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Influence of heterogeneity on relative permeability for CO2/Brine: CT observations and numerical modeling

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Abstract

The determination of relative permeability of CO2/brine fluids under reservoir condition is critical for the design of CO2 injection strategy and prediction of CO2 behavior underground through reservoir simulation. For some reservoirs only heterogeneous samples are available for measurement. Heterogeneity, such as layering or cross bedding lamination can commonly be seen in sandstone cores. The effects and mechanism of core-scale heterogeneities on macroscopic scale relative permeability must be well-addressed. Here we report two sets of laboratory core flooding experiments using Berea sandstone for steady-state measurement of relative permeability of CO2/Brine at reservoir condition [1]. Berea sandstone is relatively homogeneous but has strong bedding or lamination structures. Two Berea samples were used (cored along the directions parallel to and perpendicular to the bedding, and named Berea-1 and Berea-2 respectively). We recorded the pressure and discharge volume to get the relative permeability curves for both samples; and utilized the X-ray computed tomography to estimate the distributions of porosity and CO2 (or Brine) saturation for Berea-2. The measured phase relative permeability of Berea-2 sample is greatly deviated from Berea-1. To further investigate the effects of core-scale heterogeneity on the measurement of relative permeability, we carried out a series numerical simulation on core scale using Tough2ECO2N code with building models based on X-ray CT scan images. By comparing the numerical results, we found the heterogeneity of capillary pressure field under one injection direction plays a dominant role in CO2/brine saturation patterns, flow regime and apparent relative permeability model.

Keywords: relative permeability; heterogeneity; capillary pressure; numerical simulation

1. Introduction

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Carbon sequestration is a developing technology proposed to reduce the effects of global warming from greenhouse gas emissions. There is a growing body of activities worldwide to investigate storage of carbon dioxide (CO2) in deep subsurface porous formations. How do the CO2/brine migrate underground and further how and how much the injected CO2 will be trapped are the most important scientific issues of CO2 geological storage. The determination of relative permeability of CO2/brine under reservoir condition is a key point for the design of CO2 injection strategy and prediction of CO2 behavior underground through reservoir simulation. Usually, a reservoir displays a variety of heterogeneities at all scales. Though the standard measurement of relative permeability demands homogeneous sample, for some reservoirs unfortunately, only heterogeneous samples are available. Whether the heterogeneities have effects on relative permeability measurement could lead to a major problem in performing realistic field reservoir simulation studies, that how to relate laboratory core measurements of relative permeability and residual CO2 saturation to the field scale to incorporate these effects in simulation. Therefore, the effects of core-scale heterogeneities on relative permeability and further on a macroscopic scale simulation must be well-addressed. Probably the most common heterogeneity in sandstone samples is layering or lamination.

There are several studies already have reached this topic through experiment and numerical modelling. Corey firstly pointed out that the layout of small-scale heterogeneity with different the flow direction may generate large errors in the relative permeability curves [2]. Numerical simulation results of Hupper show that the well distributed heterogeneities have little effect on apparent relative permeability, but as the heterogeneities become channel-like, their influence on flooding behavior becomes pronounced [3]. And also Hornarpour claimed that relative permeability gained for along-bedding and across-bedding flow are different [4]. In the research field of CO2 storage, several studies about relative permeability measurements of CO2/brine fluids have been published ([5-7]). The role of small-scale heterogeneity related capillary pressure field on CO2 trapping attracts more attentions [8]. It is suggested the CO2/Brine fluids, trapping amounts, flow paths and flow regime are determined by the capillary pressure field. Krevor et al. gave the evidence that high CO2 trapping due to strong capillary heterogeneity using X-ray CT [9].

