GHGT-11

Numerical study on the field-scale aquifer storage of CO$_2$ containing N$_2$

Ning Wei*, Xiaochun Li, Ying Wang, Yan Wang, Weizhong Kong

State Key Laboratory for Geo-mechanics and Geo-technical Engineering, Institute of Rock and Soil Mechanics, Chinese Academy of Sciences, Wuhan 430071, China

Abstract

The possibility of co-injecting these gaseous compounds with CO$_2$ to decrease the operational cost of carbon capture and storage by lowering the requirement of CO$_2$ capture or adding impurities is being considered. Some studies have analyzed the possible geochemistry effects of impurities such as H$_2$S and SO$_2$. However, few studies have focused on the effect of N$_2$ or other non-condensable gas impurities in CO$_2$ stream. Accordingly, this study performed some preliminary numerical simulations on the migration process of CO$_2$/N$_2$ mixture. A modeling tool was established based on the pressure-volume-temperature, viscosity, solubility, and relative permeability characteristics, as well as on the capillary pressure curve, geochemistry model, and COMSOL-Multiphysics software. Then, the migration processes of different N$_2$/CO$_2$ mixtures were evaluated using the modeling tool. The numerical simulation results showed the following: 1) co-injection of CO$_2$ and N$_2$ decreased the storage capacity of CO$_2$ in the aquifer; 2) CO$_2$ plume with N$_2$ moved faster than pure CO$_2$ plume, and CO$_2$ plume with N$_2$ had a higher gas saturation than pure CO$_2$ plume; and 3) a chromatographic partitioning process occurred during the migration process of the gas mixture, suggesting that N$_2$ in the migration front may be an effective monitoring or warning gas for CO$_2$ leakage given the non-toxicity and inertness of N$_2$.

© 2013 The Authors. Published by Elsevier Ltd.
Selection and/or peer-review under responsibility of GHGT
Keywords: Impure CO$_2$; N$_2$; chromatographic partitioning; deep saline aquifer; solubility trapping

Nomenclature

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha$</td>
<td>phase of fluid ( $\alpha$ is the wetting or non-wetting phase in the form of $w$ or $nw$)</td>
</tr>
<tr>
<td>$\rho_\alpha$</td>
<td>density of $\alpha$-phase fluid (kg·m$^{-3}$)</td>
</tr>
<tr>
<td>$\mu_\alpha$</td>
<td>dynamic viscosity of $\alpha$ phase (Pa·s)</td>
</tr>
<tr>
<td>$p_\alpha$</td>
<td>pressure of $\alpha$ phase (Pa)</td>
</tr>
<tr>
<td>$k_j$</td>
<td>absolute permeability tensor of porous media (m$^2$)</td>
</tr>
<tr>
<td>$k_{\alpha\prime}$</td>
<td>relative permeability of $\alpha$ phase (m$^2$)</td>
</tr>
</tbody>
</table>

* Corresponding author. Tel: +86-13995659295 ; fax: +86-02787198967 .
E-mail address: nwei@whrsm.ac.cn

