Effect of Flow Rate, Gravity, and Sub-Core Scale Heterogeneities on CO_2/Brine Relative Permeability Measurements in Horizontal Core Floods

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Motivation

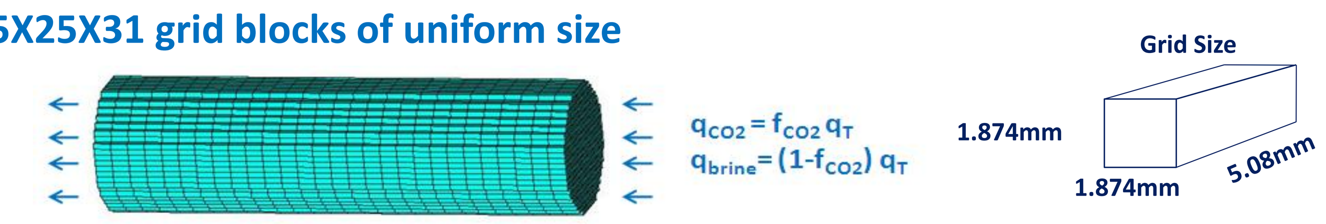
This paper presents an assessment of the conditions under which accurate core-scale relative permeability measurements of CO_2/brine at reservoir conditions can be obtained. The results are based on the high resolution of 3D simulation results of relative permeability measurements over a range of relevant conditions. The combined effect of flow rate, capillary pressure, gravity, and sub-core heterogeneity on steady-state multiphase flow experiments have been simulated at different fractional flows of CO_2 to gain a more quantitative assessment of the influence of these parameters on relative permeability measurements and to allow defining operational regimes under which reliable measurements can be attempted. A systematic parametric study of the flow mechanism is important to solve the issues we have in the steady-state multiphase flow system.

Define simulation input parameters: ϕ, k, P_c, k_r → Generate steady-state synthetic data sets (S_{CO2}, ΔP_{CO2}) → Calculate relative permeability (Steady-State Method)

Fig. 1 Overview of scientific approach

Numerical Simulation: Core Description

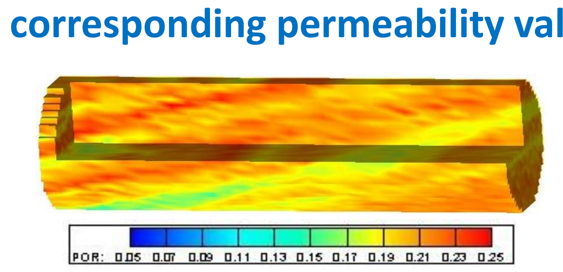
25X25X31 grid blocks of uniform size



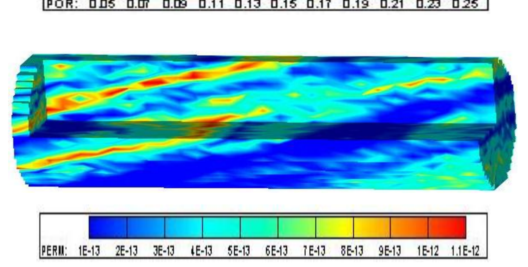
- **Simulator: TOUGH2 MP with ECO2N module** (Pruess 2005; Zhang et al. 2003, 2007)
- **Co-inject CO_2 and brine into a brine saturated core at reservoir condition (T=50˚C and P=12.4 MPa)**
- **Assign main input parameters for each grid element: porosity, permeability, capillary pressure curve and relative permeabilities**

Simulation Input: Porosity and Permeability

- The homogeneous core study uses mean porosity and permeability values
- The heterogeneous core study uses measured porosity values and generates the corresponding permeability values based on porosity-permeability equation



3D Porosity Map by X-ray CT Scanner (29 lateral images data)



Permeability Map: High Contrast Model

Berea Sandstone
ϕ_{mean}=20.3%
k_{mean}=430 md
L=15.24 cm
H=5.08 cm

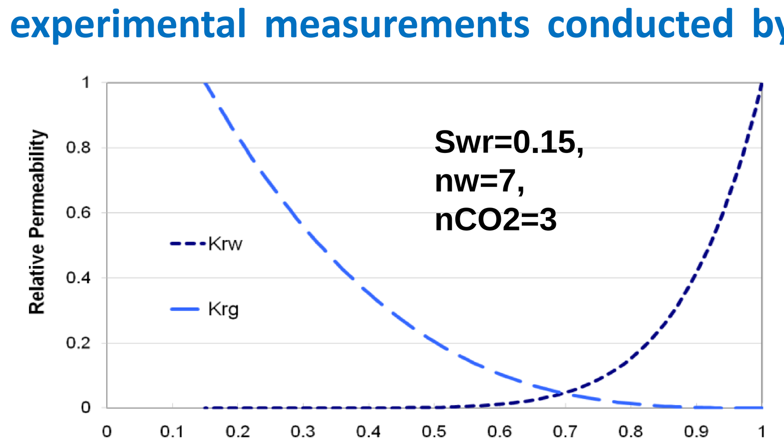
High degrees of heterogeneity generated from porosity-permeability relations has been compared to the homogeneous core to study the sub-core heterogeneity effect on relative permeability

