

Numerical Simulation of CO₂ Storage and Seismic Monitoring in Saline Aquifers

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- Storage of CO₂ in geological formations is a procedure employed to reduce the amount of greenhouse gases in the atmosphere to slow down global climate change.
- Geologic sequestration involves **injecting CO₂ into a target geologic formation** at depths typically >1000 m where pressure and temperature are above the critical point for CO₂ (31.6C, 7.38 MPa).
- First industrial scale CO₂ injection project: Sleipner gas field (North Sea).

- The analysis of CO₂ underground storage safety in the long term is a current area of research.
- We present a methodology integrating **numerical simulation of CO₂-brine flow and seismic wave propagation** to model and monitor CO₂ injection.
- The model of the formation is based on the porosity and clay content distribution considering the variation of properties at the site with pressure and saturation.

- Present the two-phase fluid flow equations used to simulate CO₂ injection.
- Describe a viscoelastic model for wave propagation that considers dispersion and attenuation effects.
- Show numerical simulations of CO₂ injection and time-lapse seismics to monitor the migration and dispersal of CO₂ after injection in the Utsira formation at the Sleipner field.

- The simultaneous flow of brine and CO₂ is described by the well-known **Black-Oil formulation** applied to two-phase, two component fluid flow.
- In this model, CO₂ may dissolve in the brine but the brine is not allowed to vaporize into the CO₂ phase.
- This formulation uses, as a simplified thermodynamic model, the quantities R_s , B_b and B_{CO_2} as PVT data:

- $R_s = \frac{V_{dCO_2}^{SC}}{V_b^{SC}}$: CO₂ solubility in brine
- $B_{CO_2} = \frac{V_{CO_2}^{res}}{V_{CO_2}^{SC}}$: CO₂ formation volume factor
- $B_b = \frac{(V_{dCO_2}^{res} + V_b^{res})}{V_b^{SC}}$: brine formation volume factor

An algorithm developed by Hassanzadeh (2008) can be used to estimate the above PVT data.

The Black-Oil equations for two-phase flow in porous media are obtained combining conservation of mass of each component with two-phase Darcy's law.

$$\nabla \cdot \left[\frac{\kappa k_r \text{CO}_2}{B_{\text{CO}_2} \eta_{\text{CO}_2}} (\nabla p_{\text{CO}_2} - \rho_{\text{CO}_2} g \nabla D) + \frac{\kappa R_s k_{rb}}{B_b \eta_b} (\nabla p_b - \rho_b g \nabla D) \right] + q_{\text{CO}_2} = \frac{\partial \left[\phi \left(\frac{S_{\text{CO}_2}}{B_{\text{CO}_2}} + \frac{R_s S_b}{B_b} \right) \right]}{\partial t}$$

$$\nabla \cdot \left[\frac{\kappa k_{rb}}{B_b \eta_b} (\nabla p_b - \rho_b g \nabla D) \right] + q_b = \frac{\partial \left[\phi \frac{S_b}{B_b} \right]}{\partial t}$$

Two algebraic equations complete the system:

$$S_b + S_{\text{CO}_2} = 1, \quad p_{\text{CO}_2} - p_b = P_C(S_b)$$

Numerical solution of the Black-Oil formulation of two-phase flow in porous media.

The unknowns for the Black-Oil fluid-flow model are the **fluid pressures** p_{CO_2} , p_b and the **saturations** S_{CO_2} , S_b for the CO₂ and brine phases.

They were computed using the public domain software **BOAST**, which solves the differential equations applying **IMPES**, a finite difference technique.

- One important mechanisms of P-wave attenuation and dispersion in fluid-saturated porous media at seismic frequencies (1-100 Hz) is known as **mesoscopic loss**.
- It is caused by heterogeneities in the solid frame and saturant fluids larger than the pore size but much smaller than the predominant wavelengths (**mesoscopic-scale heterogeneities**).
- These effects are caused by equilibration of wave-induced fluid pressure gradients via a **slow-wave diffusion** process (Type II Biot waves).

- Due to the **extremely fine meshes** needed to properly represent these type of media, numerical simulations at the macroscale is very expensive or even not feasible.
- **Our approach:** Determine **complex and frequency dependent P-wave** modulus

$$E(\omega) = \lambda(\omega) + 2\mu(\omega)$$

at the mesoscale using **White's theory for patchy saturation**.

