Time-lapse seismic modeling of CO_2 sequestration at Quest CCS project

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ABSTRACT

A time-lapse analysis was carried out to investigate the theoretical detectability of CO_2 for the Shell Quest project. Quest is a Carbon Capture and Storage (CCS) project in Alberta conducted by Shell Canada Energy, Chevron Canada Limited, and Marathon Oil Canada Corporation. The target formation for injection is Basal Cambrian Sandstone (BCS) which is a deep saline aquifer at an approximate depth of 2000 meters below surface. The purpose of this study was to simulate the seismic response of the BCS after injecting 1.2 million tonnes of CO_2 during a one-year period of injection. This was done using Gassmann fluid substitution and seismic forward modeling. A geological model for the baseline scenario was generated based on data from well SCL- 8-19-59-20W4. For the monitor case, Gassmann fluid substitution modeling was undertaken to model a CO_2 plume within BCS. Numerical stack sections for both scenarios were obtained and subtracted to study the change in the seismic response after injecting CO_2. The difference section shows the location and the spacial distribution of the plume. Based on these results the CO_2 plume could be detected in the seismic data after a year of injection.

INTRODUCTION

Carbon Capture and Storage (CCS) is one of the methods for reducing the emissions of CO_2 in the atmosphere. In this process, the produced CO_2 from large emitters is captured before it can be released into the atmosphere. It is transported and then injected into a deep geological formation for permanent storage. Quest Carbon Capture and Storage is a joint CCS project between Shell Canada Energy (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). The purpose of this project is to reduce the CO_2 emission from Scotford Upgrader by storing it in a deep geological formation. The location of the Scotford Upgrader is about 5 km northeast of Fort Saskatchewan, Alberta, within an industrial zone (Figure 1). The selected geological formation for the CO_2 storage is Basal Cambrian Sands or BCS, which is a saline aquifer within Western Canadian Sedimentary Basin (WCSB), with an approximate depth of 2000 meters below the surface. Figure 2 shows the regional stratigraphic section for the zone of interest along with a closer view of the Quest storage complex.

Several studies on the feasibility of CCS in Canada have been carried out (Bachu et al., 2000; Bachu and Stewart, 2002). Bachu investigated possible suitable geological formations for carbon storage projects throughout Canada. The storage sites are preferred to be close to industrial regions with high levels of CO_2 production. The study results show that the most suitable formations are within the Western Canadian Sedimentary Basin (WCSB) where deep saline aquifers are overlain by several extensive aquitards to decrease the possibility of leakage. Therefore, BCS is suitable for permanent storage of CO_2 since it is sealed from the above by Middle Cambrian Shale (MCS), Lower Lotsberg Salt, and Upper Lotsberg Salt (Figure 2). Furthermore the BCS has a porosity of 8-24% and a permeability of 1mD to > 1D; therefore it provides good conditions for CO_2

sequestration. It is expected that the BCS will contain the CO_2 emission from the Scotford upgrader for decades (Shell, 2010).

FIG. 1: area of study and the location of well SCL-8-19-59-20W4

Monitoring the sequestered CO_2 is one of the important aspects of the CCS technology and is carried out through the injection, closure, and post-closure phases to track the injected CO_2 and detect any possible leakage into the upper geological formations. This is to ensure that the sequestered CO_2 is stored permanently and there is no possibility of leakage.

Change of the pore fluid leads to the change in the physical properties of the rock (Gassman, 1951; Smith et al., 2003). Therefore, seismic methods could be utilized to analyze the status of CO_2 during different phases of the CCS project. It is found that the P-wave velocity decreases once the CO_2 injection starts. This could be detected in the seismic data in the form of reflection time shift and amplitude change.

The goal of this study was to investigate the theoretical detectability of CO_2 in Quest project. For this purpose Gassmann fluid substitution was undertaken to calculate the properties of BCS after injecting CO_2. The theory and results are explained in the following pages.