Simulation Input : Relative Permeability Curves

The relative permeability curves used in the simulations are power-law functions. These three parameters in the relative permeability functions were chosen to fit the relative permeability data calculated from experimental measurements conducted by Perrin and Benson (2010).

$$k_{r,CO_2}=\left(\frac{1-S_w}{1-S_{wr}}\right)^{n_{CO_2}}$$

$$k_{r,w}=\left(\frac{S_w-S_{wr}}{1-S_{wr}}\right)^{n_w}$$



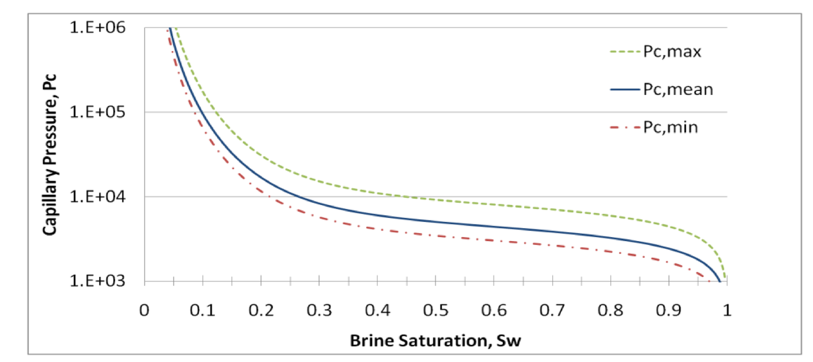
Relative permeability curves are the same for both homogeneous and heterogeneous core studies.

Simulation Input : Capillary Pressure Curves

- Homogeneous cores: one uniform capillary pressure curve for each grid element based on mean porosity and mean permeability values
- Heterogeneous cores: each grid element has a unique pair of porosity and permeability values; hence a unique capillary pressure curve

$$P_{c,i}(S_w)=\sigma\sqrt{\frac{\Phi_i}{k_i}}J(S_w)$$

$$J(S_w)=A\left(\frac{1}{S^{\lambda_1}}-1\right)+B(1-S^{\lambda_2})^{1/\lambda_2},\quad S=\frac{S_w-S_p}{1-S_p}$$



To replicate the spatial variations in CO_2 saturation observed in the experiments, the capillary pressure characteristic curve must be different in each grid element.

Boundary Conditions

Inlet BC: Designed to mimic the diffuser plate where CO_2 and brine are injected into the core

Outlet BC: (i) Imposed time-independent Dirichlet boundary condition (P and T remain unchanged) (ii) Capillary pressure gradient between the last rock slice and the outlet slice is set to zero. This condition is needed to mimic the observed lack of large saturations at the downstream end of the core (Fig.2).

