TNO Built Environment and Geosciences

NITG/Geological Survey
Princetonlaan 6
P.O. Box 80015
3508 TA Utrecht
The Netherlands

www.tno.nl

T +31 30 256 42 56
F +31 30 256 44 75
info@nitg.tno.nl

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Description of the data processing flow, detection potential and boundary conditions of crosswell seismic techniques

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Date	January 27, 2006
Author(s)	P. Winthaegen
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Contents

1 Introduction

Subsurface monitoring of CO_2 being stored in geological formations is not only important for health, safety and environment aspects, but also to verify that the CO_2 is stored in the planned rock formations and is behaving as predicted within excepted boundaries. In general, monitoring for CO_2 storage is applied for (Winthaegen *et al.*, 2005):

- Health, safety and environment (HSE) issues: It is important that during injection it can be ensured that health, safety and environment are not jeopardised. Seismic monitoring, e.g., can demonstrate the integrity of the geological seal including possible faults. Additional monitoring techniques (e.g. logs, gas sample analysis, direct concentration measurements) focus on the well bores, nearby mine galleries and the surface, but are also be used to improve the seismic interpretation.
- Reservoir understanding: Monitoring the injected CO_2 within the reservoir will result in improved knowledge of the storage characteristics. It will also contribute to the geological and dynamic 'reservoir' model that can be used to predict future behaviour of the stored CO_2. Important is the determination of the breakthrough time, when the injected CO_2 reaches the production well. As a result of injecting the CO_2 in coal also the resulting coal bed methane can be monitored. Also for the reservoir understanding additional to the seismic monitoring other measurements are applied, e.g. temperature, pressure and contents of produced water and gas samples. These measurements also contribute to an enhanced dynamic reservoir understanding and the migration of CO_2 and methane within the coal layers.

For the latter aspect conventional monitor techniques are used that are also applied by the oil and gas industry for hydrocarbon exploration and production management. One of the most commonly applied techniques is seismic investigation where source and receivers are located near the surface. For marine applications the source and receivers are deployed in the water and towed behind a ship. In general these techniques work well for hydrocarbon exploration, but the results depend on the size of change in the subsurface with respect to the amount of change in seismic response and noise. The changes in seismic response are site specific, but it may be generally assumed that due to the relative small amounts of CO_2 that are injected during storage – as compared to the amounts of hydrocarbon extracted during production - the changes in seismic response will be small. A third aspect of interest in relation to the monitoring for CO_2 storage is therefore:

- Improvement of monitoring techniques. It is investigated if time-lapse crosswell seismic measurements can be used for CO_2 storage in order to obtain a higher resolution image that can also accurately present the changes in seismic response as a result of storage.

Crosswell seismic acquisition has already been tested and performed on CO_2 storage sites: Kaniów, Poland (RECOPOL project; Winthaegen and Westerhoff, 2002; van Bergen et al., 2005) and Nagaoka, Japan (Saito et al., 2006).

2 Crosswell technique

2.1 Acquisition

Crosswell acquisition uses a well in which a seismic source is deployed and another well in which the receivers are positioned. The method has the advantage that the acquisition is applied near the target geological formations reducing the loss of seismic signal due to long travel paths and also avoiding the strong attenuating weathered layer. The borehole source must be able to fit the borehole and, at the same time, should be powerful enough to generate a seismic signal that can be detected at some distance from the source well. When the well is water filled hydrophone receivers may be used. Alternatively, geophones are clamped to the casing. Within the survey a layout is performed by moving the source progressively with depth, while keeping the receiver string (containing a number of receiver channels) at the same depth. After completing all source positions the receiver string is moved to the next location and the same procedure is applied. With this method the area between the wells is sampled by all source-receiver combinations. Dense sampling occurs in the middle between the wells and poorer sampling near the wells and at the top and the bottom of the source and receiver measurement depth intervals (Figure 1).

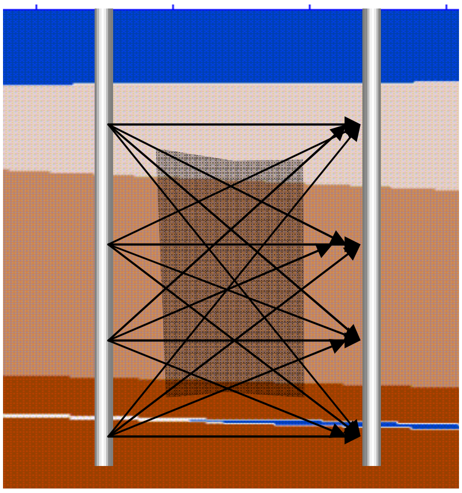

Figure 1: Example of a subsurface model with two vertical wells. The sources are positioned in the left well; the receivers are positioned in the right well. Possible ray paths of direct waves are drawn from 4 source positions to 4 receiver positions. As can be derived from the ray path density, the indicated grey area between the wells is best sampled. The areas below the lowest positions, above the top positions and near the wells are less well defined.

