Analysis of Field Vertical Seismic Profiling (VSP) Data: Cranfield 3D-VSP Project

6 April 2017
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Cover Illustration: 2D slice through Cranfield 3D-VSP data, superimposed on co-located 3D surface seismic, with arrow indicating location of the VSP sensors (yellow line).


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Analysis of Field Vertical Seismic Profiling (VSP) Data:
Cranfield 3D-VSP Project

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<tr>
<td>1D</td>
<td>One-dimensional</td>
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<tr>
<td>2D</td>
<td>Two-dimensional</td>
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<tr>
<td>3C</td>
<td>Three-component</td>
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<td>3D</td>
<td>Three-dimensional</td>
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<tr>
<td>4D</td>
<td>Four-dimensional</td>
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<tr>
<td>AVA</td>
<td>Amplitude variation with angle</td>
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<tr>
<td>AVO</td>
<td>Amplitude variation with offset</td>
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<tr>
<td>AZMI</td>
<td>Above zone monitoring interval</td>
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<tr>
<td>CDP</td>
<td>Common-depth-point</td>
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<tr>
<td>DAS</td>
<td>Detailed Area Study</td>
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<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced oil recovery</td>
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<tr>
<td>FFID</td>
<td>Field file ID</td>
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<tr>
<td>LANL</td>
<td>Los Alamos National Laboratory</td>
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<td>LBNL</td>
<td>Lawrence Berkeley National Laboratory</td>
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<tr>
<td>NRAP</td>
<td>National Risk Assessment Partnership</td>
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<tr>
<td>OVSP</td>
<td>Offset vertical seismic profiling</td>
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<tr>
<td>PNNL</td>
<td>Pacific Northwest National Laboratory</td>
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<tr>
<td>SECARB</td>
<td>Southeast Regional Sequestration Partnership</td>
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<tr>
<td>SSEB</td>
<td>Southern States Energy Board</td>
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<tr>
<td>TVF</td>
<td>Time-variant filter</td>
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<td>TWT</td>
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<td>VSP</td>
<td>Vertical seismic profiling</td>
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<tr>
<td>WAVSP</td>
<td>Walk-away vertical seismic profiling</td>
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<tr>
<td>ZVSP</td>
<td>Zero offset vertical seismic profiling</td>
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EXECUTIVE SUMMARY

The investigations in this report address one of the priority research topics of the National Risk Assessment Partnership (NRAP) Strategic Monitoring Working Group—the research need of quantifying and improving temporal and spatial resolution of monitoring data, in this case three-dimensional (3D) borehole based seismic data. The resulting Cranfield 3D vertical seismic profiling (VSP) study consists of two different investigations of VSP technology as it applies to the storage of anthropogenic carbon dioxide (CO₂). These investigations are firstly, an examination of the subsurface spatial resolution of 3D-VSP technology compared to more expensive, lower frequency 3D surface seismic technology, including the potential economic and technical value for subsurface monitoring of large volumes of anthropogenic CO₂. The second investigation relates to the value of least-squares, reverse-time migration processing for coping with the sparse distribution of VSP seismic sources and the avoidance of processing artifacts that may mimic low offset faults or other subsurface discontinuities. Such artifacts could result in the incorrect estimation of higher project risk, greater geologic uncertainty, and could result in negative impacts to project schedule or budget.

The key findings of this report relate the relative spatial resolution of reflections at the reservoir depth (which are used to monitor the storage of CO₂) and in above zone monitoring intervals (AZMI), which are used to monitor for leakage. For the Cranfield data set, this study found that the 3D-VSP data have only slight improvements over conventional 3D surface seismic in the resolution of the high amplitude, continuous reflector for the Tuscaloosa injection formation, but that a real advantage of 3D-VSP is found in the improved imaging of weakly reflective, discontinuous reflectors in a potential AZMI. At Cranfield such reflectors above the injection formation form an important zone for leakage monitoring. At other sites, the reservoir interval may consist of weakly reflective seismic events whose imaging could be improved by 3D-VSP. This improvement in imaging is essential in being able to detect and quantify changes in subsurface properties related to seismic monitoring.

The examination of reverse-time migration processing of VSP data investigated the complications of migration artifacts caused by less than ideal shot and receiver intervals and by sparse distribution of source stations, two common situations in the acquisition of VSP data. This study found that least-squares reverse-time migration is able to flatten the common but troublesome processing of artifacts known as migration smiles (an upward bending of the ends of reflections) and is able to extend the lateral imaging region. This methodology also produces images with a higher spatial resolution, and is especially beneficial when the amount of data is limited by sparse seismic energy sources. Two advantages of least-squares reverse-time migration of VSP data are demonstrated in this work: (1) it significantly improves the spatial resolution of the layer images, which is critical to calibration and quantification of seismic data, and (2) it extends the horizontal imaging region to areas that are not able to be imaged using conventional reverse-time migration.
1. **INTRODUCTION:**

The investigations in this report address one of the priority research topics identified by the National Risk Assessment Partnership (NRAP) Strategic Monitoring Working Group—the research need of quantifying and improving temporal and spatial resolution of monitoring data. Three-dimensional (3D) surface seismic surveys constitute one of the most accepted technologies for characterizing sites for potential storage of large volumes of anthropogenic CO₂, and for monitoring and managing stored or industry-utilized CO₂. However, 3D surface seismic data are often more amenable to qualitative rather than quantitative analysis. In addition, monitoring of changes in seismic properties, typically using time-lapse or four-dimensional (4D) surveys as a proxy for monitoring changes in reservoir properties, is often focused on restricted vertical intervals in areas with injection or monitoring wellbores, rather than at larger scales addressed by 3D surface surveys. An earlier NRAP report focused on the temporal resolution of vertical seismic profiling (VSP) data, but could not address the important issue of spatial resolution. Accordingly, this report focuses on research into the spatial resolution of 3D seismic data acquired by geophones placed in a borehole (VSP technology) and on improving depth imaging processing for the specific challenges of 3D-VSP technology.
2. **VERTICAL SEISMIC PROFILE (VSP) SURVEYS**

In VSP surveys, seismic sources are placed at the Earth’s surface and an array of geophones is placed in a borehole. Borehole seismic surveys have been a standard oilfield technology for several decades. The resulting data were generally used for velocity surveys and for one-dimensional (1D) mapping of seismic reflectors near the borehole.

Placing seismic sensors in the borehole and locating seismic sources on the Earth’s surface allows the recording of higher frequencies than is possible when sensors are placed on the Earth’s surface. This is the result of the seismic waves having to propagate only once through the weathering zone, which attenuates higher frequencies with each traverse. As a result of up to twice the frequency content, resolution of subsurface features can be considerably increased. In addition to recording higher frequency data, borehole seismic data typically have a higher signal-to-noise ratio, particularly when the geophones can be strongly coupled to the wellbore (e.g. Paulsson et al., 2004).

