Modeling Long-Term CO₂ Storage in Aquifer with a Black-Oil Reservoir Simulator
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Abstract
This paper presents results of modeling long-term CO₂ storage in a shallow saline aquifer with a commercial black-oil reservoir simulator. Realistic CO₂/water phase behavior (pVT properties) covering all pressure, temperature and compositional conditions accounted for during the simulations have been used. The pressure and temperature in the aquifer is above the CO₂ supercritical conditions giving rise to the existence of a two-phase fluid system of CO₂ as a supercritical fluid (“gas”) and CO₂ dissolved in the aqueous phase. The objective was to model scenarios of CO₂ storage in aquifer with emphasis on the sensitivity of CO₂ distribution in the deposit with respect to critical CO₂ saturations during the injection period and to residual CO₂ saturation for water reentering CO₂ filled volumes (hysteresis in fluid saturations). The re-distribution of water occurs after stop of CO₂ injection due to gravity segregation of dense CO₂ saturated water and CO₂-free water. The impact of various reservoir parameters has been studied, including average permeability, vertical to horizontal permeability ratio (kᵥ/kₜ₀), relative permeability, and capillary pressure. For the saturation functions the main focus has been on end points and hysteresis effects. It is observed that storage of CO₂ as residual gas is most important for low kᵥ/kₜ₀ ratios.

Introduction
The concentration of carbon dioxide (CO₂) continues to increase in the atmosphere as a result of CO₂ release from anthropogenic sources including burning of fossil fuels. The atmospheric concentration of CO₂ has increased from the pre-industrial age level of about 280 ppm to 370 ppm today¹. This value is higher than the concentrations observed over the last 400,000 years.

The current emissions of CO₂ into the atmosphere exceed the capacity of the natural CO₂ cycling system to absorb the emissions. Accumulation of CO₂ and other greenhouse gases in the atmosphere results in an accompanying increase of global atmospheric temperature. Reduction of the pH of the upper ocean level is another result of accumulation of CO₂ in the atmosphere.

Large-scale storage of CO₂ in geologic formations will contribute to meet the challenge of stabilizing the concentration of CO₂ in the atmosphere. Oil, gas and condensate reservoirs are relevant locations to consider for CO₂ storage because their proven geologic seal that trapped the buoyant hydrocarbon over a geological timescale and because of the already acquired geologic description. A prerequisite is that the geologic seal has not been damaged during the production and that the abandoned wells do not leak CO₂ to the surface².

In lack of petroleum reservoir for CO₂ storage purpose, deep saline formations are possible alternatives. They are more common worldwide and thus constitute a larger potential storage volume. The disadvantage is that they usually are much less characterized than petroleum reservoirs. Especially, there is normally no proven seal before injection starts.

Characterization of the aquifer is an important part of the total evaluation of the aquifer as a reliable long-term CO₂ deposit site. Detection and proper description in the simulation model of potential vertical flow barriers, topography of cap rock, faults, and other potential pathways for flow that will dominate the storage capacity and reliability of the aquifer must be considered carefully.

This paper is about storage mechanisms of CO₂ in deep saline aquifers. Gravity segregation of CO₂ towards the top of the aquifer will dominate the flow caused by the density difference between injected CO₂ and brine unless flow barriers in the aquifer restrict the vertical segregation. Large volume aquifers with reasonable permeability (to allow good injectivity), high thickness, and good communication over long distances will be the most attractive. In this setting large volumes of CO₂ can be injected without a risk of significant rise of the aquifer pressure.

The injected CO₂ will on a 1000 years time-scale diffuse into the underlying aquifer column. The resulting brine/CO₂ mixture is slightly denser than the virgin brine. This density difference will cause instability and induce convective currents in the aquifer enhancing the dissolution rate of CO₂ into the aqueous phase. The CO₂-saturated brine segregates downwards the aquifer and mixes with fresh brine. Provided a good vertical communication in the aquifer, the CO₂ will eventually dissolve in the aqueous phase and the dissolution is mainly controlled by the induced convective currents³.
Linear stability analysis has been used to estimate the time required for this instability to occur in anisotropic permeability distribution\(^5\). In most cases of practical interest, the longest timescale required for complete dissolution of the injected CO\(_2\) could be thousands of years, depending crucially on the vertical permeability of the aquifer.

