Feasibility of Time-lapse VSP Monitoring at the Aquistore CO₂ Storage Site Using a Distributed Acoustic Sensing System

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Abstract

The Aquistore carbon storage project, located near Estevan, Saskatchewan, Canada, aims to employ 3D time-lapse seismic techniques to monitor injected CO₂ at depths of 3100 - 3350 m. During early stages of the injection schedule, vertical seismic profiling (VSP) will primarily be utilized, given its inherent advantages in imaging close to the borehole. Distributed acoustic sensing (DAS) possesses the capability of providing a cost-efficient, high-resolution alternative to traditional geophone methods in VSP. In this study, an evaluation is made of baseline DAS and traditional geophone VSP data from an observation well located 150 m away from the injection well. Comparative images are analyzed for quantities of injected CO₂, ranging from 27 kt to 330 kt to determine the visibility of the CO₂ plume over time. The study demonstrated that DAS VSP is a feasible technique for reservoir monitoring at the Aquistore site. The CO₂ plume should be visible near the borehole after 90 days (27 kt of CO₂) of injection, with increasing clarity over a three-year duration.

Keywords: VSP; DAS; Aquistore; monitoring; seismic; CO₂;

1. Introduction

Aquistore is a geological carbon storage project, where CO₂ is captured from a nearby coal-fired power plant (SaskPower's Boundary Dam Power Station), transported via pipeline to the Aquistore site, and injected for long-term storage into a deep (~3200 m) sandstone formation in the Williston Basin (see Figure 1 for location). Monitoring of the CO₂ plume is necessary to ensure its containment within the reservoir. Both surface seismic (e.g., Arts et al., 2004; Urosevic et al., 2010; White, 2013; Ivandic et al., 2015) and vertical seismic profiles (VSP; e.g., Ahmadi and Morozov, 2011; Coueslan et al., 2013) are commonly employed for monitoring in carbon storage projects. VSP monitoring is often preferred during the initial stages of injection due to the capability of VSP to image near the borehole with higher frequency content and greater signal to noise ratio (SNR) when compared to an equivalent surface seismic survey (O'Brien et al., 2004). Other advantages of VSP include the ability to accurately tie reflections to geological horizons intersected by the wellbore, reliably verify velocity models with a zero-offset shot, characterize downgoing energy, and reduce ghosting effects (Hardage, 2000; Kuzmiski et al., 2009). At Aquistore, VSP is currently being utilized for time-lapse monitoring during the early stages of injection.

The past fifteen years has seen the emergence of optical fiber-based seismic sensors employed in seismic surveying (Bostick, 2011), particularly in geophysical surveillance and in-well monitoring. The Aquistore project has utilized distributed acoustic sensing (DAS) for VSP employing a fiber optic cable that is permanently deployed on the outside of the casing of a deep observation well.

This study aims to investigate the feasibility of using a DAS system for time-lapse VSP monitoring of the Aquistore CO₂ storage. First, we compare DAS VSP results against data recorded simultaneously with a conventional wireline geophone system. The real DAS data are then used to estimate the degree of data repeatability that can be achieved with this system. In the second part of the study, synthetic time-lapse VSP data are calculated and processed for CO₂ fluid flow simulations that have been done for CO₂ injection quantities ranging from 27 kt to 330 kt. The resultant synthetic time-lapse VSP images are compared against the data repeatability from the real data to assess the expected visibility of the CO₂ plume over time and to evaluate the feasibility of long-term monitoring of the CO₂ plume at the Aquistore site.

Figure 1: Location map of the Aquistore CO₂ storage site (boxed area). The east-west and north-south lines selected for image comparisons are indicated as blue dots.

1.1. Geological setting

The Williston Basin is ideal for CO₂ storage and has already been employed for such in previous projects. The basin contains an abundance of depleted petroleum reservoirs which have successfully hosted injected CO₂ at various depths in the Weyburn-Midale (Saskatchewan, Canada) and Northwest McGregor (North Dakota, United States) projects. Coal seams in the basin have also been shown to retain injected CO₂ in the Lignite Field Validation Test in Burke County (North Dakota, United States).

At the Aquistore site, the basin is approximately 3300 m thick and is made up of Paleozoic carbonates and evaporites, and Mesozoic sandstones and shales. The Winnipeg and Deadwood formations reside at the bottom of the stratigraphic column sitting unconformably on the Precambrian basement. Brine-filled porous sandstones of the Winnipeg and Deadwood formations constitute the target reservoir for CO₂ injection and storage. Together, these formations are approximately 150 m thick and are capped by the Icebox shale, which as the uppermost unit of the Winnipeg formation forms the principal local sealing unit. The Prairie Evaporite in this region is ~150 m thick and occurs at a depth of ~2500 m. It forms the primary regional seal for deep CO₂ storage. Regionally, the target reservoir formations are characterized by high permeabilities of up to 1000 mD

and moderate porosities of ~11-17 % (Whittaker and Worth, 2011), whereas the Aquistore site is characterized by somewhat lower porosities and permeabilities (see Table 1).

