3D VSP ACQUIRED WITH DAS ON TUBING INSTALLATION: A CASE STUDY FROM THE CO2CRC OTWAY PROJECT

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ABSTRACT

Distributed Acoustic Sensing (DAS) can revolutionize the seismic industry by using fiber-optic cables installed permanently to acquire on-demand VSP data at fine spatial sampling. With this, DAS can solve some of the issues associated with conventional seismic sensors. Studies have successfully demonstrated the use of DAS on cemented fibers for monitoring applications, however, such applications on tubing deployed fibers are relatively uncommon. Application of tubing deployed fibers is especially useful for preexisting wells, where there is no opportunity to install a fiber behind the casing. In the CO2CRC Otway Project, we acquired a 3D DAS VSP using a standard fiber-optic cable installed on the production tubing of the injector well. We aim to analyze the quality of the 3D DAS VSP on-tubing, as well as discuss lessons learnt from the current DAS deployment. We show the limitations associated with the DAS on-tubing, as well as ways to improve the quality of the datasets for future surveys at Otway. Due to the reduced coupling and the long fiber length (~20 km), the raw DAS records show a high level of noise relative to the signal. Despite the limitations, the migrated 3D DAS VSP data recorded by cable installed on tubing is able to image interfaces beyond the injection

depth. Furthermore, we discuss that the signal to noise ratio might be improved by reducing the fiber length.

INTRODUCTION

The installation of permanent receivers in wells is a common recent trend in the seismic industry that allows for constant reservoir surveillance (Lumley, 2001). Installing permanently conventional receivers, however, is significantly expensive and it involves the associated risk of electronic equipment failure. Distributed Acoustic Sensing (DAS) avoids many of the problems associated with conventional seismic sensors, utilizing an unobtrusive small sensing element that can be permanently deployed in the wellbore annulus. Optical fiber is remarkably robust and avoids the risks associated with downhole electrical and mechanical components.

DAS data is acquired by connecting a fiber-optic cable to an Interrogator Unit (IU). The IU sends a series of laser pulses along the fiber. DAS senses changes of strain on the cable by analysing variations in the backscattered light (Parker et al., 2014). The use of DAS in borehole seismic, in particular, offers certain advantages over geophones and hydrophones, such as long equipment survivability, dense spatial sampling, and full well coverage, making it especially suited for permanent reservoir monitoring. Though DAS is a rapidly developing technology, it still has certain disadvantages, such as lack of broadside sensitivity.

DAS has been tested in a wide variety of field applications, including surface and offset VSP acquisitions (Correa et al., 2017a; Daley et al., 2013; Miller et al., 2012; Willis et al., 2016), as well as hydraulic fracturing, microseismic detection, and earthquake detection (Bakku et al., 2014a; Lindsey et al., 2017; Webster et al., 2013). Successful results have been published when using DAS for reservoir monitoring, showing that DAS presents enough repeatability for time-lapse applications (Harris et al., 2017; Mateeva et al., 2014; Mestayer et al., 2011).

Fiber-optic cables can be permanently installed in boreholes, either cemented behind the casing or deployed on the production tubing. Cemented fiber-optic cable installations provide better coupling to the formation, thus resulting in higher signal-to-noise ratio. However, in some cases, it might be operationally impractical to cement the cable, particularly when using a preexisting well. Additionally, DAS can be acquired using a fiber optic cable deployed clamped on the well tubing. Deploying the cable on the tubing is a semi-permanent deployment that can avoid some of the complexity of cementing a cable outside the long casing string (Li et al., 2015). The installation on tubing avoids interfering with perforation operations, and the cable can be retrieved and replaced in case it's damaged. Barberan et al. (2012), Didraga (2015), and Daley et al. (2016) have demonstrated that fibers deployed on tubing can be used to acquire offset and walk-away VSP data. Mateeva et al. (2017) demonstrated the feasibility of using DAS on tubing installation for 4D VSP.

At the CO2CRC Otway Project – described in the next section – we hope to use DAS to detect the time-lapse seismic signal of an injected CO_2 mixture. For this experiment, approximately 40 km of fiber-optic cable were deployed on the surface, as well as on the tubing of the injector well. In general, tubing installations of fiber-optic cable usually present poor coupling, which leads to low quality of the DAS data. Moreover, the future stage of the project focuses on multi-well monitoring where several wells will be drilled and instrumented with DAS (Jenkins et al., 2017) - being able to use the current DAS on tubing would be beneficial as it would increase the seismic fold during the next monitoring stages.

We analyze the results of a 3D VSP data acquired with DAS on-tubing installation at Otway. We investigate the quality of the data acquired with the current tubing deployed DAS and discuss whether it is able to image the target interval. Also, we discuss the limitations associated with the current installation and what can be done to improve data quality for future surveys. As DAS is still considered an emerging technology, we believe this paper contributes to the broader knowledge of the method.

CO2CRC OTWAY PROJECT

CO2CRC Otway Project is Australia's first demonstration of the deep geological storage of carbon dioxide. The project provides technical information on the injection, storage and monitoring of carbon dioxide that will influence national policy and industry while providing assurance to the community. The site of the project is located in the southwest of the state of Victoria, in Australia (Figure 1). The Otway Project is, to this date, concluding its Stage 2C and initiating the Stage 3.