1876-6102 © 2013 The Authors. Published by Elsevier Ltd.
Selection and/or peer-review under responsibility of GHGT
doi:10.1016/j.egypro.2013.06.294
\[ \varphi \] porosity of sandstone
\[ \varphi_0 \] porosity under referent condition
\[ x_i \] \( i^{th} \) axis
\[ D \] direction vector of gravity
\[ \theta_{\alpha} \] volumetric content of \( \alpha \) phase (m\(^3\)/m\(^3\))
\[ \rho_{\alpha} \] density of \( \alpha \) phase fluid in sink or source term (kg·m\(^{-3}\))
\[ q_{\alpha} \] flux of \( \alpha \) phase in sink or source terms, including chemical and physical changes (m\(^3\)/m\(^3\)·s\(^{-1}\))
\[ t \] time (s)
\[ S_{\alpha} \] saturation of \( \alpha \) phase in rock (\( S_{\alpha}+S_{\alpha,sw}=1 \)) (dimensionless)
\[ g \] acceleration due to gravity (m\(^2\)/s\(^{-2}\))
\[ c_r \] compressibility of rock (Pa\(^{-1}\))
\[ n_{\alpha} \] total number of species in \( \alpha \) phase
\[ Q_{\alpha} \] flux in source or sink term caused by dispersion and diffusion (kg·m\(^3\)·s\(^{-1}\))
\[ M_l \] molar weight of species \( l \) in gas phase (kg·mol\(^{-1}\))
\[ C_{\alpha l} \] concentration of solute \( l \) in \( \alpha \) phase (mol·L\(^{-1}\))
\[ S_l \] concentration of solute \( l \) on solid phase (mol·L\(^{-1}\))
\[ V_{\alpha l} \] flow velocity of \( \alpha \) phase in \( i^{th} \) direction (m·s\(^{-1}\))
\[ K_w, K_m \] reaction rates of \( n^{th} \) solute in \( \alpha \) phase and on solid phase, respectively (mol·L\(^{-1}\)·s\(^{-1}\))
\[ D_{\alpha}(S_{\alpha}) \] mechanical dispersion tensor of \( \alpha \) phase in rock (m\(^2\)·s\(^{-1}\))
\[ D_{\alpha m}(S_{\alpha}) \] molecular diffusion coefficient of \( \alpha \) phase in rock (m\(^2\)·s\(^{-1}\))
\[ C_{\alpha l}^* \] \( l^{th} \) species concentration in \( \alpha \) phase in sink or source terms (mol·L\(^{-1}\))
\[ \delta_{ij} \] Kronecker delta, \( \delta_{ij} = 1, i= j, \delta_{ij} = 1, i \neq j \)
\[ \alpha_L, \alpha_T \] longitudinal and transverse dispersivities, respectively (m)
\[ V_i \] velocity component in \( i^{th} \) direction (m·s\(^{-1}\))
\[ V \] absolute average velocity of fluid (m·s\(^{-1}\))
\[ D_{\alpha,0} \] molecular diffusivity of solute (m\(^2\)·s\(^{-1}\))
\[ D_{\alpha m} \] pore molecular diffusivity of solute (m\(^2\)·s\(^{-1}\))
\[ \tau \] tortuosity factor of porous medium (dimensionless)
\[ \delta \] constrictivity (dimensionless)
\[ C_{\alpha l} \] \( l^{th} \) species on \( \alpha \) phase (mol·L\(^{-1}\))
\[ S_l \] \( l^{th} \) species on solid phase (mol·kg\(^{-1}\))
\[ k_l \] adsorption rate of \( l^{th} \) species (mol·L\(^{-1}\))
\[ k_0 \] linear distribution coefficient of \( l^{th} \) species between solid phase and \( \alpha \) phase (kg·L\(^{-1}\))
\[ r_{sl}, r_{\alpha l} \] chemical reaction rates of \( l^{th} \) species on solid surface and \( \alpha \) phase, respectively (mol·L\(^{-1}\)·s\(^{-1}\))
\[ k_{s,sw/l} \] solubility rate of \( l^{th} \) species in gas phase (mol·L\(^{-1}\)·s\(^{-1}\))
\[ S_{\alpha l} \] saturated concentration of \( l^{th} \) species on \( \alpha \) phase (mol·L\(^{-1}\))
\[ p_c \] capillary pressure, \( p_c = p_m - p_a \) (Pa)
\[ H_c \] capillary pressure head, \( H_c = p_c/(\rho_a g) \) (m)
\[ C_p \] specific capacity for water (Pa\(^{-1}\))
\[ \theta_{\alpha, m}, \theta_{\alpha, ms} \] residual and saturated volumetric contents of \( \alpha \) phase, respectively (dimensionless)
\[ \alpha_c, M, N, L \] four constants in Van Genuchten’s model, where \( L = 0.5 \) and \( M = 1-I/N \)
\[ r_m \] reaction rate (mol·s\(^{-1}\))
\[ k \] intrinsic rate constant (mol·m\(^{-2}\)·s\(^{-1}\))
\[ A \] specific reactive surface area per kg H\(_2\)O (m\(^2\))
\[ \theta, \eta \] \( pH \) power law coefficient, commonly set as unity
\[ K_m \] equilibrium constant for the chemical reaction (dimensionless)
\[ Q_m \] reaction quotient
1. Introduction

Carbon capture and storage (CCS) is regarded as a potentially effective, large-scale, economical, fossil energy-compatible, high technical-maturity option for reducing CO₂ emissions from the use of fossil fuels. A number of studies have demonstrated very high theoretical or effective capacities of deep saline aquifers [1-3]. However, the high cost of aquifer storage obstructs its large-scale use.