Table 1: Petrophysical properties of reservoir units at Aquistore based on injection well log measurements made in 2013 (EERC, 2014).

Name	Top depth (m)	Median Vp (m/s)	Median Vs (m/s)	Median density (kg/m ³)	Median Effective Porosity (fractional)	Median Permeability (mD)
Upper Black Island (sandstone)	3155	4933	3090	2574	0.04	1.7
Lower Black Island (sandstone)	3170	4868	2992	2542	0.049	2.5
Deadwood D (sandstone)	3231	4868	2989	2488	0.073	23.8
Deadwood C (sandstone)	3257	4639	2774	2580	0.047	10.2
Deadwood B (sandstone)	3281	5258	2891	2746	0.033	6.0
Deadwood A (sandstone)	3297	4897	3043	2540	0.05	10.6

1.2. Distributed Acoustic Sensing (DAS)

DAS technology eliminates the need for discrete point sensors by using the fiber itself as the sensor (Mestayer et al., 2011; Miller et al., 2012). This allows the fiber to be employed as a continuous array of receivers. DAS does not require manufactured sensors as is the case in discrete sensor systems, and only a single fiber is needed (Bostick, 2000; Hornby and Burch, 2008).

In DAS, incoming seismic waves impart localized strain on the fiber, altering the backscatter of light pulses within. This requires that the fiber is coupled via friction or pressure with the surrounding medium through which the seismic wave is propagating. The amplitude and timing of the detected variation in optical backscatter is used to compute estimates of localized strain rates in the fiber, and can thus be utilized as a distributed acoustic array capable of recording thousands of channels (Shatalin et al., 1998; Mestayer et al., 2011; Miller et al., 2012). Strain rate measurements are taken by interrogating a length of the fiber (a predetermined 'gauge length') centered on a given sensor location. Sensor spacing and gauge length need not be equal, and a measurement from a given sensor corresponds to an average across the gauge length. Nearly any optical cable may be used for DAS and can remain installed down-hole for years (Mestayer et al., 2011). With permanently installed fibers, DAS offers a reduced cost alternative to traditional geophone methods, as each subsequent survey does not require any further downhole deployment, whereas repeated temporary deployment of geophones via wireline can be very costly. Also, the depth extent of the monitoring interval for DAS is generally greater than what is practical for borehole geophone wirelines. This is especially advantageous for

geological storage monitoring (as compared to monitoring oil reservoirs) where a larger depth extent is required to track possible CO₂ migration into overlying units. Repeatability is also improved with the fiber permanently deployed, as wireline geophones are subject to coupling consistency issues; i.e., the repeatability of the signal depends on how well the clamping of the geophone tool can be reproduced. Also, there is some risk of tool loss and/or wellbore compromise each time the wireline is deployed. Currently, DAS systems are limited to high sensitivity only along the longitudinal axis (Hornman, 2016). Thus a vertically oriented fiber essentially measures only vertical components of the wavefields.

2. Methods

2.1. Data Acquisition

The observation well at the Aquistore site, drilled and completed during the fall of 2012, has been used to acquire VSP data. Stainless steel tubing with a diameter of 6.35 mm (0.25 inch) containing a bundle of optical fibers (2 multimode and 2 single mode) was strapped to the casing and cemented in place during well completion. At the end of deployment, 2766 m of the total 3400 m of fiber installed was found to be operational. The optical fibers in the well provide continuous temperature monitoring (multimode fibers) and DAS recording capability.

The success of an initial test of DAS recording at the Aquistore site in May, 2013 (Daley et al., 2014) led to the execution of an expanded pre-injection baseline 3D VSP in November 2013. This survey was recorded with both a downhole geophone array and with DAS systems connected to single-mode and multimode fibers in the observation well, allowing direct comparisons to be made between the 3 VSP data sets. The single-mode fiber DAS data are used for the comparisons with geophone data in this study. Subsequent monitoring surveys are planned with the schedule dependent on the CO₂ injection schedule.