Multivariable analysis has been used to study the effect of various aquifer parameters including impact of horizontal and vertical permeability, on permanent sequestration of CO\(_2\) in conceptual aquifer model reservoir simulation\(^5\). The study concluded that trapping of CO\(_2\) as a gas-water relative permeability hysteresis can impact significantly and that dissolution has a significant effect on the long-term fate of injected CO\(_2\). The study also concluded that permeability is the primary variable affecting migration of an injected CO\(_2\) plume and pressure buildup in the aquifer.

The Sleipner project in Norway has demonstrated the feasibility of large-scale CO\(_2\) injection into the Utsira saline aquifer. A time-lapse 3D seismic surveying program for monitoring the CO\(_2\) storage in the aquifer has accompanied the injection. The seismic surveying showed that the injected CO\(_2\) flowed horizontally beneath thin shales present in the aquifer and migrating upwards through breaks in the shales towards the cap rock of the formation\(^6\).

In this paper we will first present the different mechanisms for storing CO\(_2\) in aquifers. Then we will give a short introduction to hysteresis in gas-water systems. Thereafter the simulation model will be presented before we present the main results. Finally we conclude upon the main findings in this study.

**Mechanisms for storing CO\(_2\) in saline formations**

The following mechanisms for sequestering CO\(_2\) in saline aquifers have been described in the literature:

**CO\(_2\) solubility in formation water.** A portion of the injected CO\(_2\) will dissolve in the formation water in the aquifer and the dissolution of CO\(_2\) per unit volume of water is a function of pressure, temperature and salinity of the aqueous phase. The aqueous phase will contain the dissolved CO\(_2\) regardless of being stationary or segregated/transported to another location as long as the physical conditions are undisturbed. CO\(_2\)-saturated formation water is denser than water not containing CO\(_2\). The difference in density of CO\(_2\)-saturated aquifer water and virgin formation water triggers convection currents in the aquifer beneath the CO\(_2\) plume.

The dissolution of CO\(_2\) in formation water occurs through mass transfer from CO\(_2\) phase to aqueous phase whenever the phases are in contact. The access CO\(_2\) phase and the aqueous phases are thereby assumed to be in thermodynamic equilibrium in the model. The amount of CO\(_2\) dissolved in the aqueous phase as a function of the prevailing pressure, temperature and salinity in the aquifer, can be explicitly set in the simulation model by use of a realistic fluid property description based on laboratory pVT data of CO\(_2\)/brine mixtures of a wide range of proportions at various pressure and temperature conditions. This includes density and viscosity of both CO\(_2\) and aqueous phases at pressure and temperature of relevance.

In compositional reservoir simulators the solubility of CO\(_2\) in the aqueous phase as a function of pressure, temperature and salinity is calculated by EOS models.

**Mobile CO\(_2\) phase.** Another portion of the injected CO\(_2\) into an aquifer will be sequestered as a mobile phase of CO\(_2\) free to move laterally or migrate (buoyant) vertically towards the cap rock of the aquifer. The cap rock constitutes a no-flow boundary or barrier like a gas trap. The phase properties of the sequestered CO\(_2\) depend upon the prevailing pressure and temperature of the storage location of the aquifer. The critical point of CO\(_2\) is at a temperature of 31.04°C and a pressure of 73.82 bar. At higher temperatures and/or pressures, CO\(_2\) will exist as a supercritical fluid. At lower (subcritical) temperatures and/or pressures, CO\(_2\) can exist in two different phase states, a liquid and a gaseous state, as well as in two-phase mixtures of these states\(^7\).

**Residual CO\(_2\) saturation as hysteresis in gas-water saturation history.** Sequestration of supercritical CO\(_2\) as residual gas saturation in the aquifer occurs when formation water encroaches or invades the CO\(_2\) plume. Then some of the CO\(_2\) supercritical phase will be trapped in the pore space and a hysteresis behavior in the gas-water saturation history is experienced\(^8\).