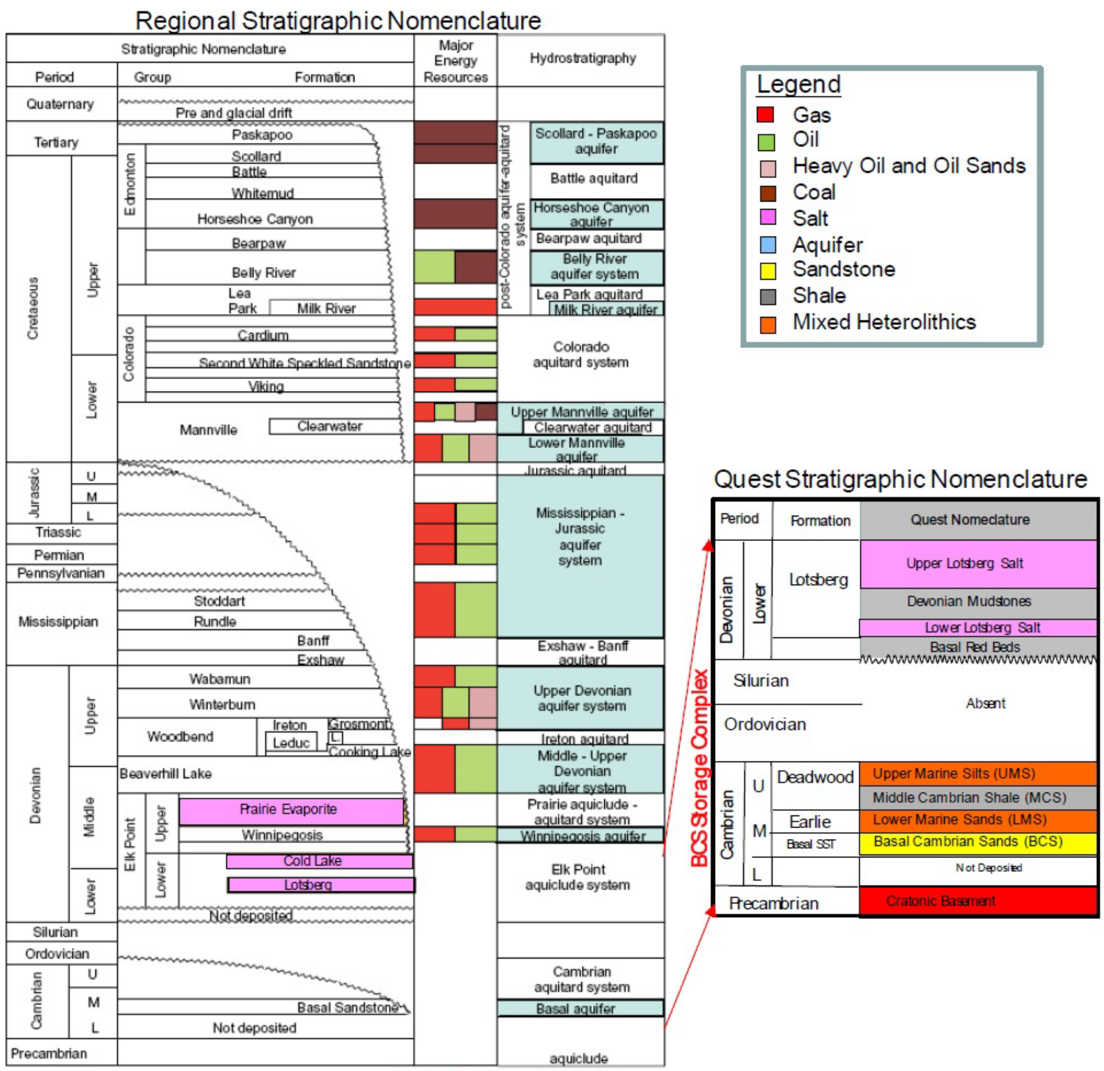

FIG. 2: The stratigraphic column of the Western Canadian Sedimentary Basin and a larger view of the Quest storage complex. The target in the Quest CCS project is the Basal Cambrian Sands (Shell, 2010).

THEORY AND RESULTS

Gassmann fluid substitution

For simulating the seismic response of the storage after the injection of CO_2, fluid substitution modeling first needed to be performed. The most commonly used method is the Gassmann method (Gassmann, 1951) which calculates the bulk modulus of the saturated rock using the known pore fluid and rock properties:

$$K_{saturated} = K_{\varphi} + \frac{\left(1-\frac{K_{\varphi}}{K_{mineral}}\right)^2}{\left(\frac{\varphi}{K_{fluid}}+\frac{1-\varphi}{K_{mineral}}-\frac{K_{\varphi}}{(K_{mineral})^2}\right)} \qquad (1)$$

where K_{φ} is the bulk modulus of the porous rock frame, $K_{mineral}$ is the bulk modulus of the rock matrix, K_{fluid} is the bulk modulus of the pore fluid, and φ is the porosity.

Gassmann equation assumes that the porous rock is homogenous and isotropic with connected pore space. Some of these assumptions might be violated in some cases, but studies show that for clean sands with high porosities, Gassmann's equation delivers reasonable results (Smith et al., 2003). Since this is the case for BCS, we can assume that these assumptions are met. From equation (1), $K_{saturated}$ could be calculated for the rock with any new fluid that replaces the in-situ fluid. For this purpose the bulk modulus of the new fluid is used in the equation. Since Gassmann assumes the pore fluid to be homogenous, the bulk modulus of the fluid mixture must be calculated from those of the individual fluids in the mixture. This could be done using the Reuss average approach:

$$K_{fluid} = \left[\sum_{i=1}^{n} \frac{S_i}{K_i}\right]^{-1} \qquad (2)$$

where K_i and S_i are, respectively, the bulk modulus and saturation of the individual fluids in the mixture. A simple volumetric mix of the individual fluids is used to calculate the density of the fluid mixture:

$$\rho_{fluid} = \sum_{i=1}^{n} S_i \rho_i \qquad (3)$$

Then, from the relation between the porosity (φ), the matrix density (ρ_m), and the fluid density (ρ_{fluid}) we have:

$$\rho_{saturated} = \rho_m(1-\varphi) + \rho_{fluid}\varphi \qquad (4)$$

When the in-situ pore fluid is substituted by a new fluid, equations (3) and (4) are used to calculate the density of the rock saturated with the new fluid. Also, from equations (2) and (1) the bulk modulus of the new saturated rock can be obtained. The changes in the density and the bulk modulus of the rock will lead to the change in seismic P and S wave velocities where:

$$V_P = \sqrt{\frac{K_{saturated}+\frac{4}{3}\mu}{\rho_{saturated}}} \qquad (5)$$

and

$$V_S = \sqrt{\frac{\mu}{\rho_{saturated}}} \qquad (6)$$

where μ is the shear modulus that is independent of the pore fluid and remains constant during the fluid substitution modeling. This method was used to calculate the properties of the CO_2 plume for generating the model after CO_2 saturation.