A total of 670 source locations were occupied for the 3D VSP survey. A semi-regular 3000 x 3000 m grid was used with nominal in-line and inter-line spacings of ~72 m and ~144 m, respectively. The original shot grid was designed based on 924 shot points, a minimum of 30-fold coverage at the reservoir depth for a 60-level geophone array deployed from 1650 m to 2650 m depth, and assuming bin dimensions of 36 x 36 m for processing. The regular grid was modified to accommodate inaccessible sites at the surface. Also, the total number of shots was reduced (to reduce costs) by eliminating shots and increasing the shot spacing at the larger offsets from the observation well. Sources consisted of single 1 kg dynamite charges located at a depth of 15 m.

The wireline geophone array consisted of 57 three-component (analogue electro-mechanical sensors) geophones installed with a vertical spacing of 15 m, centered at a depth of 1900 m. The geophones measure

particle velocity, and were installed in a Sercel Maxiwave tool, which was clamped in the observation well. The geophones have an output of 0.402 V/cm/s at 0.47% damping, and a resonant frequency of 15 Hz. The DAS data were acquired with a Silixa iDAS system using a 10 m gauge length, and preprocessing of the raw optical data to produce seismic data was done by Silixa LTD. The raw optical data which are a measure of strain rate were processed to emulate a seismic sensor spacing of 2 m resulting in 1383 traces per shot over the 2766 depth interval (Harris et al., 2015). This response can be converted to particle velocity by first integrating the traces in the time domain to convert strain rate to strain. This step is termed rebalancing since it effectively boosts the higher frequencies. Scaling this strain value by the propagation speed along the fiber, or apparent velocity, converts the response to particle velocity, as explained in Daley et al. (2015).

2.2. Data Processing

Each shot gather was processed using similar processing flows for both traditional geophones and DAS data. In this way controlled comparisons could be made throughout the analysis. Generally, the processing flow consists of the following: spherical divergence correction, spiking deconvolution, notch and low-pass filtering, and f - k filtering to remove the downgoing wavefield. A 2D Kirchhoff migration program employing the formulation of Schneider (1978) and Dillon (1988) was written to create 2D images of the subsurface at specified azimuths. A 1D isotropic velocity model was utilized in this process, and was based on sonic log measurements from the observation well, and first arrivals in a zero-offset shot. Travel time computations were performed with a 3D eikonal solver (Hole and Zelt, 1995). Multiple gathers were then stacked to build coherent images using spatial bins of dimensions 10 x 10 m in the horizontal and vertical dimensions, respectively. A dip-limited migration aperture was maintained at 6 ° due to the flatness of the stratigraphy. Prior to migrating the DAS data the response was converted to particle velocity so that the final image was geophone equivalent.

3. Seismic Results

3.1. Traditional geophones versus DAS

Figure 2: Comparison of raw vertical-component geophone data (left) and single-mode DAS data (right) for a single shot gather in the depth range of 1455 – 2295 m, where the receiver lines overlap. Of the 57 geophones, 3 did not record and yielded dead traces, resulting in 54 geophone traces and 963 DAS traces over this interval. The corresponding shot point is 46083740, which is located at a distance of 470 m from the observation well.

Figure 3: Comparison of raw DAS seismic data and vertical-component geophone data for a single shot gather. The corresponding shot point is 46083740 which is located at a distance of 470 m from the observation well. The geophone traces replace the DAS data in the depth range of 1455 – 2295 m. There are 963 single-mode DAS traces spaced at 2 m intervals and 57 vertical-component geophone traces spaced at 15 m intervals in the plot. Of the 57 geophones, 3 did not record and yielded dead traces. Blue and red rectangles show the signal and noise windows, respectively, used for Figure 4 (figure modified from Harris, 2015).

Raw wireline geophone data and raw DAS data are compared in Figures 2 and 3. A direct comparison over the same depth interval (Figure 2) highlights the direct arrival and various reflections. The reservoir reflections, found within the yellow box, are faintly above the noise in the DAS section. In Figure 3, the reflections in the DAS data generally decay in amplitude as depth increases, and have visibly lower signal than the geophones at equivalent depth. One of the factors contributing to this pertains to the directivity of the DAS system. The fibers are primarily sensitive to longitudinal strain (vertical in this case), and deeper sensors record P-waves approaching at larger angles than do their shallower counterparts (Parker et al., 2014). Also visible in Figure 3 is the abrupt decrease in signal strength at ~1000 m. This is a result of a coupling issue related to the quality of the cement job.

The frequency responses of geophones and DAS are shown in Figure 4. The geophone signal-to-noise-ratio (SNR) is up to 45 dB whereas a maximum SNR of 15 dB is observed for the DAS data. Also, the bandwidth where $\text{SNR} > 1$ is larger for the geophone data (~5-150 Hz) as compared to the DAS data (~0-80 Hz).

