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Monitoring carbon dioxide storage using passive seismic techniques

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Carbon dioxide stored in geological reservoirs to reduce anthropogenic emissions must be monitored to ensure that no leakage is occurring. One leakage risk is that injection-induced pressure increases may generate fractures in the caprock, providing a pathway for buoyant carbon dioxide to penetrate the reservoir seal. Geophones can be deployed to detect fracturing events. The rates and magnitudes of seismicity, and their hypocentres, can be used to characterise geomechanical deformation induced by injection, and thereby assess the risks of leakage through fractures. In this paper synthetically modelled data are used to show how surveys should be designed to maximise the potential for this technique within the specific remits of carbon dioxide capture and geological storage (CCS), before discussing several case examples where passive seismic monitoring has been used to monitor subsurface injection of carbon dioxide. Recommendations and suggestions are given for the deployment of passive seismic monitoring as CCS moves from pilot to full-scale demonstration and commercial projects.

Notation

P_{fl}	pore fluid pressure
α	Biot–Willis stress coefficient
δ_{ij}	Kronecker delta
σ_{ij}	applied stress (tensor)
$\sigma_{ij}^{\mathrm{eff}}$	effective stress (tensor)

1. Introduction

By providing a large volume of secure storage space, deep saline aquifers and mature oil reservoirs provide an opportunity to store carbon dioxide produced by fossil fuel power stations that would otherwise be emitted to the atmosphere (Linkohr, 2007). To store carbon dioxide securely, the reservoir must be overlain by impermeable caprock that prevents the upward migration of buoyant, supercritical carbon dioxide (Garcia *et al*., 2010). Hydraulically conductive (Barton *et al*., 1985) 'open' faults and fractures provide a pathway for fluids to move through an otherwise low-permeability rock, so it is important that the state of fracturing – length, number density and orientation – in the caprock can be determined. It is assumed that initial geological characterisation will have shown the caprock integrity to be sound before carbon dioxide injection begins at any particular site. However, even if a caprock is initially sound, its integrity could be compromised during the injection phase. Therefore, it must be ensured that engineering activities, in particular the pore-pressure increases induced by injection, do not generate any new fractures, or reactivate previously closed fractures, that could provide a pathway for carbon dioxide leakage (Damen *et al*., 2006).

This paper will outline how passive seismic monitoring (PSM) can be used at carbon dioxide capture and geological storage (CCS) sites to ensure that the integrity of the caprock has not been compromised by injection activities. Geophones placed in boreholes around the reservoir, or larger arrays placed on the ground surface, can detect the seismic emissions produced by fracturing events. Accurately locating the sources of seismic emissions images how the reservoir and caprock is deforming in response to pore-pressure changes, and thereby the risks posed to security of storage. The present paper outlines the technical basis of PSM, and its development in the hydrocarbon industry, before discussing how arrays can be designed specific to the challenges of monitoring a CCS site (as opposed to monitoring hydraulic fracture stimulation) and to maximise the information provided about storage security. Results are presented from two cases where PSM has been used to monitor carbon dioxide injection during a hydraulic fracture stimulation and a pilot CCS site, and the lessons learnt that can be used when developing monitoring programs for large-scale commercial CCS sites.

1.1 Microseismicity and passive seismic monitoring

When fluids are injected into or produced from porous reservoir rocks, pore-pressures are changed. The stress applied to a rock (σ_{ij}) is coupled to the pore-fluid pressure (P_{fl}) by way of the

Biot–Willis parameter (α), giving the effective stress tensor, σ_{ij}^{eff}. Therefore, except for rare cases with near-zero α, pore-pressure change alters the effective stress following (Terzaghi, 1943)

$$\sigma_{ij}^{\text{eff}} = \sigma_{ij} - \delta_{ij}\alpha P_{\text{fl}}$$

where δ_{ij} is the Kronecker delta. The mechanical deformation induced by effective stress change can create or reactivate faults and fractures (Segall, 1989), releasing seismic energy. This process is directly analogous to earthquakes, except that the magnitudes of events generated in and around reservoirs (commonly with moment magnitudes as low as -1 to -4) are far smaller, so are often termed microearthquakes or microseismic events.

The seismic energy released by a microearthquake can be detected using arrays of seismometers placed either in boreholes near the regions of interest, or by larger arrays of seismometers sited on the surface. A range of seismic phases can be recorded, including the familiar P- and S-waves, which may travel complicated paths between the event and receivers. The polarisation of the arriving P wave, the differences in travel-time between P and S waves, and the moveout of arrival times across the array, are used, along with a pre-defined subsurface velocity model, to compute a location for the source of the waves – the event hypocentre – which represents where brittle failure has occurred as a result of mechanical deformation (Eisner *et al.*, 2010a; Zimmer *et al.*, 2007).

The first deployments of PSM were in the mining and hydrothermal industries (Maxwell, 2010; Maxwell *et al.*, 2010a). The technique was first used in the oil and gas industry in the late 1970s, although its use was rather experimental. A significant increase in the deployment of PSM began in the late 1990s, with the development of tight and shale gas fields, such as the Barnett shale, that required natural and induced fractures to be produced economically. As the oil industry moves increasingly towards unconventional resources such as shale gas and heavy oil, where an understanding of how production activities affect reservoir deformation becomes ever more crucial, the use of PSM is becoming a standard practice (Eisner *et al.*, 2010b).