**Mineral dissolution and carbonation.** Carbonic acid is formed when CO\(_2\) dissolves into the aquifer water. The carbonic acid reacts with various minerals in the rock matrix and dissolves reacted minerals. The dissolution products are susceptible to precipitate as stable carbonates and thereby permanently sequester a part of the injected CO\(_2\) in the aquifer. In fact this type of CO\(_2\) sequestration is desirable because precipitated carbonates is stagnant in the rock and could not leak into the atmosphere\(^9,10\).

**Theory of hysteresis in gas saturation history**

Gas-water relative permeability hysteresis model.

Hysteresis behavior of multi-phase flow in porous media, and thereby in relative permeability and capillary pressure, originates from the difference between the advancing and receding contact angle to the present fluids against the solid surface, and from the variation of pore throat to pore body ratio and the pore size distribution. The surface of the pore walls contains different minerals with different wetting characteristics towards the present fluids in the pore structure.

![Figure 1: Relative permeability hysteresis in the non-wetting phase (after Eclipse technical manual 2003\(^3\)).](image-url)
Hysteresis in the residual gas saturation of the non-wetting phase (CO2 supercritical gas) and hysteresis in the curve shape between drainage and imbibition relative permeability curves and capillary pressure curves are the two kinds of hysteresis effects of interest when formation water without CO2 in solution encroaches or invades the CO2 plume. Hysteresis in CO2 storage in aquifers due to post-injection fluid segregation is in this study limited to hysteresis in the non-wetting phase between primary drainage and imbibition relative permeability curves as illustrated in Figure 1.

Residual saturation of the trapped CO2 supercritical gas (non-wetting phase) is best calculated by Lands model.14 If a reversal of the direction along the drainage relative permeability occurs during primary drainage, the residual CO2 supercritical gas saturation is calculated from the maximum historical saturation.

Figure 1. Gas phase is defined as the non-wetting phase; water is the wetting phase in the figure. The drainage curve represents the primary drainage relative permeability curve with gas saturation increasing from point 1 to 2, and the curve 2 to 3 represents the primary imbibition relative permeability curve. The critical saturation of the imbibition curve (Sgcri) is greater than that of the drainage curve (Sgcrd). The two curves must meet at the maximum wetting phase saturation value (Sgmax).

If the primary drainage process is reversed at an intermediate point 4 (Sghy) by an imbibition process, a scanning curve between point 4 and 5 in the diagram is the result. The critical saturation remaining at point 5 is the trapped critical gas saturation (Sgcrt), which is a function of the maximum gas phase saturation reached in the run (Sgmax).

Scanning curves, k_, p_. Here the main formulas are presented, for more details see13

**Relative permeability.** For the non-wetting phase (CO2) the scanning curves are calculated using Killough’s method

\[
k^\text{imb} = \frac{k^\text{drain}(S_{g,\text{norm}})}{k^\text{drain}(S_{g,\text{maj}})}
\]

where

\[
S_{g,\text{norm}} = S_{g,\text{cri}} + \left(\frac{S_p - S_{g,\text{cri}}}{S_{g,\text{max}} - S_{g,\text{cri}}}\right) S_{g,\text{by}} - S_{g,\text{cri}}
\]

For the wetting phase (brine) no hysteresis is applied.

**Capillary pressure.** The scanning curves for water-gas capillary pressure are calculated from

\[
p_c = p^\text{drain}_c + F\left(p^\text{imb}_c - p^\text{drain}_c\right)
\]

where

\[
F = \frac{1}{S_u - S_{n,hy} + E} - \frac{1}{S_{n,\text{max}} - S_{n,hy} + E}
\]

Here E is a curvature parameter, typically of order 0.1.

**Simulation model**

A flexible reservoir simulation model for studying CO2 injection in a saline aquifer was constructed using a black-oil reservoir simulator. Here the oil is given water properties while CO2 is the gas phase. The amount of CO2 dissolved in the aqueous phase as a function of the prevailing pressure, temperature and salinity of aqueous phase in the aquifer, can be explicitly set by use of a realistic fluid property description based on laboratory pVT data of CO2/brine mixtures of a wide range of proportions at various pressure and temperature conditions. This includes density and viscosity of both CO2 and aqueous phases at pressure and temperature of relevance. Reservoir simulations are performed to determine the aquifer response to CO2 injection and to study the long-term fate of the sequestered CO2 except for mineral dissolution and carbonation.

