.7 mD. The permeability-porosity relationship is illustrated in Figure 5. The relative permeability for the CO₂ and brine phases were unknown a priori and a set of generic relative permeability curves used in a previous study for a Tako sandstone [9] were used as a starting point in the history matching. The resulting relative permeability and capillary pressure functions and corresponding curves are given in Table 1 and Figure 6. The irreducible water saturation and residual gas saturations were 0.15 and 0.05 respectively.
Table 1. Relative permeability and capillary pressure functions used in this study [7].

<table>
<thead>
<tr>
<th>Relative permeability</th>
<th>Capillary pressure (van Genuchten [8])</th>
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<tbody>
<tr>
<td>Liquid (van Genuchten [8]):</td>
<td>$k_{r_l} = \sqrt[3]{S^<em>} \left[1 - (1 - [S^</em>]^{1/m})^m\right]^2$</td>
</tr>
<tr>
<td>where</td>
<td>$P_{cap} = -P_0 \left(\left[S^*\right]^{-1/m} - 1\right)^{1/m}$</td>
</tr>
<tr>
<td>$S^* = (S_l - S_{ir}) / (1 - S_{ir})$</td>
<td></td>
</tr>
<tr>
<td>$S_{ir} = 0.15$ (irreducible water saturation)</td>
<td></td>
</tr>
<tr>
<td>$m = 0.425$</td>
<td></td>
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<tr>
<td>Gas (Corey [9]):</td>
<td>$k_{rg} = (1 - S^*)^2 (1 - S^2)$</td>
</tr>
<tr>
<td>where</td>
<td>$P_0 = 19.61$ kPa</td>
</tr>
<tr>
<td>$S^* = (S_l - S_{ir}) / (1 - S_{ir} - S_{rg})$</td>
<td></td>
</tr>
<tr>
<td>$S_{ir} = 0.0$</td>
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<tr>
<td>$m = 0.425$</td>
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### 3.3. History matching results

It was assumed that the 1D model had an initial gas (CO$_2$) saturation profile given by the CT data (0 PV curve in Figure 4). The model boundary conditions were such that the outlet was assigned a prescribed pressure which varied with time as recorded in the laboratory test; while the inlet was subjected a prescribed CO$_2$ injection rate based upon both the CT gas saturation data (before the CO$_2$ breakthrough) and the test injection rate (after the CO$_2$ breakthrough), the latter increased in stages with time. To ensure that the inject rate used in the model reflected the true amount entered into the sandstone core, the CO$_2$ injection rate prior to the CO$_2$ breakthrough was determined from the incremental increase in the gas saturation as estimated from CT data at various stages (Figure 4). CO$_2$ dissolution was not considered during the simulations. This was because that the pore water would have already been saturated with CO$_2$ in the model, due to the presence of an initial CO$_2$ saturation.

Initially the same set of relative and capillary pressure curves was used for all the gridblocks in the model. The ensuing failure to match the observed trend in the saturation profiles led to the experimentation of an empirical porosity-dependent capillary pressure. Simple linear correlations were first considered where a porosity-dependent multiplier was applied to the capillary pressure values computed using van Genuchten function in Table 1. The porosity-dependent multiplier is given by

$$ M = \frac{\phi_1 M_1 - \phi_1 M_2}{\phi_1 - \phi_2} + \frac{M_2 - M_1}{\phi_2 - \phi_1} $$

where $M_1 = 1$ for $\phi_1 = 0.265$, and $M_2 (\phi_2 = 0.257)$ was used as a tuning parameter. The multiplier as a function of porosity for three different $M_2$ is illustrated in Figure 7. The model predictions with $M_2 = 1.12$ were compared with the CT data in Figure 8a-c. It can be seen that, except at the initial stages of the CO$_2$ flooding (Figure 8a), the trend of overall CT gas saturation profiles was reasonably reproduced in the model in the period prior to the CO$_2$ breakthrough (Figure 8b). Figure 8 further shows that an improved match to the CT data could be achieved by reducing $M_2$ in stages from 1.12 to 1.03 (Figure 8c and d).
Figure 7. Porosity-dependent capillary pressure used in the history-matching.

Figure 8. Model predictions with porosity- and time (CO₂ saturation)-dependent capillary pressure and comparison with the CT profiles.
4. Discussion and conclusions

The X-ray CT imaging of the Tako sandstone plug clearly displaced a heterogeneous porosity distribution. Reinforcing the visual observation of the CT images, analysis of the CT CO₂ saturation data revealed that this heterogeneity have a strong influence on the displacement process during injection of supercritical CO₂. Furthermore, this influence became gradually less pronounced after the CO₂ breakthrough. In the early stages of core flooding, the injected CO₂ tended to first move to the larger pores, which tend to be found in higher porosity regions, with lower capillary entry pressure. With continued CO₂ injection (rising CO₂ saturation level in the core), the capillary pressure becomes increasingly dominated by the gas phase saturation (Figure 6). As a result, the impact of porosity heterogeneity had a less and less impact on the saturation distribution.

The numerical simulations carried out in this study have shown that this capillary pressure effect observed during the core-flooding test can be reasonably represented by an empirical capillary pressure multiplier that varies linearly with the local (mean) porosity. Although this result was obtained by using a 1D model, subsequent simulation effort with a 3D (5 x 5 x 24) model confirmed this finding; though a slightly higher multiplier was required to history match the mean saturation profiles. As would be expected, a 3D model yielded a much close match at the early stages of core flooding (up to 0.2 PV). This finding may be potentially useful for reservoir-scale simulation of CO₂ injection into sandstone formations with heterogeneous porosity distribution to estimate the spread of CO₂ plume.

References