A screening approach to seismic time-lapse CO_2 detectability in thin layers

Introduction

The detectability of CO_2 leakage through time-lapse seismic monitoring depends on many environmental and acquisition factors. In the overburden of sub-surface CO_2 storage sites, data availability is typically more limited than at injection levels, to the extent that estimating the geometries and the properties of porous bodies potentially hosting leaked CO_2 can be challenging. Despite these limitations, quantifying the minimum detectable amount of leaked CO_2 remains relevant for assessing the value of repeated seismic surveys during the containment phase of a CCS project. To address this quantification challenge in cases where limited information hinders the use of alternative approaches, we propose modelling a comprehensive set of synthetic wedge scenarios. Wedge models are investigated as amplitude change is expected to be the most significant time-lapse effect in the presence of small amounts of CO_2. Compared with modelling approaches based on well-log data, wedge models have the advantage of avoiding biasing the analysis towards local effects that may not be representative of the porous bodies where CO_2 leakage could migrate. As widely reported in the literature (e.g. Chadwick et al., 2005), CO_2 in a separate gas phase produces a significantly stronger seismic time-lapse signal compared to other CO_2 conditions in a brine aquifer. Therefore, when the geological model suggests the risk of leakage in a subsurface domain in which CO_2 is in gas phase, that condition should be primarily assessed for seismic time-lapse detectability.

Method

Water saturation, effective porosity, and the Petro-Elastic Model (PEM) choice significantly affect the expected seismic time-lapse response. The thickness of the layers in which CO_2 may accumulate plays also a fundamental role in the detectability of seismic time-lapse amplitude change (Widess, 1973). To investigate these effects, we propose a screening method based on modelling wedges of CO_2 accumulation within an ideally illimited brine-filled porous unit. State-of-the-art PEMs, and in particular fluid mixing laws lead to a non-linear relationship between seismic amplitudes, porosities, and CO_2 saturation changes. For this reason, there is the need to investigate all the possible porosity and saturation change conditions to detect the smallest detectable amount of CO_2 leakage. Once one or more PEMs are set up with the available data in the overburden, a large set of wedge acoustic models is generated across a range of porosity and water saturation scenarios (Figure 1).

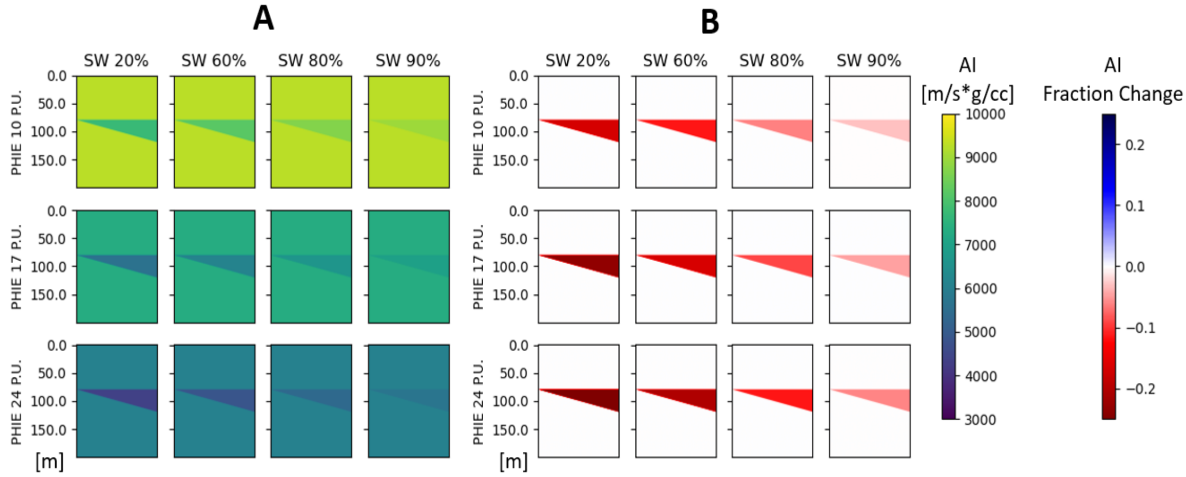

Figure 1. *Synthetic wedge models of possible CO_2 leakage in an illimited porous aquifer. Panels A shows the Acoustic Impedance modelled by letting porosity and water saturation change based on a soft-sand PEM. Panels B show the Acoustic Impedance fractional change when the wedge is filled with CO_2 with respect to the pre-injection case of illimited porous aquifer.*

