Prediction of the seismic time-lapse signal of CO_2/CH_4 injection into a depleted gas reservoir - Otway Project

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SUMMARY

Stage I of the Otway project conducted by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) in 2007-2010 included injection of 66000 tons of CO_2-rich gas into a depleted gas reservoir at Naylor field, Otway Basin, Victoria.

In this paper we present a seismic modelling study that estimates the time lapse response of CO_2/CH_4 injection into the Waarre C reservoir. Based on the static geological model, acoustic impedance inversion of the seismic baseline data as well as log data, two models with different levels of detail in the reservoir properties are built. The distribution of the injected CO_2/CH_4 mixture in the reservoir and the gas properties are obtained from flow simulations.

In order to predict the change in acoustic impedance after injection, we employed the Gassmann fluid substitution workflow. The modelled total differences in acoustic impedance for different amounts of CO_2/CH_4 injected are of the same order of magnitude for both models and reflect the CO_2 mass fractions predicted by flow simulations.

Finally zero incidence synthetic data are computed for these cases using a statistical wavelet of the baseline data. The computed synthetics are compared to surface seismic and VSP monitoring data. The repeatability of the surface seismic data is too low to detect the predicted signal. For the 3D VSP data, the time-lapse signal/noise has a similar order of magnitude as the predicted signal. It may have the level required to detect the signal.

Key words: CO_2 Sequestration, time-lapse seismic, modelling

INTRODUCTION

Seismic monitoring is an important part of any CO_2 sequestration project. The applicability of seismic monitoring depends on the effect of CO_2 injection on the seismic response. Several factors control if this effect is detectable such as geological heterogeneity of the reservoir, rock and fluid properties at reservoir conditions as well as data quality and repeatability of land seismic surveys. These variable factors make it necessary to perform a site-specific seismic modelling study to estimate the detectability of changes in the seismic signature caused by the CO_2 injection. Such modelling studies have been performed, e.g. for the CO_2 sequestration site in Ketzin (Kazemeini et al., 2010) and the Aztbach–Schwanenstadt gas field (Rossi et al., 2008).

In this case study we investigate and model the seismic time-lapse signal from CO_2/CH_4 injection into the depleted Naylor gas field located onshore in Victoria. Stage I of the Otway project consisted of the injection of 66,000 tonnes of a CO_2/CH_4 mixture into a depleted gas reservoir located at a depth of ~2 km. It is a relatively small, heterogeneous, dipping formation surrounded by complex faulting. Two wells, 300 m apart, intersect the reservoir, the injection well CRC-1 and the production/ monitoring well Naylor-1. After gas production, a gas cap at the top of the formation around Naylor-1 well was formed and approx. 20% residual gas saturation remained in the rest of the reservoir. Such conditions are not favourable for detection of the time-lapse signal from CO_2/CH_4 injection in land seismic data, since the expected changes in acoustic/elastic properties are small.

The seismic monitoring program for stage I included a baseline 3D surface seismic and 3D VSP survey in 2007/2008, two monitoring surface seismic surveys in 2009 and 2010 as well as one 3D VSP monitoring survey in 2010. In previous studies, cross equalisation and repeatability analysis of the 4D seismic data sets were presented (Pevzner et al., 2010b; 2011).

This modelling study aims to estimate the effect of the CO_2/CH_4 injection on the seismic response. In order to predict the change of the acoustic/elastic properties of the rock after injection, we employ the Gassmann fluid substitution workflow commonly used in petroleum geophysics (Smith et al., 2003; Mavko et al., 1998). For fluid substitution modelling a 3D reservoir model, based on the acoustic impedance inversion of the seismic baseline data 2008 (Asgharzadeh et al., 2010), the static geological model (Dance et al., 2009) and flow simulations (Ennis-King et al., 2010) as well as log data, is built.
Then zero incidence synthetics are computed and the time-lapse signal of the modelled seismic response is compared to the achieved level of repeatability of the field data. The predicted time-lapse signal is smaller than the time-lapse noise of the surface seismic data but it is of the same order of magnitude as the noise level in the 3D VSP data.

ROCK PHYSICS APPROACH

In order to model the change of the acoustic rock properties caused by CO_2/CH_4 injection, we apply the Gassmann fluid substitution workflow. More precisely, we use an approximate method for solving Gassmann's equation suggested by Mavko et al. (1995) which is based on the P-wave modulus (M) without the use of shear-wave velocity. In this workflow the P-wave modulus of a rock saturated with a fluid 2 is computed from the P-wave modulus of a rock saturated with fluid 1, the P-wave moduli of the fluid mixtures and the solid grain material as well as porosity.