In the case of the DAS data, the higher spatial sampling (relative to that of the geophones) can be utilized to improve SNR by multi-trace data summation methods (i.e., “stacking”), but at the expense of lowering spatial sampling. The wider bandwidth of the geophone data implies that higher resolution should be achievable with this method.

Figure 4: Signal and noise power spectra for geophone data (left) and DAS (right). As shown in Figure 3, the data windows for the noise calculations were chosen to exclude downgoing primary energy.

Figure 5 shows a comparison of VSP images for a 2D east-west section produced from the single-mode DAS data and the vertical-component geophone data. These VSP images are superposed on a comparable section modified from the 3D seismic volume of Roach et al. (2014) which was computed using data from a surface-based seismic survey. The DAS and geophone images were computed using the migration program previously described. Upgoing wavefields from 8 shot gathers located west of the observation well were used. The reflections in the VSP images are well aligned with those of the surface-based image, with maximum deviations of 40 m in the deeper reflections, an acceptable difference since the 3D seismic volume was converted to depth using an independent velocity model. Though geological boundaries are not as well defined in these VSP images compared to the surface-based seismic image, clarity is expected to improve with more sophisticated processing and the inclusion of more shots in the stacking process during 3D imaging.

Two characteristics of the DAS versus geophone images in Figure 5 are noteworthy. The DAS image provides more extensive spatial imaging above the reservoir as well as a smaller “blind spot” at depths exceeding the recording depth. These effects are the result of the larger depth interval over which the DAS records the seismic wavefield as compared to the geophone array. Comparable depth coverage could be achieved by the deployment of geophones over an equivalent depth interval but is somewhat impractical.

Figure 5: 8-fold migrated images of the single-mode DAS and vertical-component geophone VSP data (grey) with migrated section of surface data (green/blue/red) along the east-west line shown in Figure 1. Locations of various geological formations are labelled (modified from Harris et al., 2015). Geophone image shows same area as the DAS image, but has been shifted west for comparison purposes.

3.2. Seismic Repeatability

Time-lapse monitoring is fundamentally based on the repeatability of the imaging process from survey to survey. The non-repeatability of the data (in acquisition and processing) provides a lower limit on the injection-induced geological changes that can be detected. Estimates of data repeatability are most easily obtained by comparison of repeat surveys (e.g., White et al. 2015). In the absence of equivalent data from repeat VSP surveys, in this study we utilize two shots from the November 2013 pre-injection baseline survey that are located within 10 m of each other and ~1000 m from the observation well where the wavefield was recorded. The premise for this comparison is that shot points that are located very close to each other relative to the shot-

receiver offset should yield very similar although not identical data. The data from the two shots underwent a trace-by-trace cross-equalization process before a direct comparison was made. This included the application of time and phase shifts, frequency spectrum shaping filters, and amplitude scaling factors derived from RMS measurements. Each process utilized reference windows taken well above the reservoir zone. Data differences are measured using a normalized RMS (or nRMS) amplitude difference defined as:

$$nRMS = \frac{2 \times RMS_{2-1}}{RMS_1 + RMS_2}$$

This quantity ranges between 0 and 2, corresponding to identical and reversed polarity data, respectively (Kragh and Christie, 2002). A map of nRMS values was computed using a 50 m sliding window and was considered to represent a lower bound on the repeatability of the DAS surveys.

Figure 6 shows the two migrated shot gathers used for this comparison as well as their amplitude differences before and after cross-equalization. The cross-equalization was successful in aligning reflections and reconciling amplitudes throughout the illuminated area, albeit most drastically above the reservoir.

The nRMS of the amplitude difference calculated for these data is shown in Figure 7A. Most of the nRMS values are below 0.5, although significantly higher values are seen near the edges of the illuminated area and at 2550 m. The edges are expected to exhibit higher nRMS values as these locations correspond to very low amplitudes as visible in Figure 6. The RMS of the differences here becomes exaggerated when normalized by these amplitudes. A histogram of the nRMS values is shown in Figure 7B, where the mean nRMS is 0.52, and the mode is 0.29. The mean has been skewed by the high nRMS values near the edges and thus the mode may be taken as a more representative reservoir value. There does not appear to be any significant change in repeatability with respect to depth until below the reservoir.

Figure 6: 1000 m offset shots from the November 2013 pre-injection baseline survey used for repeatability analysis. Shot 45364016 (middle) underwent trace-by-trace cross-equalization to align horizons and match amplitudes to shot 45603968 (left). Resulting amplitude difference images are shown on the right. Observation well is located at 0 m.

Figure 7: A) 50 m window nRMS map of amplitude differences between shots 45364016 and 45603968 of the November 2013 pre-injection baseline survey. Observation well is located at 0 m. B) Histogram of nRMS values shown in A.