For monitoring CO_2 injection, two or more repeated crosswell seismic surveys need to be applied. Data from the first survey are used as reference and therefore the data are acquired before CO_2 injection. Data acquired during and after CO_2 injection are compared to the baseline data. Unwanted changes in seismic response are removed (e.g. calibrating of the data; see next section). The resulting change in seismic response is assigned to the true changes in the reservoir as a result of injection. Note that remnant changes in seismic response might reveal locations where CO_2 leaks from the reservoir.

As an example, synthetic shot gathers using a crosswell geometry are modelled using an acoustic approximation (Figure 2). The source is located in the left well at a fixed position at 300 m depth. The distance to the receiver well is 400 m. In this well, the receivers are located from the surface to 1250 m depth. The used geological model consists of 6 intervals (Winthaegen and Westerhoff, 2002). The thin layer at about 1050 m depth is the reservoir in which the CO_2 is injected. As a result of the CO_2 injection the seismic velocity decreases (Figure 2).

The change in seismic response due to injection is shown in Figure 3. The first event in the left and middle plot starting at about 300 ms is the direct wave between source position and the receiver positions. Note that only a small part of this direct wave travels through the thin reservoir. Other events are crossing the direct wave, are 'dipping' away from this arrival. These crossing events are reflections by the first arrival with formation boundaries. Examples of these reflections in the shown shot gathers are at about 200, 450, 1000 and 1050 m receiver depth. This agrees to the right well (receiver well) in the model presented in Figure 2. In case the seismic response is sorted into receiver gathers, i.e. the response of one receiver position for all source positions, then the reflections are made visible as function of source depth and would agree to the left well presented in Figure 2.

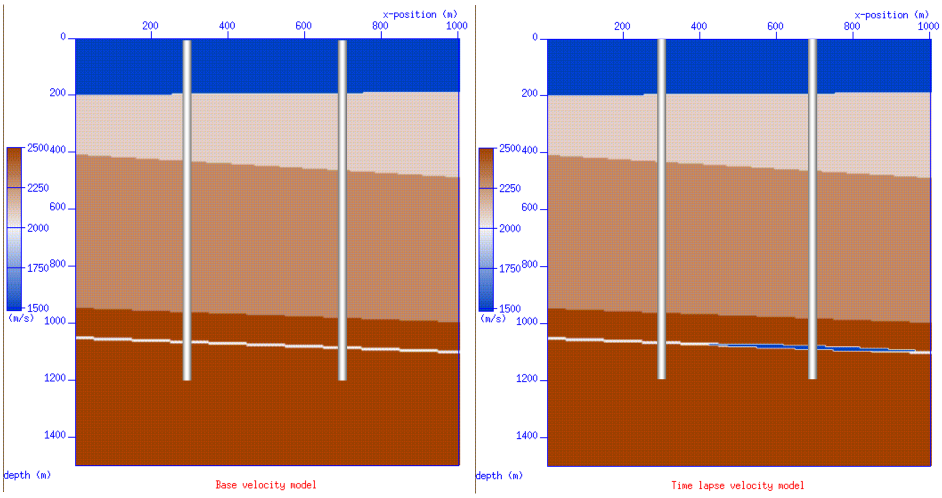

Figure 2: A seismic velocity-depth model is used to investigate the effect of CO_2 injection to the seismic crosswell response. a) the situation before injection. b) the situation after injection resulting in a reduction of seismic velocity.