Gaseous compounds can exist in the gas stream as a result of the capture process, which will increase the cost of CO₂ capture. The possibility of co-injecting these gaseous compounds with CO₂ to decrease the operational cost of carbon capture and storage by lowering the requirement of CO₂ capture or adding impurities is being considered [4, 5]. Preliminary cost analyses have shown that the co-injection of CO₂ with some impurities may cut down the total CCS cost by lowering the capture requirement of CO₂, especially from high-purity emission sources. High-purity CO₂ stream (CO₂ mole fraction > 80%) always contains small amounts of impurities, such as N₂, O₂, NOₓ, SOₓ, H₂S, and H₂O, such as, coal chemistry, oxy-fuel combustion industry, chemical looping factory, and so on. Some studies have shown that impurities such as H₂S and SO₂ affect the geochemistry, trapping mechanism, and migration of CO₂ plume [6-8]. However, few studies have focused on the effect of non-condensable gas, such as, N₂. Thus, this study aimed to analyze the effect of N₂ on the migration behavior of CO₂ plume. Some preliminary results of numerical simulations on the migration of CO₂/N₂ mixture in an aquifer at the two-dimensional (2D) scale were presented.

2. Numerical simulation model

A simulation model is established based on the basic governing equation, the pressure-volume-temperature (PVT), viscosity, solubility, and relative permeability characteristics, as well as the capillary pressure curve, geochemistry model, and COMSOL-Multiphysics software.

2.1. Basic governing equation for two-phase fluid flow

The basic assumptions for the governing equation are as follows: (1) continuous flow process; (2) isothermal properties of CO₂ and water; (3) invariable capillary pressure curve and relative permeability characteristics with changes in gas components, water salinity, and chemical reaction; (4) negligible water vapor in the gas phase; and (5) consistent viscosity and density of water.

\[ \frac{\partial \phi \cdot p_a \cdot S_a}{\partial t} = \frac{\partial}{\partial x_i} \left[ \rho_a \cdot k_{ar} \cdot k_i \cdot \left( \rho_a - \rho_a \cdot g \cdot \frac{\partial D}{\partial x_i} \right) \right] + q_a \cdot \rho_a + Q_{a0} \]  

\[ \frac{\partial (\phi \cdot \rho_a \cdot S_a)}{\partial t} = \rho_a \cdot S_a \cdot \frac{dp_a}{dt} + \phi \cdot S_a \cdot \frac{dp_a}{dt} + \phi \cdot \rho_a \cdot \frac{\partial S}{\partial p_e} \cdot \frac{dp_e}{dt} \]  

\[ Q_0 = \sum_{i=x,y,z} \frac{\partial}{\partial x_i} \left[ \phi \cdot \left( D_{s0} \cdot (S_{s0}) + D_{s1} \cdot (S_{s1}) \right) \cdot \frac{\partial C_m}{\partial x_i} \right] \cdot M_i \]  

Porosity change with the aqueous pressure:

\[ \varphi = \varphi_c = c_e \cdot (p_e - p_{sat}) \]  

Initial pressure condition:

\[ p(x, y, z, 0) = p_0 \]  

Pressure boundary:

\[ p(x, y, z, t) = p(x, y, z, t) \]  

Initial flow boundary:

\[ -k_y \cdot k_{ar} / \mu_a \cdot \left( \rho_a \cdot g \cdot \frac{\partial D}{\partial x_t} \right) \cdot n_z = I \cdot (x, y, z, t) \]
2.2. Basic equation for solute transport (aqueous and gas phases)

\[ \rho_a \cdot \Phi \cdot S_a \cdot \frac{\partial C_{aw}}{\partial t} + \frac{\partial S_i}{\partial t} = \frac{\partial}{\partial x_j} \left[ \Phi \left( D_{aw} \left( S_a \right) + D_{am} \left( S_a \right) \right) \frac{\partial C_{aw}}{\partial x_j} \right] - \frac{\partial}{\partial x_j} \left( V_{aw} \cdot C_{aw} \right) - K_{aw} \cdot \phi \cdot C_{aw} - K_{aw} \cdot S_a + q_a \cdot C_{aw} \]

(9)

Initial solute concentration in \( \alpha \) phase: \( C_{aw}(x, y, z, t) = C_{aw0} \) \( (10) \)

Initial solute concentration in solid phase: \( S_i(x, y, z, t) = S_{i0} \) \( (11) \)