In particular, PSM is commonly used to monitor hydraulic reservoir stimulations, where fluids are injected at high pressure to induce fractures, providing conduits for improved flow of hydrocarbons (Economides and Nolte, 1989). During so-called 'frac-jobs', PSM can reveal the growth of fractures propagating away from the injection well and into the formation. Typically, this technique can reveal the lengths, heights, and orientations of these fractures.

In some ways hydraulic fracture stimulation can be viewed as a worst-case scenario for a CCS site, where fluid injection, at pressures that are too high for the formation to withstand, generates intense fracturing. However, because fracturing is intentional during frac-jobs, the injection pressure is above the fracture pressure (the pore-pressure needed to overcome the applied compressive stress and the tensile strength of the rock) and so generates both tensile and shear deformation (Pearson, 1981), whereas for carbon dioxide, storage injection should be well below the fracture pressure, making tensile failure less likely and implying that shear will be the dominant mode of deformation.

PSM has also been used to monitor reservoir deformation caused by production activities where no fracturing has been deliberately stimulated (De Meersman *et al.*, 2009; Dyer *et al.*, 1999; Jones *et al.*, 2010; Segall, 1989). At the Valhall reservoir in the North Sea, over 4 m of seabed subsidence has occurred since production began in 1982 as a result of pressure depletion and compaction of the reservoir. Furthermore, gas clouds in the overburden are inferred to have developed from leakage from the reservoir through faults and fractures (Barkved *et al.*, 2003), a scenario that is highly pertinent to gas leakage from CCS reservoirs. During June and July 1998 a six-geophone PSM array was placed in a vertical well above the reservoir and several hundred events were detected (Dyer *et al.*, 1999). Accurate event locations showed how deformation in the region of the survey was being accommodated on at least two parallel faults in the overburden (De Meersman *et al.*, 2009). A similar survey was conducted at Ekofisk, another subsiding North Sea reservoir (Oye and Roth, 2003). As at Valhall, gas clouds in the overburden indicate leakage through faults and fractures. An array of six geophones was placed in a vertical well at reservoir depths. In contrast to Valhall, the majority of events were located within the depleting reservoir unit (Jones *et al.*, 2010). Clustering of events on planar surfaces helped to reveal the presence of active faults.

1.2 Passive seismic monitoring and CCS

Over shorter-term timescales, most of the carbon dioxide injected at a CCS site will exist as a free phase that is trapped below impermeable caprocks that form structural and/or stratigraphic traps. One way in which the hydraulic integrity of the caprock can be compromised is through the formation or reactivation of faults and fractures. Open fractures provide pathways for rising carbon dioxide to bypass the impermeable caprock layers, returning to the surface and making CCS at best an expensive waste of time and at worst proving a danger to nearby populations. Injection of carbon dioxide will increase the pore-pressures of the formation, which, as discussed above, can promote the formation and reactivation of fractures. The primary role of PSM for CCS is to detect the occurrence of fracturing events, and to determine whether this seismicity poses a risk to storage security.

PSM can be viewed as a technique where a null result is a good result, in that an array will be installed with the hope that no seismicity occurs. In this respect it is much like, for example, groundwater chemical monitoring, and soil gas flux measurements at CCS sites, where a satisfactory result is one where no change is detected after injection begins. However, PSM can provide advanced warning of leakage far earlier than surface chemical measurements, allowing remediation measures to be enacted before carbon dioxide has escaped to the surface. Many reservoirs have a natural rate of microseismicity occuring before injection begins. It is important that arrays be installed prior to injection to measure background microseismic rates, so that any changes to this rate can be identified. Furthermore, an array installed prior to injection might be used to identify areas already experiencing higher rates of microseismicity that would make a poor place to site an injection well.

During hydraulic fracturing, injection pressure is high enough to exceed the tensile strength of the rock, creating a hydraulic fracture that will propagate outwards from the injection well parallel to the direction of maximum horizontal stress. Microseismicity will track the formation of these fractures, allowing their orientation, length and height to be determined. At lower injection pressures (such as those used to stimulate geothermal reservoirs), tensile fractures might not be created. Nevertheless, conventional injection-induced-seismicity theory (Shapiro 2008, and references therein) dictates that microseismicity will occur at a given point when the pore pressure exceeds a critical threshold value. During injection, a region of elevated pore-pressure is created at the injection well, which moves radially outwards from the injection site. This high-pressure pulse will be tracked as a zone of microseismicity also moving radially out from the injection well. For such scenarios, both array design and data interpretation are relatively simple – events will occur around the injection well, and the extent that events move away from the injection site define the lateral extents of fracturing. However, at CCS sites, the intention is that injection should not elevate pore-pressures sufficiently to generate fracturing. Therefore PSM of CCS sites, as opposed to frac-jobs, poses a different kind of problem, both in survey design and in understanding what event locations mean.

Good geomechanical models can help resolve these issues. Forward modelling using geomechanics can help determine regions that are most at risk from microseismic activity (Angus *et al*., 2010; Verdon *et al*., 2011), and therefore the most important areas to monitor closely. By identifying zones at particular risk, monitoring arrays can be sited accordingly. Geomechanical simulation allows a range of different 'best-case' and 'worst-case' scenarios to be modelled. By predicting the microseismic response of each scenario and comparing with observations, we can differentiate these scenarios in the field. The state of the art in geomechanical modelling is to couple industry standard reservoir flow models with finite-element mechanical solvers to compute the deformation caused by production and injection in a reservoir (Dean *et al*., 2003).