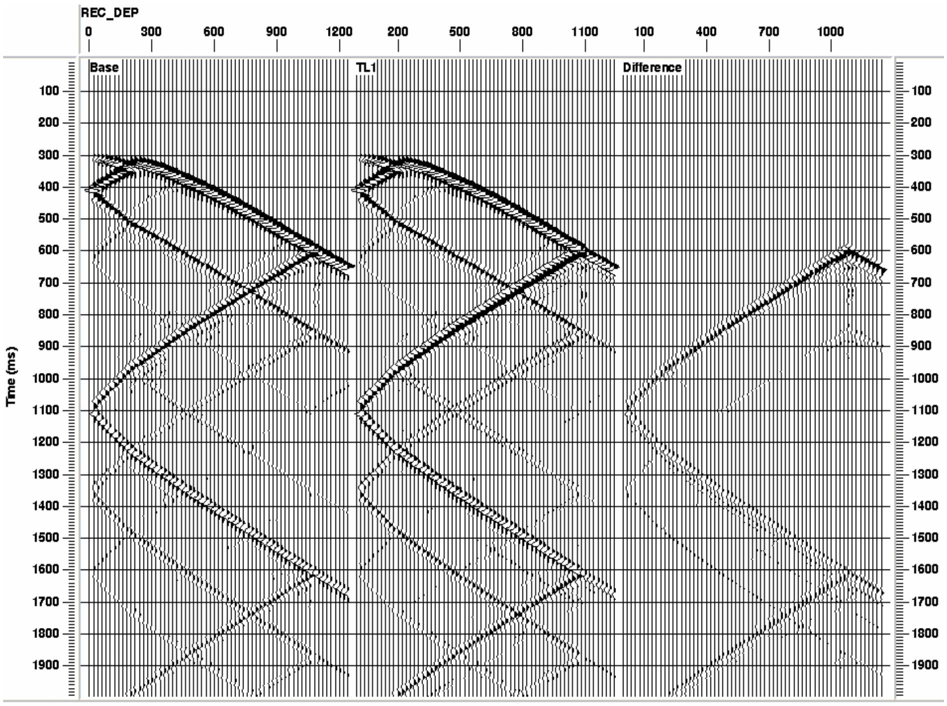

Figure 3: The source is positioned in the left well at a depth of 300 m and the receivers are located in the right well at 0-1250 m depth (x-axis). Shown are the shot gathers prior to (left) and after injection (middle; see also Figure 1). On the right the difference in seismic response is shown.

After normalisation of the data (next section) the difference is shown in the right-most picture of Figure 3. Because the direct wave travels only a small part through the injected part of the reservoir, the difference in seismic response between the baseline survey and monitor survey only exists for a small part in the direct arrival (from injection depth 1250 m onwards between 0.6 and 0.7 s recording time), but for a significant part due to the change in reflectivity including multiple reflections (respectively the dipping event to the left between 600 and 1100 ms and later recording times).

2.2 Processing and inversion techniques

The arrival times of the direct waves are used for tomographic inversion to determine a seismic velocity-depth model between the wells. Also the amplitude of the direct waves can be used when it is inverted to an amplitude tomogram. This can be used to improve the inversion results and the interpretation of the results. Here, briefly the processing and inversion is described. For a more thorough description and an alternative time-lapse inversion technique the reader is referred to another CATO report of Šijačić et al. (2006).

Note that additional to the direct waves in the crosswell data, also reflected waves from boundaries above and below the source and receiver positions can be used. The reflection data can be treated similar as conventional surface seismic data. Amplitudes are used for deriving a structural image, which can be compared to the situation of surface seismics. Amplitude anomalies in the reflection data can indicate subsurface gas accumulations.

Processing of crosswell data comprises (amongst others):

1. Adding position information to the data. Measured depth is added to the seismic data. Additional to the depth also the lateral positions must be added as the borehole is mostly not a perfect vertical line.
2. Removing the applied source signal from the data. This source signal might be a sweep instead of a perfect impulse signal.
3. Sorting of the data into source gathers.
4. Static (time) corrections for actual station positions.
5. Amplitude corrections for seismic attenuation.
6. First break picking to define the direct wave.

Form here two directions are followed:

A.
   a. Travel time tomography to derive a velocity-depth model between the wells.
   b. Match the velocity-depth model with available sonic logs.
   c. Amplitude tomography resulting in an amplitude-depth model.

B.
   a. Wave field separation. The (multiple) reflections are selected from the data.
   b. CDP mapping. The reflection data can be sorted to CDP gathers per lateral distance involving all station depths. By using the velocity-depth model, a time correction is applied resulting in horizontal alignment of the reflections (in case of a correct velocity model and a homogeneous subsurface).
   c. Stacking of the data. Summing over the offsets in the move-out corrected data results in a single trace per lateral offset. After repeating the procedure for all lateral offsets a structural image between the wells is obtained.