The Stage 1 of the Otway Project, completed in 2010, utilized conventional surface 4D seismic in conjunction with 4D VSP acquired with geophones in the CRC-1 well to conduct primarily assurance monitoring of a CO_2/CH_4 gas injection into a depleted gas reservoir at 2 km depth, into the Waarre C Formation (Urosevic et al., 2010). In addition to the monitor surveys, a check-shot was acquired in 2010 in the CRC-2 well with the objective to characterize the well surroundings as CRC-2 would become the injector for the next stage of the project, Stage 2C.

The Stage 2C of the project is focused on the monitoring of 15 kt injection of a CO_2/CH_4 gas mixture into a saline aquifer at approximately 1500 m depth, in the Paaratte Formation. The Paaratte Formation presents medium to high permeability sands intercalated with carbonaceous mud rich lithologies. For this stage, the baseline and all planned five monitor surveys have been acquired to this date.

The future stage of the Otway Project, Stage 3, focuses on multi-well monitoring approach by using mostly downhole equipment in wellbores (Jenkins et al., 2017). For this, permanently installed DAS and permanent sources will be used. In this stage, DAS will be the primary receiver array in all wells.

To monitor the evolution of the injected carbon dioxide during Stage 2C, a 3D seismic monitoring array was installed on-site in February-March 2015. The permanent seismic array consists of 909 conventional geophones and approximately 40 km of fiber-optic cable for DAS. The geophones were buried at 4 m depth at 15 m interval along 11 surface lines; the fiber cable was deployed on the tubing in the injection well (CRC-2) and then along the 11 surface lines, buried at 0.8 m depth (same trench as geophones' cables) (Pevzner et al., 2017). Two permanent vibrators are also installed on-site (Freifeld et al., 2016). In addition to the permanent array, 3-component geophone VSP shuttles and two 26,000 lb vibroseis sources are also used in the monitoring program.

The deployed ~40 km of fiber cable was roughly split in half and each half deployed continuously. One section of the fiber cable (~20 km) was deployed clamped on the tubing of the CRC-2 well in a loop, and along four surface lines. The other section of fiber cable was deployed along the remaining surface lines. The fiber-optic cable used along the well was a standard straight single-mode fiber.

To image the development of the gas plume, the monitoring strategy for Stage 2C consists of acquiring a combination of 3D surface seismic, 3D VSP, and offset VSP surveys. A baseline survey was acquired in March 2015. The first monitor survey was acquired after the injection of 5 kt; the second monitor after the next 5 kt of CO_2 fluid; the third monitor was acquired after the final injection of 5 kt, completing 15 kt of the injected gas. A fourth monitor survey was acquired after 1 year post injection in January 2017, and the fifth monitor survey was acquired 2 years post injection, in March 2018.

The 3D surface seismic acquired with the geophones was the main monitoring tool (Pevzner et al., 2017), in conjunction with the 3D VSP acquired with 3-component geophones in the monitor well (CRC-1) (Tertyshnikov et al., 2018). Simultaneously with the main surveys, 3D surface seismic was acquired with surface DAS installation (Correa et al., 2017b; Yavuz et al., 2016), and 3D DAS VSP with the fiber installation on tubing in the CRC-2 well. 3D DAS VSP on tubing was not acquired for the fifth monitor survey due to logistic issues on-site. The injection in the CRC-2 well was shut down for the acquisition of the monitor surveys.

In the future Stage 3, an early appraisal well (CRC-3) was drilled in early 2017 (Figure 1). A fiber-optic cable was installed cemented behind the well casing along the entire length of the well (~1600 m) and back. A field trial was conducted with the cemented fiber installation, where a series of offset VSP surveys were acquired using DAS and geophones. The field trial shows that DAS VSP acquired with the cemented installation presents similar signal-to-noise ratio to geophone VSP (Correa et al., 2017a). As a consequence of those results, DAS became a strong component in the monitoring for the next Stage 3 of the project. For this stage, we aim to monitor the injected plume by acquiring multi-well DAS VSP. Therefore, we hope to be able to add the current on-tubing DAS to the set of monitoring wells during Stage 3, as it would increase the seismic fold and imaging range.

DATA ACQUISITION OF 3D VSP DAS ON TUBING

In this paper, we focus on the VSP data acquired with DAS on tubing installation in the CRC-2 well during Stage 2C of the project. The CRC-2 well is a 1500 m deep vertical well, cased with 5.5 inch diameter, and fluid filled from top to bottom. The fiber was installed clamped on the tubing, along the entire extent of the well. The cable was looped at the bottom, and returning to the top of the well, where it was spliced to the surface fiber array. A DAS IU (Silixa iDASv2) was connected to the borehole end of the fiber, interrogating approximately 20 km of fiber-optic cables (the well deployment and part of the surface deployment). The IU was located close to the CRC-2 well. The installed fiber cable is straight single-mode. Temperatures in the well don't exceed ~56 ˚C, therefore, hydrogen darkening is unlikely at this point.

As DAS was a technology on trial during Stage 2C, we experimented different acquisition parameters during each survey. The acquisition parameters in the DAS IU, such as power of the optical transducer, and brightness of the emitted light, were set differently for each survey, which ultimately degraded the signal repeatability. For baseline, monitor 1, monitor 2, and monitor 3 surveys, the acquisition parameters were chosen in order to optimize the 3D surface seismic acquisition. However, this compromised the quality of the 3D DAS VSP, as the DAS box was interrogating 20 km of cable while the well section was only in the first 3 km of the fiber cable.