3.3. Seismic modeling

Seismic modeling has been conducted to assess how well the CO₂ plume may be imaged at various stages of the injection process. Time-lapse VSP differences were calculated for a range of cumulative CO₂ quantities and were compared against the levels of expected repeatability from the field data to assess the likely effectiveness of time-lapse VSP monitoring.

The seismic model used was based on the results of flow simulations through a petrophysical model. The petrophysical model constructed for the site is a stratigraphic representation (7.6 x 7.6 m cells with varying depth dimensions) spanning 34 km² and was built using well log information and 3D surface seismic data. Layers within the reservoir zone comprised 2D stochastic realizations of porosity and permeability (Peck et al. 2014).

Flow simulations were performed by the Energy & Environmental Research Center (EERC, 2014), using the seismic model and the Computer Modelling Group (CMG) fluid flow simulation software, to determine pressure and fluid saturation distributions within the reservoir. The injection scenario considered is for 3 years of injection at 301t/day as it best corresponds to the proposed injection schedule. Flow simulation results for injection periods of 90 days, 1 year, 2 years, and 3 years are evaluated, corresponding to cumulative injection volumes of 27 kt, 110 kt, 220 kt and 330 kt of CO₂, respectively. Figure 8 shows the CO₂ saturation modeled over the 3 years of injection. The injected CO₂ is concentrated in three depth intervals (A, B, C in Figure 8) within the reservoir ranging in thickness from 20 to 60 m. In each interval, the width of the CO₂ plume and the CO₂ saturation increase with total quantity of CO₂ injected. The uppermost plume (interval A) is relatively narrow (240-560 m) and has generally low-to-moderate CO₂ saturations. The CO₂ plumes in intervals B and C are much wider (680-1680 m) and have moderate-to-high CO₂ saturations. The lowermost interval (C) accepts the most CO₂.

The flow simulation results were then used to assemble the seismic models in GOCAD software, which involved assigning P and S-wave velocities and bulk densities. The 3D model had dimensions of 3500x3500x3700 m resulting in 326 million 25 m³ voxels. The baseline seismic model (i.e., corresponding to the initial reservoir state) was constructed utilizing P/S-wave velocities and densities from sonic and density log measurements above the reservoir. The sonic log was known to be unreliable from 0-975 m, and therefore P-wave velocities were computed from VSP first arrivals, and S-wave velocities were calculated assuming a Vs:Vp ratio of 1:1.73 in this range. In the reservoir, velocity and density values were computed from porosity via a recursion relation. Seismic models were constructed for each of the injection periods listed above. The changes in seismic properties due to variable CO₂ saturation in the reservoir were determined using the Gassmann model for fluid substitution (Gassmann, 1951; Smith et al., 2003). The properties of impermeable reservoir shale layers were left unchanged in all scenarios.

A 3D finite-difference seismic modeling algorithm, SOFI3D (Bohlen, 2002), was used to generate synthetic data corresponding to the same source-receiver geometry as in the pre-injection baseline VSP survey. The input parameters are listed in Table 2. Shot gathers were calculated for each point source along north-south and east-west lines, as recorded by 554 downhole sensors. These sensors were spaced 5 m from each other and spanned the same depth range as the DAS fibers. The computation time for each shot gather was ~1 hour running on a CRAY cluster utilizing 490 CPUs.

Figure 8: Modeled CO₂ saturation (fractional) in reservoir after 90 days, 1 year, 2 years, and 3 years of CO₂ injection at a rate of 301 t/day (from top to bottom). Injection well on the left, observation well on the right.

Table 2: Finite Difference Model Parameters (Modified from Melanson, 2015)

Software	SOFI3D
Finite-difference Coefficients	Holberg, 8 th order spatial operator, 2 nd order temporal operator
Minimum Velocity	P: 2450 m/s, S: 1416 m/s
Dimensions in Voxels (East, North, Depth)	700, 700, 740
Voxel Resolution (East, North, Depth)	5 m, 5 m, 5 m
Number of Receivers	554
Recorded Particle Motions	Particle Velocity (x,y,z)
Wavefield Propagation Time	3 s
Timesteps, Sample Period	10000, 0.0003 s
Source Signal	Ricker wavelet, point source, 38 Hz center frequency
Absorbing Boundary	Perfectly-matched layers, 30 voxels, 8% decay per voxel
Outputs	VSP Shot-gathers, Logs

Figure 9: DAS 400 m offset shot gather recorded in the field (left) versus equivalent synthetic shot gather (right). Probable reservoir reflections bound by yellow lines.

The raw synthetic shot gathers (see Figure 9 for an example) from these simulations were f - k filtered to remove downgoing energy and S-waves, followed by 2D Kirchhoff depth migration and stacking. Multiples appear below the reservoir reflections (Figure 9 (right)), as there is no primary reflectivity within the basement in the models.