In case of the Waarre C reservoir, fluid 1 is a mixture of formation brine and residual gas (mainly CH_4), and fluid 2 is a mixture of brine, CO_2 and CH_4. The in-situ brine properties are computed by the empirical formula of Batzle and Wang (1992), while the CO_2/CH_4 mixture properties are obtained from the flow simulation result (Ennis-King, 2010) by solving the equation of state of the GERG 2004 model (Kunz et al., 2004). To calculate the fluid bulk modulus of the brine/CO_2/CH_4 mixture we apply Wood's mixing rule. The use of Wood's equation assumes uniform saturation, a reasonable assumption for sandstones at seismic frequencies. The P-wave modulus of the solid grain material is computed by averaging the upper and lower Hashin-Shtrikman bounds of the clay and quartz volume fractions obtained from the well logs (Mavko et al., 1998).

To perform the fluid substitution modelling for the Waarre C reservoir, a 3D reservoir model populated with the described parameters is needed. For this purpose we employ information from acoustic impedance (AI) inversion, the static geological model, flow simulation and log data.

RESERVOIR MODEL

In order to construct a reservoir model, data sets in different domains, e.g. time and depth, and on different scales have to be combined. In a first step we build a reservoir model in time with seismic time horizons of the AI inversion using the RokDoc ChronoSeis package (Ikon Science). Afterwards a layer cake method is applied to convert the time model into a depth model, where the depth surfaces are fixed to the well tops in CRC-1 and Naylor-1 wells. To fit the flow simulation grid, which is in depth, into the RokDoc depth model, the top and bottom horizons of the Waarre C reservoir are replaced by the corresponding depth surfaces of the flow simulation grid.
Another issue is that the static geological model, which provides porosity estimates, is on a finer scale than the acoustic impedance inversion result. Therefore we decided to build two models with different levels of detail in the reservoir properties (fine scale and coarse scale).

In Model 1 we use the porosity of the static geological model. The reservoir model is subsequently populated with calculated AI values and P-wave moduli of the grain material from the well data, by applying collocated kriging with the porosity model as a soft property. Since the logs in CRC-1 and Naylor-1 are measured at different times post- and pre-production, respectively, we perform fluid substitution so that the AI values correspond to 20% residual gas saturation. Afterwards fluid substitution is applied to the 3D reservoir model to match the gas saturation pre injection (2008) using the prediction of the flow simulation. Outside the reservoir the AI model is built from the AI inversion volume of the seismic baseline data (2008).

In Model 2, we utilize the AI volume from the inversion of the seismic baseline data (2008). In this case we smooth the static porosity model, which shows structures on a much smaller scale, by applying a low-pass filter. The P-wave modulus of the grain material is set to the value for quartz.

Figure 1 and 2 present a comparison between the AI and porosity values of Model 1 and Model 2. We can observe that Model 1 is much more detailed than Model 2, but the average values of AI and porosity in both models are of the same order of magnitude. In summary, Model 1 honours the static geological model, while Model 2 represents the inversion result of the seismic data.

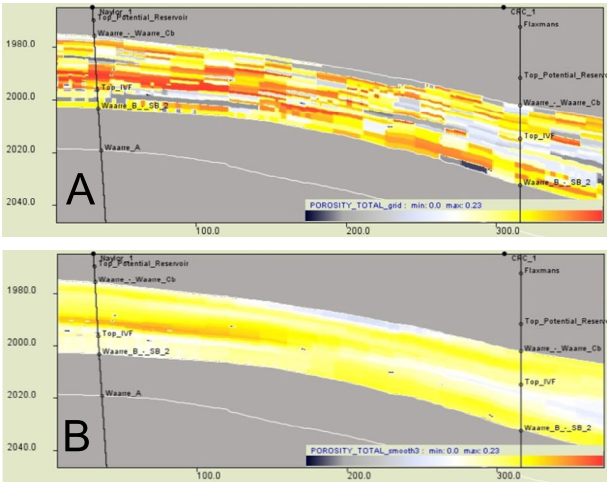


Figure 1. Slice through the unsmoothed (A) and smoothed (B) porosity model of the reservoir on a line between Naylor-1 and CRC-1.

