EXPERIMENTAL INVESTIGATION OF RESIDUAL CO\textsubscript{2} SATURATION DISTRIBUTION IN CARBONATE ROCK

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ABSTRACT
Carbon dioxide (CO\textsubscript{2}) geological injection and storage have been topical research since the reduction of CO\textsubscript{2} from atmosphere is required as one of greenhouse gas and CO\textsubscript{2} has been used for the enhanced oil recovery (EOR). In order to contribute the advancement of CO\textsubscript{2} geological sequestration and its multiphase flow analysis, a coreflood experiment using carbon dioxide and brine on the carbonate rock is conducted with in-situ saturation monitoring by X-ray Computed Tomography (CT). CO\textsubscript{2} saturated brine is used in one of the experimental processes to avoid the dissolution of carbon dioxide into the brine. It is important to measure the trapped CO\textsubscript{2} saturation to estimate the amount of CO\textsubscript{2} residual trapping in the rock. The experimental result clearly shows the relationship between rock heterogeneity and residual CO\textsubscript{2} saturation even in the same rock sample as the injected CO\textsubscript{2} flows through more porous area and it is trapped at lower porosity area. Residual CO\textsubscript{2} saturation by capillary trapping is observed on the Middle Eastern carbonate rock. The study also gives us the insight for the CO\textsubscript{2}-EOR with enhancing recovery and simultaneously storing CO\textsubscript{2} by capillary mechanism. In-situ saturation monitoring is the key to understand fluid movement and trapping. The relationships among porosity, saturation and flow rate are discussed based on the experiment and the analysis.

INTRODUCTION
CO\textsubscript{2} atmospheric emissions by human activity are considered to be one of the causes of global warming as the CO\textsubscript{2} is one of greenhouse gas. The increase of CO\textsubscript{2} emission affects global carbon cycle and it seems to relate recent unusual climate conditions. Therefore, to limit and reduce CO\textsubscript{2} emission is necessary, but it is a challenge as the primary source for the emission is energy use. Intergovernmental Panel on Climate Change (IPCC) published a special report on carbon dioxide capture and storage (IPCC, 2005) and it refers CO\textsubscript{2} capture and storage (CCS) is one of technical options to reduce greenhouse gas from atmosphere. CO\textsubscript{2} geological sequestration is considered to be a long-term storage and there are different options, such as
(1) depleted oil and gas reservoirs, (2) enhanced oil and gas recovery, (3) enhanced coal beds methane recovery and (4) deep saline aquifers. For these options, monitoring of CO₂ is necessary since one of concerns is the leakage from subsurface to atmosphere. Lower density and viscosity of CO₂ compared to brine causes the migration to the top of the geological structure and CO₂ may leak through the cap rock due to over-pressurization. Simulations of CO₂ injection and migration, therefore, have been studied by many authors (Pruess et al., 2003, Obi and Blunt, 2006). At the geological structures, four trapping mechanisms are mainly considered: (1) structural and stratigraphic trapping: the buoyant CO₂ remains as a mobile fluid but is stored under impermeable cap rocks, (2) residual phase trapping: disconnection of the CO₂ phase into an immobile fraction, (3) solubility trapping: dissolution of the CO₂ into the brine, possibly enhanced by gravity instabilities due to the larger density of the brine and (4) mineral trapping: geochemical binding to the rock due to mineral precipitation. In this paper, residual CO₂ saturation distributions in the carbonate rock are evaluated experimentally with assuming CO₂ injection into saline aquifers. Therefore, CO₂ is the nonwetting phase, and capillary trapping of the CO₂ is the important mechanism to avoid the leak from the geological storage, which can be understood by the multiphase flow experiment on the rock.

EXPERIMENT
Rock Properties
Rock samples from the Middle Eastern carbonate reservoir are used in this study. The original core is composed mainly of bioclastic grainstone and packstone with some algal fragments which form vuggy pore spaces. This rock exhibits a substantial presence of sub-micron porosity as the micro-CT image for the sister sample shown in Figure 1 with Mercury Injection Capillary Pressure (MICP) curve. The pore diameter is estimated by Washburn equation. A core plug with 38 mm in diameter and 75 mm long is used in the coreflood experiment. Prior to the coreflood, effective porosity of the plug core is measured with the X-ray CT scanner system, which gives the average porosity of 14.0% and the three-dimensional (3D) porosity distribution as illustrated in Figure 1(c). Note there is the highest porosity region with over 20 % porosity in the lower half of the image.