A north-south shot line (Figure 1) traversing the injection well was selected for comparisons between the different synthetic time-lapse VSP images. The baseline image was subtracted from each of the post-injection images to delineate the signature of the CO₂ plume over time. Then nRMS maps were computed in the reservoir, using a 10 m sliding window, to be taken as a measure of the RMS contrast between the baseline and post-injection reservoir.

Figure 10 (A) shows the migrated baseline image obtained from 15 synthetic shots spaced at ~144 m along the north-south line. The reservoir is imaged out to a radius of ~900 m from the borehole, and down to a depth of 3450 m (well into the Precambrian basement). The seismic image is calibrated against a well-based

synthetic seismogram (black trace in Figure 10) to ensure accurate depth registration of the image. At the reservoir level, prominent reflections from the top (Icebox shale at ~3120 m, negative peak) and bottom (Precambrian at ~3350 m, positive peak) of the reservoir correlate well. However, note that the reflection from the bottom of the reservoir apparently extends beneath the Precambrian interface (to ~3400 m). This is due to the sidelobes associated with the band-limited seismic wavelet: i.e., it is a result of limited vertical resolution. Furthermore, there is also apparent reflectivity observed at greater depth in the seismic image even though the seismic model contains no changes in impedance below the Precambrian boundary (3350 m). These are the result of intrabed multiples and potentially incomplete cancellation of converted phases (e.g., P-to-S conversions) during data processing. The image is poorest near the well at depths below the bottom of the recording array where a 'blind spot' occurs which is inherent to the VSP imaging geometry for offset source locations (e.g., Dillon and Thomson, 1984). This effect can be countered by widening the migration aperture, however it would be at the expense of SNR when applied to field data (Yilmaz, 1987).

1

2

Figure 10: Migrated synthetic images, showing seismic amplitude (scaled particle velocity), of the north-south line

3

shown in Figure 1 with reservoir boundaries. A) Baseline image. The observation well is marked by a vertical line

overlain with a single seismic trace computed by convolving the sonic log from the observation well with a 38 Hz Ricker wavelet. B), C) Post-injection images after 2 and 3 years, respectively.

Figure 10 (B,C) compares the baseline VSP image at the reservoir level with comparable images for the cases of 2 and 3 years of CO₂ injection. Visual inspection of these images shows that, even in the presence of large quantities of CO₂, changes are very subtle. To accentuate the dissimilarities, the corresponding time-lapse difference images for each of the injection times are shown in Figure 11. As expected, there are no amplitude differences above the reservoir (< 3120 m) and most of the amplitude residual is confined to the reservoir zone (3120-3350 m). Marked amplitude differences in the depth interval immediately below the Precambrian interface (3350-3400 m) are artifacts associated with the sidelobes of the Precambrian reflection as explained above. Smaller amplitude differences at greater depth are most likely due to changes in the intra-reservoir multiples (travel times and amplitudes) that appear within the basement due to their longer travel times and the incomplete removal of converted-wave energy during migration and stacking. Throughout the injection period, the amplitude residuals tend to increase most prominently in the bottom and below the reservoir and, after 3 years, the plume reaches the lateral extent of the illuminated zone.

Figure 12 shows the nRMS maps of the amplitude residuals. After 27 kt of CO₂ injection, nRMS values in the reservoir near the borehole exceed 1.0. Then RMS values steadily increase until 330 kt of CO₂ injection where nRMS > 1.0 as far as 700 m south of the borehole. The largest nRMS anomalies in Figure 12 occur below the zone (>3400 m) where we expect to see the effects of CO₂ presence in the reservoir (see label D). As can be seen on plots of RMS amplitude differences (Figure 13), this zone corresponds to an interval of very small amplitude differences. These small amplitude differences are accentuated in the plot of nRMS amplitude differences as they are normalized by correspondingly small amplitude reflections (Figure 10) in this zone. This demonstrates the importance of assessing nRMS values in combination with RMS values.

Figure 11: Migrated synthetic time-lapse difference images after 90 days, 1 year, 2 years, and 3 years of CO₂ injection at a rate of 301 t/day (from top-left to bottom-right). Amplitude differences are scaled by a factor of ~6 relative to Figure 10. Stratification of the plume is indicated by four labels, A-D (Compare with Figure 8).

Figure 12: 10 m window nRMS maps of the amplitude residuals of the time-lapse difference images shown in Figure 11. Plume locations from Figure 8 are shown as black outlines.

