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Reservoir Simulation And Feasibility Study For Seismic Monitoring At CaMI.FRS, Newell County, Alberta

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Summary

We present the results of reservoir simulations and feasibility study of surface seismic monitoring applied to the CO2 sequestration at the CaMI Field Research Station (FRS). We first test the influence of injection parameters, as reservoir temperature, maximum bottom-hole pressure and of the ratio vertical permeability over horizontal permeability on the amount of CO2 you can inject and on the gas plume shape. We demonstrate that if the reservoir temperature has a very small influence on the injectivity, the maximum bottom-hole pressure and the ratio of permeabilities play a key role on the gas injection. The next step is fluid substitution, necessitated to estimate the variation in elastic parameters induced by the gas injection. We test different methods to compute the bulk modulus of the fluid (Reuss, Voigt, HRV and Brie) and compare their results. We finally use a 3D finite difference modeling to simulate the seismic response in the elastic models generated for the baseline, for 1 year of injection and for 5 years of injection.

Introduction

The Containment and Monitoring Institute (CaMI) of CMC Research Institutes Inc. (CMC), in collaboration with the University of Calgary, has developed a comprehensive Field Research Station (FRS) in southern Alberta, Canada. The purpose of CaMI.FRS is to develop innovative technologies to prevent and monitor early leakages of a deeper, large-scale CO_2 reservoir. To simulate a leakage, a small amount of CO_2 (< 500 t/year over 5 years) will be injected a shallow surface (300 m depth).

To detect and monitor the injected CO_2, different geochemical and geophysical instruments are in place on the field (Lawton et al., 2015a). So far, these have been used to characterize the subsurface and will be used as baseline for the monitoring studies. A non-exhaustive list of geophysical instruments on CaMI.FRS includes a Digital Acoustic Sensing (DAS) permanently installed, VSP experiments with downhole geophones, surface seismic survey, and a permanent a10x10 array of buried 3C geophones (10m spacing, buried at 1m depth) with soon installed permanent sources.

We explain in this paper the four steps leading to the feasibility study of seismic monitoring applied to CO_2 sequestration: 1) geomodelling; 2) injection simulations; 2) fluid substitution; and 4) simulation of seismic responses.

Geostatic model

The target of injection is the Basal Belly River Sandstones (BBRS), a 7m layer thickness (from 295 to 302m depth), composed of fine to medium-grained of poorly to well sorted lithic grains. The seal is the Foremost Formation which is a layer 152 m thick composed of clayey sandstone with more or less continuous interbedded coal layers.

Porosity and permeability are two key variables required for reservoir characterization and dynamic fluid-flow simulation. We use the logs of 88 wells available in the area and two seismic volumes and build 3D layer cake laterally homogeneous models of horizontal permeability and porosity. Average permeability of the injection target is 0.8 mD, average porosity of the reservoir is 10%.

Injection simulations

We use CMG-GEM, a fluid flow simulator software and test the influence of different parameters of injection. The minimum water saturation (0.5) remains the same during the different tests as well as the relative permeability of gaseous CO_2 and water (calculated using Brooks-Corey approximation). We also assumed an initial saturation of brine of 100% in the medium.

We first test the effect of the vertical permeability, through the ratio of vertical permeability over horizontal permeability (horizontal one being known). The amount of CO_2 injected increases with the increase of the ratio. A higher vertical permeability allows the gas to migrate vertically more easily. With the vertical migration, the pressure decreases in the medium and so the injectivity can be higher.

Figure 1 shows the CO_2 saturation after 5 years of injection for different maximum bottom-hole pressure and reservoir temperature (going from [BHP=4.5MPa, T=10°C] to [BHP=5.75MPa, T=20°C]). More detailed test shows that if the reservoir temperature has very weak influence on the injectivity, the maximum bottom-hole pressure mostly drives the amount of gas injected. Instinctively, the higher is the maximum bottom-hole pressure, the higher is the injectivity.

In all the scenario tested, we can observe a downward migration (more or less important considering the injection parameters used), however no upward migration is allowed due to the quasi-null permeability at the very bottom of the seal formation.