- $\lambda(\omega), \mu(\omega)$: Lamé coefficients
- ω : angular frequency

$u = u(\omega) = (u_x(\omega), u_z(\omega))$: Time-Fourier transform of the displacement vector

Stress-strain relations in the space-frequency domain:

$$\sigma_{jk}(u) = \lambda(\omega)\nabla \cdot u\delta_{jk} + 2\mu(\omega)\varepsilon_{jk}(u),$$

$\sigma_{jk}(u)$: stress tensor $\varepsilon_{jk}(u)$: strain tensor

δ_{jk} : Kroenecker delta

$\lambda(\omega), \mu(\omega)$: complex Lamé coefficients determined using
White's theory.

Seismic modeling. A viscoelastic model for wave propagation. I

Equation of motion in a 2D isotropic viscoelastic domain Ω
with boundary $\partial\Omega$:

$$\omega^2 \rho u + \nabla \cdot \sigma(u) = f(x, \omega), \quad \Omega$$

First-order absorbing boundary condition:

$$-\sigma(u)\nu = i\omega \mathcal{D}u, \quad \partial\Omega,$$

$f(x, \omega)$ external source

- The solution of the viscoelastic wave equation with the given absorbing boundary condition was obtained at a finite number of frequencies in the range of interest using an **iterative finite element domain decomposition procedure**.
- The time domain solution was obtained using a discrete inverse Fourier transform.
- To approximate each component of the solid displacement vector we employed a **nonconforming finite element space** which generate **less numerical dispersion than the standard bilinear elements**.
- The error associated with this numerical procedure measured in the energy norm is of order $h^{1/2}$, where h is the size of the computational mesh.

Relationship among horizontal permeability (κ_x), porosity and clay content (C):

$$\frac{1}{\kappa_x(t)} = \frac{45(1 - \phi(t))^2}{\phi(t)^3} \left(\frac{(1 - C)^2}{R_q^2} + \frac{C^2}{R_c^2} \right),$$

R_q, R_c : average radii of the sand and clay grains, respectively.
Assumed relation between the horizontal and vertical permeabilities κ_x, κ_z :

$$\frac{\kappa_x(t)}{\kappa_z(t)} = \frac{1 - (1 - 0.3a)\sin(\pi S_b)}{a(1 - 0.5\sin(\pi S_b))},$$

a : permeability-anisotropy parameter ($a = 0.1$ here).

The bulk and shear moduli of the dry matrix, K_m, μ_m are computed using the Krief model:

$$K_m(t) = K_s(1 - \phi(t))^{A/(1-\phi(t))},$$

$$\mu_m(t) = \mu_s(1 - \phi(t))^{A/(1-\phi(t))}$$

Using the moduli K_S, μ_S, K_m, μ_m , porosity ϕ and permeabilities κ_X, κ_Z , the fluids bulk moduli and viscosities and the CO₂ saturation map we determine the complex and frequency dependent P-wave and S moduli at each computational cell using the White's model.

The flow simulator model uses the following relative permeabilities and capillary pressure functions:

$$K_{rg}(S_g) = K_{rg}^* \left(\frac{S_g - S_{gc}}{1 - S_{gc} - S_{bc}} \right)^{n_g}$$

$$K_{rb}(S_g) = K_{rb}^* \left(\frac{1 - S_g - S_{bc}}{1 - S_{gc} - S_{bc}} \right)^{n_b},$$

$$P_{ca}(S_g) = P_{ca}^* \left(\frac{S_g - S_{gc}}{1 - S_{gc} - S_{bc}} \right)^{n_c}.$$

S_{gc} and S_{bc} : saturations at which the CO₂ and brine phases become mobile.

A model for the Utsira formation. I

- The model of the Utsira formation has
1.2 km in the x -direction,
10 km in the y -direction
0.4 km in the z -direction
(top at 0.77 km and bottom at 1.17 km b.s.l.).
- Within the Utsira formation, there are several mudstone layers which act as barriers to the vertical motion of the CO₂.
- The initial porosity ϕ_0 is assumed to have a fractal spatial distribution based on the von Karman self-similar correlation functions. The corresponding permeabilities κ_x, κ_z were determined for a fixed clay content $C = 6\%$

- The mudstone layers are not completely sealed, having constant porosity and vertical permeability values of 24 % and 0.033 D.
- The mudstone layers have openings, that will give a path for the upward migration of CO₂.
- The top and bottom of the Utsira formation have constant porosity and vertical permeability values of 22 % and 0.02 D.