Flux boundary of solute:

\[ \frac{\partial}{\partial x_j} \left[ \Phi \cdot S_a \left[ D_{aw} \left( S_a \right) + D_{am} \left( S_a \right) \right] \frac{\partial C_{aw}}{\partial x_j} \right] = I_k(x, y, z, t) \]

(12)

Mechanical dispersion coefficient in aqueous or gas phase:

\[ D_q = \alpha_r \cdot V_{ij} \cdot \delta \gamma + \left( \alpha_L - \alpha_r \right) \cdot \left( V_{ij} / V \right) \]

(13)

Molecular diffusivity in \( \alpha \) phase in rock:

\[ D_{aw} = \delta \cdot D_{aw0} \left( 1 + \frac{s}{r^2} \right) \]

(14)

Dispersivity and molecular coefficient can be simplified as

\[ D_{aw} \left( S_a \right) = S_a \cdot D_{aw0} \]

\[ D_{am} \left( S_a \right) = S_a \cdot D_{am0} \]

(15)

Assuming the adsorption/desorption process as reversible and dynamic equilibrium, the interaction between rock and \( \alpha \) phase can be written as follows:

\[ \frac{\partial S_i}{\partial t} = k_{aw} \cdot \left[ (k_{aw} \cdot C_{aw} - S_i) \right] - \frac{r_{aw}}{1 - S_i} \]

(16)

\[ \frac{\partial C_{aw}}{\partial t} = k_{aw} \cdot \left[ (k_{aw} \cdot C_{aw} - S_i) \right] - \frac{r_{aw}}{1 - S_i} \]

(17)

The capillary pressure curve model used is Van Genuchten’s model [9]:

\[ S_w = 1 - S_{sw} = \left[ 1 + \left( \frac{\theta_{sat}}{\theta_w} \right) \right]^{-n} = \frac{\theta_{sat} - \theta_{w}}{\theta_{sat} - \theta_{w}} \]

(18)

\[ C_p = \frac{dS_w}{dp_r} = \frac{\alpha_r \cdot \left( N - 1 \right) \cdot \left( 1 - S_{sw} \right) \cdot (\alpha_r \cdot p_r)^{(N-1)}}{\left(1 + (\alpha_r \cdot p_r)\right)^{(2N+1)/N}} \]

\( (H_r > 0) \) and \( C_p = 0 \) \( (H_r < 0) \)

(19)

The relative permeability models are the Mualem and Corey models:

\[ k_{aw} = S_w^{m} \left[ 1 - \left( 1 - S_{sw} \right)^{m} \right] \]

and

\[ k_{aw} = \left( 1 - S_w \right)^{2} \quad \text{and} \quad \] (20)

2.3. Basic properties of CO2-N2 mixture

The PVT data of CO2-N2 mixture are calculated by the Peng-Robinson 78 model, and the dynamic viscosity of gas mixture is calculated through the viscosity model of Pedersen Fredenslund 1987 model. The solubility data of CO2 and N2 in brine are obtained from laboratory results.

2.4. CO2-rock-water chemistry interaction

Kinetic mineral dissolution/precipitation reactions were assumed to be governed by transition state theory. The kinetic reactions used in the simulations are shown in Table 2. The reaction rates are calculated according to a general kinetic rate law [10, 11] as follows:

\[ r_m = k \cdot A_m \cdot \left( 1 - \frac{Q_m}{K_m} \right)^n \]

(21)
The numerical simulation focuses on the effect of N$_2$ on the migration process of CO$_2$ with impurities in an aquifer. These short-term chemical reactions are considered in the simulation for the greater effect on migration of CO$_2$ plume. The equilibrium coefficient and kinetic reactions used in the reactive transport are shown in Table 1 and Table 2, respectively.

Table 1 Equilibrium reactions used in reactive transport simulations [12]

