Sensitivity analysis of the petrophysical properties variations on the seismic response of a CO_2 storage site

*Juan E. Santos *, Universidad de Buenos Aires, Facultad Ingeniería, Instituto del Gas y del Petróleo, Department of Mathematics, Purdue University and Universidad Nacional de La Plata, Gabriela B. Savioli, Universidad de Buenos Aires, Facultad Ingeniería, Instituto del Gas y del Petróleo, Lucas A. Macias, Universidad de Buenos Aires, Facultad de Ingeniería, José M. Carcione, Istituto Nazionale di Oceanografia e di Geofisica Sperimentale, OGS and Davide Gei, Istituto Nazionale di Oceanografia e di Geofisica Sperimentale, OGS*

SUMMARY

The injection of CO_2 into a saline aquifer induces changes in pore pressure and fluid saturation, which in turn induce variations in the petrophysical properties of the storage site. Thus, numerical modeling of CO_2 sequestration combining multiphase fluid flow and wave propagation simulators requires determining the time steps at which the flow parameters (porosity and absolute permeability) need to be updated during the simulation of CO_2 injection. For this purpose, this work presents a sensitivity analysis of the seismic response of the Utsira formation (where CO_2 is being injected) due to variations in its petrophysical properties. A multiphase fluid flow simulator is used to determine the spatio-temporal distribution of CO_2 and brine during injection. The porosity and absolute permeability are assumed to be dependent of saturation and pore pressure. In the wave propagation simulator the Lamé parameters include effects of mesoscopic losses due to the presence of CO_2 in the pore space. The numerical experiments allow to define the time step at which the flow parameters need to be updated to obtain accurate seismic images of the spatial distribution of CO_2 after injection, with a more precise definition of the zone where the pushdown effect is observed.

INTRODUCTION

Injection of CO_2 in deep saline aquifers is a procedure used for reducing the amount of greenhouse gases in the atmosphere (Arts et al., 2008).

This work studies CO_2 injection into the Utsira formation at the Sleipner gas field. CO_2 separated from natural gas is being injected into the Utsira sandstone, a highly permeable porous medium (Arts et al., 2008)-(Chadwick et al., 2005) with several mudstone layers which act as barriers to the vertical upward flow of the CO_2. Time-lapse seismic has proved to be a useful tool for monitoring the spatio-temporal distribution of CO_2 after injection assuming a known CO_2 saturation map (Picotti et al., 2012). Instead, in this work we generate the CO_2 saturation maps using a multiphase fluid flow simulator (Aziz and Settari, 1985) and then apply time lapse seismic using a viscoelastic wave propagation simulator to determine the spatio-temporal distribution of CO_2 (Savioli et al., 2017).

The petrophysical model of the Utsira formation assumes fractal porosity and clay content, taking into account the variation of properties with pore pressure and saturation (Carcione et al., 2003). The wave propagation simulator is based on an isotropic viscoelastic model that considers dispersion and attenuation effects. The complex P-wave and S-wave moduli are determined using the Zener model in the brine saturated mudstone layers (Carcione, 2015); and the White's theory (White et al., 1975) in zones saturated with brine and CO_2. Since CO_2 injection changes the porosity and permeability flow parameters, a sensitivity analysis is performed to determine the time step at which such parameters need to be updated. Then, frequency dependent Lamé parameters of the wave propagation simulator are computed using the pressure and saturation maps obtained from the flow simulations. These Lamé coefficients take into account the mesocopic loss effects caused by the presence of CO_2 within the Utsira sand (Santos and Gauzellino, 2017).

NUMERICAL SIMULATION OF BRINE-CO_2 FLOW AND WAVE PROPAGATION

To simulate CO_2 injection into a saline aquifer, the Black-Oil formulation commonly used in numerical reservoir simulation is applied to two-phase (CO_2 phase and CO_2 saturated aqueous phase) and two component (CO_2 and brine) fluid flow. In this approach, CO_2 component may dissolve in the aqueous phase but the brine is not allowed to vaporize into the CO_2 phase. The numerical solution of the Black-Oil model is obtained applying the public domain software BOAST (Fanchi, 1997) which solves the differential equations using the IMPES (IMplicit Pressure Explicit Saturation) finite difference technique (Peaceman, 1977).