In addition to producing images that allow interpretation of the subsurface structure, vertical seismic profiling allows: (1) calculation of seismic velocity, impedance, attenuation, and anisotropy, all of which contribute to more quantitative estimates of in situ rock properties of the near wellbore reservoir, seal, and overburden; (2) a better identification of components of the recorded seismic wave, including noise such as multiples and mode conversions; and (3) an integration of all of the above to optimize processing and interpretation of both VSP data and surface seismic data (Stewart, 2001).

2.1 **TYPES OF VSP SURVEYS**

The basic components of a VSP survey are an available borehole, preferably cased and with an adequate cement bond to allow secure clamping and coupling of the geophones with the side of the borehole and surrounding formations; a seismic energy source; a wireline truck deploying a downhole receiver array; and a recording truck (Figure 1). Receivers in downhole arrays are positioned at regular intervals, commonly 50 ft apart. The number of receivers in an array have a wide range, with 50, 80, to several hundred becoming increasingly common. The greater the number of receivers in an array, the fewer times the array must be repositioned in order to image a long borehole. Most receivers are three-component sensors (two horizontal, one vertical) and record shear (S), compressive (P), and converted mode signals. Combining P and S wave images allows inversion for rock properties that are critical in monitoring; including fluid content, pore pressure, stress orientation, and fracture set azimuths.
Figure 1: Schematic view of a VSP survey and some of the components of the seismic wavefield (from Stewart, 2001).

If a single seismic energy source position is used within a few hundred feet of the borehole, the survey is referred to as a zero offset VSP (ZVSP); if positioned at a greater distance and with one or more source points, the borehole survey is called an offset VSP (OVSP). If the source is activated at regularly spaced intervals in a line away from the well, the survey is termed a walk-away VSP (WAVSP). A WAVSP will produce a 2D seismic image. Because of the critical angle of reflection, the farthest source in a WAVSP is generally located at a distance approximately equal to the depth of the lowest receiver, and the resulting 2D image will extend about half of that distance away from the borehole. Other types of VSP surveys, based on location of the seismic source stations include multi-offset VSP and multi-azimuth VSP. A 360 degree survey consisting of OVSP’s arranged along specified azimuths is a walk-around survey. Multi-azimuth surveys are especially important for evaluating anisotropy through shear-wave splitting analysis.

2.1.1 3D-VSP

A full areal pattern of source positions on the Earth’s surface constitutes a 3D-VSP. For optimization of resources, 3D-VSP surveys are commonly piggy-backed on 3D surface seismic surveys. The simultaneous acquisition of a 3D-VSP and a 3D surface survey produce a full volumetric picture of the subsurface and allow a direct comparison of the data. However, the spacing of sources for the VSP survey usually have to be infilled to provide adequate multiplicity of coverage, or fold.

The typical 3D borehole seismic image volume is cone shaped with the top of the cone coincident with the top receiver in the borehole array (Figure 2). The size of the base of the cone is determined by the depth of the image volume and the offset of the sources.
Advantages of acquiring three component 3D-VSP data volumes include the following

- Provide higher resolution for stratigraphic and structural imaging
- Allow P-wave focused 3D coverage in areas that cannot support full 3D surface acquisition
- Access the full elastic wavefield
- Improve velocity models through tomographic anisotropic inversion

2.1.2 Seismic Monitoring for Sequestration

Seismic data form an essential part of reservoir characterization of potential and active CO$_2$ storage and enhanced oil recovery (EOR) sites, including building initial static (geologic or conceptual models) as well as numerical or dynamic reservoir, seal, and overburden models for simulating processes related to injection, reservoir management, CO$_2$ monitoring and verification of containment. In particular, time-lapse, or 4D seismic technology is critical to reduction of project risk through identification of fugitive CO$_2$ accumulations, changes in storage capacity, compartmentalization or areas of increased pore pressure, and changes in rock properties associated with seals, faults, or fracture zones (Chadwick et al., 2009).

Time lapse 3D seismic surveys have been used for monitoring velocity and density changes related to the movement of CO$_2$ at In Salah, and seven off-shore repeat surveys have been conducted at the Sleipner North Sea CO$_2$ storage site since 1994 (Chadwick et al., 2009). Time-lapse 3D utilizing shear wave data was used in identifying fracture controlled movement of CO$_2$ at the large Weyburn field in Saskatchewan (Araman et al., 2008).

Time-lapse 3D-VSP reservoir monitoring examples include the Patrick Draw (EOR) field in Wyoming (O’Brien et al., 2004) and at the Illinois Basin Decatur CO$_2$ storage project (Coueslan,
2013), while offset VSP for sequestration monitoring was used by Daley et. al. (2008), at the Frio Pilot.

2.2 THE CRANFIELD PROJECT

The U.S. Department of Energy’s (DOE) Southeast Regional Carbon Sequestration Partnership (SECARB) under leadership of the Southern States Energy Board (SSEB) conducted a Phase 2 and Phase 3 project at the Cranfield Unit (western Mississippi), led by the Texas Bureau of Economic Geology. The NRAP funded 3D-VSP project, reported here, was linked to the SECARB Phase III Early Test project and the Cranfield CO2–EOR project conducted by Denbury Onshore, LLC.

Cranfield oil and gas production is related to anticlinal four-way closure at a depth of about 9,000 ft. The field was discovered in 1943, abandoned by 1965, and refitted for CO2 EOR by Denbury Onshore, LLC. Denbury began injection for CO2 EOR in July 2008. CO2 from Jackson Dome, Mississippi is supplied to the Cranfield unit via pipeline (Hovorka et al., 2011).

The hydrocarbon reservoir is in the Cretaceous age lower Tuscaloosa Formation, and consists of highly heterogeneous channel fill sandstones. The lowest unit of the regional confining system is a thick marine mudstone in the middle Tuscaloosa (Figure 3) (Hovorka et al., 2013).

Figure 3: (a) Generalized stratigraphic section at Cranfield, (b) near surface stratigraphy based on correlations of Jeff Paine, Bureau of Economic Geology, written communication, (c) detail of the Tuscaloosa Formation generalized from wireline logs at Cranfield, and (d) core facies interpretation by Lu et al. (2013). Figure and caption from Hovorka et al. (2013).
3. CRANFIELD 3D-VSP ACQUISITION

3.1 SURVEY PLANNING

Initial planning for the 3D-VSP was conducted with the VSP contractor, Apex-HiPoint of Denver, CO. The data acquisition was planned to be coincident with acquisition of a repeat OVSP, funded by SECARB/DOE, so that the same equipment could be used without additional mobilization charge. Similarly, and more significantly, the 3D-VSP was planned to be coincident with a repeated 3D surface seismic survey to be acquired by CGGVeritas (also funded by SECARB/DOE, with support from Denbury Resources). This allowed a very large number of source points (> 500) to be acquired at essentially no additional cost. The sensors being used for the OVSP were 50 3-component, wall-locking geophones with digital telemetry. The seismic source was explosive shots which were 5.5 lbs of seismic explosive in 100–120 ft deep shot holes. With these acquisition parameters set, the design of the survey focused on maximizing spatial coverage.