Another important issue caused by the length of the cable is the maximum possible laser pulse repetition frequency (PRF). In order for the light to reach the end of the fiber and return, the maximum PRF for 20 km is ~5 kHz (considering speed of light in glass of 200×10^6 m/s), while for 3 km we could increase it by a factor of almost seven. The actual PRF used in the acquisition was only 3 kHz due to the software limitations. During the fourth monitor survey, the parameters of the DAS box were changed to optimize the quality of the borehole fiber array; this, however, did not include PRF as no changes in splicing of the array was performed and the length of the fiber remained the same.

Due to the above history, this study focuses on the 3D VSP acquired with tubing deployment during the fourth monitor survey of the Stage 2C, which was optimized for well acquisition. The DAS VSP data was acquired at every 1 m spatial sampling. We used a 26,000 lbs vibroseis truck as the seismic source, with single linear 24 s sweep from 6 to 150 Hz per shot point. The 3D survey was acquired with a single sweep per shot point, in total approximately 3000 shots at every 15 m (Figure 1).

DAS RECORDS AND SIGNAL QUALITY

We aim to analyze the acquired DAS datasets and understand what limits the signal quality. A major factor of the quality of DAS datasets is the coupling of the cable with the formation. Cementing the fiber-optic cable in the well provides the optimal coupling (Li et al., 2015). The on-tubing DAS VSP records acquired in the CRC-2 well demonstrate high levels of noise relative to the signal (Figure 2). Such poor data quality could be partially explained by the poor coupling, as the cable is deployed along the well tubing.

Figure 2 shows an example of four different shots ranging from a far offset to near offset (a – d), after the correlation with the sweep signal. High levels of random noise are seen on all shots, especially at the far offset, when the signal level is relatively weaker. Areas with noisy channels can be seen at depths of 600 m, 750 m, and 950 m on all shots.

Despite the noise, DAS was able to record direct P-waves for shots until offsets of approximately 1000 m (Figure 2a), though, at these offsets mostly down-going P-waves are visible. The closer the shot is to the well, the stronger is the signal. At a closer offset (Figure 2b), down-going and up-going P-wave reflections become visible, including an up-going P reflection at 1500 m, coinciding with the injection interval, although showing weak amplitudes.

Up-going P-wave reflections can be seen at the nearest offsets (Figure 2c and d), also at depth 1500 m. At 470 m from the well (Figure 2c), random noise is still strongly present on the data. The random noise is significantly less apparent at 100 m from the well (Figure 2d) as the signal becomes stronger.

The data suffers not only from high incoherent noise, but also by tube waves. Tube waves travel along the fluid-solid boundary in a borehole (Hardage, 1981), masking the desired P-wave reflections. They are source generated tube waves, therefore, they can be seen mostly at near offsets (Figure 2c and d). Not only down-going, but also up-going source generated tube waves can be observed on the nearer offsets. Additionally, vertical stripe-like noise is apparent in the data. The “stripe noise” originates from small movements happening on the surroundings of the DAS box. The tube waves and the “stripe” noise are both indicated on Figure 2 (c, d).

To analyze the data quality, we calculate the signal-to-noise ratio (S/N) for every shot point throughout the 3D survey. The S/N was calculated by dividing the RMS amplitude of a 20 ms window around the first breaks with the RMS amplitude of a 100 ms window of noise in the beginning of the record. To reduce the number of points and attenuate outliers, we bin the calculated S/N in every 1 ° angle of incidence and 20 m distance from shot to receiver, and then average the values in each bin.

DAS on tubing presents S/N up to 30 dB, when the incidence angle is small (wave propagation close to the direction of the fiber), at approximately 10 degrees, and at a distance of approximately 500 m (Figure 3). S/N decreases with incidence angle, naturally, as DAS measures only one diagonal component of the strain tensor (along the fiber axis); amplitudes on DAS acquired with straight fibers should decay as cosine squared of the angle of incidence (Kuvshinov, 2016), as DAS is more sensitive to waves polarized along the cable axis. S/N decays also with increased distance from the source. For waves arriving close to the fiber axis, S/N decays to 10 dB or lower at a distance of approximately 1500 m. The darker blue area on the plot indicates when the S/N level is below 0 dB, meaning that the signal is equal or lower to the noise level. This means that, at a certain angle of incidence and distance from shot, DAS is unable to acquire any signal.

Although DAS on the tubing was able to acquire sufficient signal at near offsets, its low sensitivity, hence S/N, in further offsets is a huge limitation for this type of deployment, especially when considering monitoring applications. With the current data quality, applications, such as velocity model building from first breaks, can be considered.

The overall S/N of DAS can be increased by improving the coupling of the cable with the formation, or by limiting the contrast of acoustic impedance of the cable with the surrounding materials. Additionally, S/N can be improved by vertical stacking, as a significant portion of the noise present on DAS is randomly generated by the IU (Bakku et al., 2014b; Li et al., 2015).

An important consideration is that we believe the low quality of the on-tubing 3D DAS VSP is mostly attributed to the long cable length (20 km), which means a small PRF was used in the acquisition. Reducing the cable to 3 km (only well deployment) could increase the PRF by a factor of almost 7. This means that S/N could increase up to almost 8 dB.