Geological model

In this work the data set from well SCL- 8-19-59-20W4 (Radway) was used to make a model for seismic time lapse modeling. This data set was received from Shell Canada Limited in summer 2012. The location of this well is within the Thorhild County area where the candidate injection wells are located (Figure 1). In addition, a baseline 3D seismic survey has been acquired at the area, but in this work we had access to the well data only, and our study is based on the logs from this well.

Figure 3 shows Radway well data. There are 5 tracks that show density, P-wave velocity, S-wave velocity, Gamma-ray and seismic synthetics respectively from track 1 to 5. The synthetic seismograms were generated in Hampson-Russell using the velocity and density logs and a 50 Hz zero-phase wavelet. The horizons were picked and some of the main ones are illustrated in Figure 3. As previously mentioned, the target is BCS that is a saline aquifer at a depth of approximately 2000 meters below the surface. BCS thickness, measured from the well was 49 meters, and the porosity calculated from the density log was 16 % which is a favorable porosity for CO_2 sequestration. Using the velocities and densities from the logs, a geological model was generated in NORSAR2D. Figure 4(a) shows the velocity model generated for the baseline scenario where CO_2 saturation in BCS was 0%. For more accuracy the BCS and its upper layers LMS, MCS and UMS, were divided into a set of thin layers. Specifically, in BCS there were 7 layers with an average thickness of 7 meters. The detailed view of BCS is shown in Figure 5.

The goal was to simulate the seismic response of BCS after injecting CO_2 for a year, for a total of 1.2 million tonnes. For this purpose a monitor model needed to be generated with a CO_2 plume added to BCS. The plume geometry and properties are discussed later in this report. As explained previously, CO_2 injection changes the density and the wave velocities of the reservoir rock. These changes were calculated using Gassmann fluid substitution, and based on the results, the monitor model was generated (Figure 4-b).

Fluid substitution results for BCS

To generate the monitor model, Gassmann fluid substitution modeling for BCS was performed. The parameters needed for calculations, such as $V_p, V_S, \rho,$ and φ, were obtained from the well data. In addition, the fluid properties were estimated using the CREWES Fluid Property Calculator which uses either the empirical relations presented by Batzle and Wang (1992) or the Peng-Robinson (1976) equation of state. The goal was to calculate the properties of CO_2 and brine at the conditions of the BCS aquifer where the in-situ fluid in BCS was assumed to be 100% brine. For this purpose the temperature and Pressure at BCS were needed, but since there was no adequate information about the temperature, the geothermal gradient was used for calculating the temperature:

$$T(z) = G * z + T(z_{surface}) \quad (7)$$

where z is the average depth of BCS, $T(z_{surface})$ is the temperature at the surface that was assumed to be 15 ℃, and G is the geothermal gradient which is 27 ℃/km in Alberta.

For calculating the pressure, the hydrostatic gradient was used:

$$P(z) = H * z \qquad (8)$$

where H is the hydrostatic pressure gradient that is 9.792 kPa/m . The average depth of 2050 m was considered for BCS, and the temperature and pressure obtained for this depth were 70 ℃ and 20 MPa respectively. By inserting these values in the Fluid Property Calculator, the bulk modulus and density of CO_2 and brine at these conditions were computed. These properties are summarized in Table 1. For this study, we assumed that the pore fluid is 100 % brine that will be substituted with CO_2 once the injection begins. The phase of CO_2 at this temperature and pressure is supercritical where its density is close to the density of liquid and its viscosity is similar to gas (IPCC, 2005).