3.2 SURVEY DESIGN

Initial work on the 3D-VSP included survey design analysis to understand the spatial coverage and data quality. Initial data quality is typically measured as seismic “fold”, i.e., the number of seismic traces which can be stacked together to improve image quality in each “bin” within the 3D volume. Figure 4 shows a map view of the initial surface seismic source locations with the well location and the expected fold at reservoir depth. As can be seen in Figure 4, there are some “holes” in the fold coverage near the VSP well (seen as white space within the green color). Figure 5 shows the same fold information as slices in a 3D volume, including a vertical slice through the VSP well, which shows the “inverted parabola” type coverage typical of 3D-VSP data. To improve the fold coverage for the 3D-VSP additional shots were proposed, and agreed to by SECARB and Denbury. Figure 6 and Figure 7 show the same fold maps with the additional shots that were added for the VSP survey. The design for the 3D-VSP had the 50-level array (49 of which were operational during the survey), with 50 ft spacing between geophones, placed between 5,500 ft and 8,000 ft depth in the 31-F1 borehole. A total of 7 shot lines with 195 shot holes were added between existing surface seismic shot lines to fill in the fold coverage for the 3D-VSP design.
Figure 4: Map view of the initial surface seismic source locations (purple dots) with the well location (arrow) and the expected fold at reservoir depth (colored area with scale on right side). The map is approximately 1:1 ratio with distance shown on left (northing) and top (westing) axis, in feet in a state-plane coordinate system.

Figure 5: VSP design showing fold on two “slices” through the 3D volume—a vertical slice through the VSP well and a horizontal slice near the reservoir depth. Fold (the number of summed recordings) is shown as color with color bar on right. Distances are labeled in feet.
Figure 6: Map view of the initial (purple) and additional (black) surface seismic source locations with the well location (arrow) and the expected fold at reservoir depth (colored space with scale on right side). The map is approximately 1:1 ratio with distance shown on left (northing) and top (westing) axis, in feet.

Figure 7: VSP design with extra shotpoints added, showing the fold on two “slices” through the 3D volume – a vertical slice through the VSP well and a horizontal slice near the reservoir depth. Fold is indicated by color bar on right. Distances are labeled in feet.
3.3 DATA ACQUISITION

A three-component (3C) 3D-VSP survey was acquired over part of the Cranfield oil field in November 2010 to coincide with other seismic acquisition in the field. The VSP survey was recorded simultaneously with a separately planned offset VSP and with a 3D surface seismic program to optimize use of seismic sources and logistical resources. The recording sensors for the 3D-VSP were a 50-level, 3C, wall-locking geophone string with digital telemetry. The sensor string was a “MaxiWave” instrument, manufactured by Sercel and rented for this survey. Geophones were spaced at 50 ft intervals. The seismic source was provided by 5.5 pound seismic explosive shots placed in 100–120 ft deep shot holes.

The 50-level array was placed between a depth of 5,500 to 8,000 ft below ground surface in the Cranfield Unit CFU-31-F1 borehole. Forty-nine receivers were operative during the survey. A total of seven shot lines with 195 shot holes were added between existing surface seismic shot lines to improve fold coverage for the 3D-VSP design.

Field activities commenced on November 10, 2010 and required four days to complete with one day downtime for weather. Figure 8 shows the borehole geophones being deployed. An example of raw data is shown in Figure 9. A total of 637 shot locations were recorded. Each raw data record was 5 s long with 1 ms sample rate.

Figure 8: VSP geophones showing individual elements (right) and deployment into well (left).
Figure 9: An example of the “raw” VSP data showing 3-components H1, H2, V, for 6 shot points at increasing offset from the well. Vertical axis is time in ms while the horizontal axis is Field file ID (FFID) and receiver depth in feet (REC_DEP).
4. CRANFIELD 3D-VSP PROCESSING

The data were first processed by a commercial vendor, and were subsequently processed for depth imaging at Los Alamos National Laboratory (LANL) by Sirui Tan and Lianjie Huang.

4.1 COMMERCIAL DATA PROCESSING

The data processing was conducted by Apex-HiPoint under the supervision of Pacific Northwest National Laboratory (PNNL) and Lawrence Berkeley National Laboratory (LBNL). Initial work included the following steps:

- Verify source locations using first arrivals and cross-referenced with CGGVeritas observer’s reports
- Determine geophone orientations using a hodogram analysis of first arrival energy from various sources surrounding array
- Numerically “rotate” geophones to maximize the direct arrival energy on one component for first arrival time picking (see Figure 10)
- Pick first arrival times and interpolate to all surface locations (for later upward continuation process) (see Figure 11)
- Maximize P-wave reflection energy on one component
- Time-variant rotation to maximize P-wave reflection energy on a single component
- T-function gain (t**2)
- Suppress tube wave on near-offset shots (<1,250 ft)
- Remove down-going energy, leaving only up-going P-wave reflections
- Surface-consistent amplitude compensation to balance source and receiver strength variations
- Source-consistent deconvolution (minimum-phase spiking decon)

Data quality control at this point led to modification of the processing:

- New volumes created with improved resolution over the target interval
- Data were deconvolved before wave field separation and frequencies were boosted from 6 to 100 Hz

At this point the data was prepared for migration with an “upward continuation” algorithm, developed by Apex-Hipoint, which generated data as if it were recorded on the surface (a “pseudo receiver”, thus allowing surface seismic migration algorithms to be used). Following application of time-migration, the result is a 3D volume of seismic reflectivity with an inverted parabola shape surrounding the borehole. Finally, bandpass filtering is applied to optimize imaging and/or match the surface seismic data set. Example comparisons of 3D-VSP and surface seismic data are shown in Figure 12 and Figure 13.

Two interpretation-ready data volumes are generated with the following filters:

- 6–100 Hz bandpass filter
• Time-variant filter (TVF) to match the surface cube resolution
  o 0–2,000 ms : 6–70Hz
  o 2,100–3,000 ms : 6–60 Hz
  o 3,100–5,000 ms : 6–50 Hz

Figure 10: Rotated shot record with new components, radial (R), transverse (T) and vertical (V). The radial component is oriented in the plane containing the source and the borehole, while the transverse component is normal to this plane. Vertical axis is time in ms while the horizontal axis is Field file ID (FFID) and receiver depth in feet (REC_DEP).
Figure 11: First break picks (red) displayed on selected shot gathers radial component. Vertical axis is time in ms while the horizontal axis is Field file ID (FFID) and receiver depth in feet (REC_DEP).