As seismic amplitude response is mainly driven by acoustic impedance change, in a context where little information is available for setting up a realistic model, assessing the expected zero-offset time-lapse response is recommended. The Acoustic Model contrast of Figure 1B is converted into a time-domain seismic response (Figure 2A) using a 1D convolutional approach and a wavelet consistent with the survey design. Different levels of noise in the wavelet bandwidth are added to the synthetic model to assess the visibility of seismic time-lapse effects (Figure 2B) depending on noise intensity. This fast-track approach to seismic modelling does not consider the acquisition geometry filter and will estimate the minimum amount of CO_2 in case of a dense enough seismic acquisition.

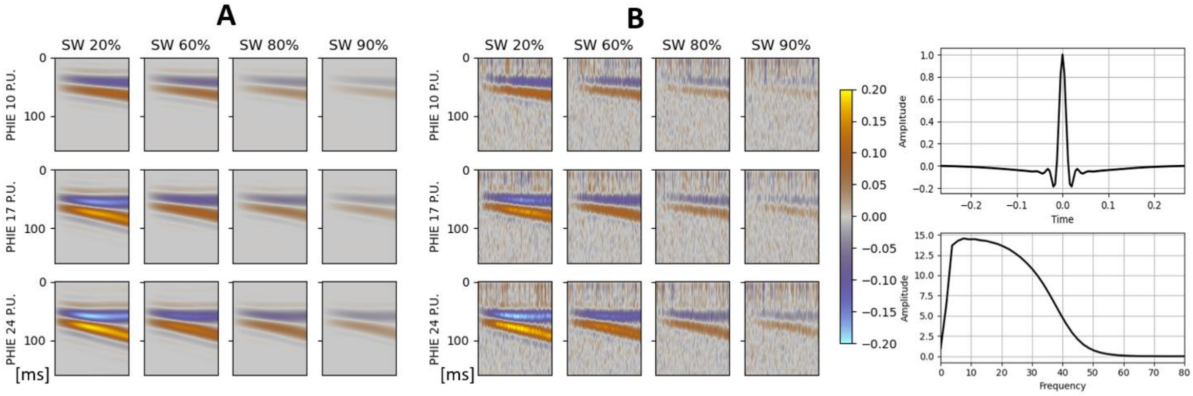

Figure 2. *Synthetic zero-offset seismic model in time domain obtained from the Acoustic Impedance differences of Figure 1B and from the wavelet reported on the right-hand side of the present figure. Panels A show the model in the absence of noise, panels B show the model in the presence of additive Gaussian Noise (σ=0.04) in the seismic bandwidth.*

Once all the seismic time-lapse responses have been modelled for each saturation, porosity, and thickness scenario, the maximum (or minimum) amplitude for each trace of each wedge is extracted. The resulting amplitude is analyzed against model thickness, porosity and saturation change to detect the minimum amount of CO_2 volume per unit of area that overcomes the noise threshold among the various modelled conditions. The amount of CO_2 volume per unit of area (CO_2 column) is estimated by Equation 1, where h is the bulk thickness of the layer, φ the effective porosity and Sw the water saturation.

$$CO_2\ column = (1 - Sw)\varphi h \qquad 1$$

Subsequently, the minimum lateral extent the CO_2 plume shall reach to be detected by 3D surface seismic is estimated. This task is achieved by computing the theoretical "migrated" lateral resolution, defined as the minimum horizontal distance between two nearby reflecting objects that permits their discrimination as distinct features. In Equation 2 (modified from Vermeer, 2012), lateral resolution *Res* is function of the seismic wavelength λ at CO_2 accumulation and the migration aperture angle α (depending on acquisition geometry):

$$Res \cong \frac{\lambda}{2(\sin\alpha)} \qquad 2$$

Information about expected seismic lateral resolution, transformed into areal extension is then combined to previously calculated CO_2 volume per unit of area to determine the minimum detectable CO_2 volume. Based on the CO_2 density adopted in the PEM, the volume of CO_2 leakage is eventually transformed into a mass of CO_2 leakage. This final outcome provides a fruitful connection to the industrial CO_2 injection plan, inferring a possible timeframe in which to consider surface seismic monitoring relevant for the mitigation of the risk associated with potential gas leakage.

