Introduction to this special section: Passive seismic and microseimic—Part 1

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The increase in the United States' production of unconventional gas from about 5% in 1995 to around 60% in 2009 is because of hydraulic fracture stimulation of horizontal wells, an advance in engineering technology equivalent to the introduction of 3D and 4D in reflection seismic (Figure 1).

However, the process of inducing failure by raising fluid pressure in the reservoir is hardly a new technological breakthrough. The first well-documented account of this is probably of a technique employed by the Romans in 77 CE to undermine and instantly remove vast quantities of mountainside to extract gold from the buried mother lode at Las Médulas in northwest Spain.

Their engineers used a technique known to Pliny the Elder as "Ruina Montium," literally to "destroy the mountain" using the force of water to exploit the rich mineral resources of the area. It was an amazing feat of engineering which led Pliny to say when he first arrived there, "What happens in Las Médulas is far beyond the work of giants."

The Roman engineers constructed a vast hydraulics network to channel water from as far away as 100 kilometers up the face of the mountains. There, the water was stored in large reservoirs until the sluice was opened to wash down the soil in a sudden rush of water—and within the mountains, where thousands of men dug galleries and channels out of the rock. There was only one exit, where the water was let in to bring down the mountain and release the gold-bearing rock as the enormous pressure caused the mountain to explode *(http://www.typicallyspanish.com/news/publish/article_20790.shtml).*

In the modern era, hydraulic fracturing has been applied to low-permeability hydrocarbon-bearing rocks since the 1950s. To be effective, this type of stimulation requires either the opening of existing natural fractures or the presence of geomechanical brittleness within the formation capable of supporting extensive induced fractures. Hence, the ability to estimate the size of the stimulated rock volume is fundamental in optimizing horizontal well completions for the capital-intensive development of these types of reservoirs.

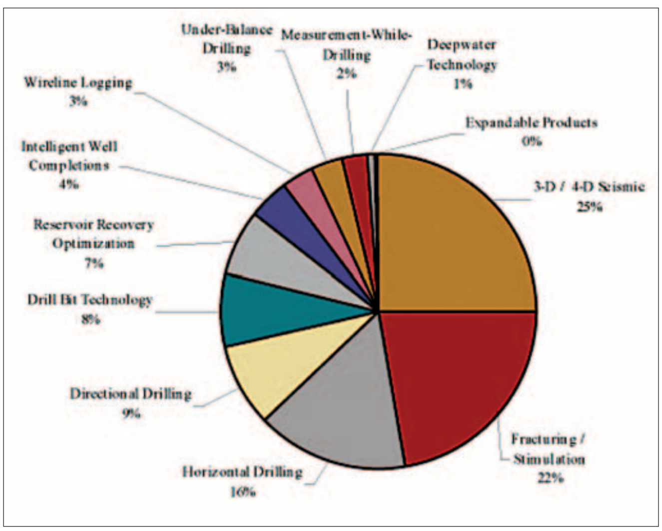

Figure 1. *Lehman Brothers E&P survey most influential 2006 technology.*

Passive microseismic monitoring has been one of the key technologies initially proposed and patented as far back as the 1970s by Bailey and published by Edwards in *TLE* in 1992 in "The untapped potential of seismic imaging." The best description I've heard of passive microseismic monitoring was given by Peter Duncan (the 2008 SEG/AAPG Distinguished Lecture) where he compared microseismic to reflection seismic, as a stethoscope is to ultrasound recordings.

Because of this engineering need to map the stimulated portion of the reservoir through locating the sources of seismic waves generated by various modes of rock failure, microseismic monitoring has forced the reflection seismologist into the domain of the engineer, and vice versa. This mapping is achieved by interpreting the cloud of microseismic event locations obtained from processing the P- and/or S-waves generated in the reservoir during stimulation (i.e., fracking). This provides a backward view of bypassed pay potential for restimulation or a forward-looking optimization of well and stage spacing to avoid costly "over" stimulation.

So has passive microseismic monitoring of hydraulic fracture stimulation replaced 3D reflection seismic as the most utilized geophysical method to appear in a decade? Is microseismic a breakthrough on the same scale as 3D was in the 1970s and '80s?

These questions may be more a function of one's discipline, as engineers embraced a fledgling microseismic technology well before geophysicists and in many cases in preference to 3D.