Figure 12: Five separate crosslines (xline), each a 2D slice of 3D-VSP migrated data volume inserted in equivalent surface seismic 2D slice. Vertical axis is time in ms while the horizontal axis is Field file ID (FFID) and receiver depth in feet (REC_DEP).
4.2 SPATIAL RESOLUTION OF COMMERCIAL TIME-IMAGING

Understanding the spatial resolution of monitoring tools is an important component of risk assessment. The impact component of risk is related to the ability to mitigate the impact. The ability to mitigate problems, such as leakage from a subsurface containment zone, is fundamentally linked to the ability to detect and spatially localize the problem. The spatial resolution of monitoring tools controls the ability to detect and mitigate leakage and other risk impacts. This study investigated the resolution of seismic monitoring and, in particular, a comparison of 3D surface seismic and 3D-VSP. The key findings relate the relative spatial resolution of reflections at the reservoir depth, which change with CO₂ saturation and thus can be used to monitor the storage of CO₂, and in AZMI, where potential changes are used to monitor for leakage. Increasing spatial resolution allows improved monitoring of these reflection changes.

Figure 14 and Figure 15 show a small subset of the entire 3D data sets—a part of one 2D slice through both volumes. Figure 14 shows the surface seismic data and Figure 15 shows the 3D-VSP data superimposed on the spatially equivalent surface seismic data. The reservoir interval reflection is at approximately 2,300 ms two-way time (TWT). The AZMI used for analysis is at approximately 1,800 ms TWT. For the reservoir reflector the 3D-VSP has comparable, but slightly higher resolution (Figure 15). This increased resolution can be seen by comparing the time period or “thickness” of the large amplitude event wavelet at 2,300 ms, which has a black-red-black color scale. In the case of imaging the storage reservoir, the 3D-VSP does not provide significant extra value. However, the conclusion for the AZMI is quite different. Comparing the event at 1,800 ms in Figure 15, only the 3D-VSP (not the 3D surface seismic) has

Figure 13: Five separate crosslines (xline), each a 2D slice of 3D-VSP migrated data volume inserted in equivalent surface seismic 2D slice. Vertical axis is time in ms while the horizontal axis is Field file ID (FFID) and receiver depth in feet (REC_DEP).
clear imaging of this reflection event. The general poor reflectivity observed on the 3D surface seismic in this zone indicates very limited ability to image and therefore monitor for leakage, while the clear reflector seen on the 3D-VSP indicates a better prognosis for time lapse monitoring. **3D-VSP provides an improved ability to image (and likely monitor) in relatively weakly reflective zones near a wellbore.** Figure 16 and Figure 17 provide additional views of the improved imaging of events with poor reflectivity in the overburden above the reservoir.

![Image of 3D surface seismic volume](image)

**Figure 14:** A 2D slice of the 3D surface seismic volume showing crossline 197 for in-line cdps 1,008 to 1,108. The CO2 injection well, where the 3D-VSP sensors were located is indicated by yellow dashed line and black arrow. The storage reservoir reflection is at about 2,300 ms.
Figure 15: A 2D slice of the 3D surface seismic volume showing crossline 197 with the same 2D slice of the 3D-VSP data inserted. The 3D-VSP data has limited lateral extent and an inverted parabolic shape. The CO$_2$ injection well, where the 3D-VSP sensors were located is indicated by yellow dashed line and black arrow.
Figure 16: Two 2D slices of the 3D surface seismic volume showing crossline 197 for in-line cdp 1,008 to 1,108. The CO2 injection well with the 3D-VSP sensors is indicated by yellow dashed line and black arrow. The low amplitude, low reflectivity overburden interval is circled.
Figure 17: VSP slices inserted into the 3D seismic volume. The improved VSP imaging of events in low reflectivity overburden indicates potential for monitoring for leakage.
5. **IMPROVED DEPTH IMAGING PROCESSING**

The techniques of depth imaging in VSP are largely influenced by depth migration of surface seismic data. Wyatt and Wyatt (1981) proposed the VSP-CDP (common-depth-point) technique. It is based on an approximate mapping of VSP data to a seismogram that appears as if it were recorded at the Earth’s surface. This mapped data can then be treated with CDP processing. More direct migration approaches were later developed to improve imaging. In prestack-depth migration, wavefields are extrapolated from receiver locations to an imaging region and imaging conditions are applied to obtain high-resolution subsurface images. With more accurate wavefields at an imaging region, more information could be extracted and better images produced. From the late 1980s to the late 1990s, Kirchhoff migration was the dominant depth-imaging method because of its flexibility and computational efficiency (Etgen et al., 2009). For example, Dillon (1988) and Bicquart (1998) processed VSP data using Kirchhoff migration. The disadvantage of Kirchhoff migration is mainly that the contribution of a data trace to an image is limited to a single raypath, which cannot properly handle complete wave-propagation paths for complex structures. This limitation can be overcome using wave-equation migration methods, particularly using reverse-time migration based on the full two-way wave equation. The pioneers of reverse-time migration of VSP data include Sun and McMechan (1986) and Whitmore and Lines (1986). The biggest advantage of reverse-time migration is that it can correctly handle complex velocity structures to account for wave propagation along all possible directions. It also gives us a full wavefield from which angle-dependent reflectivity information can be recovered by an extended imaging condition (Sun and Sun, 2010).

The success of prestack-depth migration methods relies on wide acquisition aperture and a sufficient number of sources and receivers in a seismic survey. However, only a limited number of receivers can be placed in a single borehole in VSP surveys. For example, there are only 49 operational receiver levels in the Cranfield 3D-VSP survey, compared to thousands of receivers in a typical 3D surface seismic survey. This means there are not enough common-shot migration images to stack to reduce image artifacts and obtain a good image. Compared to surface seismic surveys, the imaging regions of VSP surveys are limited to relatively small areas around the borehole and beneath the receivers.

The goal of this work on VSP depth imaging is to improve the spatial image resolution and to extend the imaging regions away from the borehole. Such improved imaging techniques would provide us with a more informative image of the reservoir (higher spatial resolution) with less uncertainty.