A good understanding of the geomechanical factors in play is especially necessary for carbon dioxide injection into mature hydrocarbon reservoirs, which will have a long history of stress change during depletion, as well as pre-existing pore-pressure gradients around production wells. Of particular concern is that the stress path will be hysteretic during production and subsequent injection. This means that although reservoir pore-pressures might be returned to virgin pre-production conditions by injection, the effective stress tensor may be very different, promoting fracturing and seismicity in the reservoir and in the overburden (Santarelli *et al*., 1998).

2. Event location methods and survey design

The two most common methods for detecting microseismic events are to deploy a geophone array in a vertical borehole close to the reservoir, or to deploy a larger array of geophones at the surface. Typically, vertical borehole arrays provide improved detection limits (i.e. can detect smaller events) and greater vertical resolution, while surface arrays can cover a wider area, and often provide greater lateral resolution (Chambers *et al*., 2010; Eisner *et al*., 2010a). The case examples presented in this paper use vertical borehole arrays, so this method is the focus of the paper. See Duncan and Eisner (2010) for a review of surface PSM methods.

For downhole monitoring, several (usually 5–20) geophones are cemented in place, usually spaced 10–50 m apart. The geophones are connected to a recording device at the surface. The three (X, Y, Z) or four (tetrahedral) component geophones record the arrival of P and S waves generated by a microseismic event. Each event occurs at an unknown location, at an unknown time, which must be computed using the arrival times and the particle motions of each phase. P and S waves travel at different speeds through the rock, and prior to event location a velocity model for both phases must be constructed, commonly using borehole sonic log measurements, and/or surface seismic observations. Typically, for vertical wells, a one-dimensional (1D) 'layer-cake' velocity model is used. Based on the velocity model, the differential travel time between the two phases can be used to compute the distance of the event from each geophone in the array. Triangulation between the sensors in the array then provides the event location.

The majority of downhole arrays are set in vertical wells. Triangulation using such an array, with a layer-cake velocity model, will provide only the radial distance from the array, and event depth. The azimuth of the event from the array remains unknown. However, as it is a longitudinal wave, the particle motion of a P wave is parallel to the direction of wave travel. Therefore, by analysing the particle motion at the geophones during the passage of the P phase, the event azimuth can be determined. Automated picking and location algorithms exist that allow passive seismic analyses to be conducted in near real time (Oye and Roth, 2003).

To calibrate the velocity models, as well as to determine the orientations of the geophones, a check shot is usually used. Usually this takes the form of a small explosive used to perforate the casing of a nearby well. As the shot has a known location, the velocity model and geophone orientations can be calibrated such that the perforation location computed by the geophones provides a good match.

2.1 Location uncertainties

The two main sources of location uncertainty are the presence of noise on the seismograph traces, and inaccuracies in the velocity model. The presence of noise leads to inaccuracies in both picking the onset times of the P and S phases, and in particle motion analysis. Inaccuracies in the velocity model accrue from extrapolating and discretising sonic log and three-dimensional (3D) seismic data into a layer-cake velocity model that will not fully represent real, in situ rocks. The random error introduced by noise and picking errors leads to an uncertainty in hypocentral location (Eisner *et al.*, 2009). Errors in the velocity model can generate systematic biases in event location that can be harder to quantify. For instance, if velocities are underestimated the events will tend to be located more closely to the monitoring well than they should.

Typically, location errors are broken down into error in the horizontal plane (X–Y error) and error in depth location (Z error). The quality of event location can be described by travel-time residuals between picked and expected arrivals, the number of geophones on which picks can be made, the consistency of azimuthal take-off angles (computed from particle motion analysis), and the signal to noise ratio of the seismograms. Zimmer *et al.* (2007) provide a method to combine these influences to generate a single number representing the quality of an event location.

2.2 Detection limits

The majority of events around hydrocarbon reservoirs have moment magnitudes of between −1 to −4. With events of such small magnitude, detectability becomes an important issue. Typically, detected event magnitudes are plotted as a function of distance from the array, describing an envelope of minimum detectable magnitude (Figure 1). Beyond this limit, events do not produce a detectable signal above the noise on the geophones. The detectability envelope is controlled by the amount of attenuation experienced by the seismic wave as it travels through the rock, and the amount of noise at the geophones. Seismic energy released by the source is attenuated through a number of mechanisms, including geometrical spreading of the wavefront, scattering from small-scale heterogeneities, and inelastic processes such as internal friction and viscous flow of fluids within the pore space excited by the seismic wave. The amount of attenuation can vary strongly between rock types, and is especially promoted by the presence of fractures, and by compressible fluids such as carbon dioxide. The likely detectability threshold is a factor that must be taken into consideration when designing an array to monitor CCS.

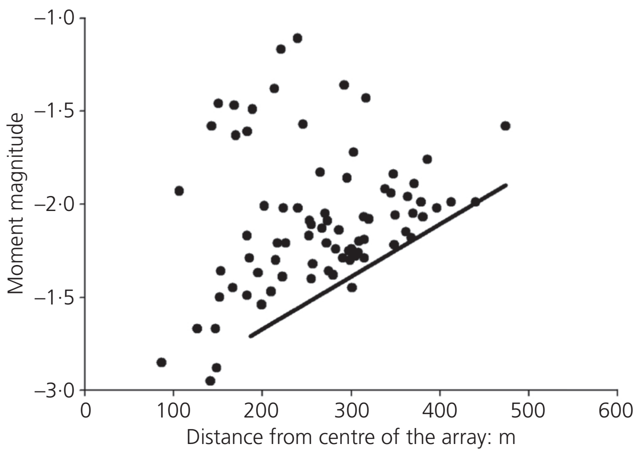

Figure 1. A typical magnitude–distance plot, from the Weyburn microseismic array (modified from Verdon *et al.*, 2010a), which shows the minimum detectability threshold