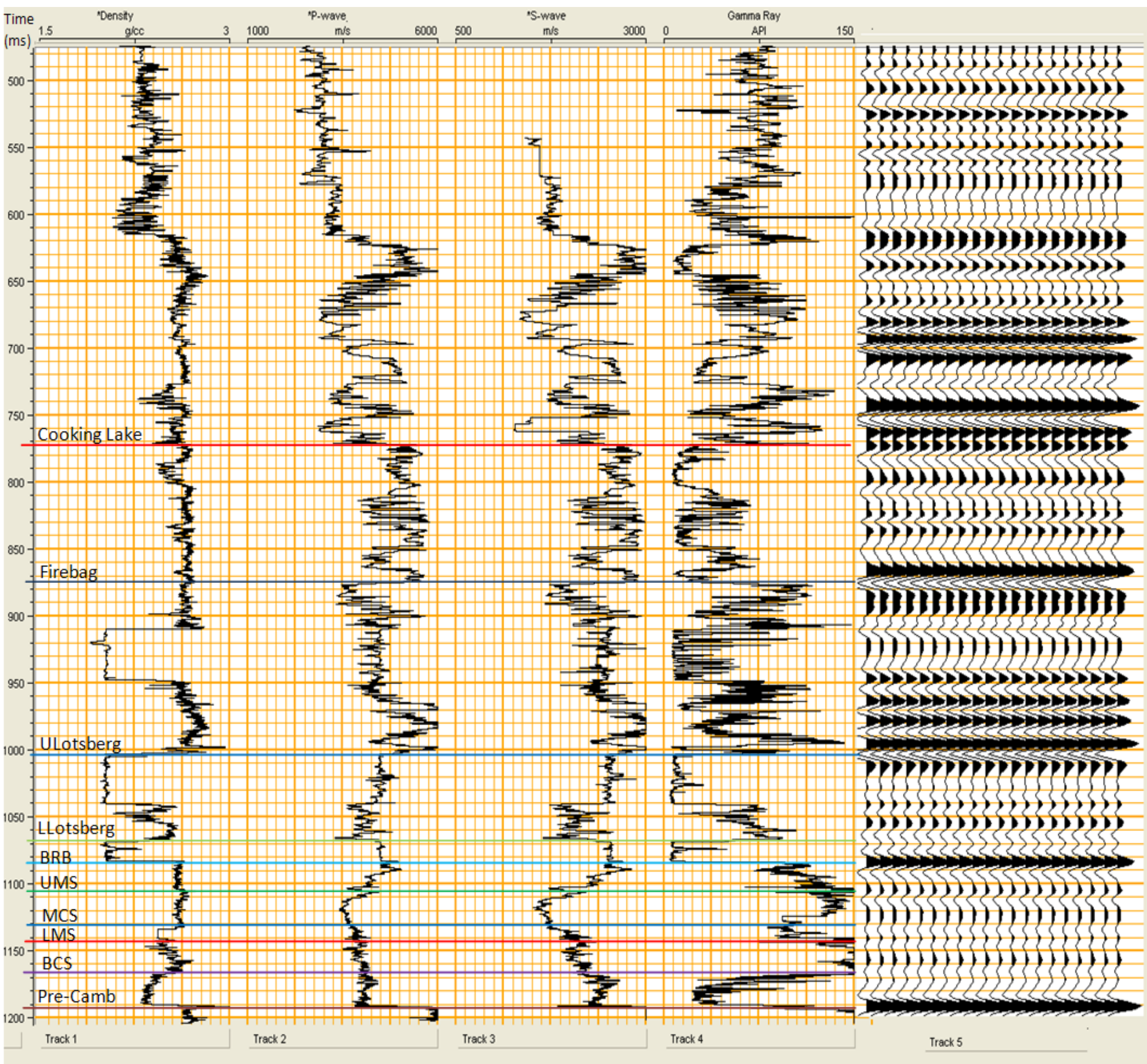

FIG. 3: Data from well SCL- 8-19-59-20W4 and some of the horizons in the zone of interest. Tracks 1 to 5 show the density, P-wave velocity, S-wave velocity, Gamma-ray and synthetic seismograms respectively.