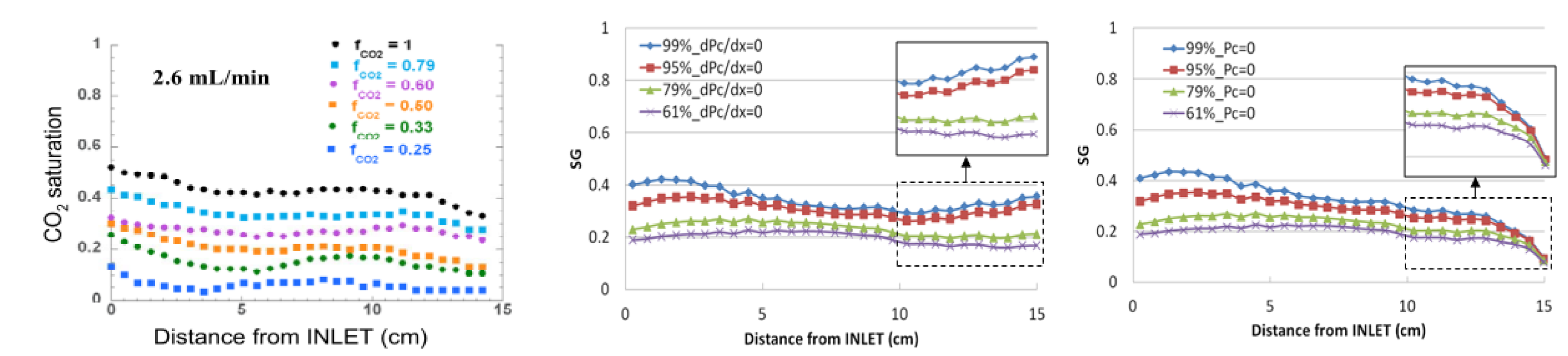


Fig. 2 CO_2 saturation along the Berea Sandstone core for different fractional flows of CO_2 at a total injection flow rate 2.6 ml/min: (a) Experimental results; (b) High contrast model with boundary condition dP_c/dx=0; (c) High contrast model with boundary condition P_c=o

The imposed Dirichlet boundary condition with dP_c/dx=0 qualitatively provides a much better match to the data. Thus, all the simulations presented in this paper are implemented Dirichlet boundary condition with dP_c/dx=0.

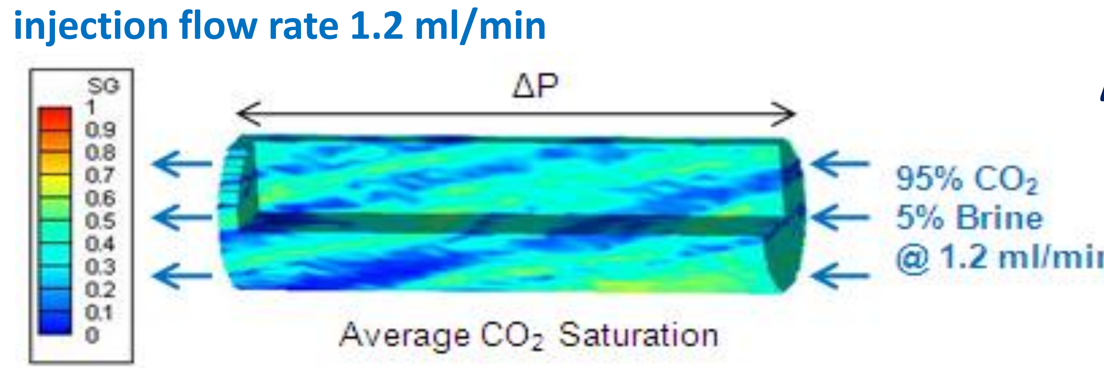
Simulation Input : Total Injection Flow Rates

The last important input parameter is the total injection flow rate. Flowrates range from 10 ml/min to 0.1 ml/min, which is practical for relative permeability experiments.

For a given flow rate, simulations of co-injection of CO_2 and brine are run until the pressure drop and core-averaged saturation reach steady-state. All of our simulations have been confirmed to run long enough (more than 10 pore volume injected) to reach steady-state.

Simulation Output: Saturation and Pressure Gradient

Example: CO_2 saturation distribution at steady-state for 95% fractional flow of CO_2 at a total injection flow rate 1.2 ml/min



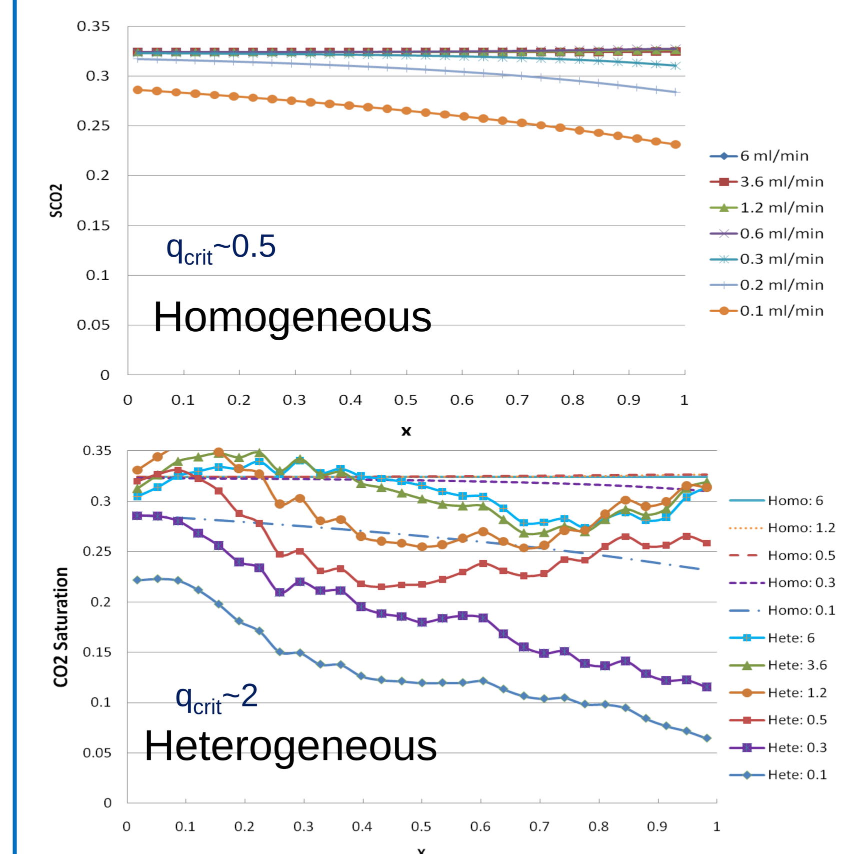
$$\Delta P_{CO2}=P_{CO2,inlet}-P_{CO2,outlet}$$