Figure 13: 10 m window RMS maps of the amplitude residuals of the time-lapse difference images shown in Figure 11. Note that amplitudes are scaled by a factor of ~ 6 relative to Figures 10 and 10A.

4. Discussion

The nRMS maps of amplitude differences (Figure 12) can be compared with the modeled CO_2 distributions (Figure 8). To facilitate the comparison, outlines of the CO_2 plumes from Figure 8 are superposed in Figure 12. The stratification of CO_2 within distinct high-permeability zones (depths A, B, C) and the width of these zones are well captured in the seismic images, albeit with poorly defined borders. The uppermost zone A is the least prominent in the seismic images due to its low porosity and resulting relatively lower CO_2 saturations. Low associated nRMS values imply that only under excellent repeatability conditions will this zone be imaged. Zones B and C have associated large nRMS values indicating that they will be well imaged even with moderate repeatability. The apparent continuation of the zone C nRMS anomaly below the Precambrian surface is primarily due to a limitation in seismic resolution; i.e., the 38 Hz zero-phase wavelet used in modelling has a dominant wavelength of ~ 100 m at the reservoir depth (compare with Figure 10a). The significance of Zone D in the nRMS image is discounted based on a comparison with the corresponding RMS image which shows this is a zone characterized by very low amplitudes.

Repeatability estimates from the real field data (Figure 7) suggest that injection-induced nRMS differences will have to exceed ~ 0.3 in order to be visible. The time-lapse difference nRMS values (Figure 12) in the reservoir associated with the presence of CO₂ generally exceed this value for each of the four injection volumes considered. After 90 days (27 kt CO₂), zones B and C meet this visibility criteria near the borehole, whereas zone A will likely not be visible until 1 to 2 years (110 kt to 220 kt CO₂). It appears that saturation values above ~ 0.3 are well imaged in Figures 11 and 12, and consistently meet the visibility criteria.

It should be noted that the repeatability inferred from the RMS values calculated in this study is likely underestimated for several reasons: 1) The comparison presented is for single shot gathers, so random noise likely contributes far more than for a multi-fold (i.e., stacked) image that is the end product of standard data processing; 2) outliers in the difference images can be exaggerated in nRMS images if the amplitudes are regionally low; and 3) the shots were located 1000 m from the observation well, and thus have lower SNR than closer shots which would be included in producing a multi-fold VSP image. Due to the fact that the shots were not collocated, but ~ 10 m apart, there is an expected deviation in signal that was not quantified in this study.

The repeatability of dynamite shots in the vicinity of the Aquistore site has been demonstrated in previous studies. White et al. (2015) report a mean nRMS value of 0.55 and standard deviation of 0.17 for raw data from 261 repeat shot gathers that were recorded by a permanent surface array of 630 geophones at the Aquistore site. The baseline and monitor surveys were acquired in March 2012 and May 2013, respectively. Roach et al. (2015) achieved a global nRMS value of 0.07 for migrated stacks of these data. The nearby Weyburn field which employed dynamite sources also maintained good repeatability (nRMS 0.30-0.34) for at least 4 surveys conducted over a period of 7 years (White, 2013). We expect that comparably low nRMS values may be achieved for fully processed, multi-fold time-lapse VSP images for the Aquistore site. If this is the case, then the plume would meet the visibility criteria for its entire volume for any of the cases shown above.

The advantages of traditional 3C geophones as compared to DAS for VSP recording include a higher frequency response, higher SNR, and omni-directional sensitivity. However, DAS has the advantage of providing an order-of-magnitude increase in the number of sensors and a larger recording aperture which results in imaging over a larger depth interval. The latter is certainly an advantage for CO₂ monitoring where surveillance of the layers overlying the reservoir is essential. DAS also has the advantage of requiring less effort in field deployment as compared to wireline geophones particularly in the case where fiber cables were permanently installed during well-completion. In this study, DAS SNR (and hence data repeatability) prove to be adequate for the purposes of time-lapse imaging in spite of the lower sensitivity of DAS as compared to traditional geophones. As next generation DAS technology is developed and post-processing methods improve, the sensitivity discrepancy between DAS and traditional geophones will hopefully be reduced.