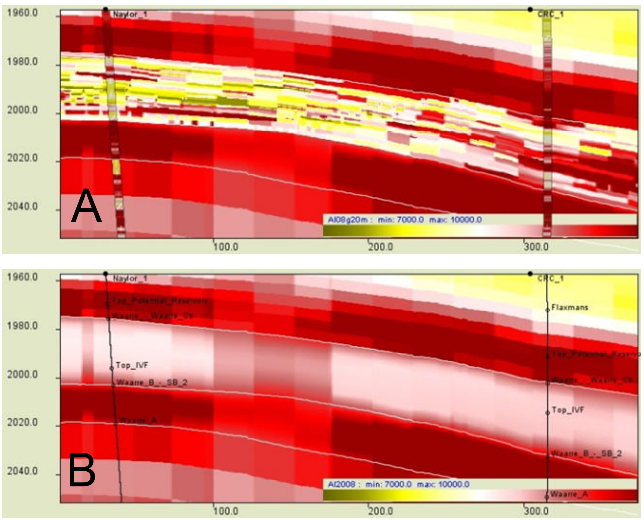
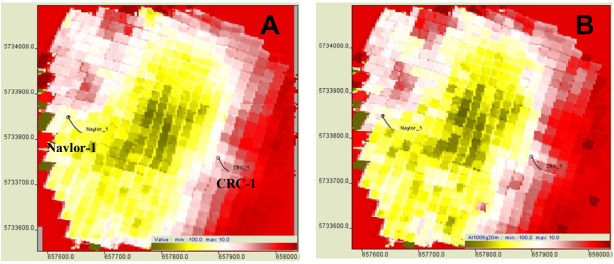


Figure 2. AI (g/cc*m/s) for Model 1 (A) and Model 2 (B) on a line between Naylor-1 and CRC-1

MODELLING RESULTS

We performed fluid substitution modelling for the conditions of pre injection (2008), injection of 35,000 t (2009) and 66,000 t (2010) of a CO_2/CH_4 mixture. In case of Model 1, the modelling was only carried out in areas where the porosity values are above 6%, since smaller porosity values produced unrealistic results. For Model 2 (smoothed porosity), the porosity values are above 6% in the entire model.

Figure 3 shows a map of the absolute difference in AI between 2010 and 2008 for Model 1 and Model 2. The difference is of the same order of magnitude for both models. It can be observed that the AI in the reservoir decreases from 2008 to 2010, since brine is replaced by the CO_2/CH_4 mixture. As expected, the difference in AI reflects the distribution of CO_2 mass fraction for the year 2010 predicted by the flow simulations. This prediction shows that the CO_2 migrates below the gas cap and not into the gas cap located at the top of the reservoir near Naylor-1. This explains the smaller changes in this part of the reservoir. The largest change in AI occurs half-way between Naylor-1 and CRC-1.
Qualitatively the same results are obtained for 2009 with a smaller decrease in AI compared to 2010. For comparison to the field data the fine scale model is used in the next section.



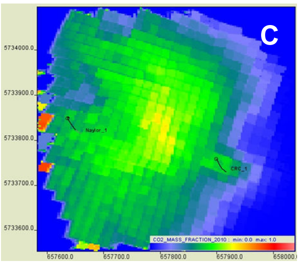


Figure 3. Absolute difference of AI (m/s*g/cm3) between 2009 and 2008 for Model 1 (A) and Model 2 (B) and CO_2 mass fractions for 2009 (C) - averaged over the depth interval of the reservoir zone.

COMPARISON TO SEISMIC DATA

The modelled scenarios correspond to the monitoring surface seismic data in 2009, 2010 and to the 3D VSP data in 2010. To compare the modelling results to the seismic data, zero incident synthetics are computed by convolving the calculated AI volumes with a statistical wavelet, extracted from the surface seismic data 2008.

Figure 4 presents a comparison between the synthetic and surface seismic data in 2008 and the time-lapse signal 2008-2010. The left column contains the synthetic section (A) compared to the field data (C) in 2008. The right column shows the predicted time-lapse response (B) and a slice of the time-lapse difference volume obtained from the seismic data (D). Unfortunately the modelled signal level is significantly smaller than the time-lapse noise in the surface seismic data.

For further comparison the NRMS difference of 2010-2008 is computed from the synthetic volumes over all differences related to changes in the reservoir level. The resulting map is shown in Figure 5. Compared to the NRMS maps of the seismic data, we observe that the repeatability of the surface seismic data is too low to detect the signal (Figure 5). For the time-lapse 3D VSP data, the achieved NRMS difference is also below the level required to detect the signal robustly. But in this case the predicted signal has at least a similar order of magnitude as the time-lapse noise. Further the predicted time-lapse signal for Model 2 (Figure 5) is somewhat higher and suggests that the VSP data may have the level of repeatability comparable to the level required to detect the signal. However quantitative interpretation of the time-lapse 3D VSP data is challenging due to variable fold and mean offset distribution along the reservoir.