$$\Delta P_w=P_{w,inlet}-P_{w,outlet}=(P_{CO2}-P_c)_{inlet}-(P_{CO2}-P_c)_{outlet}=\Delta P_{CO2}-\Delta P_c$$

Drainage relative permeability has been calculated based on the main simulation outputs such as gas pressure, capillary pressure and the saturation:

$$q_w=\frac{kk_{r,w}}{\mu_w}A\frac{\Delta P_w}{L}=\frac{kk_{r,w}(S_w)}{\mu_w}A\frac{\Delta P_{CO2}-\Delta P_C}{L},\quad q_{CO_2}=\frac{kk_{r,CO_2}(S_{CO_2})}{\mu_{CO_2}}A\frac{\Delta P_{CO_2}}{L}$$

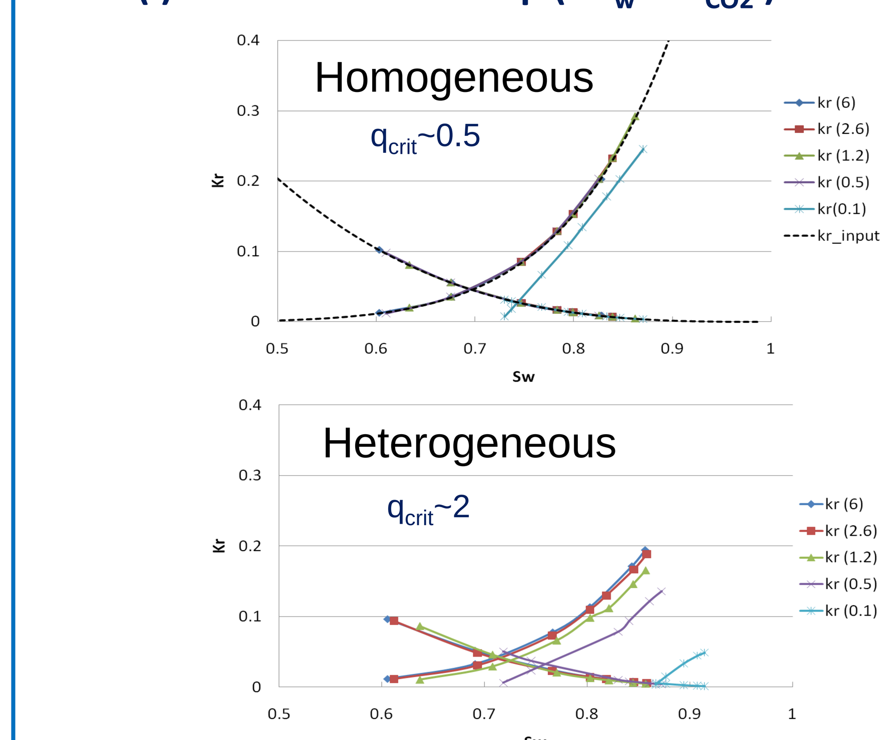
Simulation Results : Average CO_2 Saturation/Relative Permeability Calculations