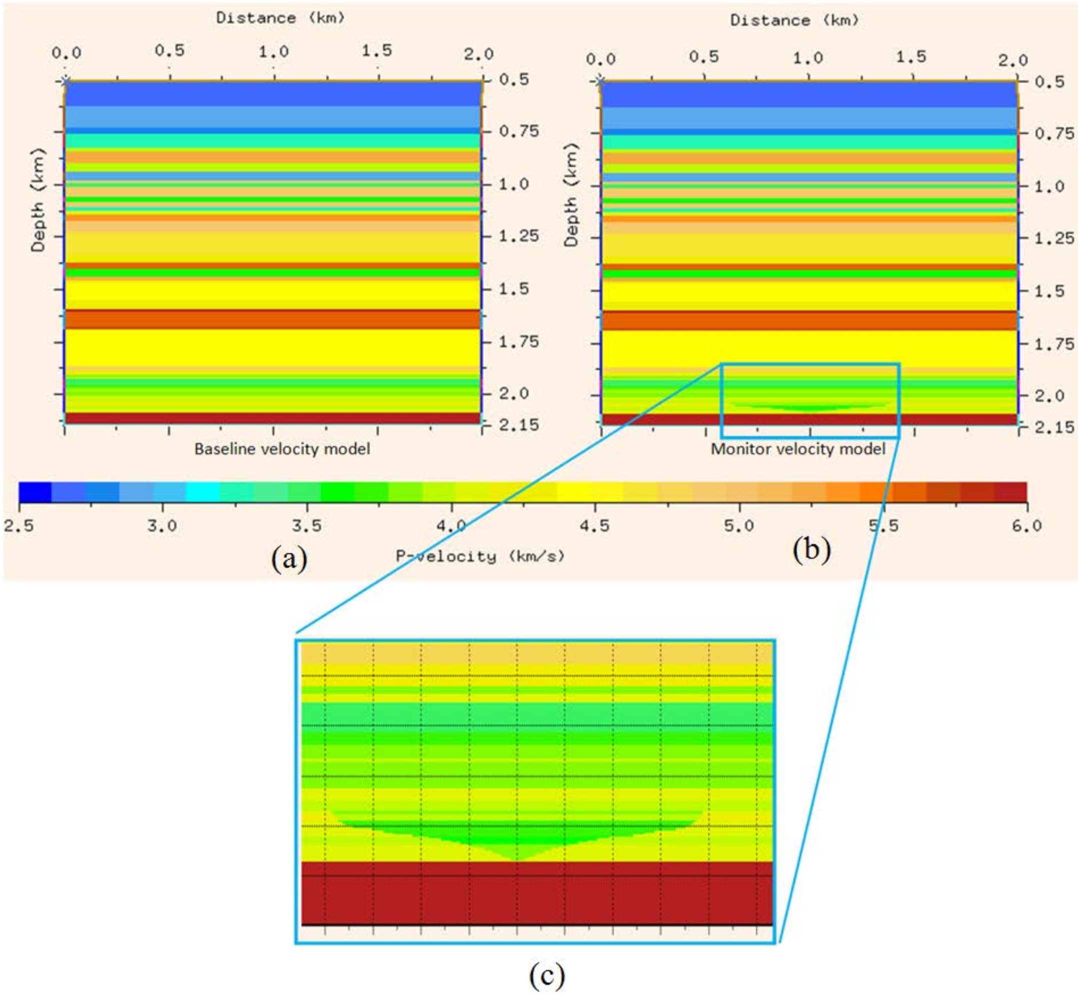

FIG. 4: The P-wave velocity model for baseline (a) and monitor (b) scenarios, and a closer view of the CO_2 plume in BCS(c).

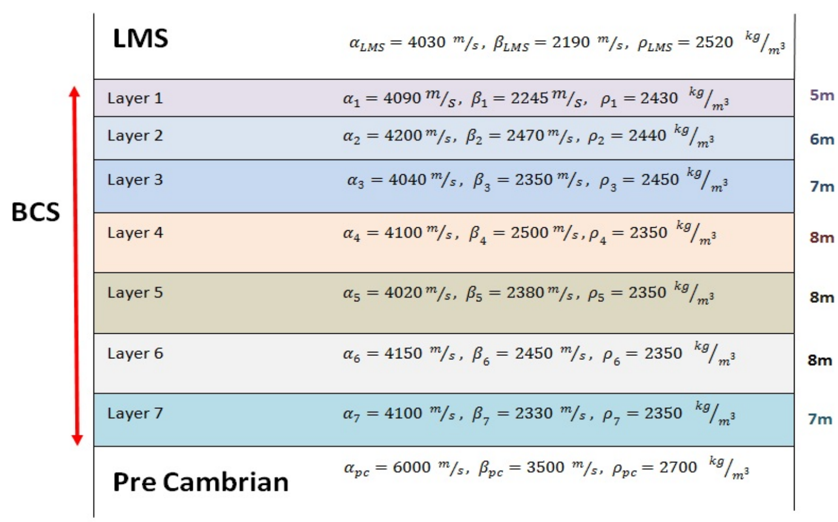

FIG. 5: A detailed view of BCS in the model, where it is divided to seven thin layers.

After computing the fluid properties, fluid substitution modeling was performed to calculate the properties of the plume. Using equations (2) and (3), the properties of the brine and CO_2 mixture were calculated for different levels of CO_2 saturation. Next, from equations (1) and (4), the bulk modulus, the density and finally the P-wave velocity of the new saturated rock were calculated. This was done for all 7 layers within BCS, and the results are shown in Figure 6. This figure illustrates the changes in P-wave velocity versus CO_2 saturation for all 7 layers within BCS. Note that the velocity changes rapidly for the saturation values below 20%, and gradually for values above 20%. The curves are different for each layer which is due to the difference in the rock properties of these layers. However, for all layers the maximum change occurs between values of 40% to 45% CO_2 saturation. Therefore, for time lapse modeling we chose the amount of 40% CO_2 saturation for the monitor model to obtain a better time-lapse seismic response.

Fluid	Bulk modulus	Density	P-wave velocity
CO_2	81.6 MPa	0.625 g/cm^3	361 m/s
Brine	3046.1 MPa	1.071 g/cm^3	1686 m/s

Table 1: CO_2 and brine properties calculated at the BCS temperature and pressure.