Additional processing is required when comparing the monitor crossswell data with the baseline crosswell data. This processing is required because changes in acquisition conditions might have taken place. Some important parameters for which need to be corrected for are: strength source signal, repeatability of the source signal (e.g. strength), exact depth locations, contact with the borehole wall, and noise.
Before picking the first breaks the following steps are applied on both data sets:

1. Removing the RMS amplitude values.
2. Spectral whitening that removes the noise and equalises the frequency content.
3. Frequency filtering to further improve the signal to noise ratio.

After picking the first breaks:

1. Analysis of travel time deviations between both data sets. The deviations are expected to be at the reservoir level due to injection.
2. Analysis of the velocity-depth models after inversion.
3. Analysis of the amplitude-depth models after inversion.

After deriving the reflection data with depth (pre- and post-stack)

1. Analysis of the amplitude in the stacks
2. When required normalisation of the monitor data to the baseline data for an assumed unchanged interval in the overburden.

After this normalisation the changes in reflection amplitude and possible travel time changes should agree to the response of the real changes that occurred (as a result of injection) in the subsurface.

The seismic inversion starts with the system of linear equations, e.g. in a general form:

$$dt = J\ dm\ ,$$

where dt is the vector of travel time differences between the picked travel times and the model predicted travel times, dm is the vector of model parameter perturbations (velocity nodes) and J is a sensitivity matrix. The elements in the matrix determine the relation between a change in model-predicted travel times to a change in model parameters. To solve these equations a least-squares inversion is applied by minimising the following expression:

$$\|\ J\ dm - dt\ \|^2 = \text{minimum}\ .$$

Note that the velocity nodes are positioned as the result of defining a grid between the well. The nodes are located on the grid points. Normally, a regular (squared) grid is defined, but alternatively rectangular grid block can be defined if it is expected to better solve local geology structures (Figure 4).

A standard ray tracing method can be applied to model travel paths and to derive the travel times related to the used velocity-depth model. Instead of using the conventional ray theory to predict travel paths, scattering can be taken into account in case of the situation of a more complex subsurface (e.g. Williamson, 1991). Note that, in general, the location of the CO_2 reduces the seismic velocity. Therefore, the CO_2 location might be difficult to image using tomography. As an extra constraint to obtain a correct (fine layered) subsurface model well information can be used. Pratt and Sams (1996) propose a method to upscale the borehole information to match the resolution of the crosswell data.

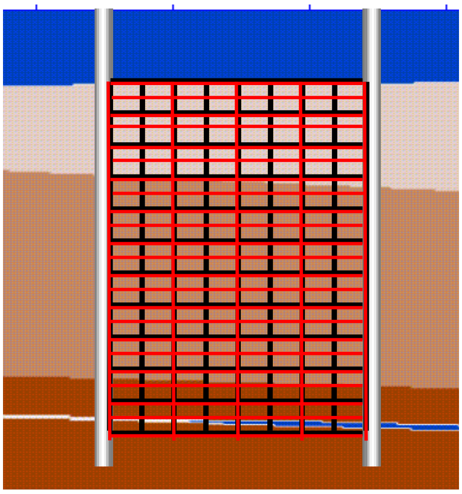

Figure 4: Grid parameterisation of the subsurface model: definition of a squared grid (black) and a rectangular grid (red) to be used for tomographic inversion between the wells. Only for demonstration purposes very coarse grids are displayed. As a result of the inversion seismic velocities (or seismic amplitudes) are allocated to the grid cells.

3 Detection potential and boundary conditions

As mentioned in the previous chapter the travel times of the direct waves are used and, additionally (or alternatively), reflection information can be used. For both methods the repeatability of the survey is important. The repeatability depends on the applied source (the repeatability of the source signal), the position of the source and receivers (e.g. cable stretch) and the coupling between source and receivers with the subsurface. Any changes will result in unwanted changes in seismic response. Changes in equipment and acquisition geometry will also result in unwanted changes and should be avoided. Effects can be reduced by individual processing of the data sets.

Also for both methods the measurement length is important. A short measurement length will result in high resolution signal. For reflection data the ability to distinguish certain subsurface objects is improved. This is especially important as the changes in response are expected to be small. Thin reservoirs can be better imaged.

For the travel time tomography, a short measurement length (actually travel path) also improves the result. Similar to reflection data, also here smaller size objects can be detected as the Fresnel zone is smaller. The size and the influences on the Fresnel zone are discussed by Šijačić et al. (CATO report, 2006).

When comparing to other seismic acquisition methods, the crosswell acquisition results in the best resolution. The measurement length is in general shorter and therefore high frequencies can be used. Also the weathered layer, that strongly attenuates high frequencies, is avoided. In Table 1 an overview of different methods is shown (after Paulsson *et al*, 1996). With decreasing measurement length the resolution will increase.

