Is there a future for passive seismic?

Peter M. Duncan, of Houston-based Microseismic Inc, provides a frank appraisal of the potential and challenges for the use of passive seismic techniques in hydrocarbons exploration and development.

Geophysicists have been using earthquake energy to image the deep structure of the earth for nearly a century. The geothermal resource people have used sound to locate the pipes and vents that channel subterranean hot water and steam for decades. Only recently has the oil and gas industry begun to use passive seismic techniques such as these to solve some of its day-to-day exploration and development problems. The renewed interest in the passive approach has been driven in part by the move to explore in more difficult frontier terrains and, in part, by the current 'smart oilfield' initiatives where passive's ability to map dynamic events, like the opening of fractures or the movement of fluids, is of particular interest.

In this article I present some of our experiences with passive seismic during the past two years over a diverse range of projects ranging from structural imaging to hydraulic fracture monitoring. Not all of these projects have been successful, even in a technical sense. The purpose here is to facilitate a broader understanding of the method and appreciation for the potential of passive seismic.

What is passive seismic?

First, let's be clear on what I mean by passive seismic. Passive seismic is seismic imaging using sources of opportunity. Rather than the standard airguns, vibrators, or dynamite that a crew usually puts to good use, a passive seismic crew merely deploys an array of receivers and……listens. They are listening for earthquakes and microseisms, some naturally produced and some the result of production activity, but all useful to imaging what's going on in the reservoir.

In my parlance there are two kinds of passive seismic imaging: one aims to create static images of the subsurface rather like conventional 3D seismic, and the other aims to map the dynamic activity taking place in the reservoir, rather like 4D seismic, but continuous rather than episodic.

Structural mapping

Passive seismic transmission tomography creates 3D structural images using the observed travel time of seismic signals originating from micro-earthquakes occurring below the target. A sparse array of independent seismographs is deployed above the target. The array usually consists of 20 to 100 stations each recording the output of a three-component (3C) geophone. The stations may function in a triggered mode, recording only when an event is detected, or continuously. Typical imaging areas for such an array are 300 to 1500 km^2. The 3C phones quite often are placed 10 to 30 m below the surface to get away from the noisy surface environment. The stations may store their data locally, but often are linked to the processing centre by some form of telemetry.

With the array established, the survey proceeds by capturing the seismic signals that have traversed the target. Assuming an initial velocity model, the observed micro-earthquakes are located in time and space using long-standing location methods based upon picks of the P and S phase arrival times at each observation station. Once a number of events has been located, one flips the process, assumes that the origin time and hypocentres of the events are known, and uses some form of travel time inversion to estimate a new velocity model. The three-component nature of the observations allows for estimation of the Vp and the Vs velocity structures. As more events are added to the dataset, finer estimates of the velocity structure can be achieved. The process continues in this boot-strapping fashion until the desired resolution is reached. (For more details on this type of passive seismic, see Kapotas et al., *First Break*, **21**, December 2003.)

Surveys of this sort may take six to 18 months to achieve a useful resolution, so one might ask where and when such a survey becomes cost effective. Certainly in flat, open country a more conventional reflection survey is probably a better solution. But, in mountainous terrain, passive can be as much as an order of magnitude less expensive. In environmentally sensitive areas the benign environmental impact of passive means that a survey, which might otherwise never get permitted, becomes possible. In highly cultured areas as well, the low impact presence of passive increases the likelihood of obtaining permits.

Just over a year ago MicroSeismic was engaged to map an area in the American Rockies with passive seismic. An array of 20 recording stations was deployed over about 300 km^2. The array was operated as 20 independently triggering, earthquake recording stations. Captured events were correlated using GMT time recorded by a GPS receiver at each station. The recording units were RefTek 72s.

Counting only events that triggered three or more of the stations, we typically recorded five to 10 events each day. But upon examination most of these were discarded either as coincident noise or as events occurring too far away to be of use to the tomography. This reduced our rate of earthquake capture to less than 1/day. Estimation of the magnitude for the captured events showed we were seeing events only down to about M_L=0.5. In an attempt to lower the detection threshold and hence boost the earthquake count we have recently taken several steps. We have set the phones in shallow boreholes to reduce the noise floor. We have moved from individual station triggering to continuous recording as it was determined that different local conditions were making the triggering inconsistent, station to station. We also moved the stations farther apart to give a bigger capture basin. These changes appear to have increased the number of valid earthquakes being recorded.