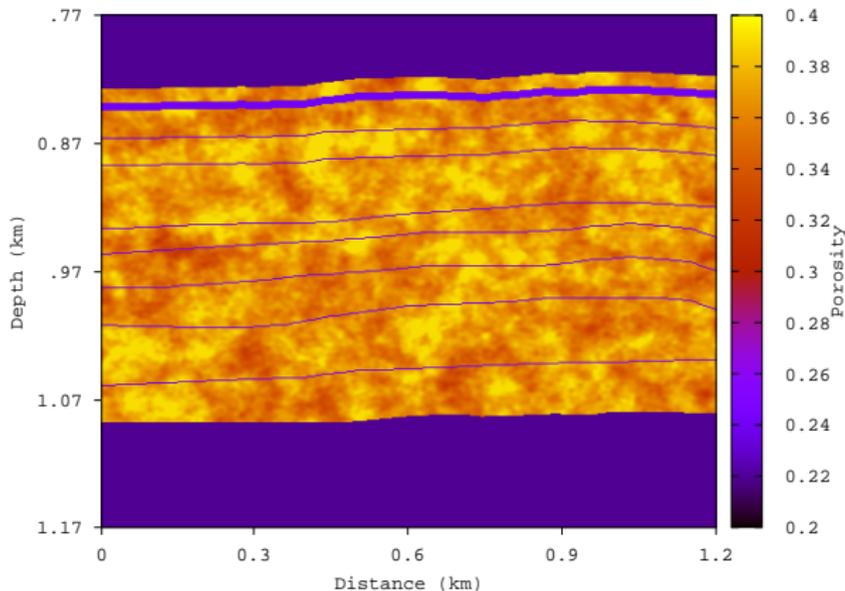
Initial porosity ϕ_0 of the formation before CO₂ injection.

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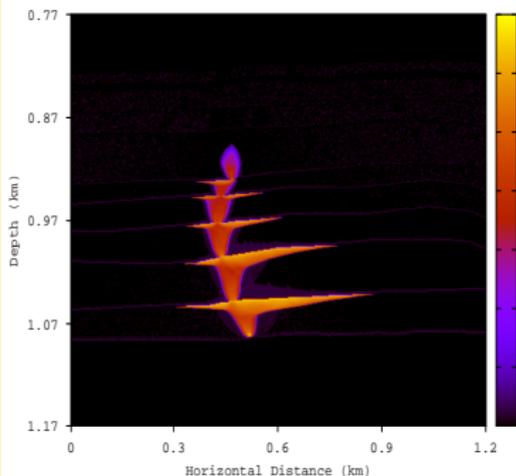
Multiphase
Fluid-Flow Model



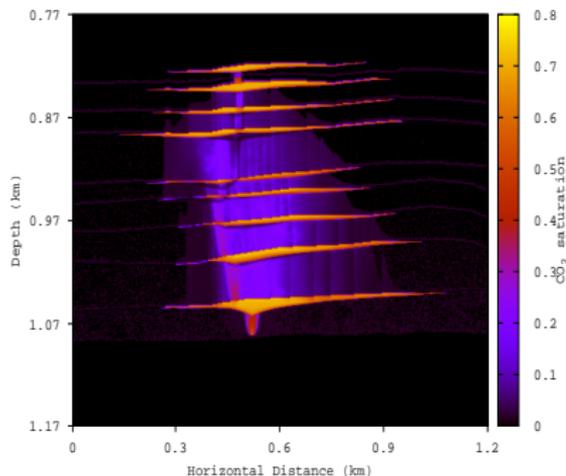
- At the Utsira formation CO₂ is injected at a constant flow rate of one million tons per year at $x = 0.6$ km, $z = 1.082$ km
- The flow simulation mesh: $n_x = 300$ in the x -direction, $n_y = 5$ in the y -direction and $n_z = 400$ in the z -direction.
- The model is 2.5D since the properties are uniform along the y -direction, which has an extension of 10 km.
- The source source is located at the third grid point along the y -direction.