<table>
<thead>
<tr>
<th>Equilibrium reaction</th>
<th>Log equilibrium coefficient</th>
<th>Kinetic reaction</th>
<th>Log equilibrium coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO$_2$ (aq) + H$_2$O = HCO$_3^-$ + H$_3$O$^+$</td>
<td>-6.266</td>
<td>MgHCO$_3$ (aq) = Mg$^{2+}$ + 2HCO$_3^-$</td>
<td>-1.13</td>
</tr>
<tr>
<td>CaCO$_3$ (aq) + H$_2$O = Ca$^{2+}$ + HCO$_3^-$</td>
<td>6.54</td>
<td>MgSO$_4$ (aq) = Mg$^{2+}$ + SO$_4^{2-}$</td>
<td>-2.76</td>
</tr>
<tr>
<td>CaHCO$_3^-$ = Ca$^{2+}$ + HCO$_3^-$</td>
<td>-1.13</td>
<td>CO$_2$ + H$_2$O = HCO$_3^-$ + H$_3$O$^+$</td>
<td>6.531</td>
</tr>
<tr>
<td>CaSO$_4$ (aq) = Ca$^{2+}$ + SO$_4^{2-}$</td>
<td>-2.23</td>
<td>CO$_3^{2-}$ + H$_2$O = CO$_2$ + 2H$^+$</td>
<td>16.681</td>
</tr>
<tr>
<td>MgHCO$_3$ (aq) = Mg$^{2+}$ + HCO$_3^-$</td>
<td>-1.13</td>
<td>HCO$_3^-$ = H$^+$ + CO$_2$ + H$_2$O</td>
<td>10.329</td>
</tr>
<tr>
<td>CaMg(CO$_3$)$_2$(aq) = Ca$^{2+}$ + Mg$^{2+}$ + 2CO$_3^{2-}$</td>
<td>-17.09</td>
<td>CaCO$_3$ (aq) = Ca$^{2+}$ + CO$_2$ + H$_2$O</td>
<td>-8.48</td>
</tr>
</tbody>
</table>

Table 2 Kinetic reactions used in reactive transport simulations [12]

<table>
<thead>
<tr>
<th>Kinetic reaction</th>
<th>Intrinsic rate constant, $k_i$ (mol-m$^{-2}$s$^{-1}$)</th>
<th>Activation energy, $E_a$ (kJ mol$^{-1}$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anhydrite = Ca$^{2+}$ + SO$_4^{2-}$</td>
<td>$2.07 \times 10^1$</td>
<td>14.3</td>
</tr>
<tr>
<td>Calcite = H$^+$ + Ca$^{2+}$ + HCO$_3^-$</td>
<td>$2.03 \times 10^2$</td>
<td>23.5</td>
</tr>
<tr>
<td>Dolomite $=2$H$^+$ + Ca$^{2+}$ + Mg$^{2+}$ + 2HCO$_3^-$</td>
<td>$4.13 \times 10^3$</td>
<td>52.2</td>
</tr>
<tr>
<td>Magnesite = H$^+$ + Mg$^{2+}$ + HCO$_3^-$</td>
<td>Set to Calcite</td>
<td>Set to Calcite</td>
</tr>
</tbody>
</table>

3. Numerical simulation of gas mixture migration process

Based on the models listed above, the modeling tool is established using COMSOL Multiphysics software. A 2D axial symmetric model is adopted. Fig 1 shows the schematic of the case and boundary conditions. The initial water pressure in deep saline formation is 12 MPa. The injection rate is 1.6×10$^6$ m$^3$·a$^{-1}$ by one single vertical well. The basic hydraulic properties of geological formation are shown in Table 3. The chemical species of water in deep saline formation are shown in Table 4, and the mineralogical composition of sandstone in aquifer is shown in Table 5.

![Fig 1. Schematic of the simulated case](image-url)
Table 3 Basic hydraulic properties of geological formation

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>27</td>
</tr>
<tr>
<td>Molecular diffusion coefficient in aqueous phase (m²·s⁻¹)</td>
<td>1 × 10⁻⁹</td>
</tr>
<tr>
<td>Permeability coefficient (mD)</td>
<td>100</td>
</tr>
<tr>
<td>Residue water content, θ_{res}</td>
<td>0.05</td>
</tr>
<tr>
<td>Longitude dispersion coefficient (m)</td>
<td>0.05</td>
</tr>
<tr>
<td>Saturate water content θ_{ss}</td>
<td>0.30</td>
</tr>
<tr>
<td>Transverse dispersion coefficient (m)</td>
<td>0.005</td>
</tr>
<tr>
<td>VG constant a_v (m⁻¹)</td>
<td>1.8</td>
</tr>
<tr>
<td>Gas molecular diffusion coefficient (m²·s⁻¹)</td>
<td>1 × 10⁻⁶</td>
</tr>
<tr>
<td>VG constant N</td>
<td>1.84</td>
</tr>
</tbody>
</table>