Results

The proposed methodology has been applied to a shallow overburden scenario described by a soft-sand PEM in which fluid bulk modulus has been estimated by Brie et al. (1995) model and fluid replacement has been performed under Gassmann (1951) assumptions. Such modelling is described by the acoustic wedge of CO_2 presented in Figure 1. From that model, CO_2 columns have been computed and maximum amplitude extractions from the CO_2 plume base event have been performed both in the absence (Figure

2A) and in the presence of noise (Figure 2B). In the application, the range of investigated thicknesses spans from 0.1 to 40 m, effective porosities from 5 to 30 P.U., water saturations from 0 to 1. Extracted amplitudes have been overlaid by CO_2 columns for varying porosity and saturation conditions in Figure 3. The same amplitude extraction, in the presence of modelled noise (Figure 4) provides a threshold on seismic detectability of the minimum CO_2 column (volume of CO_2 per unit of area).

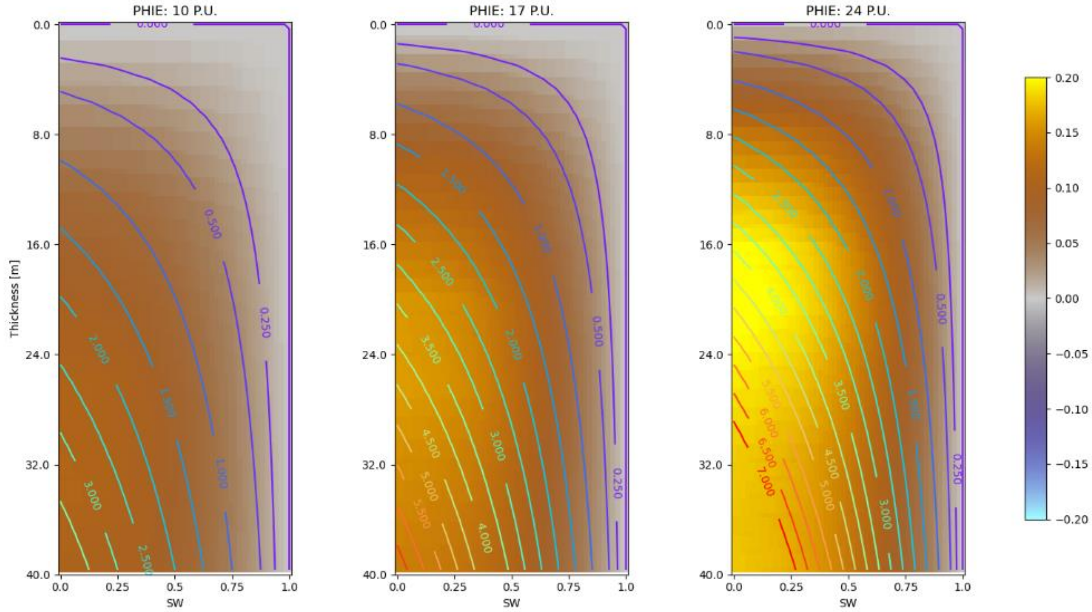

Figure 3. *Maximum Amplitude extraction at base of wedge model (CO_2 to brine contrast) event in time domain from Figure 2A (in the absence of noise). Amplitude is overlaid with CO_2 column contours.*