On the other side, relative permeability is a measure of phase flow and trap ability of larger scale compared to the small-scale heterogeneity. It has to include the effect of capillary heterogeneity. Though some studies suggested the heterogeneities of permeability and capillary pressure could have effects on relative permeability and residual CO2 saturation, no direct experiment and numerical modeling related heterogeneity with injection direction have tested. To understand the impacts of small-scale heterogeneities and injection direction on relative permeability, we carried out two sets of laboratory core flooding experiments using Berea sandstone for steady-state measurement of relative permeability of CO2/Brine at reservoir condition. Berea sandstone is relatively homogeneous but has strong lamination structures. Two Berea samples were cored along the directions parallel to and perpendicular to the bedding, and named Berea-1 and Berea-2 respectively. We recorded the pressure and discharge volume to get the relative permeability curves for both samples and utilized the X-ray computed tomography (CT) to estimate the distributions of porosity and CO2 (or water) saturation for Berea-2. The details of experiment method and result for Berea-1 have been reported in another paper [1]. In this paper, firstly we will briefly introduce the comparison of the results of Berea-2 and Berea-1. Then we try to analyse the discrepancy between them through observed CO2 saturation pattern from X-ray CT scan images and further CO2 saturation pattern and flow paths from numerical modelling using TOUGH2 with the ECO2N module to find the mechanism. When modelling, the focus of this study is not real quantitative analysis of fluid, but how the capillary heterogeneity controls saturation pattern and influence the relative permeability.

2. Materials and Method

2.1. Relative permeability data

The core flooding experiments were performed on Berea sandstone at the confining pressure 12 MPa, the pore pressure 10 MPa, and the temperature 40 C. The core used in laboratory experiments is 3.5 cm in diameter and 7.0 cm long with a mean porosity of 24.3% and the average absolute permeability of 65 mD. The steady state method is used for measurement of relative permeability [1]. The total injection flow rate of CO2/Brine was 0.5 ml/min. The steady state was determined by monitoring the outflow ratios of two fluids using a pressurized separator and X-ray CT. The gained relative permeability curves are showed in Fig.1. The relative permeability curves show different characters. The Berea-1 presents higher irreducible brine saturation and lower residual CO2 saturations; however, the Berea-2 has relatively higher residual CO2 saturations but lower residual brine saturations. We used the van Genuchten-Mualem model to get the best-fit models for knowing the trend of the whole saturation scope. Generally, the relative permeability of brine phase of Berea-2 is much higher than Berea-1 and the relative permeability of CO2 phase of Berea-2 is lower than Berea-1. Therefore, it seems that heterogeneities with different orientations to injection directions lead to different relative permeability curves.

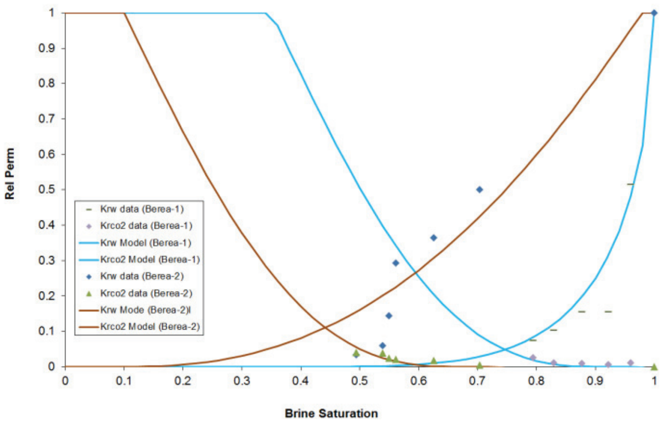


Fig.1. the measured relative permeability data and best-fit curves using the van Genuchten-Mualem model