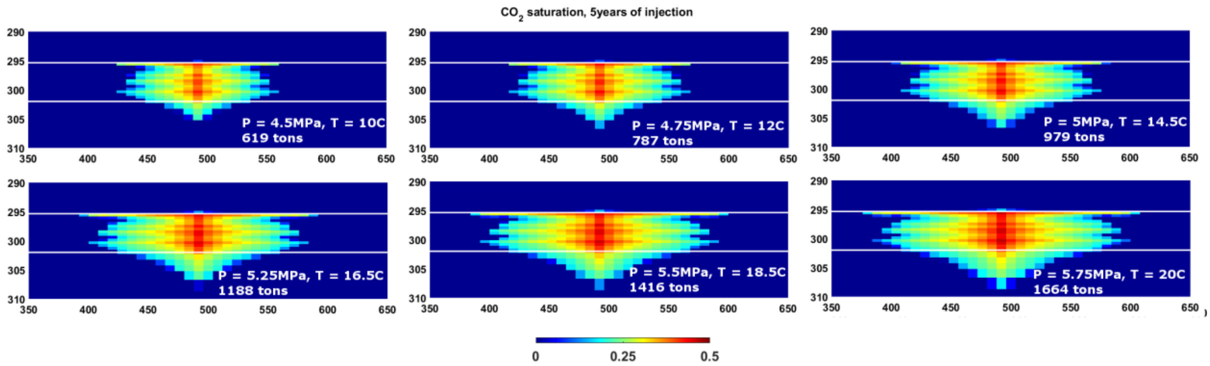

Figure 1 *Effect of the reservoir temperature and the maximum bottom-hole pressure on the gas saturation for 5 years of injection.*

Fluid substitution

We use Gassmann's equation (Gassmann, 1951) to compute the new saturated bulk modulus needed to compute the new elastic parameters due to gas injection (Macquet et al. 2017). The set of parameters injection chosen are $k_v/k_h = 0.1$, T=20°C and maximum BHP=5.75MPa (Figure 1, bottom right). The main uncertainty of this method is the way to compute the fluid bulk modulus which depends on how the components of the fluid mix together. We test the different methods described in the literature: the Reuss, Voigt, and Brie equations describing respectively an uniform saturation, a patchy saturation and a semi-patchy saturation. Figure 2 shows the elastic parameters variations expected after 5 years of injection for the three saturation behaviors. We can see that using a patchy saturation gives less variation for the P-wave velocities than an uniform saturation (-4% and -22% respectively) as the fluid bulk modulus is higher in the first case (Figure 4.a). S-wave velocity and density variation are not affected by the saturation behavior considered and are the same in the three cases.