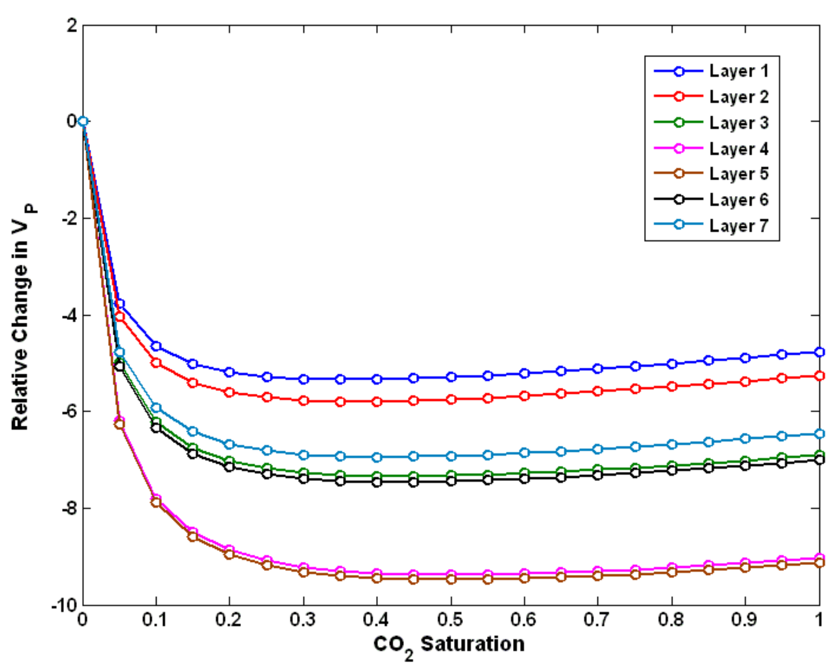

FIG. 6: Relative change in P-wave velocity versus CO_2 saturation for each of the 7 layers within BCS.

CO_2 Plume size estimation

To study the time lapse response of the Quest project, a simulation of the CO_2 plume was required. The plume was assumed to have a semi-conical shape as shown in Figure 7. Due to the difference between the densities of water and CO_2 -the buoyancy force-, CO_2 tends to migrate towards the top of the formation (Negara et al., 2011). Consequently, the plume would have a shape similar to what is illustrated in Figure 7.

Plume size was calculated using information from the Quest project (Shell, 2010) and the properties of CO_2. For this purpose, the plume was approximated with a cone with a radius of R and the height of 49 meters, which is the thickness of BCS. The goal was to estimate the Radius of the plume after injecting CO_2 for one year, amounted to 1.2 million tonnes. As mentioned previously, the maximum change in P-wave velocity due to injection occurs at 40% CO_2 saturation. Therefore the CO_2 plume was assumed to have 40% CO_2 saturation to obtain a better time-lapse seismic response. Knowing the density of CO_2 from previous calculations (Table1), the volume of the CO_2 plume could be calculated:

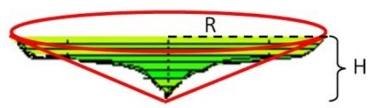

FIG. 7: The CO_2 plume in the monitor model is approximated with a cone to estimate the plume radius after one year of injection.

$$V_{CO_2} = {M_{\mathrm{CO_2}}}/{(\rho_{\mathrm{CO_2}})} = \frac{1.2 \times 10^9 kg}{\left(625 \ {kg}/{m^3}\right)} = 1.92 \times 10^{6} \ m^3$$

This is the volume of CO_2 occupying 40% of the pore space that is 16% of the rock volume. Therefore to calculate the volume of the cone, the volume of CO_2 must be divided by the porosity (16%) and CO_2 saturation (40%):

$$V_{\mathrm{cone}} = \frac{1.92 \times 10^{6} \ m^3}{0.16 \times 0.4} = 3 \times 10^{7} m^3$$

Then the radius of the cone could be calculated from:

$$V_{\mathrm{cone}} = \frac{1}{3} \pi R^2 H$$

$$R = 764 \ m$$

So the radius of the plume yields approximately 764 meters after a year of injection. In this study a plume with a radius of 800 meters was assumed and used for seismic forward modeling.

Time-lapse seismic modeling:

For the time lapse analysis of the Quest project, two seismic datasets were generated for the baseline and monitor surveys. The baseline model represents the model with zero percent CO_2 saturation in BCS. In the monitor model, a semi-conical shape CO_2 plume with a radius of 800 meters and CO_2 saturation amounted to 40% was added to BCS. The rock properties inside the plume were obtained from the Fluid substitution results. Figure 4(b) shows the P-wave velocity model for the monitor scenario, and a closer view of the CO_2 plume is shown in Figure 4(c). It is evident that the P-wave velocities inside the plume are less than those outside the plume. These changes in P-wave velocity and density cause a change in the amplitude and traveltimes in the monitor seismic response relative to the baseline.

A 2D survey designed for this study was composed of 101 shots with 500 live receivers for each shot, with a symmetrical split spread layout. The receiver and shot spacing were respectively 10 and 100 meters. Therefore, the survey covered a line with the total length of 10000 meters with a maximum fold of 25 at the centre. For generating the shot gathers the model was extended to 10000 meters where for the monitor model the CO_2 plume was added to BCS at the centre of the line. The synthetic shot gathers for both baseline and monitor scenarios were generated using NORSAR2D which is seismic ray-tracing modeling software. The wavelet used was a zero phase Ricker wavelet with the dominant frequency of 50 Hz. Figure 8 shows four adjacent shot gathers generated for the baseline survey.