**Effective pressure.** The simulator used has no simple options for including thermal gradients. To account for the temperature variation with depth a trick is therefore used by introducing an effective, temperature adjusted pressure. Normally both temperature and pressure increases with depth. E.g. since increased temperature reduces the viscosity while increased pressure increases it the result turns out to be a very small variation in CO2 viscosity by the effective pressure in the reservoir where typically p=80-100 bar and T=29-36°C. In the simulations we have used

\[\mu_{\text{CO}_2}\left(p_{\text{eff}}\right) = 0.0548 \text{ cP}\]
\[\mu_{\text{brine}}\left(p_{\text{eff}}\right) = 1.2742 - 0.0052 p_{\text{eff}} \text{ cP}\]

where \(p_{\text{eff}}\) is in bar. The dependence of \(\mu_{\text{brine}}\) on \(R_S\) is neglected. Reservoir density for CO2 and brine as function of effective pressure are shown in Figure 2 and Figure 3. Note that the brine density increases when CO2 dissolves.

**Figure 2:** CO2 density \(\rho_g\) as function of effective pressure.
Boundary conditions. To mimic an infinite reservoir horizontally the pore-volume of the cells around the boundary are multiplied by a large factor (10^4).

Saturation functions. The relative permeability curves are of Corey type with exponents determined from laboratory measurements

\[ k_w = \left( S_w^* \right)^{\varepsilon}, \quad S_w^* = \frac{S_w - S_{wir}}{1 - S_{wir}} \]  

\[ k_r = \left( 1 - S_w^* \right)^{\gamma}, \quad S_w^* = \frac{S_w - S_{wir}}{1 - S_{wir} - S_{gr}} \]

where \( S_w = S_{gwir} \) or \( S_w = S_{gcri} \) for drainage and imbibition respectively. Exponent values used are \( \varepsilon = 4 \) and \( \gamma = 0.5 \).

Typical relative permeability curves are shown in Figure 4. For the drainage capillary pressure a van Genuchten model \( C_t \) is used

\[ P_c = P_0 \left( \frac{\tilde{S}_w}{\lambda} - 1 \right)^{\lambda}, \quad \tilde{S}_w = \frac{S_w - S_{wir}}{1 - S_{wir}} \]

with parameters \( \lambda = 0.7 \) and \( S_{wir} = S_{wir} \). For the imbibition curve a straight line tangential to the drainage curve going through \( S_{gcri} \) and zero for higher water saturations was used, see Figure 5. The imbibition curve had to be zero above \( S_{gcri} \) to get the same trapped gas saturation for scanning curves calculated from relative permeability curves and from capillary pressure curves in ECLIPSE. However, this gives somewhat unphysical capillary pressure curves. Fortunately the effect of capillary pressure is small on reservoir scale simulation and the main properties should be captured even if the details are not strictly correct.

Trapped gas. The trapped (or residual) gas saturation is calculated using a modified version of Land's \( L_{14} \) and Killough's \( K_{15} \) method to allow nonzero \( S_{gord} \) as in \( L_{13} \)

\[ S_{gcri} (\hat{r}, t) = \min \left( S_{gphy}, S_{gord} \right) + \max \left( 0, \frac{S_{gphy} - S_{gord}}{A + C \left( S_{gphy} - S_{gord} \right)} \right) \]

where the functions min() and max() are introduced to get correct results for \( S_{gphy} < S_{gord} \) where

\[ S_{gphy} = S_{gphy} (\hat{r}, t) = \max_{r_{ct}} S_g (\hat{r}, t) \]

is the highest saturation reached so far. In addition

\[ A = 1 + a \left( S_{gmax} - S_{gphy} \right) \]

\[ C = \frac{1}{S_{gcri} - S_{gord}} - \frac{1}{S_{gmax} - S_{gord}} \]
Here a parameter \( \alpha \) is introduced to improve convergence, the default value is \( \alpha = 0.1 \).