Figure 1 shows a perspective section and a depth slice through the compressional wave velocity (Vp) structure as determined after about 12 months recording and 200 validated events. The structure appears to reflect the geology as known from sparse 2D seismic in the area, but the resolution of this mapping is far from adequate to this point, so recording continues.

Mapping the motion

In the second type of passive seismic, often called micro-seismic monitoring, the micro-seismic activity itself becomes the imaging target. By mapping the distribution of seismic noise sources in and near the reservoir, we hope to tell something about the dynamic activity present at the reservoir, whether that is active faulting, fracturing, or some form of fluid motion.

One of the more common applications of micro-seismic monitoring is hydraulic fracture monitoring. Typically an array of eight to 12, 3C geophones is clamped at, or just above, the reservoir level in a wellbore near the frac well. First break picks are made on the direct arrivals of the seismic waves that are generated by the fracturing rock. Fairly standard earthquake location algorithms are then used to locate the hypocentres of the observed events. A mapping of the event locations over time mirrors the development of fracturing. Often these results are presented as movies which nicely reflect the dynamic nature of the process. Similar downhole observations have been used to map seismic activity related to steam injection, CO2 injection, and reservoir compaction (see for example, Wilson, S., et al., *First Break*, October 2004).

The events associated with activity in the reservoir are usually very small, typically with magnitudes (M_L) in the range of -1 to -3. The need to see and pick the arrival times of the signal from these events as discrete p and s phases, in order to calculate hypocentre location with standard earthquake location technology, mandates using geophones placed in a borehole close enough to the reservoir to achieve a sufficient signal-to-noise ratio. The need for an observation well and the limits on observation distance (usually 1000 m or less) may prevent this technique from being useful on some projects.

A different approach to micro-seismic monitoring, our proprietary passive seismic emission tomography (PSET), is to use an array of geophones deployed on the surface. A typical array will consist of 40 to 100 stations distributed over a few km^2. The array is sequentially beam steered at all points of interest in the subsurface and a 3D map of emission energy is made. The map reflects much of the same information as the hypocentre location map obtained with the downhole array. This method may offer some logistical and economic advantages over the downhole application.

Flow test monitor

One of our first ventures in the field of emission tomography was to the foothills of western Canada for Burlington Resources. Our assignment was to monitor a fracture and production flow test in a gas well. Depth of the sandstone reservoir was about 3200 m. An array of nine, three-component geophones was deployed on surface over an area of about 30 km^2 centred on the target well with the farthest stations being about 3 km from the well. A Kinematrics K2 seismic recorder was placed at each station and set to record continuously during operations on the well. Data were stored on flash memory at each station. Time synchronization was achieved with a GPS derived time signal recorded in the data headers. The recording period covered approximately 15 days while frac'ing and testing were performed in the well. The stations had to be individually turned on and off, and the flash memories replaced when full, which made for a fairly difficult field process since access to the stations was quite limited. Weather, access difficulties, and wildlife interference, in particular one hungry bear, were such that most data were recorded with at least one and sometimes four stations not working.

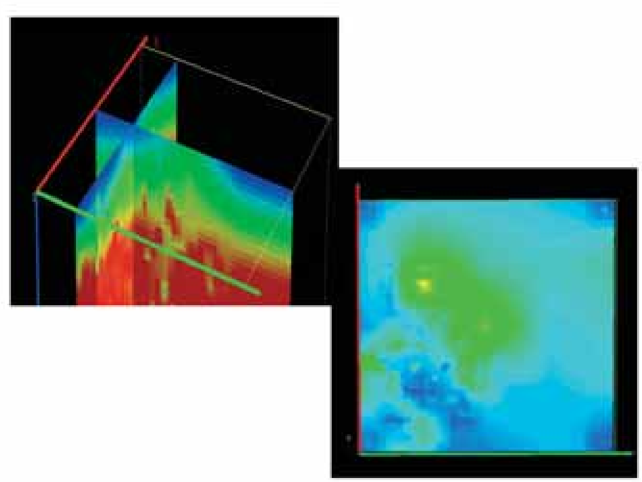

Figure 1 *Velocity structure (Vp) determined from passive seismic. Depth slice is 60 x 60 km at 2 km depth. Base of green in depth cube is at about 6 km. Velocities range from 1800 m/s (blue) to 6500 m/s (red)*