2.3 Survey design

To maximise the benefits of PSM, careful survey design should be conducted. As accurate event locations rely in part on triangulation between geophones, the accuracy of an event location will be controlled by the locations of the geophones on which it is detected. By assuming likely error distributions in P- and S-wave picking accuracy, it is possible to compute the probability distribution function (PDF) for a given event location (Eisner *et al.*, 2009, 2010a). This approach can be used to examine the ability of a particular array to accurately locate events: a narrow, tightly constrained PDF implies that an event will be well located by an array; a broad PDF implies an event will be poorly located. Figure 2 presents a brief analysis showing how array aperture, the location of an event relative to the array, and the use of multiple vertical arrays, affect the accuracy of an event location.

Wider array apertures (the distance between topmost and bottom geophones) improve the basis for triangulation, and so reduce the error in vertical location (Figures 2(a) and (b)). However, increasing aperture too far will simply extend the

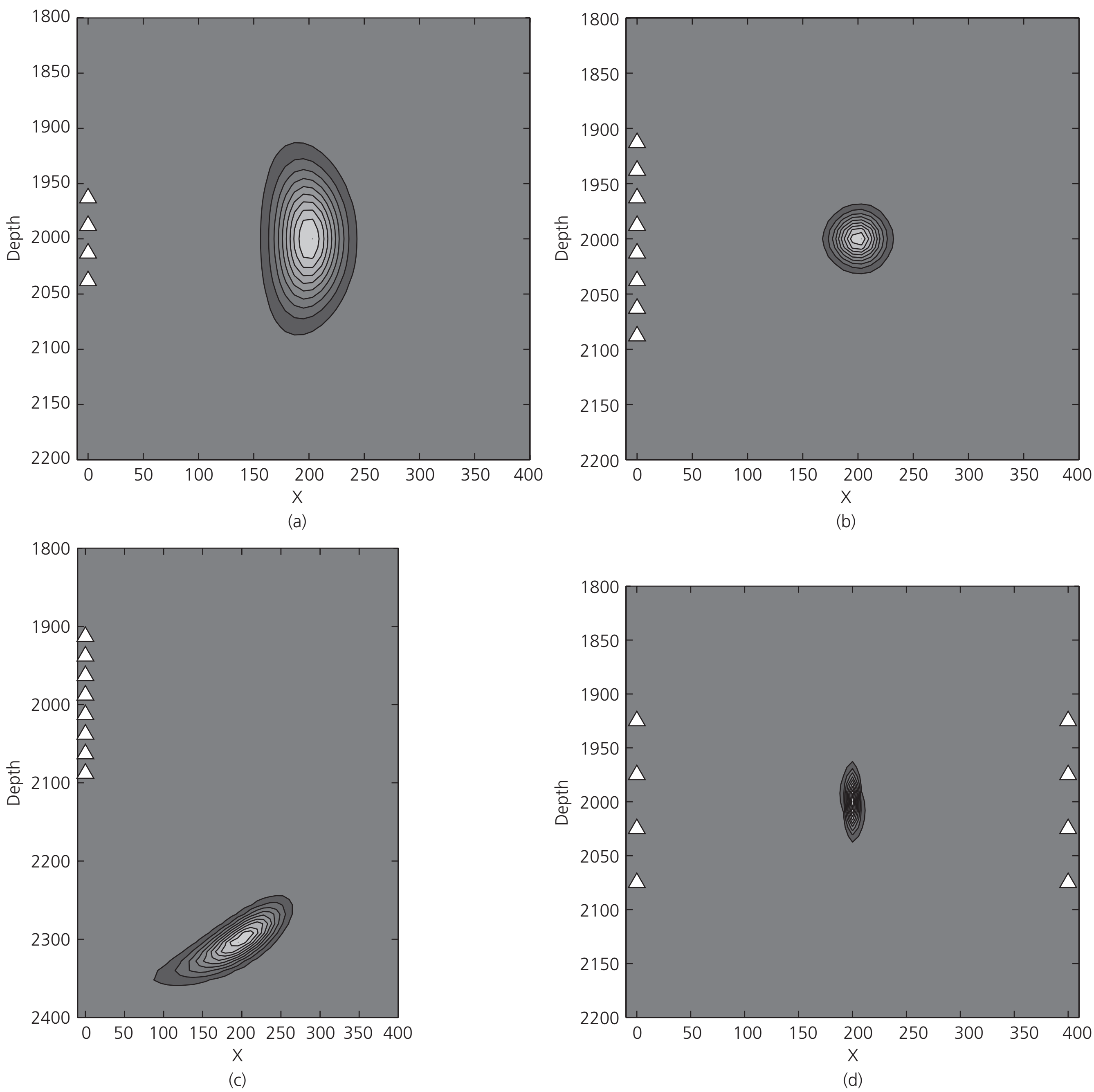

Figure 2. Cross-sections of synthetic event location probability density functions, showing how array aperture affects event location. Geophone locations are marked by white triangles. With a narrow aperture (a), the event depth is poorly constrained. Increasing the aperture (b) improves the depth location accuracy. However, if the event occurs above or below the array (c), event locations may not be as accurate. Multiple arrays in different boreholes ((d) has two arrays at $x = 0$ and $x = 400$) can substantially improve horizontal event location accuracy

ends of the array beyond the detection limits, rendering them useless. Events can be located most accurately when they occur at the same depth as the array. When an event occurs below the array, the event PDF becomes smeared (Figure 2(c) in comparison with Figure 2(b)), increasing the error in both horizontal and vertical location.