Least-squares migration is a promising imaging method to achieve this goal. The idea is that the imaging principle can be formulated as an inverse problem based on a least-squares function (Tarantola, 1984). The inverse problem can be solved either using iterative migrations (Nemeth et al., 1999; Dai et al., 2012) or using a migration followed by applying an inverse of the approximate Hessian matrix of the misfit functional (Plessix and Mulder, 2004; Valenciano et al., 2006). The first implementation of least-squares migration was based on Kirchhoff migration (Nemeth et al., 1999). Recently, least-squares migration is implemented with reverse-time migration and such methods are thus called least-squares reverse-time migration (Tang, 2009; Wong et al., 2011; Dai et al., 2012). It has been shown that least-squares reverse-time migration of surface seismic data can reduce the artifacts in the conventional reverse-time migration images and enhance the image resolution. However, there are few reports on least-squares reverse-time migration of VSP data. Two advantages of least-squares reverse-time migration of
VSP data are demonstrated in this work: (1) it significantly improves the spatial resolution of the layer images, and (2) it extends the horizontal imaging region to areas that are not able to be imaged using conventional reverse-time migration.

5.1 METHODS FOR DEPTH IMAGING PROCESSING

The theory of least-squares reverse-time migration is based on the Born approximation of the scalar-wave equation given by

$$\frac{1}{c(\mathbf{x})^2} \frac{\partial^2 p(\mathbf{x},t;\mathbf{x}_s)}{\partial t^2} - \nabla^2 p(\mathbf{x},t;\mathbf{x}_s) = s(t;\mathbf{x}_s),$$

where $c(\mathbf{x})$ is the wave speed and $p(\mathbf{x},t;\mathbf{x}_s)$ is the pressure field from the source $s(t;\mathbf{x}_s)$. A perturbation in the wave speed $c(\mathbf{x}) \rightarrow c(\mathbf{x}) + \delta c(\mathbf{x})$ leads to a perturbation in the wavefield $p(\mathbf{x},t;\mathbf{x}_s) \rightarrow p(\mathbf{x},t;\mathbf{x}_s) + \delta p(\mathbf{x},t;\mathbf{x}_s)$. Under the Born approximation, the wavefield perturbation $\delta p(\mathbf{x},t;\mathbf{x}_s)$ can be computed using

$$\frac{1}{c(\mathbf{x})^2} \frac{\partial^2 \delta p(\mathbf{x},t;\mathbf{x}_s)}{\partial t^2} - \nabla^2 \delta p(\mathbf{x},t;\mathbf{x}_s) = m(\mathbf{x}) \frac{\partial^2 p(\mathbf{x},t;\mathbf{x}_s)}{\partial t^2},$$

where the reflectivity model is defined as $m(\mathbf{x}) = \frac{2\delta c(\mathbf{x})}{c(\mathbf{x})^3}$ (Dai, 2012). The wavefield $\delta p(\mathbf{x},t;\mathbf{x}_s)$ is recorded at the receiver position $\mathbf{x}_g$ by $d(\mathbf{x}_g,t;\mathbf{x}_s)$. The migration operation of the common-shot gather $d(\mathbf{x}_g,t;\mathbf{x}_s)$ is carried out using the conventional reverse-time migration given by

$$m_{\text{mig}}(\mathbf{x};\mathbf{x}_s) = \int_{t_1}^{t_2} \frac{\partial p(\mathbf{x},t;\mathbf{x}_s)}{\partial t} \cdot \frac{\partial q(\mathbf{x},t;\mathbf{x}_s)}{\partial t} dt,$$

where $q(\mathbf{x},t;\mathbf{x}_s)$ is the back-propagated recorded wavefield computed using

$$\frac{1}{c(\mathbf{x})^2} \frac{\partial^2 q(\mathbf{x},t;\mathbf{x}_s)}{\partial t^2} - \nabla^2 q(\mathbf{x},t;\mathbf{x}_s) = d(\mathbf{x}_g,t;\mathbf{x}_s).$$
In matrix notations, the Born approximation (Equation 1) is represented using

\[ d = Lm. \]

The reverse-time migration operator (Equation 2) is the adjoint operator of \( L \)

\[ m_{\text{mig}} = L^T d. \]

Generally, \( L^T \neq L^{-1} \) and thus the reverse-time migration image \( m_{\text{mig}} \) is only a rough approximation of the reflectivity model \( m \).

Least-squares reverse-time migration aims to solve the reflectivity model \( m(x) \) by minimizing the least-squares functional

\[ J(m) = \| Lm - d \|_2^2. \]

A preconditioned conjugate gradient algorithm is used to find the minimizer iteratively. The illumination compensation preconditioner (Plessix and Mulder, 2004) is commonly used to speed up the convergence. The following preconditioner is used to improve migration images in the deeper region:

\[ m_{\text{mig}}(x; x_s) = \frac{\int \frac{\partial p(x, t; x_s)}{\partial t} \frac{\partial q(x, t; x_s)}{\partial t} dt}{\sqrt{\int \left( \frac{\partial p(x, t; x_s)}{\partial t} \right)^2 dt \int \left( \frac{\partial q(x, t; x_s)}{\partial t} \right)^2 dt}}. \]

It is similar to the normalization strategies (Kaelin and Guitton, 2006; Chattopadhyay and McMechan, 2008) for more balanced amplitudes in reverse-time migration images. Note that the conventional reverse-time migration is the first iteration of the least-squares reverse-time migration.

5.2 RESULTS FOR DEPTH IMAGING PROCESSING

The improvement of least-squares reverse-time migration was first demonstrated over the conventional reverse-time migration using 2D synthetic VSP data, then the similar image improvement was shown using 2D and 3D-VSP data acquired at the Cranfield site.
5.2.1 Velocity Model

Layered velocity models obtained from the ZVSP data acquired at the Cranfield field site are used for migration imaging. A median filter with a window size of 3 grid points was applied to the slowness (inverse of velocity) model obtained using the ZVSP data, and the resulting velocity model is shown in Figure 18a. For synthetic tests, the slowness is further filtered using a median filter with a window size of 7 grid points to eliminate some large oscillations in the model (Figure 18b).

![Figure 18](image.png)

(a) A velocity model obtained after applying a median filter with a window size of 3 grid point to the model obtained from the zero-offset VSP data.

(b) A velocity model obtained after applying another median filter with a window size of 7 grid point to the model in (a).

Figure 18: Layered velocity models used for migration imaging. The model in (a) is used for migration of the field data, and that in (b) is used for synthetic tests.

5.2.2 Synthetic Examples

A synthetic 3D-VSP dataset was generated for sources located on the Earth’s surface. The configuration of the receiver array is the same as that used for recording the Cranfield 3D-VSP data. The central frequency of the source wavelet is 40 Hz.

First, synthetic data was generated with 15 sources evenly distributed with a spatial interval of 250 m (approximately 3 wavelengths). This spatial interval is similar to that of the Cranfield 3D-VSP survey. Reverse-time migration and least-squares reverse-time migration were conducted using the synthetic data, and the migration images obtain are shown in Figure 19. It was observed that the image obtained using the conventional reverse-time migration contains significant artifacts because of the sparse distribution of the sources. The least-squares reverse-time migration not only significantly reduces the artifacts, but also extends the horizontal imaging region to areas that cannot be imaged using the conventional reverse-time migration.