Since CO\(_2\) is allowed to dissolve in water also trapped gas will dissolve in non-saturated water flowing past. As a first approximation it is assumed that trapped gas dissolves equally fast as free gas, thus

\[
S'_{\rho}(\vec{r},t) \rightarrow S'_{\rho}(\vec{r},t) \xi(t)
\]

(1.12)

where

\[
\xi(t) = \frac{V^{\text{SN}}_{\text{CO}_2}(t)}{V^{\text{SN}}_{\text{CO}_2}(t) + V^{\text{RT}}_{\text{CO}_2}(t)}
\]

(1.13)

A more correct method should probably have a somewhat lower dissolution rate for the trapped gas compared to the free gas.

**Results and discussion**

The most important simulation model parameters are summarized in Table 1.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid</td>
<td>20 × 20 × 20</td>
</tr>
<tr>
<td>Grid block size</td>
<td>300 m × 300 m × 10 m</td>
</tr>
<tr>
<td>Model size</td>
<td>6000 m × 6000 m × 200 m</td>
</tr>
<tr>
<td>Top of reservoir</td>
<td>-800 m</td>
</tr>
<tr>
<td>Porosity</td>
<td>25%</td>
</tr>
<tr>
<td>Permeability ( k_h )</td>
<td>20 -2000 mD</td>
</tr>
<tr>
<td>Temperature ( T_{\text{top}} )</td>
<td>29°C, ( T_{\text{bottom}} ) = 36°C</td>
</tr>
<tr>
<td>Pressure ( p_{\text{top}} )</td>
<td>≈ 80 bar, ( p_{\text{bottom}} ) = 100 bar</td>
</tr>
<tr>
<td>Salinity</td>
<td>3.0 wt.-%</td>
</tr>
<tr>
<td>Density (std. cond.)</td>
<td>( \rho_w = 1019 \text{ kg/Sm}^3 )</td>
</tr>
<tr>
<td>Viscosity ( \mu_w )</td>
<td>0.85 cP</td>
</tr>
<tr>
<td>Solubility ( R_{\text{max}} )</td>
<td>28.56 Sm/Sm³</td>
</tr>
<tr>
<td>Gas formation volume factor ( B_g )</td>
<td>0.0026 Rm/Sm³</td>
</tr>
<tr>
<td>Injection rate</td>
<td>1.4×10^{10} Sm³/day (≈10^{10} tons/year)</td>
</tr>
<tr>
<td>Injection period</td>
<td>25 years</td>
</tr>
</tbody>
</table>

It is evident that many of the reservoir parameters may have an influence on how the CO\(_2\) is distributed in the reservoir. We have focused on the following:

**Grid block size.** It is important to test if the results are sensitive to the resolution of the (artificial) numerical grid. The effect of doubling the number of grid blocks in each direction from 20 to 40 and reducing the size correspondingly to keep the reservoir size constant was small. All important physics thus seems to be modeled sufficiently precise with our rather coarse grid.

**Effect of capillary pressure.** A typical example of the effect of varying the capillary pressure scaling factor \( p_0 \) as given in Eq. (1.3) is shown in Figure 5. The effect appears to be rather small. This is as expected since capillary effects are most important at smaller scales. In the following results for different capillary pressures will be used without any special justification.

**Effect of critical gas saturation \( S_{g\text{cr}} \)** Even in a model without hysteresis gas may become trapped. This is achieved by setting the critical gas saturation \( S_{g\text{cr}} = S_{g\text{cri}} > 0 \). In Figure 7 a typical result is shown. As expected the amount of trapped gas increases with the critical gas saturation. Another possibility is to fix e.g. \( S_{g\text{cri}} = 25\% \) and study the effect of variations in \( S_{g\text{cr}} \). An example is shown in Figure 8. Also here the amount of trapped gas increases with \( S_{g\text{cr}} \), but the effect is much smaller.
Figure 8: Effect of $S_{gord}$ on CO2 distribution after 1000 years for $K_h=200$ mD, $K_v/K_h = 0.01$, $S_{wir}=20\%$, $S_{gri}=25\%$, $p_0=100$ mbar.