Figure 2(d) examines the reductions in location error provided by introducing a second vertical array. The event PDF is better constrained because rather than relying solely on differential P–S arrival times to compute the radial distance from the array, the differences in P and/or S phase arrival times between the different arrays provides an alternative means to compute source-receiver distances. When using a single array, source-receiver azimuths can only be computed using P-wave particle motion, which can be influenced by near-receiver effects, such as meso-scale heterogeneities. With data from multiple vertical arrays, triangulation can be used to constrain the X–Y location of the hypocentre. Furthermore, multiple arrays, with appropriate spacing based on event detectability, will increase the areal extent covered by a PSM array.

A key part of this process of survey design is to identify where microseismic events are likely to occur, so that recording arrays can be placed accordingly. In frac-job scenarios this is relatively easy to predict, as events occur in the vicinity of the injection point. However, it is harder in CCS scenarios, where injection is below the fracture pressure, to predict where (if anywhere) seismicity will occur. Geomechanical models can be used to identify regions of the reservoir and/or overburden that will be most prone to failure and microseismicity (Angus *et al*., 2010; Verdon *et al*., 2011), so arrays can be designed that monitor these features most effectively. It is also important to consider which features of the microseismic data need to be constrained most accurately. For example, when monitoring frac-jobs it is often the X–Y locations that are most important, as they delineate the length and orientation of the fracture. In contrast, for CCS the location in the X–Y plane may not be as important as its depth, because a microseismic event in the reservoir may be of little regard, while an event located in the overburden could be very significant if it is caused by upward migration of carbon dioxide. Therefore an array whose primary aim is to minimise errors in location depth might be the most appropriate for CCS scenarios.

An array designed to minimise depth location errors will have a larger aperture and, where possible, should be placed straddling the reservoir–overburden interface. This will allow the most accurate determination possible of whether an event is located in the overburden or in the reservoir. Furthermore, as most events will usually occur in and around the reservoir, so an array at this depth will have the best opportunity to detect as many events as possible. Where X–Y event locations are deemed to be important, multiple arrays in multiple wells will provide the best method of ensuring accurate horizontal locations.

So far only the basic aspects of event location have been described. Substantial improvements can be made to event locations using more involved methods, for example improved phase picking using cross correlation (Rowe *et al*., 2002); multiplet identification (De Meersman *et al*., 2009); combined multiple geophone polarisation analysis (De Meersman *et al*., 2005); particle motion dip based corrections (Jones *et al*, 2010); and statistical collapsing of data points into discrete clusters (Jones and Stewart, 1997).

Current developments in passive seismic analysis are moving beyond simply locating event hypocentres. Using surface-based or multiple downhole arrays, it is possible to compute event focal mechanisms (e.g. Eisner *et al*., 2010c; Rutledge *et al*., 2004), which provides a more complete understanding of the fracturing event, including the orientation of the fracturing plane, and stress conditions at the time of fracturing. Statistical analysis of event magnitude distributions can be used to reveal fault reactivation and other geomechanical attributes of the reservoir (Grob and van der Baan, 2011; Maxwell *et al*., 2010b). Additionally, by measuring the birefringence of recorded S-waves, it is possible to infer the intensity and orientation of any fracture sets along the raypath between source and receiver (Verdon and Kendall, 2011). However, such methods are beyond the scope of this paper. The following section will discuss several examples of where PSM has been used to monitor carbon dioxide injection.

3. Case studies

3.1 'Worst case' – carbon dioxide induced fracturing

First, PSM results are presented from a frac-job that used carbon dioxide as the fracturing fluid (Verdon *et al*., 2010b). As discussed above, although not directly analogous to a CCS site because injection at CCS sites will never intentionally go above the fracture pressure, this situation can be viewed as a worst-case scenario for CCS, where injection has led to significant fracturing, making it possible to examine the effectiveness of PSM as a monitoring tool in such situations.

The set-up for injection and PSM can be seen in Figure 3. An array of 12 three-component geophones was placed in a vertical borehole a short distance from the injection well. After injection, events image the formation of fractures propagating away from the injection well (Figure 3(a)). Additionally, in Figure 3(b) events can be seen rising vertically, tracking fractures forming almost 100 m above the injection site. Event location uncertainties are shown by the ticks in Figure 3. The evolution of the microseismic cloud can be seen more clearly