Figure 2 presents a contoured slice at the reservoir level through the seismic energy field observed just as the choke was opened to flow test the reservoir. Rate of flow was on the order of 10 mmcf/day. The data represent the sum of energy released over a 50 second period. The seismic data were filtered to a 0-10 Hz passband prior to stacking. The elongate anomaly in the NE-SW direction is consistent with there being a series of events along a line in that location (see Figure 3). Note also the brighter spot at the centre of the array, coincident with the well perforation point. Frankly we were quite surprised, even sceptical that the patterns being seen here were related to the flowing well. It seems amazing that the effects of opening the choke can propagate to several kilometers distance from the well in only a few seconds. The coincidence in time between the opening of the choke and the event occurrence, and the fact that the 'fracturing' direction coincides with the direction of maximum principal stress at the well, did suggest that what we were seeing just might be real.

Hydraulic fracturing

The previous example, while very encouraging, left us without proof that what was being recorded were real events. This resulted in us being contracted by Burlington to monitor the hydraulic fracture of a horizontal well at the same time that the frac was monitored with a more conventional downhole technique. An array composed of 100 3C geophones was deployed over a 2 km x 3 km area centred on the well. Continuous seismic recording in the form of consecutive one minute long records was achieved using a Sercel 408 recording unit. Recording began about 24 hours before the frac and continued for about 24 hours after frac'ing ceased. The seismic energy distribution in a one minute stack was calculated for the entire eight hours of frac time and for selected times before and after the frac.

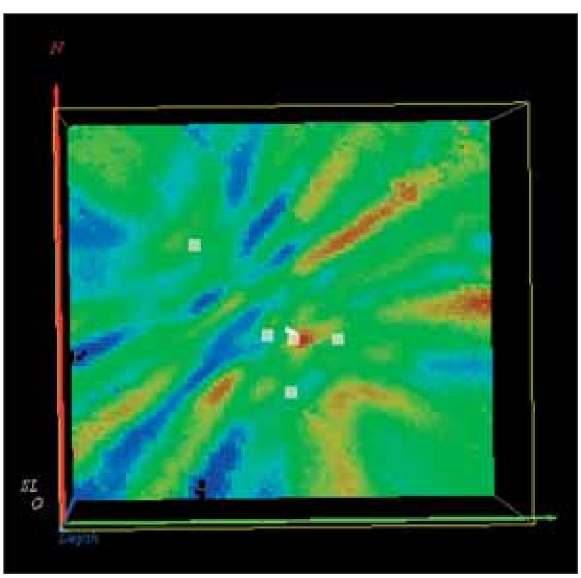

Figure 2 *3200 m depth slice through a 50 s PSET stack at onset of flow test. White squares are seismic stations. Test well is at centre station of array. Map is 6 km x 6 km. Hotter colours indicate areas of greater emission energy.*

Figure 4 is a depth slice through the stack at the reservoir level of about 2300 m for one of these minutes during the frac. We interpret that energy distribution to be the result of noise created as the rocks fracture under the imposed pressure. Rather than mapping the individual event hypocenters, we are mapping the cumulative signal from some unknown number of fracture events that occurred during the stacking interval. The figure shows an alignment of the energy distribution largely perpendicular to the well and hence, in the direction of maximum principal stress as expected. There is some indication of a conju-