To properly represent wave propagation in the assumed model of the Utsira sand it is necessary to include the mesoscopic loss mechanism. This mechanism is related to the conversion of fast P and S waves into slow waves due to the fluid and frame heterogeneities and the associated wave induced fluid flow. In zones where CO_2 is present, we 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 (White et al., 1975), where $\lambda(\omega)$ and $\mu(\omega)$ are the Lamé coefficients and ω is the angular frequency. Shear wave attenuation is taken into account using another relaxation mechanism, related to the P-wave White mechanism, to make the shear modulus $\mu(\omega)$ complex and frequency dependent. In zones where only brine is the saturating fluid, the complex bulk and shear moduli as function of frequency are determined using a Zener model. These complex moduli define an equivalent viscoelastic model at the macroscale that takes into account dispersion and attenuation effects occurring at the mesoscale (Santos and Gauzellino, 2017).

RESERVOIR GEOLOGICAL MODEL

The formation is a uniform shaly sand with clay content $C = 6\%$ and initial fractal porosity.

The pressure dependence of properties of the flow parameters is defined by the relation between porosity $\phi(t)$ and pore pressure $p(t) = S_b p_b(t) + S_g p_g(t)$,

$$\frac{(1-\phi_c)}{K_s}(p(t) - p_H) = \phi_0 - \phi(t) + \phi_c \ln\frac{\phi(t)}{\phi_0}, \qquad (1)$$

where ϕ_c is a critical porosity, ϕ_0 is the initial fractal porosity at hydrostatic pore pressure p_H and K_s is the bulk modulus of the solid grains (Carcione et al., 2003).

The relationship among horizontal permeability κ_x, porosity and clay content C is (Carcione et al., 2003) ,

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

where R_q = 50 μm and R_c =1.5 μm are the average radii of sand and clay particles, respectively.

Also, as permeability is anisotropic, we assume the following relationship between horizontal and vertical permeability κ_z (Carcione et al., 2003)

$$\frac{\kappa_x(t)}{\kappa_z(t)} = \frac{1-(1-0.3a)\sin\pi S_b}{a(1-0.5\sin\pi S_b)}, \qquad (3)$$

a being the permeability-anisotropy parameter.

The formation is considered isothermal and the initial pressure p_H is the hydrostatic pore pressure computed using equilibrium conditions. CO_2 properties (viscosity, density and bulk modulus) are obtained from the Peng-Robinson equations (Peng and Robinson, 1976) as a function of temperature and pore pressure.

The bulk and shear moduli of the dry matrix, K_m, μ_m, are computed using the Krief equation (Krief et al., 1990) as follows:

$$K_m(t) = K_s(1-\phi(t))^{A/(1-\phi(t))} \quad \mu_m(t) = \mu_s(1-\phi(t))^{A/(1-\phi(t))}. \qquad (4)$$

Using the moduli K_s, K_m, μ_m, the porosity ϕ and permeabilities κ_x, κ_z, as well as the fluids bulk moduli and viscosities, in zones where CO_2 is present the complex and frequency dependent Lamé coefficients $\lambda(\omega), \mu(\omega)$ were determined using White's theory for patchy saturation (White et al., 1975).

NUMERICAL EXAMPLES

We consider a model of the Utsira formation having 1.2 km in the x-direction, 10 km in the y-direction and 0.4 km in the z-direction (top at 0.77 km and bottom at 1.17 km b.s.l.). The pressure-temperature conditions are $T = 31.7z + 3.4$, where T is the temperature (in ^{o}C) and z is the depth (in km b.s.l.); $p_H = \rho_b g z$ is the hydrostatic pressure, with ρ_b = 1040 kg/m^3 the density of brine and g the gravity constant. Besides, within the formation, there are several mudstone layers with openings, that will give a path for the upward migration of CO_2 .