The number of sources was then increased to 29. All sources are evenly distributed at the Earth’s surface with a spatial interval of 125 m (roughly 1.5 wavelengths). The resulting migration images obtained using the conventional reverse-time migration and least-squares reverse-time migration are shown in Figure 20. Compared to Figure 19, the images in Figure 20 contain fewer migration artifacts. In addition, the least-squares reverse-time migration image in Figure 20 gives a larger horizontal imaging region compared to that obtained using the conventional reverse-time migration.
Figure 19: Migration images of the synthetic 3D-VSP data from 15 sources on the Earth’s surface with a spatial interval of 250 m. Least-squares reverse-time migration in (b) provides an image with a higher resolution and fewer image artifacts than that in (a), and extends the imaging region beyond that in (a).

Figure 20: Migration images of the synthetic WAVSP data from 29 sources on the Earth’s surface with a spatial interval of 125 m. Least-squares reverse-time migration in (b) provides an image with a higher resolution than that in (a), and extends the imaging region beyond that in (a).
5.3 MIGRATION IMAGING OF CRANFIELD 3D-VSP FIELD DATA

A portion of the Cranfield 3D-VSP data was then increased to demonstrate the improvement of least-squares reverse-time migration over the conventional reverse-time migration. Data was selected from sources located: (1) approximately along a North-South line; (2) approximately along an East-West line; and (3) in a 2D area around the monitoring well where the receiver array is placed.

5.3.1 VSP Migration with Data from Sources along a North-South Line

First, 21 and 46 seismic sources were selected located approximately along a North-South line from the Cranfield 3D-VSP data volume for demonstrating the advantages of least-squares reverse-time migration. The selected sources are depicted in Figure 21. The migration images with 21 sources are shown in Figure 21, and those obtained using data from 46 sources are displayed in Figure 23. In both Figure 22 and Figure 23, the least-squares reverse-time migrations significantly improve the image resolution and produce more continuous layer images than the conventional reverse-time migrations. The least-squares reverse-time migrations also extend the imaging region beyond those of the conventional reverse-time migrations, as observed in the synthetic examples. When the amount of data for migration was increased, the image quality of least-squares reverse-time migrations improved more significantly than that of the conventional reverse-time migrations.

![Figure 21: Sources selected along a North-South line for reverse-time migration. In each panel, the dots represent the source locations and the cross mark indicates the location of the monitoring well.](image-url)
5.3.2 VSP Migration with Data from Sources along an East-West Line

Next, 22 and 41 sources were selected located approximately along an East-West line from Cranfield 3D-VSP data for migration imaging. The sources picked around an East-West line are shown in Figure 24. The migration images obtained using VSP data from 22 sources and 41 sources are depicted in Figure 25 and Figure 26, respectively. Compared with Figure 22 and Figure 23, the depths of the layers are similar, which to some extent confirms the reliability of the images. The same improvement of the least-squares reverse-time migrations was observed over the conventional reverse-time migrations as the migrations for the North-South line.
Figure 24: Sources selected around an East-West line. Each dot represents a source and the cross marks represent the monitoring well.

Figure 25: Images obtained using (a) the conventional reverse-time migration and (b) the least-squares reverse-time migration with VSP data from 22 sources around the East-West line (Figure 7a) in Cranfield 3D-VSP data. The image within the reservoir in (b) has a higher resolution and a larger horizontal imaging region than that in (a). Color indicates migrated reflection amplitude, with green near-zero amplitude.

Figure 26: Images obtained using (a) the conventional reverse-time migration and (b) the least-squares reverse-time migration with VSP data from 41 sources around the East-West line (Figure 7b) in Cranfield 3D-VSP data. The image within the reservoir in (b) has a higher resolution and a larger horizontal imaging region than that in (a). Color indicates migrated reflection amplitude, with green near-zero amplitude.
5.3.3 3D-VSP Migration with Data from Sources around the Monitoring Well

VSP data from 346 sources (Figure 27) and 13 receiver levels was used to conduct 3D migration imaging. The 13 levels are chosen from every fourth receiver from the whole array. The 3D migration images obtained with the conventional reverse-time migration and least-square reverse-time migration are shown in Figure 28 (front view) and Figure 29 (back view). The 3D images contain more noises than the 2D images because the data used for migration are from only a quarter of the total receivers. However, the improvement of least-squares reverse-time migration over the conventional reverse-time migration is clearly demonstrated in Figure 28 and Figure 29; the layer images of the least-squares reverse-time migrations have a higher resolution and a larger lateral imaging region than those obtained using the conventional reverse-time migration. From the 3D image in Figure 28(b), the layers bend slightly upward in the negative X-direction. This is consistent with the dome structure of the reservoir (Lu et al., 2012).

Figure 27: Source locations in a 4 km × 4 km region around the monitoring well. Each dot represents a source and the cross mark indicates the location of the monitoring well.

Figure 28: Front views of 3D migration images obtained using (a) the conventional reverse-time migration and (b) the least-square reverse-time migration with 3D-VSP data from 346 sources and 13 receiver levels acquired at the Cranfield EOR field. The image in (b) has a higher resolution and larger imaging region than that in (a).
5.4 DISCUSSION OF DEPTH IMAGING PROCESSING

The imaging principle requires that the shot and receiver intervals should be less than a half of the wavelength of the important reflection events to avoid the spatial image aliasing. However, cost-effective time-lapse 3D seismic monitoring cannot afford to use the ideal shot and receiver intervals. For example, the average horizontal distance among the adjacent sources in the Cranfield 3D-VSP survey is approximately 210 m or 3 wavelengths. The sparse distribution of sources can lead to strong migration artifacts including migration smiles, e.g., see Figure 19a. Least-squares reverse-time migration is able to flatten the migration smiles and extend the lateral imaging region (Figure 19b).

When the number of sources in synthetic VSP data increased, the migration artifacts were almost invisible, as shown in Figure 20. In this case, the benefit of least-squares reverse-time migration is primarily the larger imaging region compared to the conventional reverse-time migration (comparing Figure 20a to Figure 20b). However, for the migration of field VSP data containing noises, the increase of the amount of data leads to more significant improvement in the images of least-squares reverse-time migration than in those of the conventional reverse-time migration (comparing Figure 25a and Figure 26a; Figure 25b and Figure 26b). In other words, the least-squares reverse-time migration utilizes VSP field data for imaging more effectively than the conventional reverse-time migration.