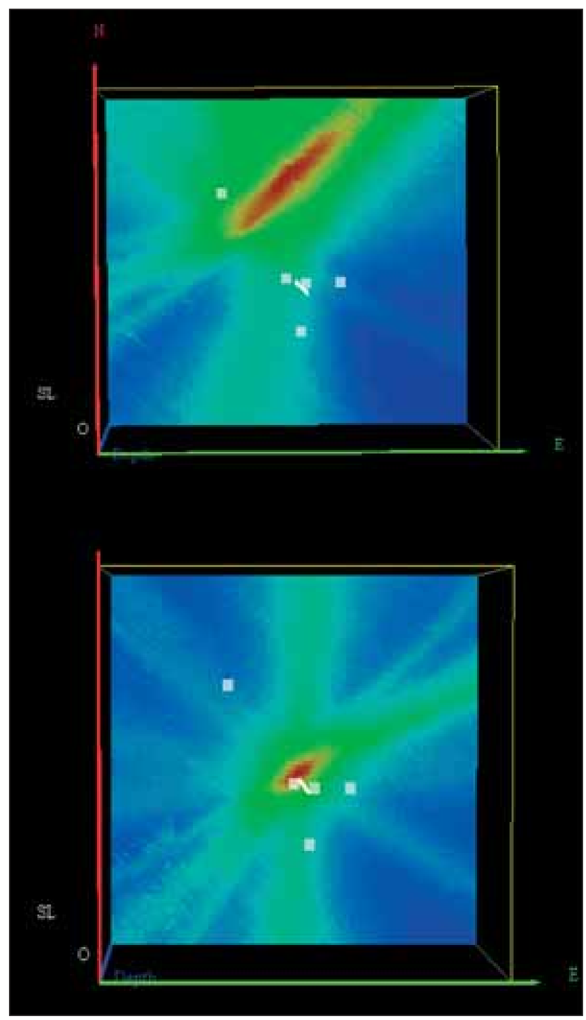

Figure 3 *Forward model PSET stacks to correspond with data in Fig. 2. Upper figure anomaly is caused by 3 events at reservoir depth aligned along the length of the red contour. Lower figure anomaly is caused by a single event at perforation point in the well.*

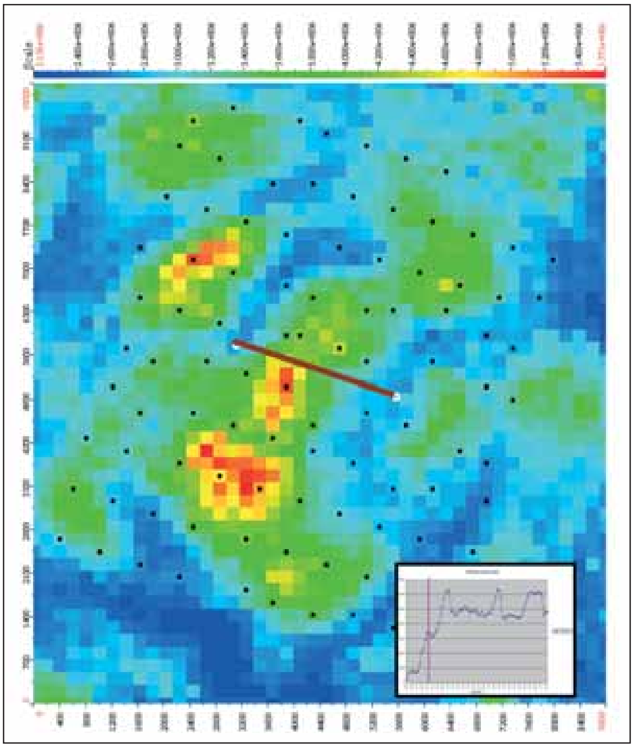

Figure 4 *Depth slice at the reservoir level through a PSET emission energy cube derived from one minute of observation time during a hydraulic fracture stimulation of a horizontal well. The black dots are the observation station locations. The brown line terminated by the white dots represents the location of the horizontal portion of the well. The hotter colours represent areas of higher energy acoustic emission. The inset shows the frac pressure history with the red line being the time of this stack. The distances along the axes are in feet. The map is 3400 m in the NS direction and 2700 m EW. The energy distribution is consistent with fractures being set up in two directions, one parallel to the direction of maximum principal stress (thought to be perpendicular to the well), and a conjugate set at right angles to this direction.*

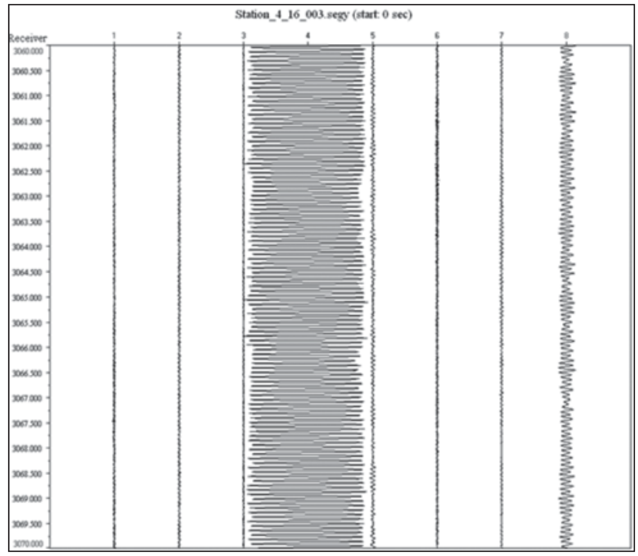

Figure 5 *10 s record of the east-west horizontal component of the seismic signal recorded at eight stations on a field delineation project. Dominant ringing at 12 Hz is probably related to compressors operating in the field.*