3D VSP DAS PROCESSING AND IMAGING

The DAS data acquired by the cable on the well tubing went through three main stages of processing (Table 1). We first used a MATLAB script to read the datasets in its native format and assign the geometry to the DAS traces. The depth on DAS traces were calibrated by doing tap tests on the fiber cable to pin point a specific position on the cable with a known geographical location. As the VSP and surface seismic were acquired simultaneously, each dataset contains the well data, as well as sections of surface lines, so the script selects the area of interest along the cable.

The DAS IU had no communication with the vibroseis truck. As the geophone and DAS surveys were acquired simultaneously, we match the GPS time of the sweeps (recorded in the first trace of the geophone records) to the GPS time on the DAS data in order to assign shot point numbers and coordinates to each DAS record. As the DAS IU native measurement is the strain rate, the DAS record is converted to the strain response by integrating each trace over time. The strain data is then correlated with the source sweep signal and saved to SEG-Y files.

In the next step of the processing, the data is loaded into seismic processing software. A simple noise attenuation flow is applied to the DAS VSP datasets, consisting of a 5 to 100 Hz band pass filter and three passes of 2D spatial alpha-trimmed mean filter. The 2D spatial filter was targeting mainly tube wave noise and the vertical “stripe” noise present in the raw data. Prior to each pass, each component (up-going and down-going) of the tube wave was flattened so the filter would distinguish the noise. The “stripe” noise was also attenuated by using a 2D spatial filter with the same parameters. To obtain the up-going P-wave reflections, we flatten the first breaks and apply 2D spatial filtering, followed by *f-k* filter. Spectral shaping was applied to the data to flatten the frequency spectrum.

Figure 4 shows four shot points with varying offsets (same shot points as displayed in Figure 2), raw after the correlation with the source sweep (a – d), after noise attenuation (e – h), and after wavefield separation (i – l). Down-going and up-going PP reflections are difficult to identify on the raw records (Figure 4a-d). After the noise attenuation (Figure 4e-h), most of the coherent noise was attenuated. The tube wave noise that quite pronounced in source line 29 and shot point 57, was mostly attenuated. P-wave up-going reflections are still difficult to identify and high levels of random noise still remain in the data.

Figure 4i-l shows the obtained up-going P-wave reflections after wavefield separation. Up-going P-wave reflections are present along the well, however, reflections are weak and noise is still an issue in the records. Reflections can be identified mainly at depths 1150 m and 1500 m, the latter coinciding with the depth of the gas injection. These reflections are clearer at the nearest offset (Figure 4l).

The up-going wavefield data was migrated using a modified version of 3D Kirchhoff migration algorithm. The Kirchhoff migration implementation has a cosine term to account for the angle between the direction of the travel and the vertical (Sheriff and Geldart, 1995). In order to take into account the dependency of DAS sensitivity on the angle of incidence, we modify the migration algorithm by adding an additional cosine to the weight term. We migrate the data using a 3D grid consisting of 219 inlines, and 265 crosslines, with 7.5 x 7.5 m bin size, and 2 m depth bin. The migration was set to image the depth range from 760 m to 2400 m, in order to reduce the run time while focusing on the target area. Additionally, the amplitude polarity of the migrated dataset was reversed.

After migration, most of the random noise present on the shot gathers was attenuated (Figure 5) due to the stacking nature of the migration algorithm. Figure 5a shows inline 119 and crossline 119 from the migrated DAS VSP cube. DAS is able to image the reflections along the well, until over 2000 m depth. The injection interval, corresponding to ~1250 ms reflection, was also imaged. A time slice at 1250 ms (Figure

5b) was extracted from the volume, which shows the spatial extension of imaging at the injection interval. The image presents quite a narrow illumination range, of approximately 300 m from the wellhead, as a result of the weak signal at the far offsets. Despite the low quality of the raw datasets, DAS acquired by a cable on tubing was able to produce a good image of the subsurface around the well.

In order to evaluate the reflections imaged by DAS, we compare an inline from the DAS migrated cube with a check-shot recorded by geophones in CRC-2 (this check-shot was acquired during Stage 1, as discussed previously). Geophone up-going waves are recorded with different polarity than DAS up-going waves as geophones measure the particle velocity vector, thus distinguishing also the direction of the particle movement. To compare DAS and geophones, the polarity of the DAS was flipped during the processing so it would match the polarity of the geophones.

Additionally, we produced a corridor stack from the acquired DAS data in order to identify matching reflections with the DAS migrated cube and with the geophone check-shot. A single sweep recorded with DAS showed nearly no visible reflections, therefore, to produce the corridor stack, we selected the nearest offset shots and stacked them to improve the S/N. For this, we selected the shots after wavefield separation, up to 120 m radius from the well (33 shots in total). VSP normal move-out (NMO) correction was applied to the selected shots to correct them to zero offset, then they were stacked. After stacking the shots, 15 adjacent traces on the resulting data set were also stacked to further improve S/N. From the resulting data set, we produced the corridor stack.

Figure 6a shows half of an inline from the DAS cube, coinciding with the well location. Figure 6b shows a corridor stack produced from the DAS data, Figure 6c shows a corridor stack produced from the geophone check-shot. Figure 6d shows the geophone check-shot after NMO correction, and Figure 6e shows the DAS up-going P-waves after NMO correction (after stacking NMO corrected shots). Only half of the DAS inline is shown for comparison purposes.