This study shows that the least-squares reverse-time migration method is one of the best imaging tools among different migration schemes for 3D-VSP imaging where sources are usually sparsely distributed. Least-squares reverse-time migration of VSP data produces images with a higher spatial resolution and increases horizontal imaging regions compared to the conventional reverse-time migration. Least-squares reverse-time migration images can be used for accurate characterization of reservoir structures and is expected to facilitate more reliable monitoring of reservoir changes caused by CO₂ injection. The benefit of the least-squares reverse-time migration is largest when the amount of data is limited, such as 3D-VSP surveys where sources are sparsely distributed at the Earth’s surface. Therefore, least-squares reverse-time migration appears to be one of the best imaging tools for cost-effective and reliable monitoring for geologic carbon storage using 3D-VSP surveys.
6. **RESULTS**

The comparison of conventional processing for 3D surface seismic and 3D-VSP showed notably different results for the reservoir interval and the AZMI. For the high-amplitude reservoir interval, the 3D-VSP does not provide significant extra value at this site. However, the conclusion for the AZMI at this site is quite different. Comparing the reflectivity at an intermediate depth, only the 3D-VSP (not the 3D surface seismic) has clear imaging of reflection events. The generally poor reflectivity observed on the 3D surface seismic in this zone suggests less ability to monitor for leakage, while the clear reflector seen on the 3D-VSP suggests a better prognosis for time lapse monitoring. **Therefore, 3D-VSP has an improved ability to image the geology, and thus improve the ability to quantify changes in relatively weak reflective zones near a wellbore.**

A technique was also investigated for improving resolution beyond that of conventional processing, using least-squares reverse-time migration. The least-squares reverse-time migration utilizes VSP field data for imaging more effectively than conventional reverse-time migration.

**This study shows that the least-squares reverse-time migration method is one of the best imaging tools among different migration schemes for 3D-VSP imaging where energy sources are usually sparsely distributed on the Earth’s surface.** Least-squares reverse-time migration of VSP data produces images with a higher spatial resolution and greater horizontal imaging distance (away from the well) as compared to conventional reverse-time migration. Least-squares reverse-time migration images provide an improvement over standard seismic processing for more accurate characterization of reservoir structures and are expected to show improved quantification of reservoir changes caused by CO₂ injection. Therefore, least-squares reverse-time migration appears to be one of the best imaging tools for cost-effective and reliable monitoring for geologic carbon storage using 3D-VSP surveys.
7. CONCLUSIONS AND DISCUSSION

The Cranfield 3D-VSP study consists of two different investigations of VSP technology as it applies to the storage of anthropogenic CO\textsubscript{2}. These investigations are firstly, a comparison of the subsurface spatial resolution of 3D-VSP technology compared to 3D surface seismic technology, and the potential economic and technical value of 3D-VSP technology for monitoring. The second investigation considers the value of least-squares reverse-time migration processing for coping with the more sparse distribution of seismic sources involved with VSP surveys and avoidance of processing artifacts that may mimic low offset faults or other subsurface discontinuities. Such artifacts may result in the incorrect conclusion of higher project risk, greater geologic uncertainty, or result in negative impacts to project schedule or budget.

For the Cranfield dataset, the 3D-VSP data have only slight improvements over conventional 3D surface seismic in the resolution of high amplitude, continuous reflectors (such as the top of the Tuscaloosa formation); however, a real advantage of 3D-VSP at Cranfield is found in the improved imaging of weakly reflective, apparently discontinuous reflectors. At Cranfield such reflectors occur above the injection formation in an important leakage monitoring zone. At other sites, the reservoir interval may consist of weakly reflective seismic events whose imaging could be improved by 3D-VSP. This improvement in imaging of weak reflectors is critical to being able to better calibrate and quantify changes in fluids and rock properties during monitoring.

In this examination of reverse-time migration processing of VSP data, the complications of migration artifacts were caused by less than ideal shot and receiver intervals and by sparse distribution of source stations, two common situations in the acquisition of VSP data. The least-squares reverse-time migration was found to have the ability to flatten the common but troublesome processing artifacts known as migration smiles and extend the lateral imaging region, both of which are valuable improvements. This methodology also produces images with a higher spatial resolution, and is especially beneficial when the amount of data is limited by sparse seismic energy sources. Potential topics for future studies include the use of least-squares reverse-time migration for time-lapse 3D seismic monitoring, and further improvement of time-lapse monitoring with sparse-array data acquired using optimal survey designs.

In general, borehole seismic imaging is an intermediate scale measurement which does not give the large spatial sampling of surface measurements, but has potentially higher resolution in the vicinity of a borehole. This makes borehole methods particularly useful for well leakage detection and monitoring, but less useful for detecting fault/fracture leakage or other caprock seal problems. However, once a fault/fracture leakage has been detected, it is likely that a monitoring well would be needed to improve understanding of the leakage situation.

An extension of 3D-VSP work is 3C 3D-VSP, which can utilize shear-wave response to better understand subsurface properties. An intermediate application is processing for converted wave volumes (P- to S-wave conversion) whenever a P-wave 3D surface survey is being shot, and especially when the source is a less expensive vibe source as opposed to explosive shots (so that additional source stations can be cheaply added). Modern VSP surveys will almost always use 3C sensors, allowing converted wave recording with no extra cost.

The analysis of the 3D-VSP presented here, and potential further use of this specific Cranfield dataset, is best viewed in the context of the many other studies focused on monitoring the DAS site at Cranfield. As part of the larger Cranfield project team, the NRAP team investigated related topics such as seismic anisotropy and analysis of the 3D surface seismic. These topics
were considered in the context of NRAP’s interest in improving and quantifying spatial resolution of seismic monitoring. These research results are presented in the Appendix.

Finally, the Cranfield 3D-VSP leveraged the acquisition of a 3D surface seismic survey (as do many 3D-VSPs), however much of the energy from a large 3D survey will be beyond the critical angle for a given VSP, and typically extra in-fill shots are required for a 3D-VSP because the VSP has fewer sensors. Issues such as the need for in-fill shots is an example of the need for careful pre-survey planning and modeling, which directly affects the spatial resolution obtained from the acquired dataset.
8. REFERENCES


APPENDIX: ADDITIONAL RESEARCH PLANNED AND/OR STARTED

As discussed, the 3D-VSP analyzed here is a single “snapshot” in time. A key next step to continue this work would be acquisition of a time-lapse 3D-VSP along with another repeat of the 3D surface seismic. Spatial sampling with the current data was investigated; however, temporal sampling and CO₂ saturation quantification require time-lapse (4D) datasets and could not be investigated.

Several additional uses of the Cranfield 3D-VSP were considered during the course of this work, including the following:

- Identification of azimuthal features, including fracture zones for monitoring
- Reservoir anisotropy, improving conceptual and numerical models for inter-wellbore scale prediction for monitoring management
- Inversion of dynamic properties of the reflected wavefield using Amplitude versus Offset or Azimuth (AVO/AVA) analysis. There is a need for survey planning to assure appropriate angular illumination.