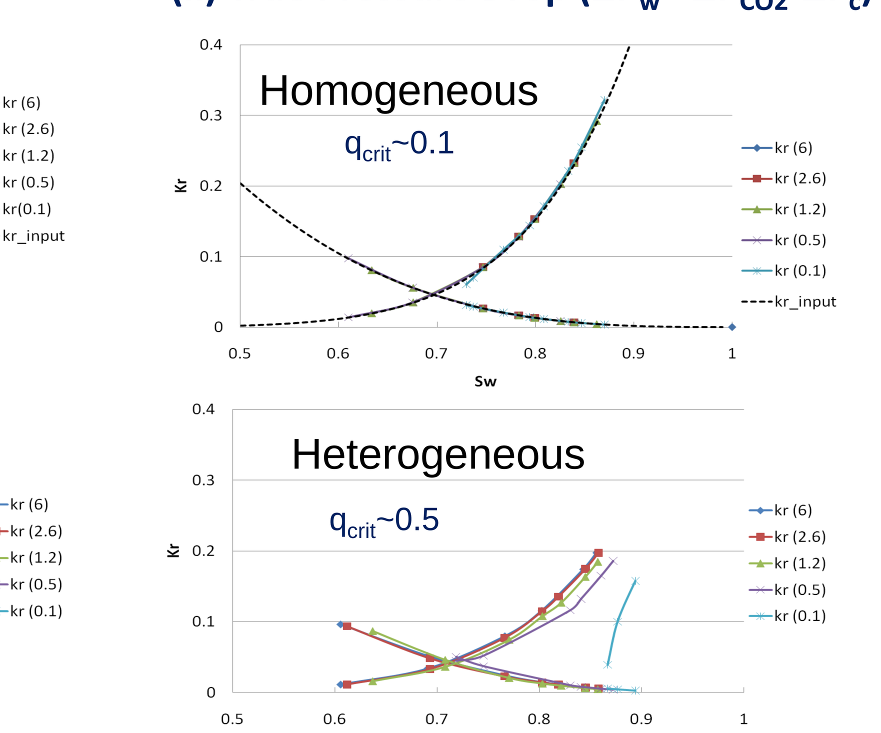
CO_2 saturation as a function of the distance from the inlet at a 95% fractional flow of CO_2 over a large range of flow rates (0.1 ml/min-6 ml/min):

- The minimum flowrate required eliminating the saturation gradient along the length of the core is defined as the "critical flowrate (q_{crit})".
- The combined effect of viscous, gravity, and capillary forces leads to the observed saturation gradient.
- Core heterogeneity will enhance the flow rate dependency, decrease the average saturation, and increase the saturation gradient.

(i) Same Pressure Drop ($\Delta P_w=\Delta P_{CO2}$)



(ii) True Pressure Drop ($\Delta P_w=\Delta P_{CO2}-\Delta P_c$)

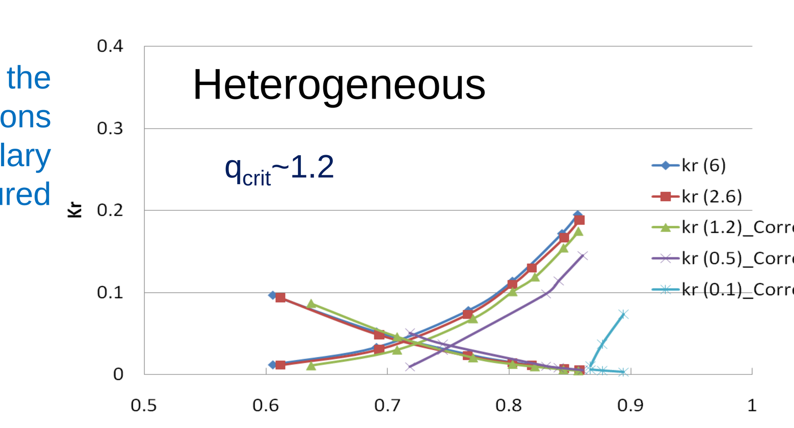


(iii) Capillary Pressure Corrected Pressure Gradient

It is possible to estimate capillary pressure gradients based on the average saturation values at the inlet and outlet end. Once saturations at the ends of the core are known, the corresponding capillary pressure values can be estimated from independently measured capillary pressure curves:

$P_{c,inlet}=P_C(S_{inlet})$, $P_{c,outlet}=P_c(S_{outlet})$

Therefore $\Delta P_c=P_C(S_{inlet})-P_c(S_{outlet})$



○ The simulation suggests that a relative uniform saturation is required in order to get reliable relative permeability measurements.

○ Above the critical flowrate (viscous-dominated regime), saturation is constant and flowrate independent, and the calculated relative permeability is also independent of flowrate.

○ Below the critical point, decreasing flow rate will result in saturation gradients along the core and hence result in large deviation of relative permeability to water.

○ The accurate whole-core drainage relative permeability can be obtained even with the highly heterogeneous core once the flow rate is above the critical value.

General Rule: The accurate whole-core relative permeability measurements can be achieved when

$$N_{cv}=\frac{kLp_c^*}{H^2\mu_{CO_2}}\frac{A}{q_T}\le 10$$

which assures that the flowrate is in the viscous-dominated regime. N_{cv} is the capillary number, the ratio of capillary to viscous force.

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