2.2. X-ray CT scan

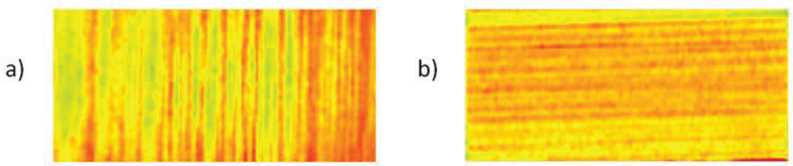


Fig.2 (a) and (b) X-ray CT images of Berea-1 and Berea-2

X-ray CT can provide nondestructive three-dimensional visualization and detailed description of fluid distribution in heterogeneous porous media at micro-scale (e.g. Krause et al., 2011; Krevor et al., 2011). Using images from X-ray CT as a basis, the saturation pattern and flow mechanisms could be studied synthetically and would offer more opportunities to correlate the CO2 distribution with rock porosity structure. CT number is a value to describe the intensity of the X-rays after attenuation when x-rays transmitted through the sandstone. The digital CT numbers and images map the variation of X-ray attenuation within porous media, which relates closely to density transitions corresponding to boundaries between materials or phases. Through simple computational conversion from CT number, the in situ phase saturations can be continually monitored in three dimensions by voxel in a coreflood experiment. The equipment we used was Toshiba Aquilion ONE with accuracy of 0.35×0.35×0.5 mm.

We took the CT scanning of only dry-state for Berea-1 and dry-state, brine-saturated-state, and CO2/Brine- steady-state for Berea-2. Fig.2 shows the X-ray CT images of Berea-1 and Berea-2. The heterogeneity of lamination can be seen observed clearly.

We can use the CT data of Berea-2 to get porosities and saturation values. The equations and model involved in for determining the voxel porosity and saturation values from CT numbers are the following:

$$\phi = \frac{\Delta CT}{\overline{\Delta CT}}\bar{\phi} = \frac{CT_{brine}^{sat} - CT_{dry}}{\overline{CT_{brine}^{sat}} - \overline{CT_{dry}}}\bar{\phi} \tag{1}$$

$$S_{CO2} = k(CT_{Scan} - CT_{brine}^{sat}) = \frac{CT_{Scan} - CT_{brine}^{sat}}{CT_{CO2}^{sat} - CT_{brine}^{sat}} \tag{2}$$

where CT_{brine}^{sat}, CT_{dry}, CT_{CO2}^{sat} and CT_{Scan} are the CT number of each voxel for of full brine saturated core, CT number of for dry core, CT number of for full CO2 saturated core, and CT number of for each examining scan, respectively, and the overlines of CT number and porosity ϕ indicate the averages of CT number and porosity over the whole sample. k is the coefficient that relates CO2 saturation to the difference of the CT number between examining scan and the brine saturated state. To eliminate the effect of pore size on x-ray absorption coefficients, we used the average CT number $\overline{CT_{dry}}$ and whole-core porosity $\bar{\phi}$. Fig.3 shows the porosity map and saturation map of steady state of Berea-2 when the injecting ration of CO2/Brine is 1:1.

2.3. Numerical model parameters

The accurate simulation of core flooding needs the details of physical model. One challenge to successfully conducting numerical modelling at core scale is accurate representation of the sub-core permeability and capillary pressure distribution at corresponding X-ray CT voxel scale. However, permeability cannot be measured at the sub-core scale. Krause et al. suggested that link permeability to measured sub-core scale porosity using the Kozeny-Carman equation is one way [10].

$$k = S \cdot \phi^3 / (1-\phi)^3) \tag{3}$$

S is a scaling factor makes the average of all permeability values is equal to the average permeability of the core, 430 mD.

Capillary pressure distribution with change of saturation could also be critical to simulate real-style saturation pattern. For simplicity, assuming that the contribution of capillary pressure of small pores is much larger than large pores, then we use threshold value of porosity to divide the model as two parts, that the grids in lower porosity than porosity threshold are with capillary pressure function; on the other hand, the other grids with porosity larger than porosity threshold has no capillary pressure.