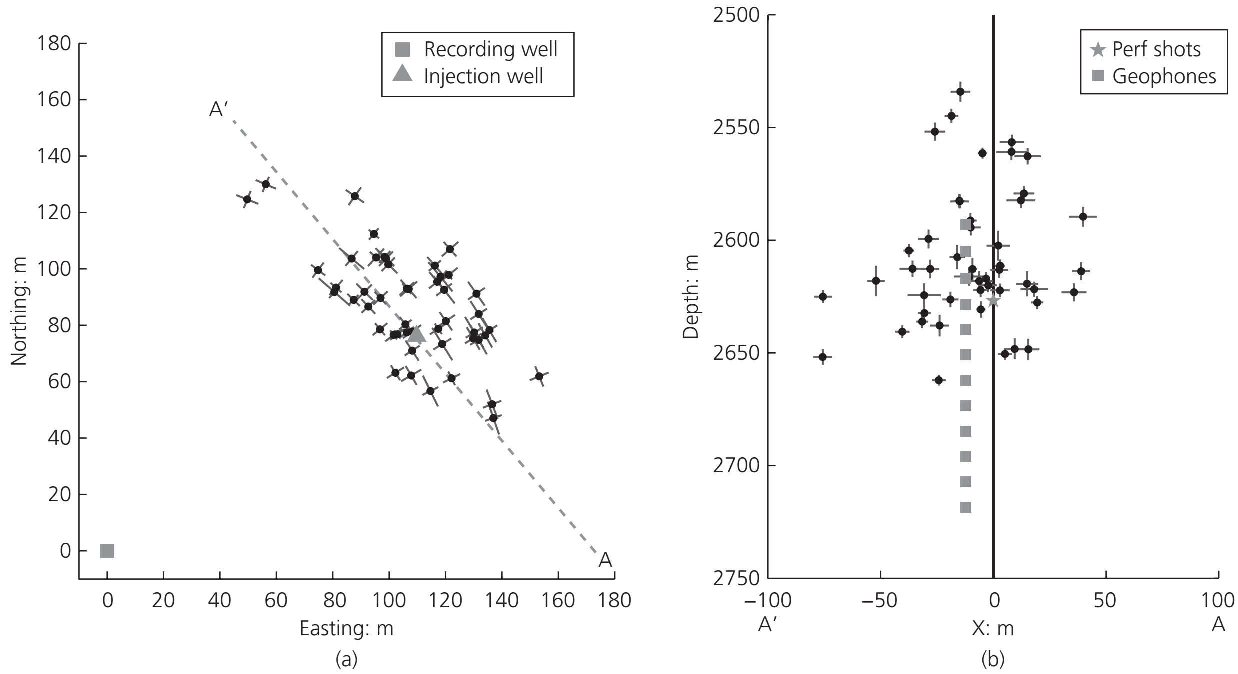

Figure 3. Microseismic event locations during the hydraulic fracture stimulation, in (a) map view and (b) cross-section perpendicular to the trend of fracturing. In (a) the locations of the injection well (grey triangle) and recording array (grey square) are marked. The limits of the cross-section (A–A′) are also marked in (a). Geophone depths and the injection interval are marked respectively by grey squares and star in (b). Ticks show 95% confidence limits. In map view, the events track the formation of fractures extending to the NW and SE of the injection site. In cross-section, some of the events are located well above the injection point

in Figure 4, which plots event depth as a function of occurrence time, along with the fluid injection rate. During injection, the microseismic cloud moves above the injection point. A plot of magnitude against distance (Figure 5) shows a reasonable degree of detectability, with events smaller than magnitude −3 being detected throughout the region of interest. It has been suggested that the presence of events 100 m above the injection point is at least facilitated by, if not a direct result of, the increased buoyancy and mobility of carbon dioxide in comparison to other injection fluids such as water (Verdon *et al.*, 2010b). Certainly, this case documents the type of PSM observation that would be of concern to operators – carbon dioxide injection has raised pressures enough to compromise the integrity of rocks around and overlying the injection point, and buoyant carbon dioxide appears to be rising vertically. This demonstrates that PSM is able to detect potential caprock integrity issues very quickly.

3.2 Weyburn

Carbon dioxide has been injected at Weyburn in Saskatchewan, Central Canada, since 2000, for the purposes of both enhanced

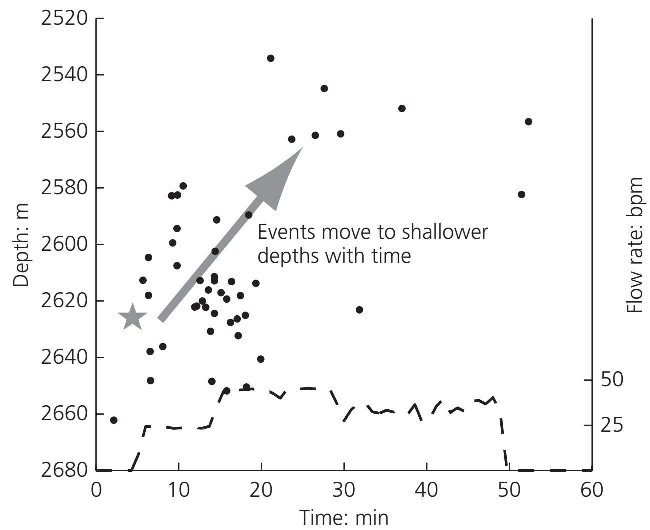

Figure 4. Event depths as a function of time from the start of injection during the hydraulic fracture stimulation. The grey star marks the injection depth. During the first 30 min of injection, the upper envelope of seismicity moves above the injection depth. The injection rate is also plotted (dotted line)