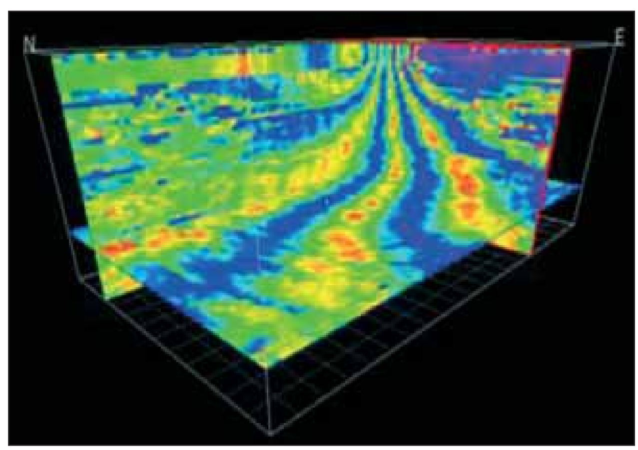

Figure 6 *Perspective view of the emission energy stack from the dataset illustrated in Figure 5 showing the effect of the narrow band noise on the stack.*

gate fracture system at right angles to this direction as well. These results are in good agreement with those obtained from the downhole observations, lending more confidence in this surface approach to micro-seismic monitoring.

Some noise is just noise

Lest I give the impression that things always go as planned, let me reveal one more case history. The assignment was to monitor a gas field in southwestern Colorado to see if we could delineate the limits of the field, or at least the limits of drainage, from the distribution of seismic noise generated by the production of gas from the reservoir. During the monitoring process several of the producing wells were shut in and then reopened in order to affect pressure changes in the reservoir. The reservoir depth was about 2700 m. An emission tomography array of nine 3C geophones was set in the field covering an area of about 15 km^2. Continuous recordings over a two week period were made using Kinemetrics K2 recorders.

Figure 5 is a 10 s record from this dataset. It is immediately obvious that the record is dominated by the noise seen on station 4, a pervasive 12 Hz signal that was found to be present, with several harmonics, at all stations. The source of the noise was eventually tracked to the compressors used in the field to assist in producing the gas. There were several of these throughout the field, with station 4 being the closest station to a compressor unit. Short of turning off the compressors, we found no tactic to defeat the compressor noise in our data. When station 4 was removed from the stack, the noise on station 8 then dominated, and so on until there were no stations left in the stack (see Figure 6). The strength of the harmonics of the 12 Hz signal made an attack on the noise with filters quite unworkable. We had no success removing the reverberation with deconvolution either. It seemed that the compressor noise was caught in the low velocity surface layer and resonating throughout the field. Our likely solution was to set the geophones in shallow holes drilled below this low velocity layer. We tested this theory with one shallow hole to 4 m that was dug with a hand auger. The signal on this buried geophone showed some improvement with regard to the 12 Hz noise. A deeper hole would likely have done even better. Unfortunately, the permits in hand at the time did not allow for drilling boreholes on this project while we were in the field.

Conclusion

Our experience over the past two years with several different applications of passive seismic has been encouraging but not without disappointments. More geophones rather than less are recommended both for noise reduction and redundancy. Placing the phones below the weathered layer appears generally useful for reduction of surface noise. As one might expect, success in the passive arena appears to be a signal-to-noise game. If one can successfully get signal up and noise down, then the method appears to give very satisfactory results.

Where I see an exciting future for passive seismic is in the field of real time dynamic process monitoring: frac monitoring, mapping of active or reactivated faults, and tracking of injected fluids. Whether one uses a surface array or geophones placed in a wellbore closer to the reservoir, we are in a very real way placing a stethoscope on the chest of the earth and listening. The limiting factor at present is that we don't have a lot of experience to draw upon with which to interpret these sounds. There lies the challenge for the future of passive seismic.