- The petrophysical properties of the formation are time dependent due to the CO₂ injection and the consequent increase in pore fluid pressure.
- These properties change at a much slower rate than pressure and saturation.
- Hence, we have two time scales, and we use a much larger time step to update petrophysical properties than to run the flow simulator.
- In this simulation, the petrophysical properties are updated every year, while the time step for the flow simulator is 0.125 d.

CO₂ saturation maps after 1 and 3 years of injection. I



(a) CO₂ saturation after 1 year of injection



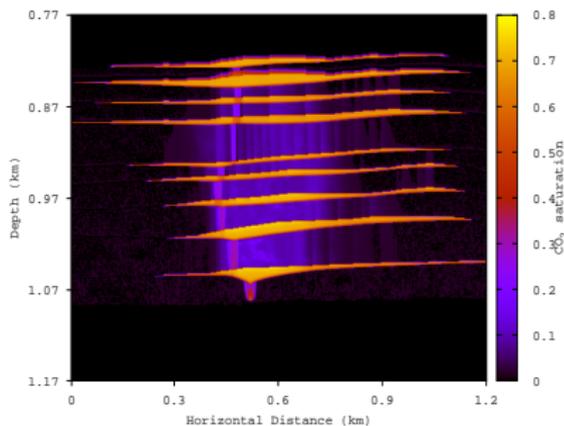
(b) CO₂ saturation after 3 years of injection

CO₂ is seen to move upwards and accumulate below the mudstone layers.

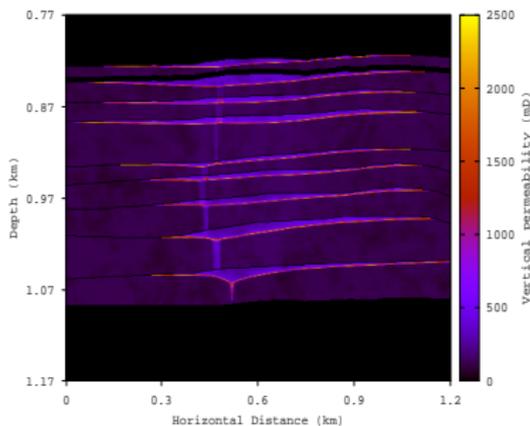
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(a) CO₂ saturation after 7 years of injection



(b) Vertical permeability distribution after 7 years

In Figure a) CO₂ continues to move upwards and accumulate below the mudstone layers. Figure b) shows the updated saturation dependent vertical permeability.

Time-lapse seismics applied to monitor CO₂ sequestration. I

- We use 2-D slices of CO₂ saturation and fluid pressure maps obtained from the flow simulator to construct a 2-D model of the Utsira formation. The mesh is 600 cells in the x -direction and 200 cells in the z -direction.
- The seismic source is a spatially localized plane wave of main frequency 60 Hz located at $z = 772$ m. A line of receivers is located at the same depth to record the Fourier transforms of the vertical displacements.
- The plane-wave simulation (a flat line of point sources at each grid point at the surface) is a good approximation to the stack.

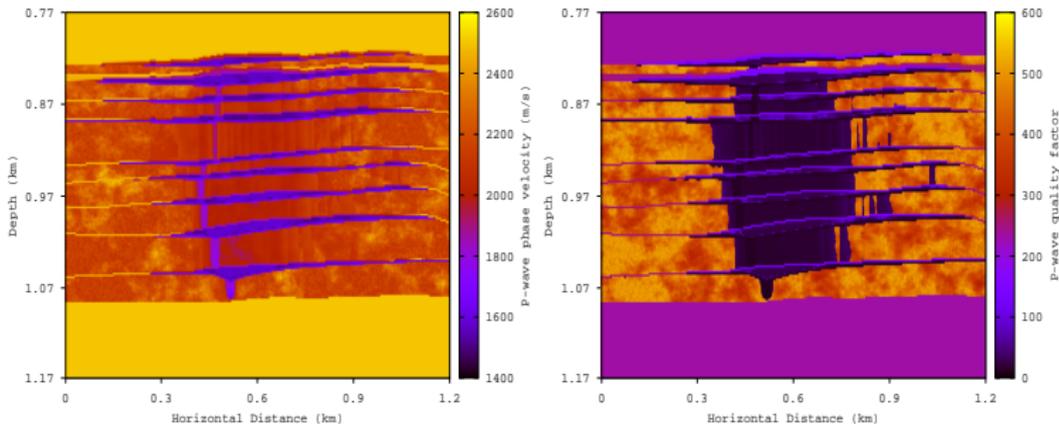
Time-lapse seismics applied to monitor CO₂ sequestration. II