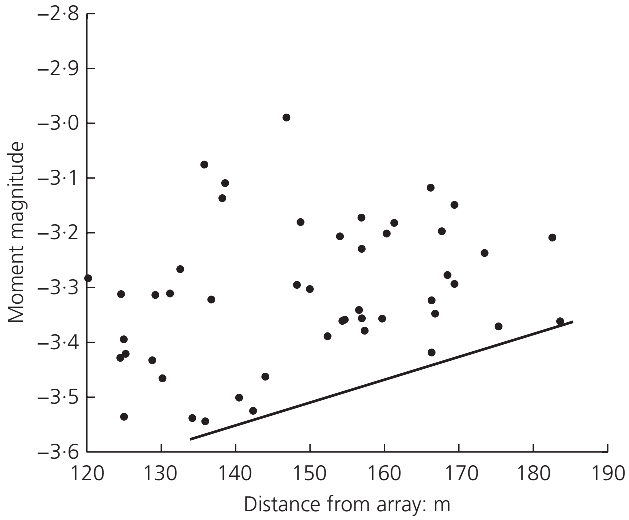

Figure 5. Detected event magnitudes as a function of distance from the array during the hydraulic fracture stimulation, showing the detectability limits. In this case events as low as −3·4 are detected almost 200 m from the array

oil recovery and storage. The reservoir is set in carbonate rocks of Mississippian age, at a depth of ~1430 m. Approximately 3Mt of carbon dioxide are injected annually, through over 20 injection patterns, at a rate of between 100 and 500 t/day per well. In August 2003 a passive seismic monitoring array was installed in one injection pattern. The array consisted of eight geophones placed in a disused vertical borehole (see Figure 6). The geophones were spaced at intervals of 25 m, between depths of 1180–1350 m. Carbon dioxide injection began in the nearby well in January 2004. Further details on the observed microseismicity can be found in Maxwell *et al.* (2004), White (2009) and Verdon *et al.* (2010a, 2011), and are summarised below.

Events have been located using the methods outlined above. Engineering and cost constraints mean that the array was placed over 100 m above the reservoir, and has a relatively small aperture. As shown in Figure 2, event locations for such a geometry will be quite poorly constrained. Some events have error ellipses extending over 100 m (marked by the ticks in Figure 6). This highlights the concerns raised during the discussion of array design – a small aperture array placed above the hypocentres will struggle to accurately locate the depths of seismicity. However, despite the limitations imposed by array geometry, Figure 6(b) shows that many of the events appear to be located in the overburden.

The six-month period between array installation in August 2003 and carbon dioxide injection in January 2004 provided a window to observe the background seismicity rate. Eight events were recorded, primarily associated with production activity in the horizontal well to the SE. Event locations are plotted in Figure 6. During January 2004, when carbon dioxide injection began, 17 events were recorded. Thirteen of these occurred when the well was injecting water as a precursor to carbon dioxide injection, with four occurring afterwards. These events are clustered between the injection well and a horizontal production well to the NW, with most of the events located closer to the production than the injection well. During the summer of 2004, injection rates were increased, and 31 events were detected, again located around the production well to the NW. Figure 1 plots event magnitudes against distance from the array, from which detection limits can be inferred.

After this period, the monitoring system was disabled to allow a controlled source four-dimensional (4D) survey, followed by maintenance and improvements to the recording system. The system was switched on again in late 2005. The only significant microseismicity during this period was a cluster of 21 events in January 2006, located near to the southeastern horizontal production well. No seismicity has been detected since early 2006. In total 69 locatable events have been detected during the injection period. This is a very low rate of seismicity (compared with, for example, Segall, 1989; Dyer *et al.*, 1999; Jones *et al.*, 2010, with typical detection rates of 100 s to 1000 s of events per month), implying either that carbon dioxide injection has not generated much deformation, or that deformation is occurring aseismically.

Conventional injection-induced seismicity theory suggests that microseismic events should initially cluster around the injection well, before moving radially away as the pressure pulse spreads (Shapiro 2008). However, at Weyburn the majority of events occur near the production wells even at the onset of injection – a radial progression of events through time is not witnessed. Additionally, many of the events were located in the overburden, which under a conventional approach, ignoring geomechanical effects, implies a pore pressure connection into the overburden, and therefore the possibility of carbon dioxide leakage. Therefore representative geomechanical models are needed to fully understand the seismicity at Weyburn (Verdon *et al.*, 2011). These geomechanical models show that, because of the particular geometry of injection and production wells at Weyburn, carbon dioxide injection increases the effective shear stress at the *production* wells, and in the overburden above production wells, rather than at the injection well (Verdon *et al.*, 2011). Microseismic events are most likely to occur in regions where shear stress is elevated, so this helps understand why microseismicity at Weyburn is primarily located around and above the production wells. This model demonstrates that microseismic events