The generated shot gathers were then processed in the VISTA seismic processing package. Since this was a synthetic data without topography, no static correction was needed. In addition the velocity model was known already, so the data was ready for NMO correction. After NMO correction the traces were sorted into CMP and stacked. The CMP stack sections are shown in Figures 9 and 10 for the baseline and monitor surveys respectively. It is evident that there are some changes in the seismic response of BCS for the monitor scenario. To see the changes more clearly, the baseline section was subtracted from the monitor section to obtain the difference section. Figure 11 illustrates the difference of the two sections. It is clear that the CO_2 injection has caused changes in the amplitude and traveltimes relative to the baseline survey, which leads to residual events in the difference section. In terms of the shape and size of the plume, it is observed that the horizontal extent of the plume could be estimated with a good precision from the difference section. Also the top of the plume is detectable due to the change in amplitude of the reflector on top of BCS. Although the plume had a semi-conical shape distribution, the change in the seismic response appears to be more in cylindrical shape. This is due to the time shift of the reflectors beneath the two ends of the plume.

CONCLUSION

A geological model was generated based on the well data and was used for modeling the baseline seismic survey. The model was modified to simulate the monitor survey by adding a CO_2 plume to BCS. The properties of the plume was calculated using Gassmann fluid substitution and assuming 40% CO_2 saturation which causes the maximum time lapse effect. The size of the plume was estimated based on the expected injected amount of CO_2 after one year injection and also the porosity of BCS. This plume had a semi-conical shape to better describe the CO_2 distribution affected by the buoyancy force. Synthetic shot gathers were generated in NORSAR2D for both baseline and monitor scenarios and were processed in the VISTA seismic processing package to obtain the stacked CMP sections. The difference section was obtained by subtracting the baseline section from the monitor section to observe the change in seismic response after injecting CO_2. The result showed that the injection of CO_2 caused a change in amplitude and traveltimes within and underneath the plume which caused a difference in the monitor seismic response. The horizontal distribution and also the top of the plume were clearly observable in the difference section. However, the shape of the plume did not appear in a semi-conical shape since there were time shifts in the reflectors underneath the plume ends. It could be concluded from this results that BCS could be monitored based on its seismic response after the injection of CO_2. However this study was based on a well log data set. In the future, more precise 2D and 3D models could be generated from seismic data and other well data available for the area to study the detectability of CO_2 more accurately.

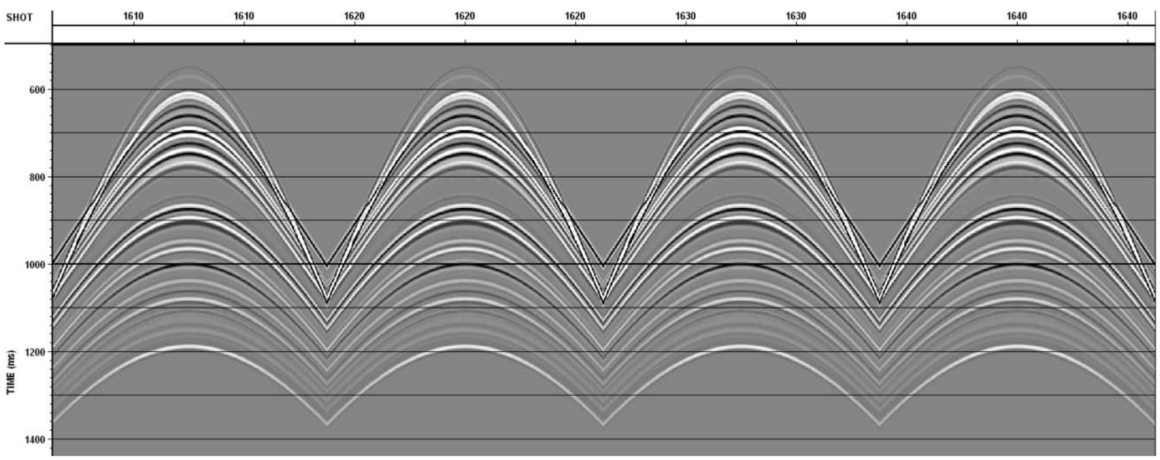

FIG. 8: An example of the generated shot gathers for the baseline survey.