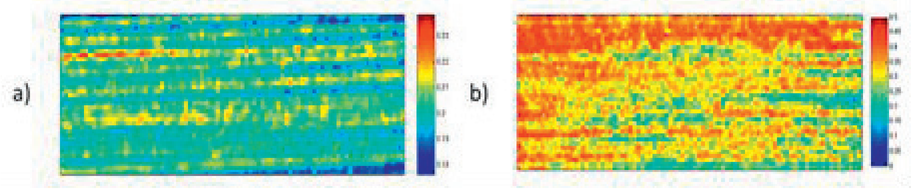


Fig.3. (a) and (b) are porosity map and saturation distribution map of Berea-2, estimated from voxels of CT numbers

We use the measured mercury injection data firstly to construct an air-mercury capillary pressure curve and then convert the air-mercury data to CO2/brine phases (Bennion and Bachu, 2009). The converted capillary pressure curve from mercury injection measurement and the fitting curve using van Genuchten model can be seen in Fig. 4.

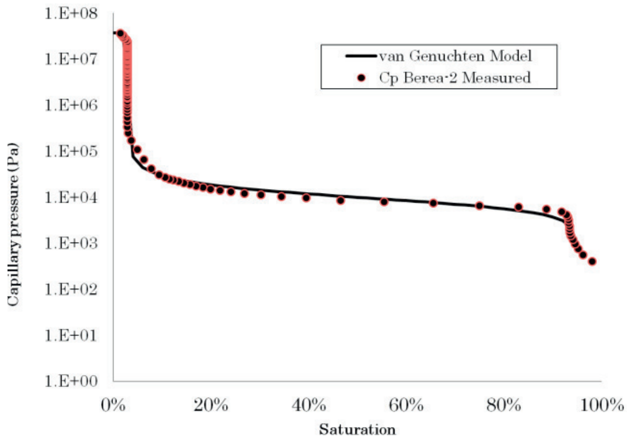


Fig. 4. Measured capillary pressure curve (Cp Berea-2 Measured) and fitted van Genuchten model for CO2 and Brine in Berea sandstone.

Due to the Berea-1 and Berea-2 is the same rock and only Berea-2 has X-ray CT scan data of both dry state and brine saturated state, we firstly take simulation of fast unsteady state only for Berea-2, which is to compare with saturation pattern from X-ray CT scan.

Then we construct the models of one along the directions parallel to the bedding (Berea-2b) and the other one perpendicular to the bedding (Berea-1b) from the same X-ray CT image of Berea-2 to investigate the effects of heterogeneity and injection direction on steady state relative permeability. The benefit of this way is there will be closer degrees of heterogeneity of two models, which makes the effects of injection direction to a heterogeneity field easier to observe. And also the size of model is reduced, which is time-saving during modeling. The models are chose as a smaller region of original Berea-2 model, and their grids are divided into 160×80 grid blocks, which are still as the same precision as pixel of CT image.

The modeling strategy is that we use the relative permeability curves of Berea-1 as input relative permeability function. Firstly, we will carry out three unsteady state runs, including cases of no capillary pressure consideration, capillary pressure within all grids and capillary pressure within only grids having porosities smaller than threshold porosity, to examine the effects of capillary pressure field on CO2 saturation pattern. The satisfied model is chosen to compare with CT results.

Then we make the on/off switch of the parameters of permeability and capillary pressure to see the variation and deviation of output relative permeability curves under two different injection directions. The model with pattern or the trend of deviation that is similar to the one between Berea-1 and Berea-2 will be selected to characterize the flow regime.

3. Results and discussion

3.1. Saturation Pattern

Fig.5 (a-c) displays the saturation distribution of CO2 during unsteady state run. From comparison of these CO2 distribution patterns, one can easily find that, if only consider variation of permeability or only consider one set of capillary pressure curve for whole core scale or not consider capillary pressure distributing only occur in small porosity grids, it is difficult to produce the images with distribution of CO2 in patchy style that still some patches unreachable for CO2 by simulation, which can be seen from CT images. But while the capillary pressure function is just applied to small porosity areas, the heterogeneous patchy distribution of CO2 can well be simulated.