Seismic method	**Resolution**	**Measurement length**
Surface acquisition	20 -70 m	100 – 10000 m
Walk-away offset VSP	10 – 70 m	100 – 7500 m
Reverse w-a offset VSP	2 – 10 m	100 – 4000 m
Crosswell	1 – 5 m	10 – 1000 m

Table 1: Relation between the seismic methods, the resolution and the measurement length (after Paulsson et al., 1996).

Although the resolution of the seismic method using crosswell acquisition is the highest, there are also some points of attention when using crosswell seismic acquisition.

Using travel times, in case of a low velocity layer, e.g. a gas or oil filled reservoir, it might be difficult to determine the correct velocity as it is difficult to pick the first arrival. Waves travelling along the surrounding higher velocity layers will refract towards the low velocity layer covering the direct wave that travelled through the low velocity layer only (Figure 5). Situations further reducing the seismic velocity are in case CO_2 is injected in: water filled reservoirs, oil reservoirs and, depending on the situation, almost depleted gas reservoirs.

Another point of attention is bringing the seismic signal into the subsurface and towards the receivers. Tube waves, travelling in the well, might be generated. Because in the well there is almost no attenuation, the amplitudes can be high compared to the seismic signals. During the acquisition it should be investigated how the tube waves can be reduced (e.g. placing ‘dampers’).

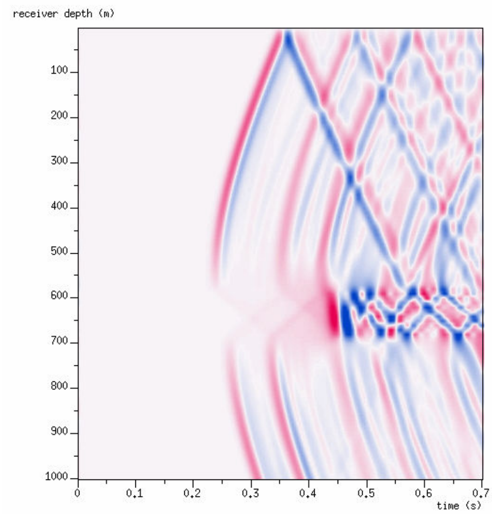

Figure 5: Example of synthetic modelled data showing crosswell arrival times. A low velocity interval is present at 600-700 m depth (Winthaegen, 2005). The travel paths through the low velocity layer arrive at about 0.45 s. Note the bow-tie structures in this low-velocity interval that correspond to travel paths through surrounding layers.

For the purpose of imaging the subsurface, for calibrating the geological model and to monitor the injected CO_2 and possible changes in the subsurface the following can be concluded. The HR surface seismic acquisition has the advantages of being a conventional method and that a structural image can be obtained. Disadvantages are lesser resolution and poorer repeatability. Crosswell seismology has the advantage of obtaining the best resolution and the highest repeatability. As for the Vertical Seismic Profiling (VSP) method the crosswell measurements are taken as a function of depth and not of travel time as in the surface method. Disadvantages are the processing effort and a less structural image that might be obtained. The VSP method will give in between results, where the reverse VSP method yields the higher resolution. Note that the crosswell methods will only provide a 2D image, while the surface seismic method and the VSP could be applied in 3D resulting in a spatial image of the subsurface.

4 Discussion and conclusions

Downhole seismic techniques such as cross-well, VSP, and reverse VSP offer superior resolution as compared to traditional surface seismic investigation techniques (reflection, refraction). The spatial coverage of downhole methods, however, is restricted to the area close to the wells, whereas surface seismic techniques may potentially be applied in a much wider area.

Since changes in near surface properties (e.g., seasonal changes in depth of the groundwater table) may significantly affect the repeatability of surface seismic investigations the suitability of downhole seismic techniques for monitoring purposes is apparent.

The practical application of downhole techniques is constrained by the availability of boreholes. For monitoring CO_2 storage projects typically existing injection and/or production wells will be used since drilling of additional (monitor) wells is expensive. Accessibility of these wells, however, may be limited (in particular during injection/production).

Application of downhole techniques may be furthermore constrained by the availability of suitable downhole sources and receivers. Whereas surface seismic techniques do not require dedicated hardware, downhole techniques (in particular in holes with existing infrastructure) may require significant adaptations in the hardware employed.

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6 Signature

Utrecht, January 2006 TNO Bouw en Ondergrond

H. Pagnier
Group leader

P. Winthaegen
Author