As a geophysicist, I am somewhat surprised by the fact that a technology which shares its earthquake seismological origins with reflection seismic has been championed and advanced by experts outside of my discipline. After all, isn't microseismic just downhole VSP or coarse 3D recording without a controlled surface source?

This situation, finding myself late to the party by a few years, can be explained by appreciating that passive monitoring of microseismic or earthquake events is essentially the same method at differing scales, and that my immersion in reflection seismic has left me behind the eight ball.

The common ground between all three methods (earthquake seismology, microseismic monitoring, and active reflection seismic) is in using propagating elastic waves to remotely sense specific subsurface phenomena of interest (e.g., brittle rock failure or intact conventional hydrocarbon reservoirs) but the similarities end here. Earthquake and microseismic monitoring image and characterize discrete, isolated subsurface sources in real time or post-completion with sparse acquisition geometries at up-to-kilometer spacing. For earthquake seismology, receiver stations can even be at spacings of hundreds of kilometers because of large depth-distance scales. Restrictions such as aliasing or Nyquist are not part of any discussion in these methods that might be seen primarily as sophisticated trilateration. All that is needed is an accurate arrival-time pick that eliminates the waveform and hence the impact of sampling on imaging. However, modern seismologists forward-model these waveforms from the located hypocenter and compare them to the observed ones because this helps constrain moment tensor solutions and some even go as far as using migration methods to image events, as described in one of the following *TLE* articles.

By contrast, 3D seismic uses dense arrays of controlled surface sources and receivers, with the aim of predicting a predrill result from an overwhelming ensemble of reflections and diffractions that represent in-situ stratigraphy and geometry. Consequently, sampling in azimuth and offset within the Nyquist criterion has a major impact on the requirements for accurate pre- and poststack imaging. In fact, microseismic monitoring might be considered a unifying link between earthquake seismology, 3D, 4D, geomechanics, and completions. Microseismic monitoring might also be thought of as closing the scale gap between 3D seismic, VSP and, well logs (Figure 2).

My entry to the microseismic world commenced by chance when I attended an early SEG workshop in 2008, generously sponsored by Apache through the foresight of Mike Bahorich (Apache's executive vice president and chief technology officer). Mike's opening address included the following trends:

- Barnett shale completions: 2001 = 100 frac stages costing \$9 billion, 2007 = 1100 frac stages costing \$19 billion
- 30% of completions have been microseismically monitored
- Lack of engineering credibility/acceptance
- Less for surface than downhole monitoring
- Microseismic confirmation of surface 3D stress/fracture mapping?

The observation I found most interesting and compelling was that 30% of completions were monitored microseismically. At the time, it occurred to me that this was my opportunity to regain relevance with my engineer managers. They viewed microseismic as both believable and useful; while my traditional role in reflection seismic was becoming redundant as gas shale plays were homogenous, thereby obviating the need to characterize their spatial variability. This also explained the disconnect in the past decade, between an exponential run up in the United States' land rig count mostly for horizontal completions with a sustained decline in United States land seismic crews (Figure 3).

This brings me to the present. In the past few years, the reflection seismologist has come in from the cold, so to speak,

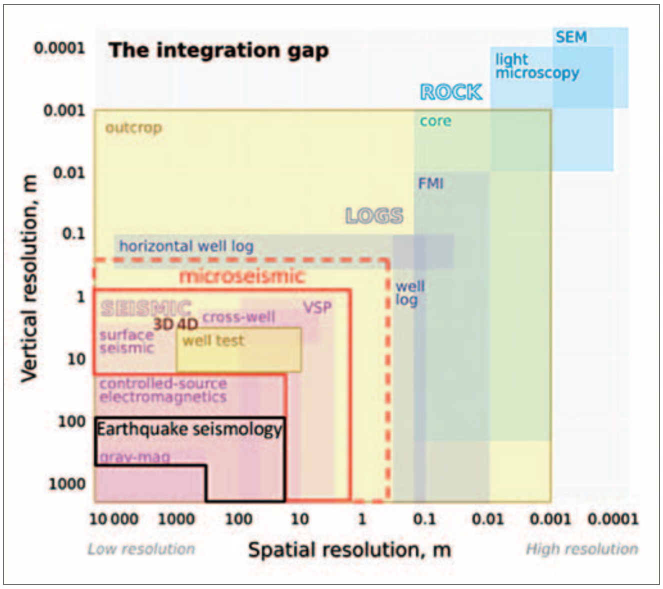

Figure 2. *Adapted from:* Geophysical Applications—Using Geophysics for Hydrocarbon Reserves and Resources Classification and Assessment *(Hall 2010 Agile Geoscience).* Canadian Society of Exploration Geophysicists, Chief Geophysicist Forum Reserves Subcommittee for consideration by the SPEE Calgary chapter for an update to the Canadian Oil and Gas Evaluation Handbook (COGEH).