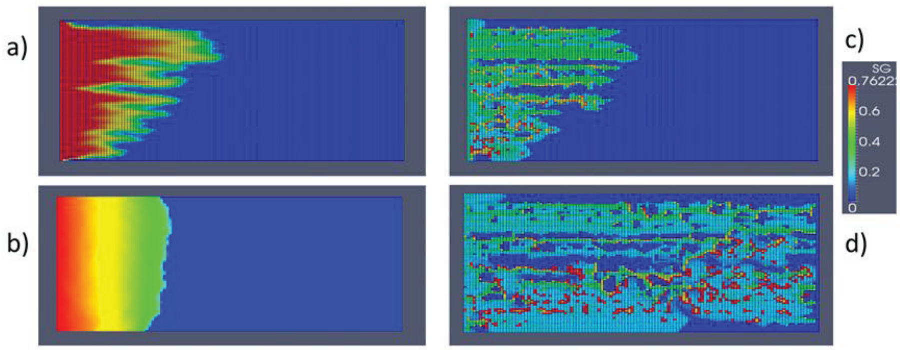


Fig. 5. (a) Saturation pattern of Model.a with one capillary pressure function for all the domain; (b) Saturation pattern of Model.b without capillary pressure; (c) Saturation pattern of Model.c with one capillary pressure curve only for grids with smaller porosity than threshold porosity; (d) Saturation pattern when Model.c get steady-state

Fig.5 (d) basically simulates the fluids saturation patterns, and it captures the main character as CT image. The layering heterogeneity which is the main characteristic of capillary pressure field here of Berea-2 sample controls the migration and distribution of fluids dominantly. The CO2 gas has priority to flow into the area with larger porosity and low capillary pressure, if the connectivity is available. The high porosity beds act as CO2 channels and have higher degree of CO2 saturation as observed from CT scan images. Cells of low permeability with a high capillary entry pressure could be as barriers to CO2 migration. It can be observed that, the patchy style CO2 saturation distribution can exist always; and even close to steady state, some areas are still gas phase CO2 unfavorable. However, these areas can entrap high saturation of CO2 around them when they contact with high permeable zone. Thus, even the injection fractional flow of CO2 just 10%, the saturation of CO2 at these areas can reach much higher.

However, there are still differences between simulation results and CT observations, e.g. the highest CO2 saturation is in the high porosity beds in CT scan images; however, the highest CO2 saturation distribution is around the contact margins of high porosity area and low porosity area. These differences could be caused by dimension-down effects (3D to 2D), since in 3D cells have more connectivity and the accumulation of CO2 around the contact margins should become less. Another reason may be the capillary pressure function, since the capillary pressure measurement was obtained from a small volume, which cannot represent the entire sample.

3.2. Relative permeability modeling

Fig.6 illustrates the modelling output relative permeability curves of capillary pressure field not considered case (a) and considered case (b) respectively. In Fig.6 (a), which is the case without consider the capillary pressure distribution; it can be observed the modelling output relative permeability points of Berea-1b and Berea-2b are overlapping, though the brine phase points of them still have some deviation to the input relative permeability curve (Bere-1). And in Fig.6 (b), the overall trend of relative permeability is that the brine phase of Berea-2b is higher than Berea-1b and input Berea-1, while the relative permeability of CO2 phase of Berea-2b is lower than Berea-1b; and the relative permeability of Berea-1b is similar to the input Berea-1..