Experimental Setup/Procedure
The experimental diagram and its main part with X-ray CT scanner and the core holder are shown in Figure 2. The experimental temperature is 40°C and the overburden pressure is 2,000 psig. The key steps of the coreflood experiment are as follows:
1) Take a CT image of the plug core under dry condition.
2) Inject CO₂ and take a CT image under 100% CO₂ saturation (supercritical CO₂ condition).
3) Inject brine and take a CT image under 100% brine saturation to calculate the porosity distribution.
4) Inject CO₂ saturated brine and take a CT image under 100% CO₂ saturated brine saturation.
5) Inject brine again to saturate the core.
6) Inject CO₂ at the designed flow rate until no more brine is produced and the pressure difference becomes stable. In-situ saturation monitoring is conducted by the X-ray CT during the CO₂ flooding experiment. Some CO₂ dissolve to the brine and the process takes time to stabilize.
7) Inject CO₂ saturated brine to confirm the CO₂ trapping in the rock sample.

Our previous paper describes a full detail of coreflood procedure with in-situ saturation monitoring by X-ray CT under designated temperature conditions (Okabe et al., 2006) as well as the accuracy of the CT measurements (Oshita et al., 2000). The accuracy of CT derived porosity and saturations depends on an attenuation contrast of X-ray between fluid phases. In this study, 15wt% NaI is used as a dopant to the brine phase and the accuracy of the measurements of porosity and saturations is evaluated at ±1 Bulk Volume% and ±2 Pore Volume%, respectively. The temperature is kept at 40ºC during the experiment and the overburden / pore pressures are 2,000 / 1,420psig. Fluid permeability measured in the course of the above steps is 6.7md for the plug core. Both CO₂ flood and waterflood are conducted at a flow rate of 0.5cc/min except the flow rates for the CO₂ injection are changed to 1cc/min and 4.5cc/min after 5 and 10PV, respectively.

RESULTS
The carbonate core plug shows strong heterogeneity in terms of the porosity and the saturation distributions illustrated in Figure 3. CO₂ flows through porous areas (lower parts of the horizontal cuts in each figures), which is similar to the water injection to the mixed-wet carbonate rock. As shown in Figure 3(a) and (b), CO₂ firstly dissolves into the brine phase as the saturation change is not clearly shown. The difference of CT value between brine and CO₂ saturated brine is very small as the density contrast is little. The saturation change, however, is observed after 2PV CO₂ injected in Figure 3(c) as the density contrast between CO₂ and brine can be captured by CT value. At the 5PV injection, the flow rate is increased from 0.5cc/min to 1cc/min and then 4.5cc/min at the 10PV injection. The average water saturation is decreased to 0.6. In order to estimate the residual CO₂ saturation with rock heterogeneity and to confirm the capillary trapping of CO₂, CO₂ saturated brine is then injected as shown in Figure 3(g)-(i). The water saturation cannot be restored to the initial condition even after 7.5PV injection and the heterogeneous water saturation distribution is observed. The residual CO₂ saturation distribution correlates the porosity distribution as shown in Figure 4(b). The trapped CO₂ saturation in this carbonate rock is 0.23 on average, which excludes the amount of dissolved CO₂ into brine.
CONCLUSION
In order to visualize and understand the CO$_2$ saturation distribution in the rock sample, the coreflood experiment using CO$_2$, CO$_2$ saturated brine and reservoir brine is conducted with in-situ saturation monitoring by X-ray CT. CO$_2$ saturated brine is used to avoid the dissolution of carbon dioxide into the brine in order to measure the residual CO$_2$ saturation. The experimental result clearly shows the relation between rock heterogeneity and residual CO$_2$ saturation even in the same rock sample. The injected CO$_2$ flows through more porous area and it is trapped at lower porosity region. The trapped CO$_2$ saturation in the experiment is 0.23 on average, which excludes the amount of dissolved CO$_2$ into brine. Residual CO$_2$ saturation by capillary trapping is observed on the Middle Eastern carbonate rock. The study also gives us the insight for the CO$_2$-EOR with enhancing recovery and simultaneously storing CO$_2$. In-situ saturation monitoring is the key to understand fluid movement and trapping. For the future work, microstructures of the rocks and fluid interactions will be investigated by the pore-scale modeling.

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REFERENCES
Figure 1. (a) A grey scale tomographic image of the carbonate subsample with 5 mm in diameter and the voxel size 2.8 \( \mu \text{m} \). (b) Mercury Injection Capillary Pressure (MICP) experimental data for the subsample. Note that only \( \approx 50\% \) of the pore space is connected via resolvable throats in the micro-CT image data. (c) three-dimensional (3D) porosity distribution of the plug core (horizontal cut) used for the coreflood experiment.

Figure 2. The X-ray CT coreflood system with developed temperature control units for designed temperature conditions. The orange rubber heater covers the coreholder and the line heaters are attached to the fluid injecting lines. The diagram on the right is typical coreflood experimental system.
Figure 3. X-ray CT derived saturation distribution during the CO\textsubscript{2} flood (a-f) and post-flood by the CO\textsubscript{2} saturated brine (g-i) on the carbonate rock. The horizontal cuts are visualized and the scale shows water saturation.

Figure 4. X-ray CT derived water saturation distribution during the CO\textsubscript{2} flood (a) and post-flood by the CO\textsubscript{2} saturated brine (b) on the carbonate rock.