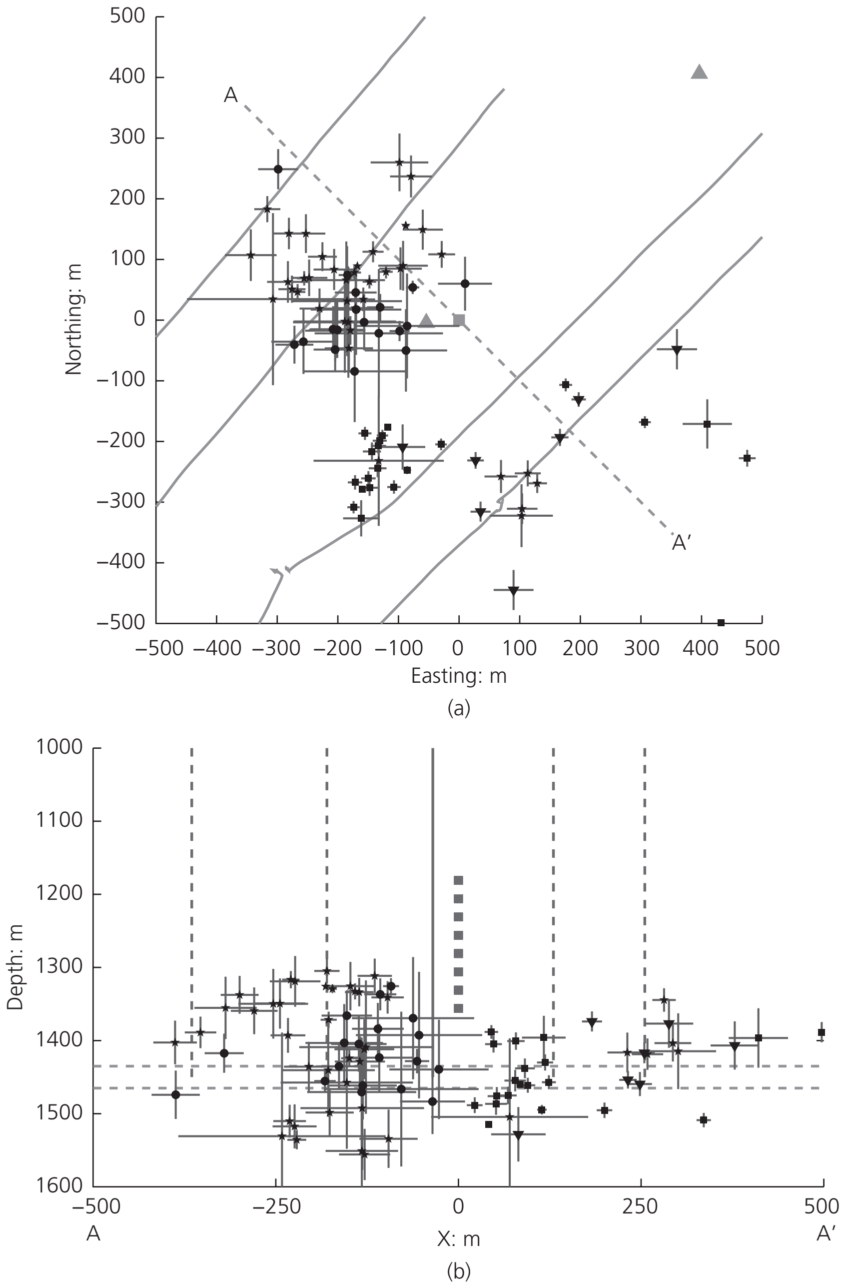

Figure 6. Weyburn microseismic event locations in map view (a) and in cross-section perpendicular to the horizontal well trajectories (b). In (a) the horizontal production wells are marked by grey lines, the injection wells by grey triangles, and the observation well by the grey square. The limits of the cross-section (A–A′) are also marked. In (b) the geophones are marked by grey squares, the injection well by the solid vertical line, and the approximate positions of the horizontal producing wells by the vertical, grey dashed lines. The reservoir interval is marked by the light grey horizontal dashed lines. Events symbols correspond to time of occurrence – ▼ = pre-injection, ● = 4 months from injection (Jan–Apr 2004), ★ = high injection rate period (summer 2004), and ■ = Jan 2006, after the array had been turned on again following a 4D seismic survey and maintenance. Ticks show 95% confidence limits

in the overburden do not necessarily represent leakage. If leakage had occurred at Weyburn, then events would most likely be located above the injection well (as seen during the frac-job discussed above) rather than above the production wells, where it appears that stress transfer through the rock frame has generated the seismicity. This demonstrates the need to build appropriate geomechanical models to interpret PSM observations effectively. By modelling in advance likely PSM observations for best and worst-case scenarios, and comparing observed microseismicity with these models, it should be possible to infer how the reservoir is deforming as a result of injection, and to determine whether this deformation poses a risk to storage security.

4. Conclusions

As they cost little to maintain once installed, PSM provides a relatively cheap means to permanently monitor geomechanical deformation induced by carbon dioxide injection into reservoirs. If injection-induced effective stress changes are of significant magnitude to compromise the integrity of the caprock, PSM can provide an early warning that fracturing has occurred. If PSM analysis is conducted in real-time, this warning will come long before any carbon dioxide has returned to the surface, allowing immediate remediation action, such as drawing down reservoir pressures. Indeed, in such a scenario a PSM array would also be ideal to judge the effectiveness of remediation activity. For CCS sites, accurate event locations are required, and in particular it is important to accurately identify whether an event has occurred in the reservoir or in the caprock, as it is events in the caprock that will be of greatest concern for storage security. Synthetic modelling can be used to identify key survey design parameters that will ensure an accurate depth location. Typically this requires an array with a large aperture, while ensuring that the receivers at the ends of the array remain within the detectability threshold, placed at a depth straddling the reservoir–overburden interface. In comparison to frac-job monitoring, interpretation of microseismic activity at CCS sites is more challenging. The most effective way to interpret event observations in terms of storage security is to construct geomechanical models of the reservoir. By doing so, it should be possible to identify the parts of a reservoir most prone to microseismic activity.

The authors have discussed PSM observations from the Weyburn CCS site. PSM has also recently been installed at the In Salah CCS site, Algeria. As it has been deployed at few sites so far, a key question remains whether PSM should always, sometimes, or never be used for CCS. This will no doubt depend on site-specific circumstances, such as background seismicity rates; the degree of natural fracturing in both reservoir and caprock; and how important the risk of leakage caused by deformation is deemed to be. Nevertheless, given the current state of CCS with regard to political uncertainties and public acceptance, the most appropriate approach must be to deploy monitoring 'overkill' on early projects, thereby demonstrating to the public the safety of CCS, and providing the research community with the opportunities to further evaluate the effectiveness of a range of monitoring techniques under different circumstances. Therefore we anticipate and recommend that PSM be deployed at future CCS projects.

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