**Effect of $S_{gcri}$**. To study the effect of the maximum residual gas saturation during imbibition $S_{gcri}$ the critical gas saturation $S_{gord}$ was fixed to e.g. 5\%. Results for different reservoir parameters are shown in Figure 9, Figure 10, and Figure 11. It is evident that the amount of trapped gas is very dependent on $S_{gcri}$.

Figure 9: Effect of $S_{gcri}$ on CO2 distribution after 1000 years for $K_h=200$ mD, $K_v/K_h = 0.001$, $S_{wir}=20\%$, $S_{gri}=5\%$, $p_0=100$ mbar.

Figure 10: Effect of $S_{gcri}$ on CO2 distribution after 1000 years for $K_h=200$ mD, $K_v/K_h = 0.01$, $S_{wir}=20\%$, $S_{gri}=5\%$, $p_0=100$ mbar.

Figure 11: Effect of $S_{gcri}$ on CO2 distribution after 1000 years for $K_h=2000$ mD, $K_v/K_h = 0.1$, $S_{wir}=20\%$, $S_{gri}=5\%$, $p_0=100$ mbar.

**Effect of irreducible water saturation $S_{wir}$**. Since CO2 may dissolve in water an increase in $S_{wir}$ may have an effect in addition to an effective reduction in pore-volume. A typical result is shown in Figure 12. It may be concluded that the effect of $S_{wir}$ is small.

Figure 12: Effect of $S_{wir}$ on CO2 distribution after 1000 years for $K_h=200$ mD, $K_v/K_h = 0.01$, $S_{gri}=5\%$, $S_{gord}=25\%$, $p_0=100$ mbar.
Effect of horizontal permeability $k_h$. In Figure 13 the effect of varying the horizontal permeability from 20 mD to 2000 mD for a constant ratio $k_v/k_h$ is shown. It appears that most gas is trapped for intermediate permeability values, but the overall variations are relative small.

![Figure 13: Effect of $K_h$ on CO$_2$ distribution after 1000 years for $K_v/K_h = 0.01$, S$_{grd}=5\%$, S$_{gri}=25\%$, p$_0=100$ mbar.](image)

Effect of permeability ratio $k_v/k_h$. In Figure 14 and Figure 15 the effects of variations in $k_v/k_h$ are shown for $k_h = 200$ mD and 2000 mD respectively. It is evident that the amount of trapped gas decreases when $k_v/k_h$ increases. In Figure 16 the time development for the models Figure 14 is shown. The difference is clearly related to the vertical migration as illustrated in Figure 17 to Figure 20. In these figures the CO$_2$ distribution is shown after 1000 years. The dissolved gas is related to gas saturations by using

$$S_{g,diss} = B_g \frac{1}{B_w} R_S$$  \hspace{1cm} (1.14)

For higher vertical permeability the amount of trapped gas decreases much faster with time. This is due to more effective mixing of brine and CO$_2$ resulting in more CO$_2$ being dissolved. This is particularly evident in Figure 20 where the lower display clearly shows convective patterns start developing. As mentioned earlier convection may strongly enhance dissolution and in fact be the most important mechanism for dissolution.

![Figure 14: Effect of $K_v/K_h$ on CO$_2$ distribution after 1000 years for $K_h = 200$ mD, S$_{grd}=5\%$, S$_{gri}=25\%$, p$_0=100$ mbar.](image)

![Figure 15: Effect of $K_v/K_h$ on CO$_2$ distribution after 1000 years for $K_h = 2000$ mD, S$_{grd}=5\%$, S$_{gri}=25\%$, p$_0=10$ mbar.](image)

![Figure 16: Effect of $K_v/K_h$ on time development of trapped gas. Here $K_h = 2000$ mD, S$_{grd}=5\%$, S$_{gri}=25\%$, p$_0=100$ mbar.](image)
Figure 17: Cross-section of CO₂ plume after 1000 years for \( K_h = 200 \text{ mD}, K_v/K_h=0.001, S_{wir}=20\%, S_{grd}=5\%, S_{gri}=25\%, p_0=100 \text{ mbar} \). From top to bottom: \( S_g \), \( S_g\text{,trapped} \), \( S_g\text{,free} \), and \( S_g\text{,diss} \). Note that different color scale is used.