CO_2 is injected during two years in the Utsira formation at a constant flow rate of one million tons per year. The injection point is located at the bottom of the formation: x = 0.6 km, z =1.082 km. The simulation uses a mesh with equally-spaced blocks in each direction: $n_x = 300$ in the x-direction, $n_y = 5$ in the y-direction and $n_z = 400$ in the z-direction. During the CO_2 injection simulation we need two levels of temporal increments: 1) time step Δt used to solve the flow equations, in this case we choose $\Delta t = 0.08$ day that satisfies the CFL stability restrictions; 2) time step Δt_g at which the petrophysical properties are updated. As the petrophysical properties depend on changes in pressures and saturations, the second time step has to be much larger than the first one. So we perform numerical experiments to determine a suitable Δt_g larger than Δt but still able to honour the petrophsical changes. The results of some of these experiments can be seen in Figures 1, 2 and 3. These figures show 2D vertical slices (corresponding to $ny = 3$) of the CO_2 saturation fields after two years of CO_2 injection, without updating the petrophysical properties (Figure 1) and updating that properties every 30 days (Figure 2) and 15 days (Figure 3). As injection proceeds, part of the injected fluid migrates upwards and the openings in the mudstone layers generate chimneys. Figure 1 shows very well defined chimneys. On the other hand, Figures 2 and 3 are very similar and they are both different from Figure 1. As CO_2 saturation increases, vertical permeability updated with equation 3 also increases. This fact facilitates the CO_2 upward motion across the layers and, as a consequence, CO_2 chimneys become less defined as injection time increases. Therefore we choose $\Delta t_g = 30$ days in order to take into account the effect of updating the petrophysical properties.

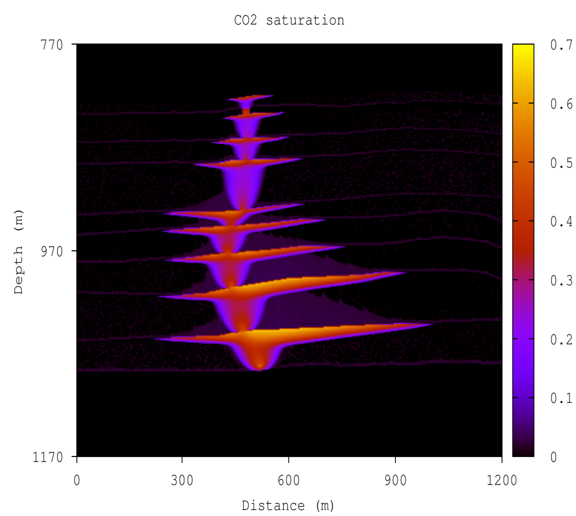

Figure 1: Spatial distribution of CO_2 after 2 years of injection without updating the petrophysical properties.

Now, we analyze the effect of updating the petrophysical and seismic properties in the synthetic seismograms. Figures 4 and 5 show the synthetic seismograms after 1 year of CO_2 injection without updating the petrophysical properties (Figure 4) and updating the petrophysical properties every 30 days (Figure

5).

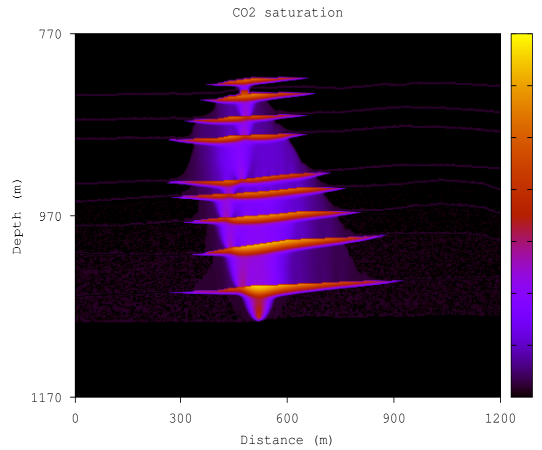

Figure 2: Spatial distribution of CO_2 after 2 years of injection updating the petrophysical properties every 30 days

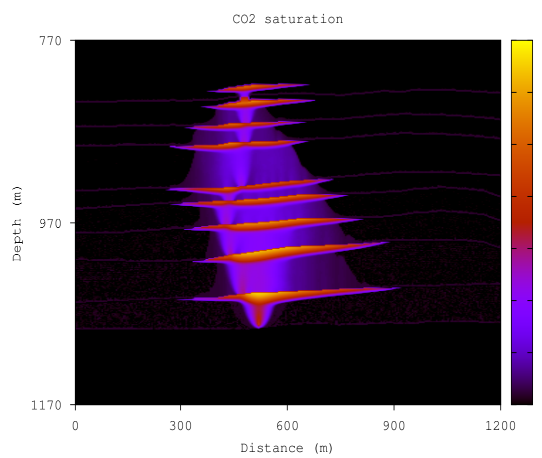

Figure 3: Spatial distribution of CO_2 after 2 years of injection updating the petrophysical properties every 15 days.