5. Conclusions and Outlook

Synthetic time-lapse VSP amplitude differences have been calculated for fluid-flow simulations of CO₂ injection in a deep reservoir for quantities of CO₂ ranging from 27 kt to 330 kt. Comparison of the associated nRMS values against DAS data repeatability estimated from actual field data indicates that individual decameter-thick CO₂ layers in the reservoir should be visible for total injection quantities of as little as 27 kt of CO₂. Imaging of the CO₂ layers should be robust for the lower part of the reservoir as this is where the majority of the injected CO₂ resides, resulting in strong seismic differences. In contrast, CO₂ within the upper reservoir occurs at lower saturations and in a lower porosity zone with the result that visibility of the plume will likely be confined to a volume near the borehole until later in the injection timeline. Due to the ability of VSP to image near the wellbore with greater frequency range and SNR as compared to surface seismic, VSP will be employed to monitor the CO₂ during the early stages of injection, whereas surface surveys will likely be used in later phases to characterize the greater expanse of the CO₂ plume. At future stages of processing and imaging, comparisons will continue to be made with the surface seismic results to evaluate the assumption that VSP will provide better plume characterization in the reservoir. The first post-injection VSP survey is tentatively scheduled for March 2016, when the reservoir is expected to contain more than 27 kt (90 days) of CO₂. In future seismic analysis, it is clear that measures should be taken to better image the CO₂ plume. This includes characterizing and removing inter-bed multiples, wavelet-processing to attenuate outer lobes, time-variant time shifts to account for the altered velocity profile introduced by the CO₂, and close attention to the removal of undesirable wave-modes. Also, it will be necessary to expand the processing and imaging to 3D.

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Figure Captions

Figure 1: Location map of the Aquistore CO₂ storage site (boxed area). The east-west and north-south lines selected for image comparisons are indicated as blue points.

Figure 2: Comparison of raw vertical-component geophone data (left) and single-mode DAS data (left) for a single shot gather in the depth range of 1455 – 2295 m, where the receiver lines overlap. There are 54 geophone traces, and 963 DAS traces over this interval. The corresponding shot point is 46083740, which is located at a distance of 470 m from the observation well.

Figure 3: Comparison of raw DAS seismic data and vertical-component geophone data for a single shot gather. The corresponding shot point is 46083740 which is located at a distance of 470 m from the observation well. The geophone traces replace the DAS data in the depth range of 1455 – 2295 m. There are 963 single-mode DAS traces spaced at 2 m intervals and 57 vertical-component geophone traces spaced at 15 m intervals in the plot. Of the 57 geophones, 3 did not record and yielded dead traces. Blue and red rectangles show signal and noise windows, respectively, used for Figure 4 (Harris, 2015).

Figure 4: Signal and noise power spectra for geophone data (left) and DAS (right). As shown in Figure 3, the data windows for the noise calculations were chosen to exclude downgoing primary energy.

Figure 5: 8-fold migrated images of the single-mode DAS and vertical-component geophone VSP data (grey) with migrated section of surface data (green/blue/red) along the east-west line shown in Figure 1. Locations of various geological formations are labelled (modified from Harris, 2015). Geophone image shows same area as the DAS, but has been shifted west for comparison purposes.

Figure 6: 1000 m offset shots from the November 2013 pre-injection baseline survey used for repeatability analysis. Shot 45364016 (middle) underwent trace-by-trace cross-equalization to align horizons and match amplitudes to shot 45603968 (left). Resulting amplitude difference images are shown on the right. Observation well located at 0 m.

Figure 7: A) 50 m window nRMS map of amplitude differences between shots 45364016 and 45603968 of the November 2013 pre-injection baseline survey. Observation well is located at 0 m. B) Histogram of nRMS values shown in A.

Figure 8: Modeled CO₂ saturation (fractional) in reservoir after 90 days, 1 year, 2 years, and 3 years of CO₂ injection at a rate of 301 t/day (from top to bottom). Injection well on the left, observation well on the right.

Figure 9: DAS 400 m offset shot gather recorded in the field (left) versus equivalent synthetic shot gather (right). Probable reservoir reflections bound by yellow lines.

1 Figure 10: Migrated synthetic images, showing seismic amplitude (scaled particle velocity), of the north-south line
2 shown in Figure 1 with reservoir boundaries. A) Baseline image. The observation well is marked by a vertical line
3 overlain with a single seismic trace computed by convolving the sonic log from the observation well with a 38 Hz
4 Ricker wavelet. B), C) Post-injection images after 2 and 3 years, respectively.

5 Figure 11: Migrated synthetic time-lapse difference images after 90 days, 1 year, 2 years, and 3 years of CO₂
6 injection at a rate of 301 t/day (from top-left to bottom-right). Amplitude differences are scaled by a factor of ~6
7 relative to Figure 10. Stratification of the plume is indicated by four labels, A-D.

8 Figure 12: 10 m window nRMS maps of the amplitude residuals of the time-lapse difference images shown in
9 Figure 11. Plume locations from Figure 8 are shown as black outlines.

10 Figure 13: 10 m window RMS maps of the amplitude residuals of the time-lapse difference images shown in Figure
11 11. Note that amplitudes are scaled by a factor of ~6 relative to Figures 10 and 10A.