Figure 18: Cross-section of CO₂ plume after 1000 years for \( K_h = 200 \text{ mD}, K_v/K_h=0.01, S_{wir}=20\%, S_{grd}=5\%, S_{gri}=25\%, p_0=100 \text{ mbar} \). From top to bottom: \( S_g \), \( S_g\text{,trapped} \), \( S_g\text{,free} \), and \( S_g\text{,diss} \). Note that different color scale is used.

Figure 19: Cross-section of CO₂ plume after 1000 years for \( K_h = 200 \text{ mD}, K_v/K_h=0.1, S_{wir}=20\%, S_{grd}=5\%, S_{gri}=25\%, p_0=100 \text{ mbar} \). From top to bottom: \( S_g \), \( S_g\text{,trapped} \), \( S_g\text{,free} \), and \( S_g\text{,diss} \). Note that different color scale is used.

Figure 20: Cross-section of CO₂ plume after 1000 years for \( K_h = 200 \text{ mD}, K_v/K_h=1.0, S_{wir}=20\%, S_{grd}=5\%, S_{gri}=25\%, p_0=100 \text{ mbar} \). From top to bottom: \( S_g \), \( S_g\text{,trapped} \), \( S_g\text{,free} \), and \( S_g\text{,diss} \). Note that different color scale is used.
Conclusions
The following conclusions are drawn from the study.

1. A black-oil reservoir simulator with an explicit setting of pVT data of CO2-brine mixtures and a proper setting of the process dependant dynamic reservoir parameters in a flexible reservoir simulation model is a fast and proper tool to study the aquifer response to CO2 injection and the long-term fate of the sequestered CO2.

2. The dissolution of CO2 in aquifer water is the dominant mechanism of CO2 storage in deep saline aquifers provided that the vertical communication in the aquifer allows for convective mixing of the CO2 plume into the brine phase.

3. It is evident that the amount of trapped CO2 gas due to the effect of gas-water capillary pressure and relative permeability hysteresis decreases when k_v/k_h increases. The percentage of trapped gas is reduced to less than 30 % at a k_v/k_h ratio of 0.1.

4. The effect of the horizontal permeability on the amount of trapped CO2 needs further investigations. Our simulations indicate a maximum for intermediate values of k_h.

Acknowledgments
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Nomenclature

\[ \begin{align*}
 k_{rw} & = \text{relative permeability for water} \\
 k_{rg} & = \text{relative permeability for CO}_2 \text{ (gas)} \\
 \mu_g & = \text{CO}_2 \text{ (gas) viscosity} \\
 \mu_w & = \text{Water (brine) viscosity} \\
 S_{wr} & = \text{irreducible water saturation} \\
 S_{gcrd} & = \text{critical gas saturation under drainage} \\
 S_{gcri} & = \text{critical gas saturation under imbibition} \\
 S_{gmax} & = \text{maximum gas saturation} (= 1 - S_{wir}) \\
 S_{phys} & = \text{maximum gas saturation obtained so far} \\
 S_{gret} & = \text{residual/trapped gas saturation} \\
 \varepsilon, \gamma & = \text{Corey parameters} \\
 p_c & = \text{Capillary pressure} \\
 p_e & = \text{p_e scaling (related to entry pressure)} \\
 \lambda & = \text{Van Genuchten p parameter} \\
 a, A, C & = \text{Killough parameters} \\
 k_b & = \text{Horizontal permeability} \\
 k_v & = \text{Vertical permeability} \\
 FGIPT & = \text{Field Gas In Place Total} \\
 & \quad (= FGIPO + FGIFL) \\
 FGIPG & = \text{Field Gas In Place Gas} \\
 & \quad (= FGIPO + FGIPF) \\
 FGIPR & = \text{Field Gas In Place Residual} \\
 FGIPF & = \text{Field Gas In Place Free} \\
 FGIPR & = \text{Field Gas In Place Liquid}
\end{align*} \]

SI Metric Conversion Factors

\[ \begin{align*}
 mD & = 9.869 \times 10^{-16} \text{ m}^2 \\
 \text{bar} & = 10^5 \text{ Pa} \\
 cP & = 10^{-3} \text{ Pa s}
\end{align*} \]

References