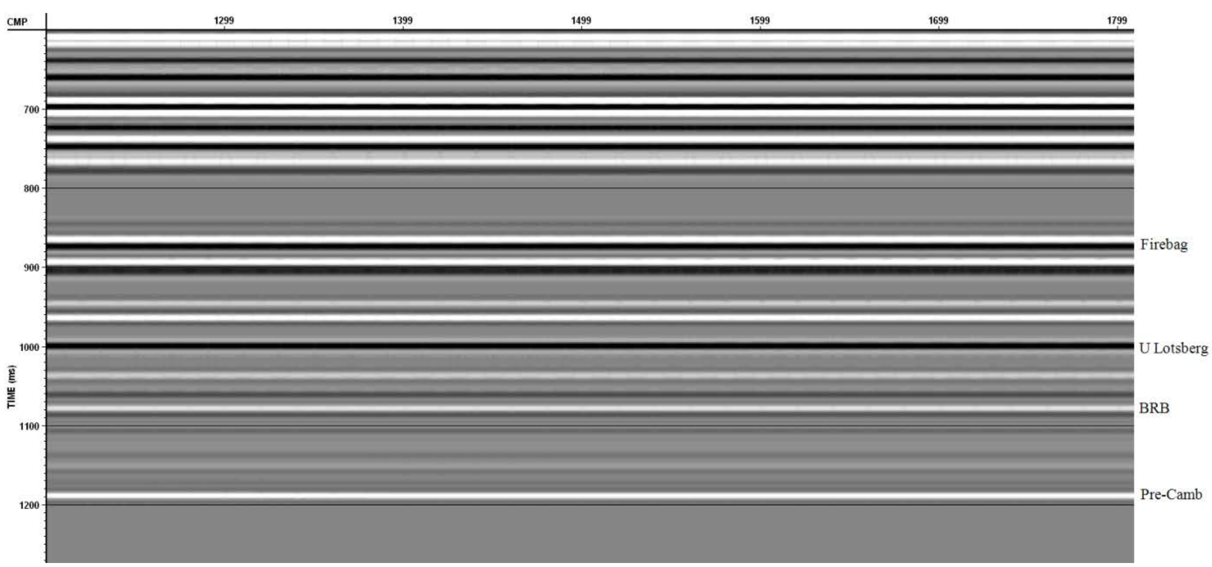

FIG. 9: Baseline stack section.

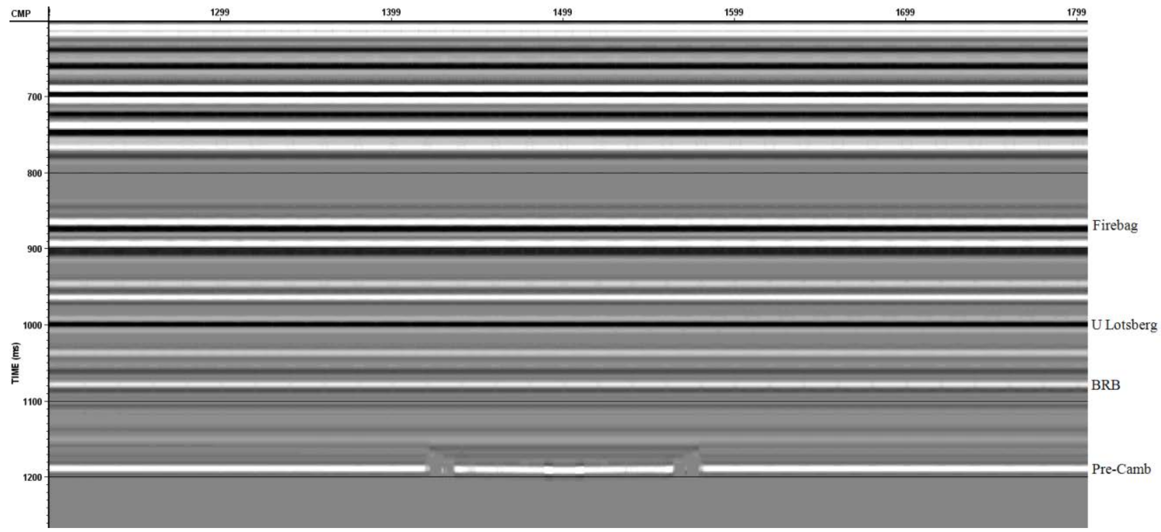

FIG. 10: Monitor stack section.

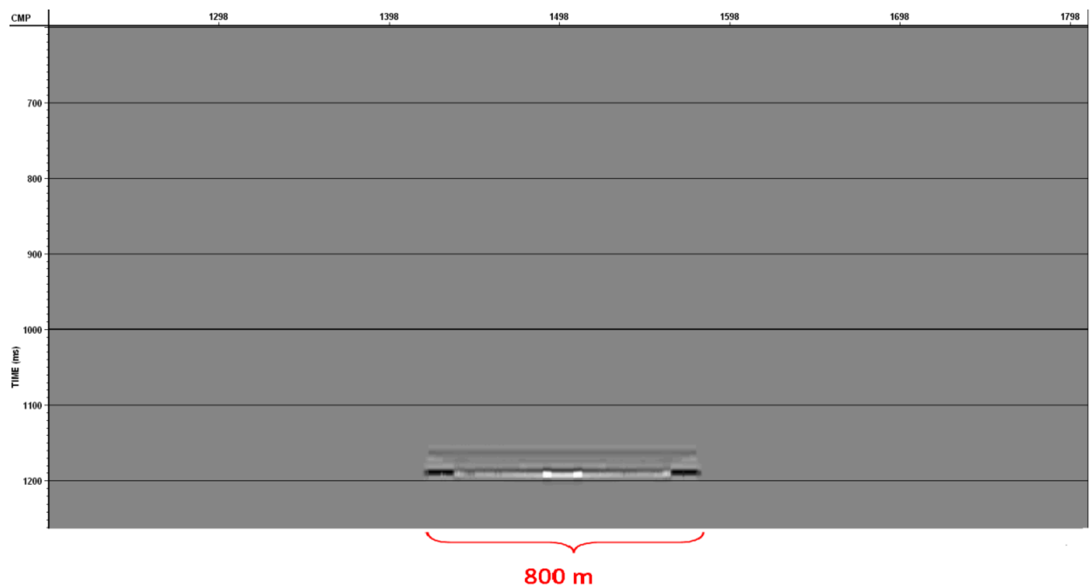

FIG. 11: Difference stack section.

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