Reflections on the inline from the DAS migration have good correspondence with the reflections recorded by the geophone check-shot, as seen at 850, 900, 1200, 1250, and 1600 ms. This shows that DAS was able to record up-going body waves. A strong reflection at ~1250 ms, corresponding to the injection interval in Paaratte Formation, is clearly seen on both DAS inline and geophone check-shot. DAS is also able to clearly image the reflection related to the Waarre C Formation at ~1600 ms, which was the target interval for the previous stage, Stage 1.

The corridor stack produced with the DAS data (Figure 6b) also shows good correspondence with the geophone corridor stack, with matching reflections at ~900, 1000, 1200, 1250, and 1600 ms. However, at ~1400 and 1500 ms, DAS and geophone corridor stacks show different behavior, possibly due to high levels of noise on DAS data. The geophone VSP NMO (Figure 6d) and the DAS VSP NMO data (Figure 6e) also present good correspondence, meaning that, although DAS records show low levels of signal, it was still clearly able to record up-going body waves.

CONCLUSIONS

We have demonstrated the results of a 3D VSP survey acquired using a standard fiber-optic cable deployed on the production tubing. The on-tubing deployment of fiber has the advantage of being retrofittable and replaceable, while not compromising well integrity. In this paper, our aim was to determine whether the on tubing deployed DAS has sufficient S/N to image the injection interval of a gas plume at the Stage 2C of the

Otway project. Moreover, we provide lessons learnt from our experience with the deployed fiber-optics array on site and ways to maximize the signal acquisition.

Due to the reduced coupling between the cable and the formation, as well as the long fiber length, the raw DAS records show low levels of signal and P-wave reflections are barely detectable on the raw records. Though, strong direct P-wave can be seen on the shot records. After processing, the up-going P-wave reflections can be identified.

The S/N of the individual records show that signal levels are similar to noise levels (0 dB) for incident waves above 55˚ at 900 m distance, to incident wave of 45˚ at distances of 1500 m. This clearly indicates that the angle sensitivity of DAS needs to be taken into consideration when planning DAS VSP surveys. Due to the nature of the noise in the data, S/N could be substantially improved by stacking multiple shots, or by maximizing the laser pulse repetition frequency in the IU.

The 3D dataset containing the up-going waves was migrated using a modified version of the Kirchhoff migration algorithm. After migration, the random noise in the data decreases due to the stacking nature of the migration algorithm. The illumination range provided by the DAS tubing deployment, however, was relatively narrow as a result of its reduced sensitivity at far offsets, imaging up to 300 m from the well.

Due to differences in the acquisition parameters between the baseline and monitor surveys, at this point we cannot verify if tubing deployed DAS has sufficient repeatability to monitor the injection. However, the results show that the migrated 3D DAS VSP data recorded by cable installed on tubing was able to image the interfaces beyond the injection depth. This was demonstrated by comparing the DAS migrated inline and the DAS corridor stack with the geophone corridor stack.

Additionally, we believe the results of the 3D DAS VSP were strongly affected by interrogating the whole extent of the cable (~20 km). Thus for further acquisitions, it is desirable to consider reducing the fiber length by detaching fiber-optic configuration in the well from the surface configuration in order to increase the laser pulse repetition rate of the interrogator unit. Potentially, an improvement in S/N from the use of the shortened cable could be close to a factor of $\sqrt{7}$ – approximately 8 dB – due to the increase in the pulse repetition by a factor of approximately 7. This tells us that we may consider using the tubing installed DAS for future monitor surveys at Otway, including the next stage of the project, Stage 3.

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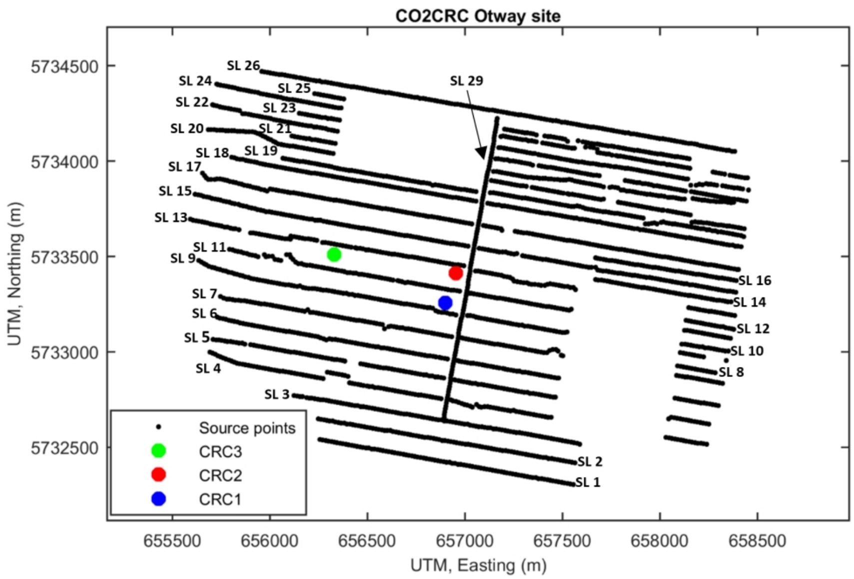
LIST OF FIGURES