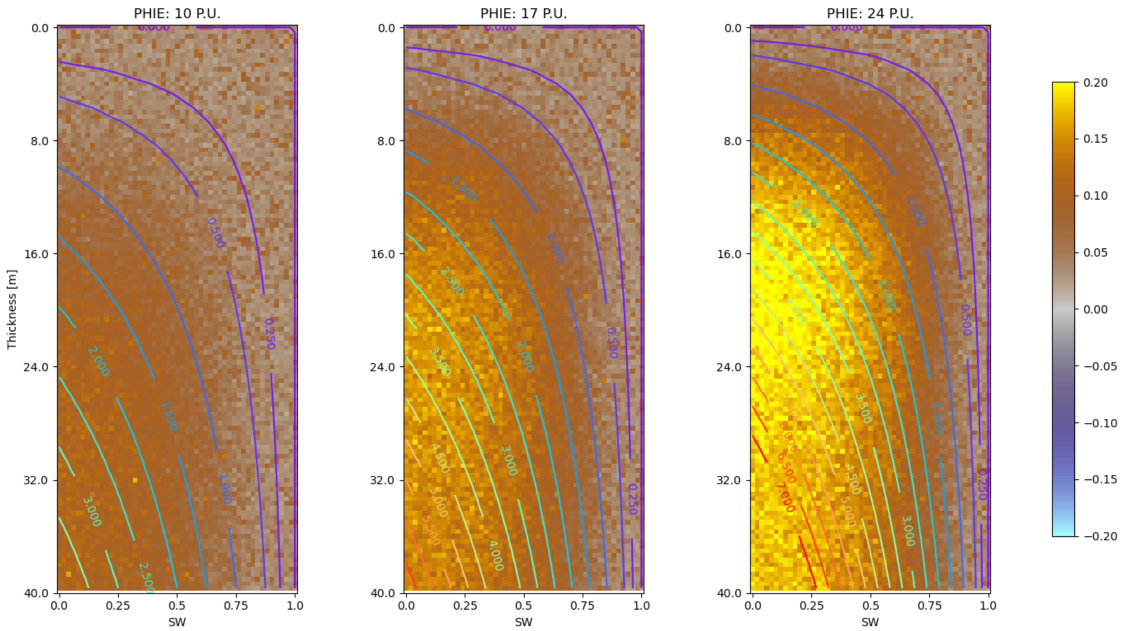

Figure 4. *Maximum Amplitude extraction at base of wedge model (CO_2 to brine contrast) event in time domain from Figure 2B (in the presence of additive Gaussian noise in the seismic bandwidth). Amplitude is overlaid with CO_2 column contours.*

In the case of Figure 4, about 0.5 m of CO_2 column can be distinguished in the 24 P.U. panel, suggesting that highly porous layers with water saturation about 0.5 may provide the best condition to detect a time-lapse seismic signal. This result is dependent on the adopted PEM. We acknowledge that investigating different mechanisms for fluid mixing with different PEMs will further expand the screening approach to the limit that using Reuss fluid mixing law will significantly lean the results towards an outcome of poor sensitivity of seismic response to CO_2 saturation: CO_2 saturated wedges with the same porosity will show a similar acoustic contrast to the brine condition. Coherently with the wedge modeling exercise, the same frequency content has been considered (e.g. 40Hz maximum frequency) for the estimation of the minimum lateral resolution of the seismically detectable anomaly. The lateral extent of the plume estimated with 30° migration aperture and the velocity from the synthetic model is about 65 m. Based on a circle of 65 m of diameter and the CO_2 density at target assumed in the PEM, the minimum gas accumulation that a seismic monitoring survey allows to detect in our example is assessed to be around hundreds of tons of CO_2. Time-shift effects are neglected by the screening method. Velocity variations in a seismically thin layer will mainly produce a phase shift effect which will enhance the time-lapse seismic amplitude with respect to the screening method which we propose. Based on the detectability threshold obtained from Figure 4 at about 0.5 m of CO_2 column, seismic amplitudes alone will show a CO_2 accumulation about 4 m thick when porosity is 24 P.U. and CO_2 saturation is about 0.5. In those 4 meters the modelled p-wave velocity in the brine case is 2664 m/s, while p-wave velocity when CO_2 leakage saturates half of the pore space is 2143 m/s. This leads to a modelled time-shift effect of about 0.7 ms. When comparing this modelled time-shift with respect to the wavelet adopted in the example, the resulting phase-shift will be minimal and difficult to estimate on real data.

Conclusions

When overburden data are limited, a screening approach based on petro-elastic and wedge modelling is proposed as a practical method to estimate the minimum detectable CO_2 leakage as a function of burial depth, thermodynamic conditions, and seismic acquisition parameters. By analysing amplitude responses under varying noise levels, the method defines detectability thresholds in terms of CO_2 column. Once this threshold is established, a fast-track estimate of leakage volume and mass can be derived through the analysis of the lateral seismic resolution. Although simplified and not including complex interference figures such as thin and porous layers interbedded with shales, the proposed approach represents an easily applicable framework for quantifying the minimum detectable CO_2 leakage using time-lapse seismic data. This is a parsimonious but significative outcome to evaluate the value of repeated seismic acquisitions for risk management in CCS projects.

Acknowledgements

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