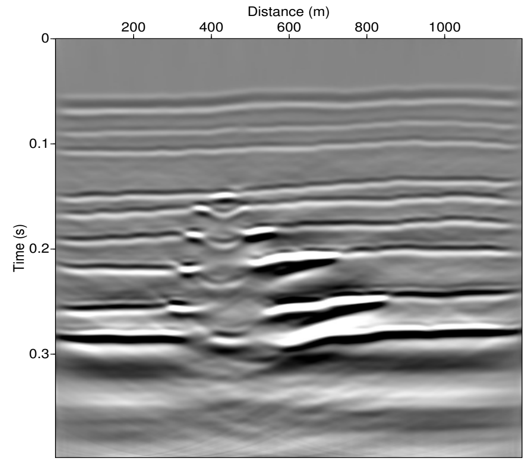

Figure 4: Synthetic seismogram after 1 year of CO_2 injection without updating the petrophysical properties.

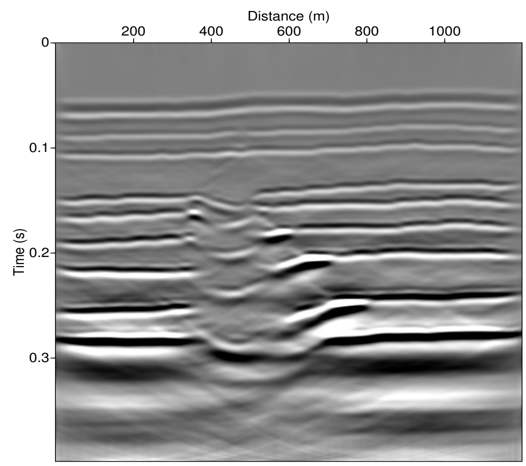

Figure 5: Synthetic seismogram after 1 year of CO_2 injection updating the petrophysical properties every 30 days

In Figure 5 the CO_2 plume induces the pushdown effect in a wider region in the horizontal direction, and moves faster in the vertical direction as compared with Figure 4 for the case when the petrophysical properties are not updated.

The same behavior is observed in Figures 6 and 7, where the synthetic seismogram after 2 years of CO_2 injection without updating the petrophysical properties (Figure 6) and updating the petrophysical properties every 30 days (Figure 7) are shown. Besides, Figure 7 shows larger CO_2 accumulations below the upper mudstone layers than Figure 6. These two seismic images are in agreement with the respective CO_2 saturation maps after two years of CO_2 injection (see Figures 1 and 2).

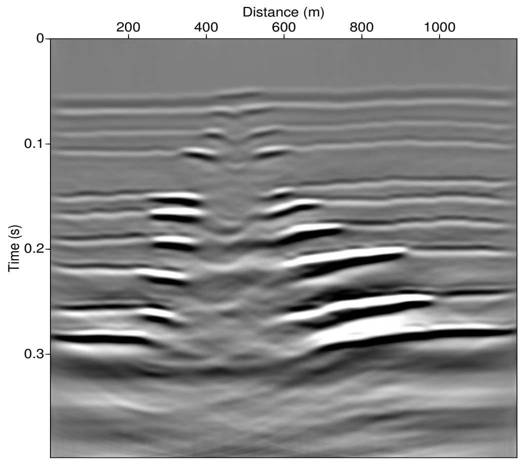

Figure 6: Synthetic seismogram after 2 years of CO_2 injection without updating the petrophysical properties.