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(a) v_p map at 50 Hz after 7 years of CO₂ injection (b) Q_p map at 50 Hz after 7 years of CO₂ injection

These Figures show how the injected CO₂ changes P-wave velocities v_p and quality factors Q_p ; both decrease in the CO₂-saturated zones. A lower value of Q_p indicates a higher attenuation.

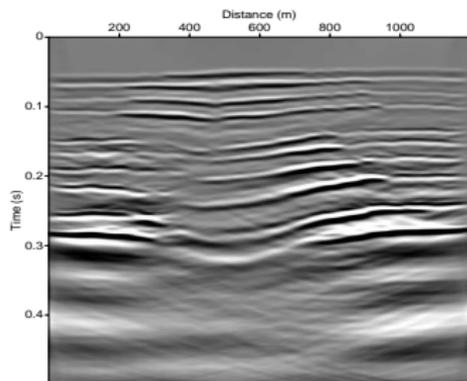
Time-lapse seismics applied to monitor CO₂ sequestration. III

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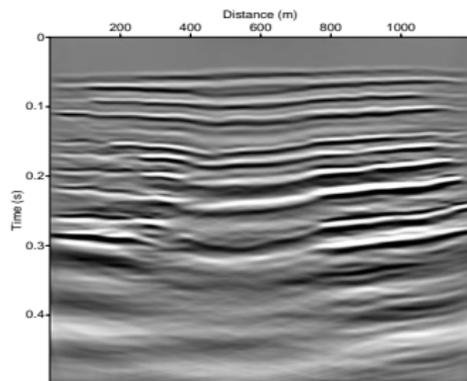
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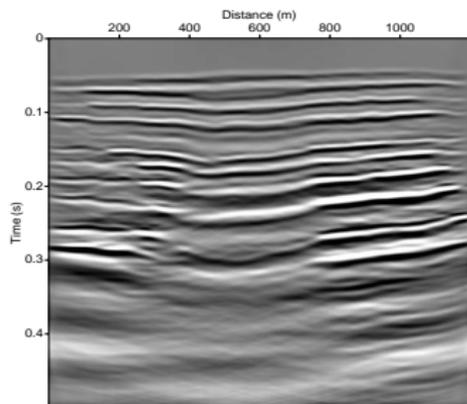


(a) Seismogram after 3 years of CO₂ injection.

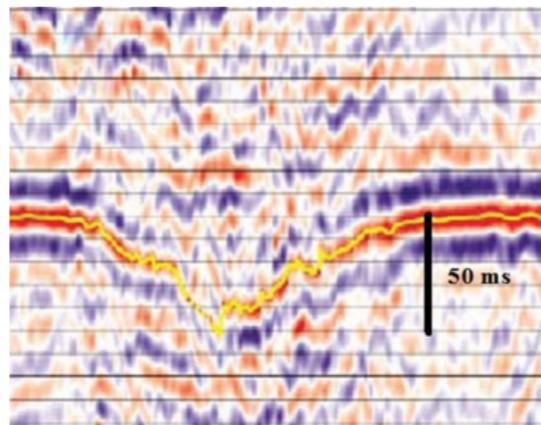


(b) Seismogram after 7 years of CO₂ injection.

Figures a) and b) show how CO₂ moves upwards and accumulates below the mudstone layers. the pushdown effect is clearly observed



(a) Seismogram after 3 years of CO₂ injection.



(b) Seismogram after 7 years of CO₂ injection.

Figures a) and b) show the delay in the arrival times of the reflections, the pushdown effect and the strong attenuation in the chimney region observed in real seismograms. The delay has been properly matched in the simulations.

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THANKS FOR YOUR ATTENTION !!!