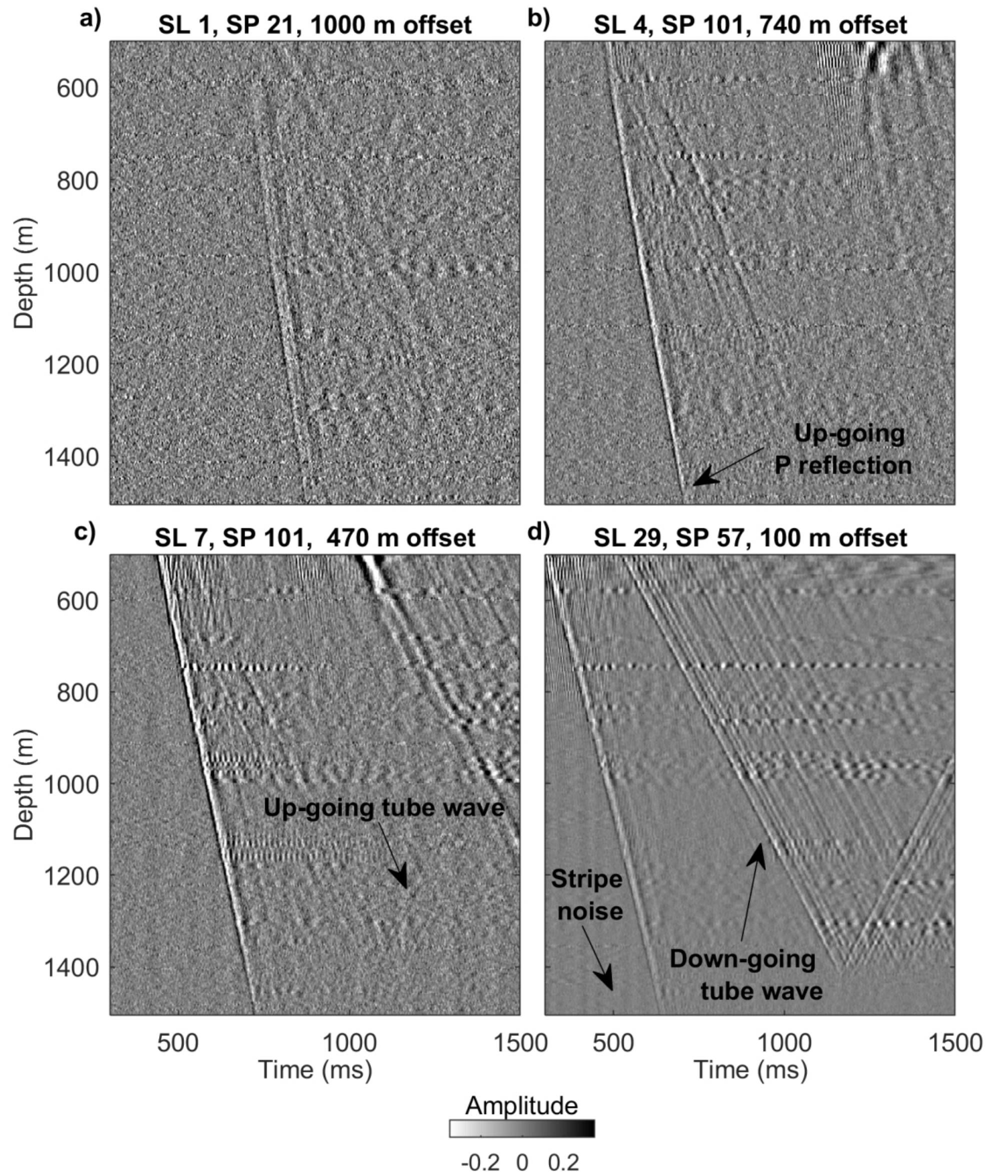
Check-shot acquired with geophones after NMO (d). DAS up-going P-waves after NMO (e).

LIST OF TABLES



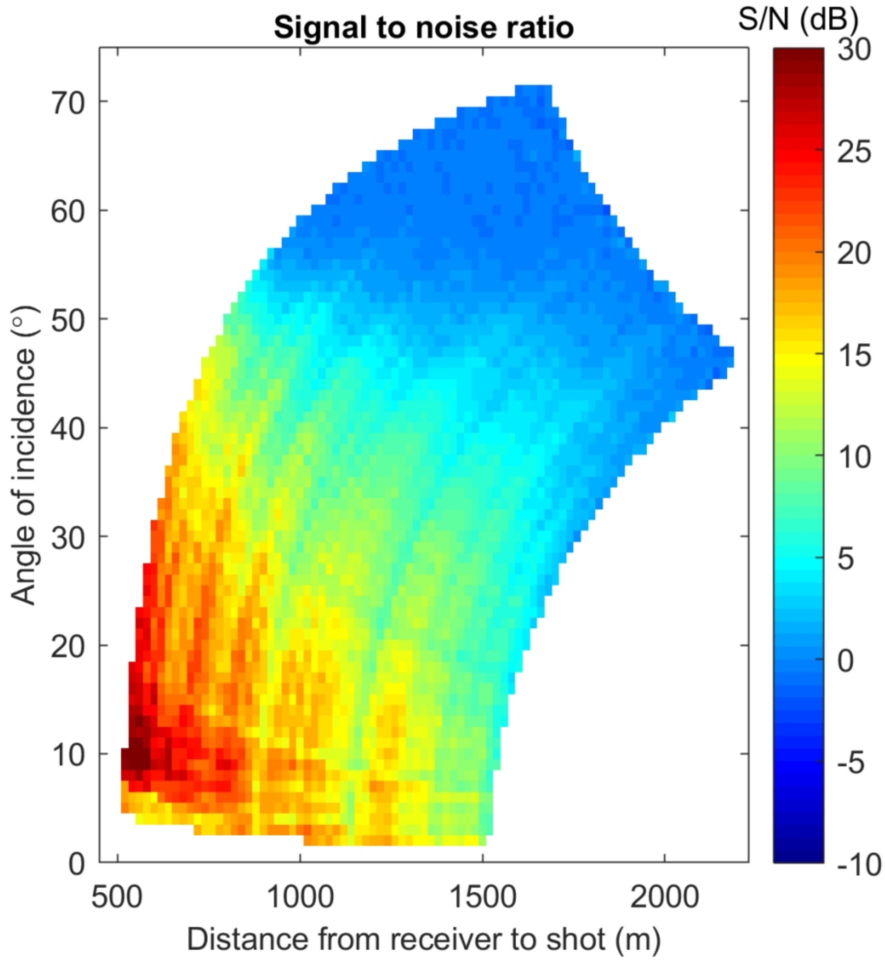
CO2CRC Otway Project site. Source point locations are displayed on the map in black. In total, there are 27 source lines (SL), which are labeled on figure.