Table 4 Chemical species of underground water in deep saline formation

<table>
<thead>
<tr>
<th>Context</th>
<th>HCO₃⁻</th>
<th>CO₂</th>
<th>Cl⁻</th>
<th>Ca²⁺</th>
<th>Mg²⁺</th>
<th>K⁺-Na⁺</th>
<th>TDS (g·L⁻¹)</th>
<th>pH</th>
<th>temperature (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Content (mg·L⁻¹)</td>
<td>2437.69</td>
<td>7.46</td>
<td>305.8</td>
<td>22.62</td>
<td>23.45</td>
<td>1216</td>
<td>3.20</td>
<td>7.8</td>
<td>50</td>
</tr>
</tbody>
</table>

Table 5 Mineralogical composition of sandstone in deep saline formation

<table>
<thead>
<tr>
<th>Mineral used in the model</th>
<th>Mole fracture (kmol·m⁻³)</th>
<th>Chemical composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>0.00225</td>
<td>CaCO₃</td>
</tr>
<tr>
<td>Magnesite</td>
<td>0.0002</td>
<td>MgCO₃</td>
</tr>
<tr>
<td>Dolomite</td>
<td>0.0003</td>
<td>CaMg(CO₃)₂</td>
</tr>
</tbody>
</table>

4. Results and discussion

The migration processes of different N₂/CO₂ mixtures are analyzed by a simulation model. The major results in the monitoring line are shown in Fig 2. Fig 2(a) shows a difference between the migration front of pure CO₂ and impure CO₂ (95% CO₂ and 5% N₂) at the same injection rate. CO₂ plume with N₂ moves faster than pure CO₂ plume, and CO₂ plume with N₂ has higher gas saturation than pure CO₂ plume. CO₂ plume with N₂ takes more pore space underground, which may be caused by the low solubility of N₂ in brine. Fig 2(b) shows that N₂/CO₂ stream produces a pH plume faster than CO₂, which may be caused by the faster movement of N₂. Fig 2(c) shows that the CO₂ concentration in gas mixture is lower than that in pure CO₂ plume. N₂ in CO₂ stream decreases the CO₂ concentration and storage capacity for low-concentration CO₂ in the gas phase. Fig 2(d) shows the presence of a high N₂/CO₂ ratio in the migration front of low-concentration CO₂ compared with the migration front of gas plume. This finding can be due to the preferential solubility and mineralization of CO₂ in brine compared with those of N₂. Consequently, CO₂ is stripped off at the leading edge of CO₂/N₂ mixture that advances through the aqueous phase and causes low CO₂ concentration in the leading front. This phenomenon can be called a chromatographic partitioning process. Fig 2(d) shows that the N₂/CO₂ molar ratio and width of the high N₂ band increase during the migration of gas mixture. The chromatographic partitioning process of N₂ in an aquifer results in the migration front of N₂ during the preferential and long-distance flow process of gas mixture. The chromatographic partitioning process also suggests that N₂ in the migration front may be an effective tracer for CO₂ leakage given the non-toxicity, inertness, and low solubility of N₂.
Fig 2. Simulation results in the monitoring line at different times

5. Conclusions

A 2D axial symmetric simulation model is established based on the PVT, viscosity, relative permeability, and solubility properties of N₂/CO₂ mixture, as well as the geochemistry model and COMSOL-Multiphysics software. Then, the preliminary simulations on the migration process of N₂/CO₂ mixture in an aquifer are studied. Several important results of the co-injection of CO₂ and N₂ are presented as follows:

1) The co-injection of CO₂ and N₂ decreases the storage capacity of CO₂ in an aquifer.
2) CO₂ plume with N₂ moves faster than pure CO₂ plume, and CO₂ plume with N₂ has higher gas saturation than pure CO₂ plume.
3) A chromatographic partitioning process occurs during the migration process of gas mixture, which is caused by the preferential solubility and mineral trapping of CO₂ in the gas phase. The N₂ front may be an effective monitoring or warning gas for CO₂ leakage given the non-toxicity and inertness of N₂.

Further work should be conducted to analyze better the viscosity, buoyancy, and storage capacity effects, as well as the sweep efficiency.
Acknowledgements

The authors gratefully acknowledge the financial support of the Projects of International Cooperation from Ministry of Science and Technology of China, Joint Research on Key Technologies of Oxy-fuel Combustion Based on CO₂ Capture and Storage System (grant number: 2012DFB60100), and the Joint Research on Low Emission Technologies for Integrated Gasification Combined Cycle (grant number: 2010DFB70560).

References