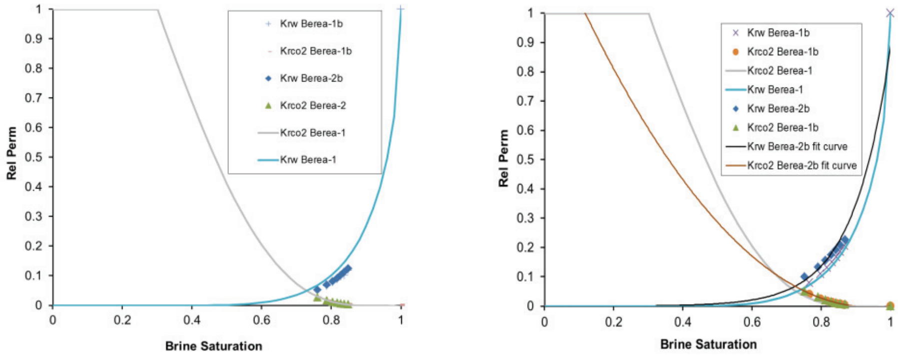
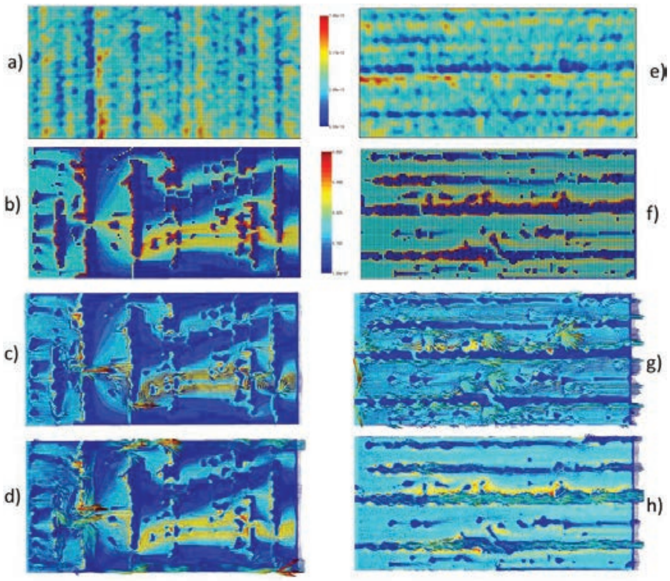


Fig. 6. (a, left) and (b, right) illustrate the modelling relative permeability curves of capillary pressure field not considered case and considered case for Berea-1b (perpendicular to the bedding) and Berea-2b (along the directions parallel to the bedding)

In Fig.7, the comparison of Berea-1b and Berea-2b reveals the difference of the saturation patterns and CO2 and brine flow patterns when the injection directions are different. These two small samples were selected from the same sample (Berea-2) originally. Therefore, the degrees of capillary heterogeneities should be close. However, when different injection directions are applied to this type of capillary heterogeneity distribution, the fluid saturation patterns and flow regimes are also different distinctively. For Berea-1b, brine preferentially occupies the interlaced fine layers, which then act as capillary barriers on CO2 flow. CO2 flow needs to increase its phase pressure to overcome the capillary entry pressure on its passing way. The competing of viscous force and capillary force finally makes the optimistic flow paths of two fluids. We can see generally the CO2 flow path is disordered and the flow velocity is changed often due to the confinement of capillary heterogeneity at different locations.

For Berea-2b, due to the injection direction of fluids is parallel to the capillary-existing-fine-layers and no-capillary-coarse-layers, the two fluids can choose their own paths easily. There are fewer interactions between two fluids on flow direction usually. Brine flows along small porosity layers while CO2 flows along larger porosity layers. However, if the brine phase moves faster along the preferential small porosity layer and accumulates at the outlet due to capillary end effects, more CO2 phase can be entrapped like macro-hydrodynamic trapping which exaggerates the CO2 phase saturation when estimate saturation-dependent relative permeability.



4. Conclusion

Our preliminary core scale simulation captures the main characters of saturation and flow pattern by using threshold capillary pressure distribution for the relative experiment of permeability measurement. The saturation distribution and flow regime under control by capillary heterogeneity and orientation respect to injection is one possible explanation for the discrepancy observed on relative permeability curves of our experiments. The uncertainty caused by capillary heterogeneity on relative permeability should be noted on reservoir modeling.

Fig. 7. (a-d) and (e-f) show the two series images of core porosity structure, the saturation pattern, the CO2 flow pattern and the brine flow pattern for Berea-1b and Berea-2b respectively, when the two phase flow gets at steady state at injection rate of 1:1, during relative permeability modelling. The arrows in c, d, g, and h reflect the velocity of CO2 flow and brine flow.

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