‘

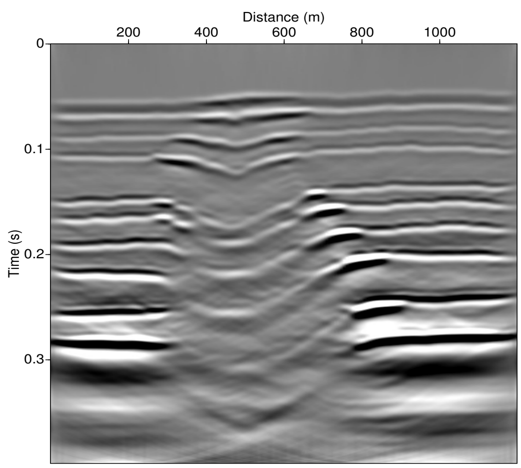

Figure 7: Synthetic seismogram after 2 years of CO_2 injection updating the petrophysical properties every 30 days

CONCLUSIONS

This work presents a numerical sensitivity analysis to determine the time steps at which the flow parameters (porosity and absolute permeability) need to be updated during the simulation of CO_2 injection. For the data used in this study, corresponding to the Utsira formation at Sleipner gas field, we determine a suitable time step of 30 days. Applying this time step, accurate seismic images of the spatial distribution of CO_2 after injection are obtained, with a more precise definition of the zone where the pushdown effect is observed.

Also, it is observed that considering the petrophysical properties updating with a suitabe Δt_g, more realistic saturation maps are obtained, with less defined chimneys, and, consequently, synthetic sismograms with wider regions of pushdown effect and larger CO_2 accumulations below the upper mudstone layers. Therefore it is neccesary to include petrophysical properties updating to accurately simulate CO_2 injection and monitoring.

REFERENCES

Arts, R., A. Chadwick, O. Eiken, S. Thibeau, and S. Nooner, 2008, Ten years of experience of monitoring CO_2 injection in the utsira sand at sleipner, offshore norway: First break, **26**, 65–72.

Aziz, K. and A. Settari, 1985, Petroleum reservoir simulation: Elsevier Applied Science Publishers.

Carcione, J. M., 2015, Wave fields in real media. theory and numerical simulation of wave propagation in anisotropic, anelastic, porous and electromagnetic media: Elsevier Science, 3rd edition, extended and revised.

Carcione, J. M., J. E. Santos, C. L. Ravazzoli, and H. B. Helle, 2003, Wave simulation in partially frozen porous media with fractal freezing conditions: J. Appl. Physics, **94**, 7839–7847.

Chadwick, A., R. Arts, and O. Eiken, 2005, 4d seismic quantification of a growing CO_2 plume at sleipner, north sea: Dore A G and Vincent B (Eds) Petroleum Geology: North West Europe and Global Perspectives - Proc. 6th Petroleum Geology Conference, 1385–1399.

Fanchi, J., 1997, Principles of applied reservoir simulation: Gulf Professional Publishing Company.

Krief, M., J. Garat, J. Stellingwerff, and J. Ventre, 1990, A petrophysical interpretation using the velocities of P and S waves (full waveform sonic): The Log Analyst, **31**, 355–369.

Peaceman, D., 1977, Fundamentals of numerical reservoir simulation: Elsevier.

Peng, D. and K. Robinson, 1976, A new two-constant equation of state: Ind. Eng. Chem. Fundam., **15**, 59–64.

Picotti, S., J. Carcione, , D. Gei, G. Rossi, and J. Santos, 2012, Seismic modeling to monitor CO_2 geological storage - 1 the Atzbach-Schwanenstadt gas field: Journal of Geophysical Research, **117**, 1–18.

Santos, J. E. and P. M. Gauzellino, 2017, Numerical simulation in applied geophysics: Birkhauser, Springer International publishing AG.

Savioli, G. B., J. E. Santos, J. Carcione, and D. Gei, 2017, A model for co_2 storage and seismic monitoring combining multiphase fluid flow and wave propagation simulators. the sleipner-field case: Computational Geosciences, **21**, 223–239.

White, J. E., N. G. Mikhaylova, and F. M. Lyakhovitskiy, 1975, Low-frequency seismic waves in fluid-saturated layered rocks: Izvestija Academy of Siences USSR, Physics of Solid Earth, **10**, 654–659.