A.1. RESERVOIR ANISOTROPY

Seismic anisotropy can be a key factor controlling the spatial resolution and precision of seismic data. Because core studies of the Tuscaloosa reservoir unit had indicated strong seismic anisotropy (Nakagawa et al., 2013), the use of existing sonic log data in the VSP well and nearby monitoring wells were investigated. Figure A1, Figure A2, and Figure A3 show results from this work.

Figure A1: Anisotropy results from above the reservoir interval 10,040–10,045 ft. Showing presence of anisotropy and the fast azimuth direction (often due to fracture orientation).
Figure A2: Anisotropy results from the reservoir interval 10,509–10,515 ft. Showing presence of anisotropy and the fast azimuth direction.

Figure A3: Anisotropy results from the reservoir interval 10,558–10,560 ft. Showing presence of anisotropy and a slight change in the fast azimuth direction.
A.2. 3D SURFACE SEISMIC ANALYSIS

Analysis of the 3D-VSP was tied to comparison of the 3D surface seismic surveys. An initial review and analysis of the 3D surface data was conducted. Two 3D reflection seismic surveys have been collected in collaboration with Denbury Resources in Franklin County, Mississippi, over the Cranfield Geophysical Monitoring area. The two surveys differed in specific areal coverage. The portion of the data that was repeated gives two 3D volumes, defined by Inlines ranging between 971 and 1,310 and Crosslines ranging between 0 and 365, were collected before and after CO2 injection into the target structure. The unit cell 3D reflection seismic survey binned horizontal spatial was 82.5 ft by 82.5 ft (25.1 m) in both surveys. The processing sequence applied to both surveys is shown in Table A1.

<table>
<thead>
<tr>
<th>Table A1: Processing sequence for 3D reflection seismic surveys</th>
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<tbody>
<tr>
<td>Shot and Receiver Geometry definition</td>
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<tr>
<td>Time Function Gain (T= 1.7)</td>
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<tr>
<td>Wavelet Transform Filter</td>
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<tr>
<td>Surface Consistent Gain</td>
</tr>
<tr>
<td>Surface Consistent Spiking Deconvolution (100 ft; 200–4,000 MS/10,200 ft; 3,200–4,400 MS)</td>
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<tr>
<td>Refraction Statics (Datum = 300 ft, correction velocity = 6,000 ft/s)</td>
</tr>
<tr>
<td>Velocity Analysis</td>
</tr>
<tr>
<td>Residual Statics</td>
</tr>
<tr>
<td>Velocity Analysis</td>
</tr>
<tr>
<td>Trim Stack</td>
</tr>
<tr>
<td>Offset Domain Noise Attenuation</td>
</tr>
<tr>
<td>Migration Velocity Analysis</td>
</tr>
<tr>
<td>1,500 MS AGC</td>
</tr>
<tr>
<td>Kirchhoff Prestack Time Migration</td>
</tr>
<tr>
<td>Stack</td>
</tr>
<tr>
<td>Bulk Shift -50 MS to Sea Level</td>
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</tbody>
</table>

Both stacked 3D reflection seismic volumes and pre-stack time migrated, NMO corrected CMP gathers were available for analysis in this geophysical monitoring activity. Seismic wavelets extracted from both surveys showed high quality, and the wavelet and signal spectrum for the first survey are shown in Figure A4.
Figure A4: Extracted wavelet (left) and signal spectrum (right) from a representative portion of the first reflection seismic survey.

From the pre-stack volumes amplitudes (Time) values additional seismic reflection post-stack attributes were calculated for both surveys. The attributes calculated are shown in Table A2.
Table A2: Post stack attributes calculated from Cranfield Geophysics Monitoring 3D reflection surveys

<table>
<thead>
<tr>
<th>Attribute (Time)</th>
<th>Acceleration of Phase</th>
<th>Band Width</th>
<th>Chaotic Reflection</th>
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<tbody>
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<td>Curvature Attributes: Azimuth / Curvedness / Gaussian / in Dip Direction / in Strike Direction / Maximum / Mean / Minimum / Most Negative / Most Positive / Shape Index</td>
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<td></td>
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<tr>
<td>Dip Azimuth</td>
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<td>Dip Variance</td>
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</tr>
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<td>Imaginary Part</td>
<td>Instantaneous Attributes: Dip / Frequency / Frequency Envelope Weighted / Lateral Continuity / Phase / Q</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normalized Amplitude</td>
<td>Parallel Bedding Indicator</td>
<td>Real Part</td>
<td>Relative Acoustic Impedance</td>
</tr>
<tr>
<td>Similarity Variance</td>
<td>Smoothed Dip of Max Similarity</td>
<td>Smoothed Similarity</td>
<td>Thin Bed Indicator</td>
</tr>
<tr>
<td>Trace Envelope</td>
<td>Wavelet Attributes: Acceleration of Phase / Apparent Polarity / Band Width / Dominant Frequency / Envelope / Envelope Second Derivative / Frequency / Frequency Envelope Weighted / Phase / Q</td>
<td></td>
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</tr>
<tr>
<td>Zones of Unconformity</td>
<td></td>
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</tbody>
</table>
Figure A5 and Figure A6 compare the two 3D reflection surveys Xlines at 197. In both surveys data are of good quality. Some variation in amplitude is seen between the surveys and different volumes can be calculated to determine an area of interest.

Figure A5: Xline 197 from the first 3D survey.
Cross plots of attributes are being investigated to determine the potential for identification of fluid change regions. In Figure A7, two cross plots are shown. Plotted are the relationships between trace sub-bands, calculated by octaves centered on 13.3 Hz and 28.8 Hz for the first and second surveys in the region of Xline 180 to 220 and Inline 1010 and 1100. The variation between the two cross plots is being investigated.
AVO was observed to vary between the surveys. For a representative location two NMO corrected, pre-stack migrated gathers are shown in Figure A8. Note the variation in AVO response between the surveys. These results are being analyzed now.
Within the region of investigation a 3D-VSP was collected. The significantly improved lateral and vertical resolution of the VSP is clearly seen in Figure A9.
Additional analysis of the reflection seismic surveys includes a systematic comparison of differences between attributes and a petrophysics-based quantitative interpretation, calculation of ant-tracked volumes, and the calculation from the 3D-VSP of seismic attributes for comparison with those calculated from the reflection seismic volumes.
NRAP is an initiative within DOE’s Office of Fossil Energy and is led by the National Energy Technology Laboratory (NETL). It is a multi-national-lab effort that leverages broad technical capabilities across the DOE complex to develop an integrated science base that can be applied to risk assessment for long-term storage of carbon dioxide (CO₂). NRAP involves five DOE national laboratories: NETL, Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), Los Alamos National Laboratory (LANL), and Pacific Northwest National Laboratory (PNNL).

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