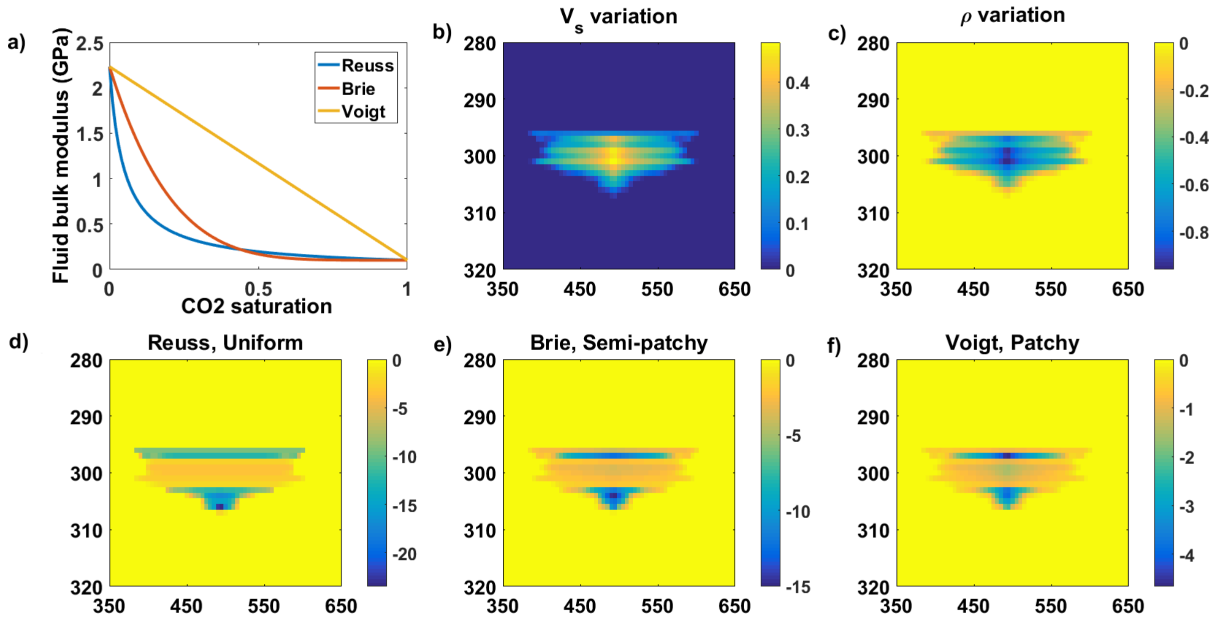

Figure 2 *2D section of the elastic parameters variations, for 5 years of injection. a) Fluid bulk modulus as a function of CO_2 saturation. b) S-wave velocity variation. c) Density variation. d) P-wave velocity variation for an uniform saturation. e) P-wave velocity variation for a semi-patchy saturation. f) P-wave velocity variation for a patchy saturation.*

Simulation of seismic responses

Seismic data are simulated using TIGER, a 3D finite-difference modelling software (from SINTEF Petroleum Research). We use the inner part of the actual baseline survey acquired in 2014 (Lawton et al., 2015b). It contains a total of 561 receivers and 561 sources (source and receiver spacing of 10m, source and receiver lines interval of 50m), for a final bin size of 5mx5m.

Figure 3 shows 2D vertical and horizontal sections of the difference between the time lapse periods and the baseline, after standard processing applied on synthetic data (deconvolution, NMO, CMP stack and post-stack migration). To be closer to real data, we add a noise corresponding to a SNR of 20 to the synthetic data. This level of noise was estimated on the data acquired on the field (Isaac and Lawton 2015). The black lines added in figure 3 show the lateral expansion of the gas plume. We can see that either for 1 year of injection (266 tons of CO_2) or 5 years of injection (1330 tons of CO_2), the reflectivity anomalies correspond to the location of the gas plume. However, for 1-year injection, we reach the detection threshold as the reflectivity anomaly is confined to the central part of the gas plume where the gas saturation is higher. The amplitude of the reflectivity anomaly is close to the amplitude of the noise. Note that those results assumed a semi-patchy saturation.