160x119mm (300 x 300 DPI)



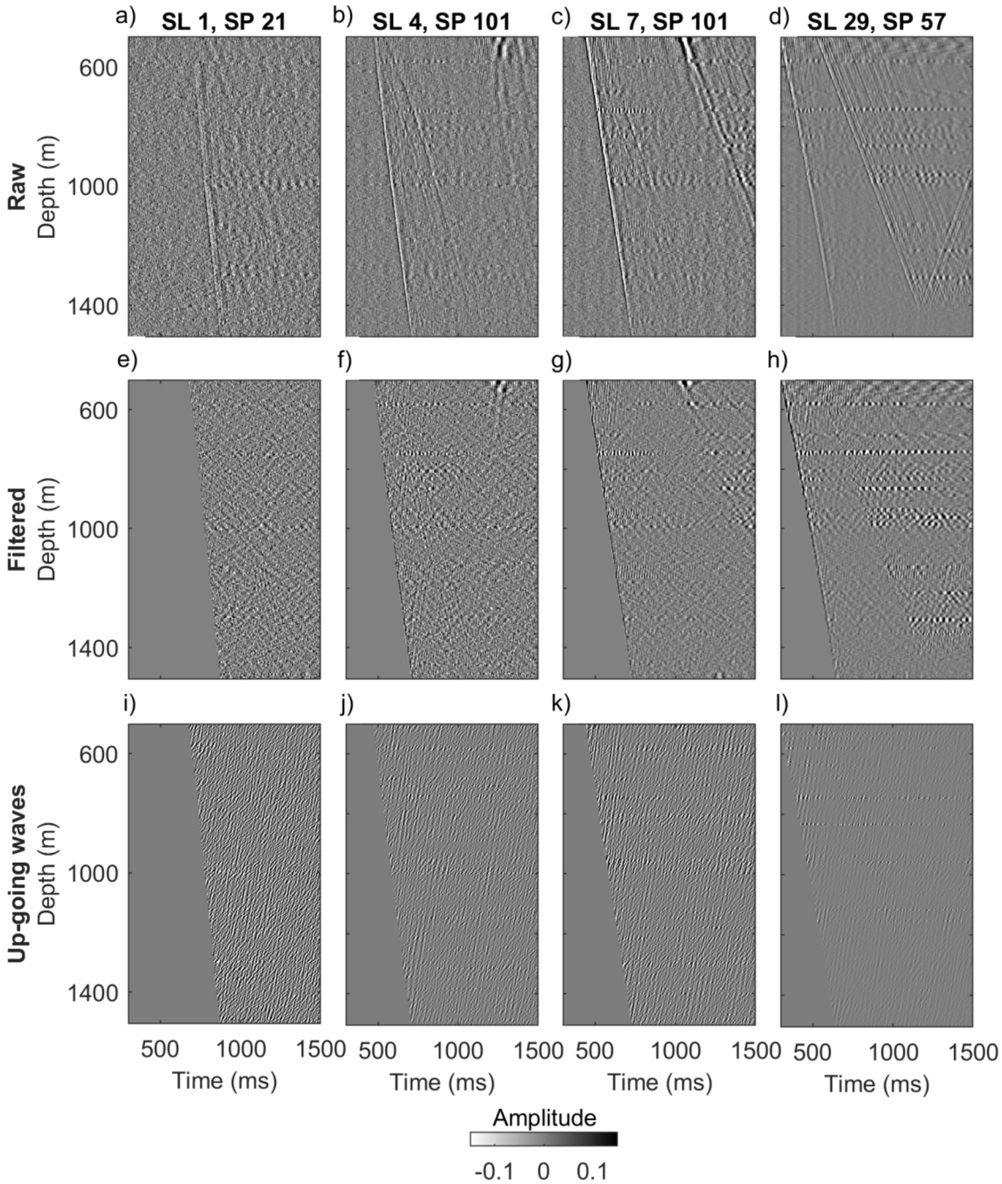
Example of shots acquired with DAS VSP on tubing, no signal processing applied after correlation. Displayed shots range from offset of 1000 m (a), 740 m (b), 470 m (c), and 100 m (d).