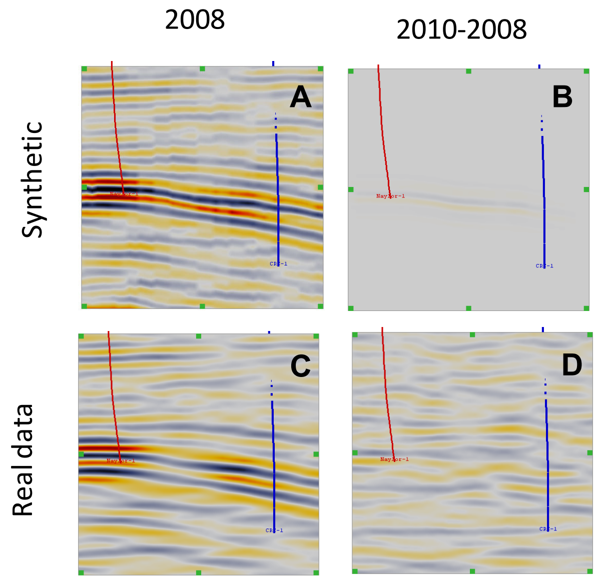


Figure 4. Synthetic (top) and field data sections (bottom) on inline 87; left plots (A and C) are the data in 2008 and right plots (B and D) are time-lapse signals 2010-2008

DISCUSSION AND CONCLUSIONS

It was shown that both models (fine and coarse scale) lead to similar results in the absolute difference in acoustic impedance and resemble the main features of the seismic data. The coarse scale model represents the amplitude distribution of the field data better (not shown here), since it is directly based on the AI inversion result. However, simple averaging of the porosity might not be a proper up-scaling to the resolution scale achieved in AI inversion. A better match between the datasets might be gained by using the AI inversion result to build a porosity model.

In general the seismic modelling study confirmed that the time-lapse signal is too small or the time-lapse noise too high to detect a signal robustly with the acquired surface seismic data. However, the predicted signal of Model 2 has the same order of magnitude as the difference between the two observed 3D VSP datasets. Further, a previous repeatability study for the surface seismic data showed a significant increase in repeatability between the first (2009/2008) and the last (2009/2010) pair of surveys due to an increase in the CMP fold and a more powerful seismic source (Pevzner et al., 2011; Urosevic, 2011). Hence, we could expect to have a similar improvement in the repeatability of the 3D VSP data, if an additional survey had been acquired in 2009 with the same acquisition parameters. This allows us to speculate that in such a case 4D VSP could probably be applicable to monitor the injection of CO_2 in a depleted gas reservoir.

ACKNOWLEDGMENTS

This work has been funded by the Commonwealth of Australia through its CRC Program to support CO2CRC research. We thank Tess Dance, Mehdi Asgharzadeh, and Milovan Urosevic for substantial contributions to this study.

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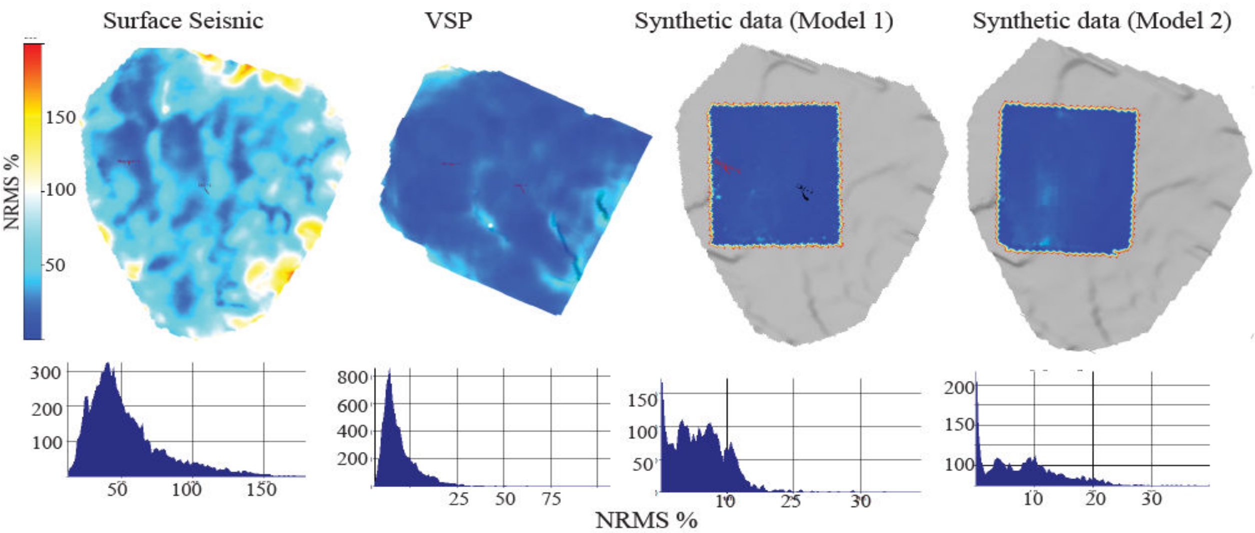

Figure 5 2008/2010, NRMS value computed over the Waarre C horizon 60 ms window for surface seismic (left) and 3D VSP (middle) surveys and the predicted NRMS difference for 2008/2010 for Model 1 and 2 (right); Histograms of NRMS values are shown below maps.