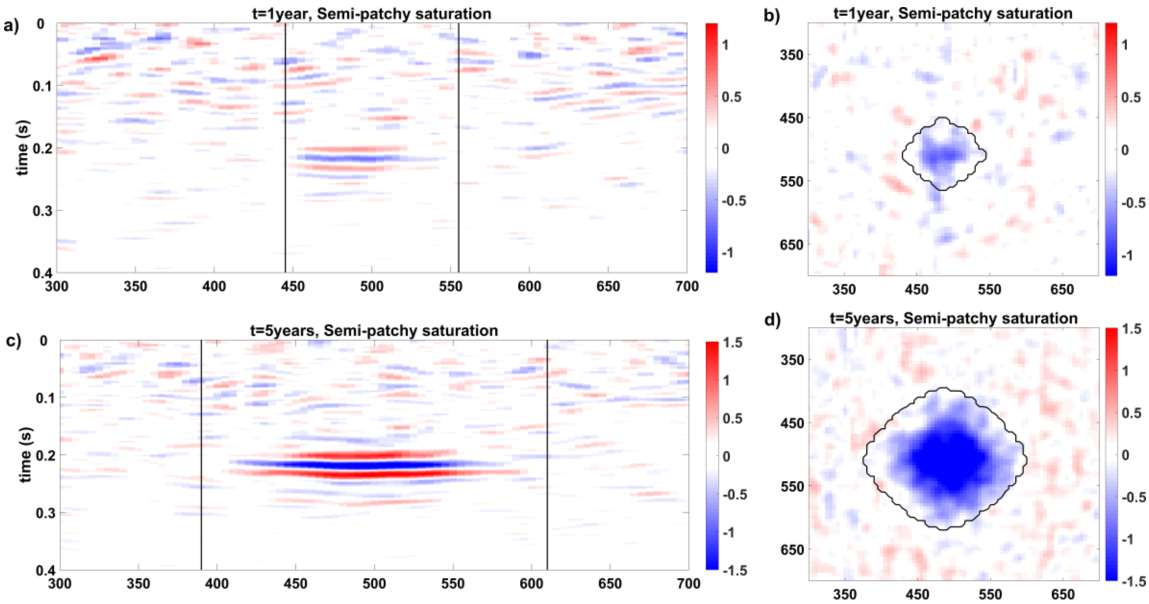

Figure 3 *Results of the difference between the simulated time lapse periods and the baseline seismic volumes, adding noise corresponding to a signal over noise ratio of 20. a) Vertical section along the injector well, for 1 year of injection. b) Horizontal section at the top of the reservoir, for 1 year of injection. c) Vertical section along the injector well, for 5 years of injection. d) Horizontal section at the top of the reservoir, for 5 years of injection. Black lines show the lateral expansion of the* CO_2 *plume.*

Conclusions

We explore the different parametres assumed during a feasability study for seismic monitoring, applied to a small amount of CO_2 injected at shallow surface at the CaMI.FRS. We test different bottom-hole pressure and different ratios of permeabilities and show their effect on the amount of injected CO_2. Instinctively, the higer those parameters are and the higher is the injectivity.

During the fluid substitution step, the main assumption is on the saturation behavior and its effect on the seismic responses. In the absence of laboratory tests, we test the different methods to compute the elastic parameters variations. If we assume a semi-patchy saturation (middle on Figure 4), the modelling shows that the detection threshold is ~250 tons of injected gas (less than 1 year of injection). If we assume uniform saturation (right on Figure 4), then we predict that plume should be detectable by seismic methods after about 1 year of injection. Full patchy saturation is a more challenging condition and it may take several years of injection for the plume to be detectable using surface seismic data (left on Figure 4).

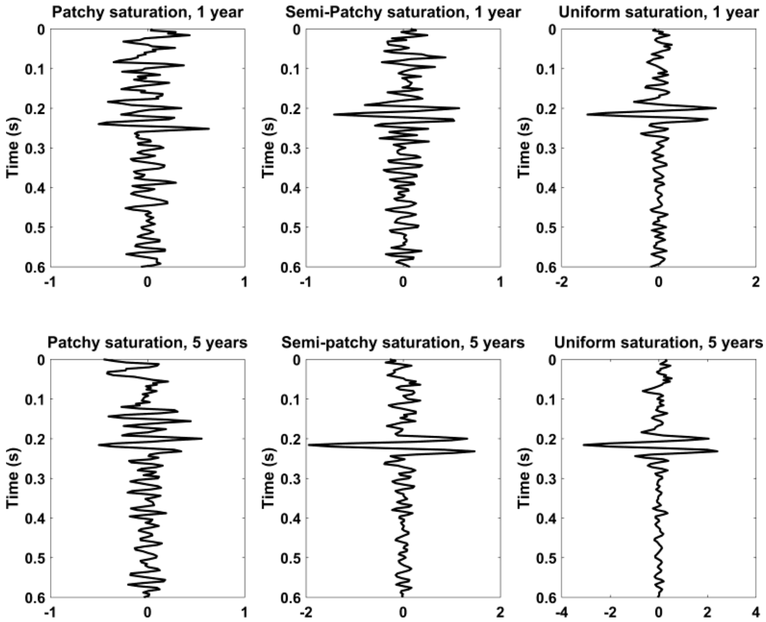

Figure 4 *Difference between the time lapses (for 1 years and 5 years of injection) and the baseline, at the center of the reservoir, for the different fluid saturation behaviors.*

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