138x162mm (300 x 300 DPI)



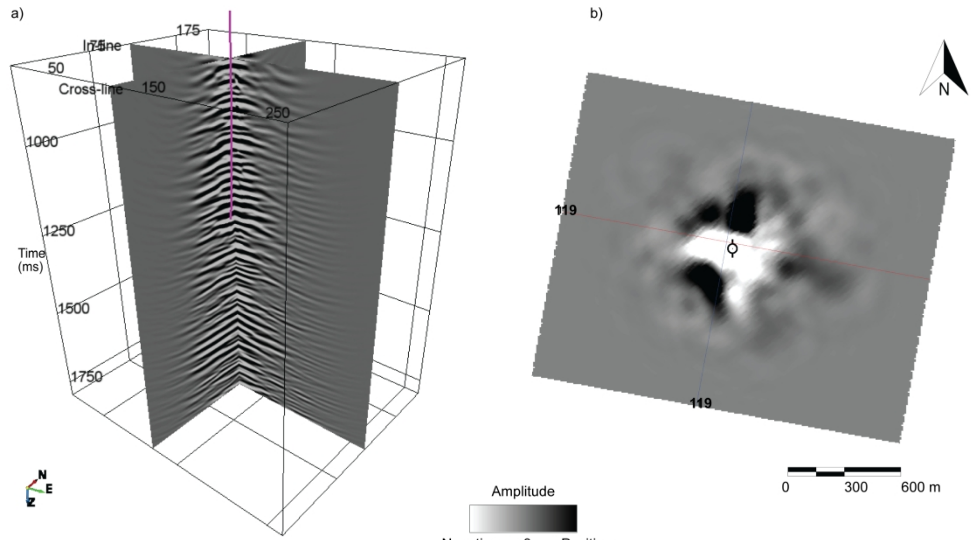
Signal to noise ratio calculated from the first breaks of all shot points, as a function of angle of incidence and shot-receiver distance.

111x111mm (300 x 300 DPI)

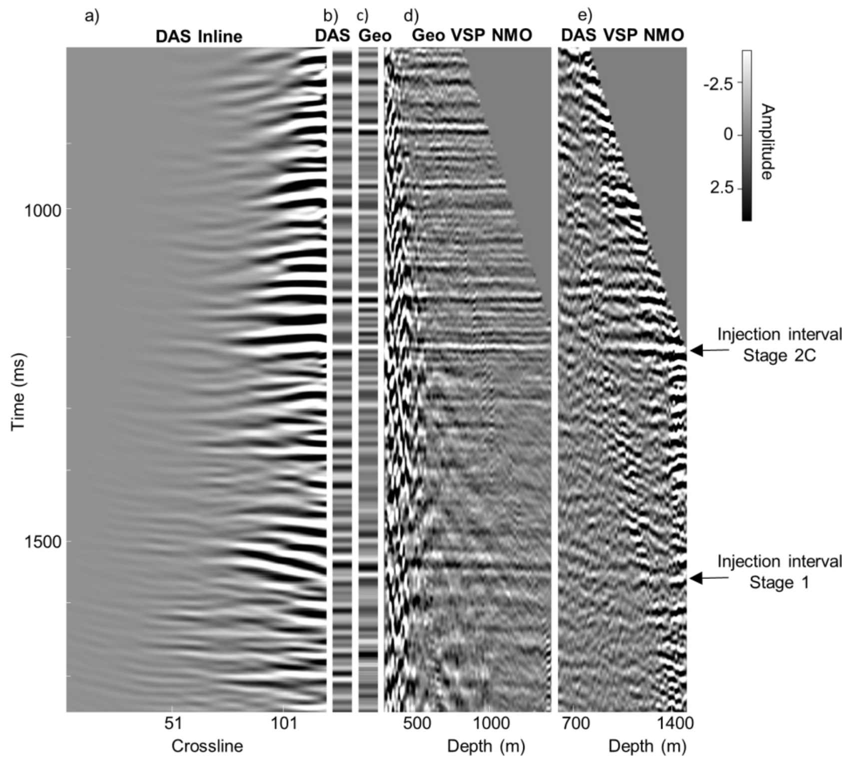


Examples of shot records acquired with DAS before noise attenuation (a-d), after noise attenuation (e-h), and after wavefield separation (i-l).

150x176mm (300 x 300 DPI)



Migrated cube (a) displaying inline 119, crossline 119, and CRC-2 well path in magenta. Time slice at 1250 ms (b).



Migrated data shown on the inline crossing the borehole from DAS VSP acquired by cable on the tubing (a). Corridor stacked produced from shots acquired with DAS (b). Corridor stacked produced from check-shot acquired with geophone array (c). Check-shot acquired with geophones after NMO (d). DAS up-going P-waves after NMO (e).

160x119mm (300 x 300 DPI)

Table 1. VSP processing flow.

Procedure	Parameter
Data input	Native iDAS format
Geometry	Coordinates applied from geophone SEGD's
Conversion from strain rate to strain	Integration in time
Correlation	Correlation with source sweep
Band pass filter	5 to 100 Hz
2D spatial filter	Alpha-trimmed mean. 30%, 101 traces. Three passes were applied with same parameters, targeting tube wave noise and "stripe" noise.
2D spatial filter	Alpha-trimmed mean. 30%, 51 traces (targeting first breaks).
Spectral shaping	Flattening frequency spectrum
FK filter	Wavefield separation
3D migration	Kirchhoff