regaining his rightful place as the microseismic expert, as evidenced by numerous *TLE* publications by geophysicists. This trend continues for 2012 where the editorial board decided to extend a single special-section topic on passive (micro)seismic to both November and December issues to accommodate the large number of excellent articles.

The first article (Tracking microseismic signals from the reservoir to surface) by Maxwell et al. presents a detailed attempt to resolve a diminishing yet ongoing controversy about detecting microseismic events at surface. To analyze and compare surface to downhole monitoring, a combined full borehole (VSP) and various surface arrays were acquired which establish magnitude limits of detection as well as validating amplitude decay from hypocenter to surface through a transmission attenuation model.

The experiment demonstrates that common events can be tracked between borehole and surface arrays and that larger-magnitude events can indeed be detected at surface. Furthermore, this unique experiment examines actual microseismic signals and degradation sampled through the full transmission path from hypocenter to surface, thereby quantifying the sensitivity of various monitoring options for the first time.

The second article (Observations and implications from simultaneous recording of microseismic surface and borehole data) by Diller and Gardner deals with a related topic that explores the analysis of surface microseismic data under the guidance of co-recorded borehole microseismic data. Important findings in this article include critical issues with time synchronization between the two seismic recording systems; the authors recommend colocated and co-recorded geophones from both arrays during data acquisition. This article also outlines a robust velocity modeling process using co-recorded velocity calibration from surface and borehole. In addition, several critical quality control measures for discriminating "false positive" events in surface microseismic data are re-examined and discussed.

The third article (High-quality surface microseismic data illuminates fracture treatments: A case study in the Montney) by Birkelo et al. continues with a surface-monitoring theme. The authors state that monitoring hydraulic fracture stimulations from the surface is a technique that, in the past, met with mixed success. They reason that passive surface monitoring has often been treated as if it were only a minor variant of the familiar and ubiquitous 3D reflection seismic method. However, unlike reflection seismic sources, fracturing or rock failure emits both P-wave and a much larger amount of S-wave energy. Therefore, to adequately capture the full microseismic wavefield, surveys must be designed to record and process both wave modes emitted by the fracture process. Additionally a large 3C surface array will capture the radiation pattern of the events to allow reconstruction of the fracture mechanism. They illustrate these concepts using data from a surface array acquisition from the Montney Formation in western Canada which produced high-quality microseismic data. They show fracture growth during hydraulic stimulation that was controlled by pre-existing fractures in some, but not all of the frac stages. Finally, they describe a technique to identify and use a subpopulation of microseismic events that better describes the portion of the reservoir stimulated by fluid and proppant pumping.

The fourth article (Path effects in subsurface microseismic monitoring) by Hogan and Eaton describes path effects that represent relative changes in amplitude and phase that might occur during wave propagation. This arises because of differing effects on wave energy when traveling in different directions (i.e., borehole microseismic recordings consist of signals transmitted in a horizontal direction parallel to bedding, whereas surface microseismic data record signals traveling perpendicular to bedding). They investigate the effects of near-horizontal propagation through relatively simple layered models with analysis based on finite-difference simulations of acoustic wavefields. Various models are considered, including a homogeneous medium, simple periodic, and more complex layering derived from well-log and other data. For each inhomogeneous case considered, the resulting path effects are complex and highly variable, despite the simplicity of the underlying model. They conclude that while preconditioning steps such as velocity-model smoothing may yield wavefield results that are seemingly plausible, they may still vary substantially from an actual recorded wavefield.

The fifth article (Path quality assessment of microseismic event locations and traveltime picks using a multiplet analysis) by Kocon and van der Baan presents a post-processing framework to assess and improve event location accuracy. Event location accuracy influences the reliability of information from advanced analysis of microseismic data including moment tensor inversion. The aforementioned analysis may be used to examine the effects of changing parameters such as steam injection temperature or well spacing. Event location accuracy is directly tied to subsurface velocity knowledge, modeled P- and S-wave travel times, and the accuracy of arrival picks that are

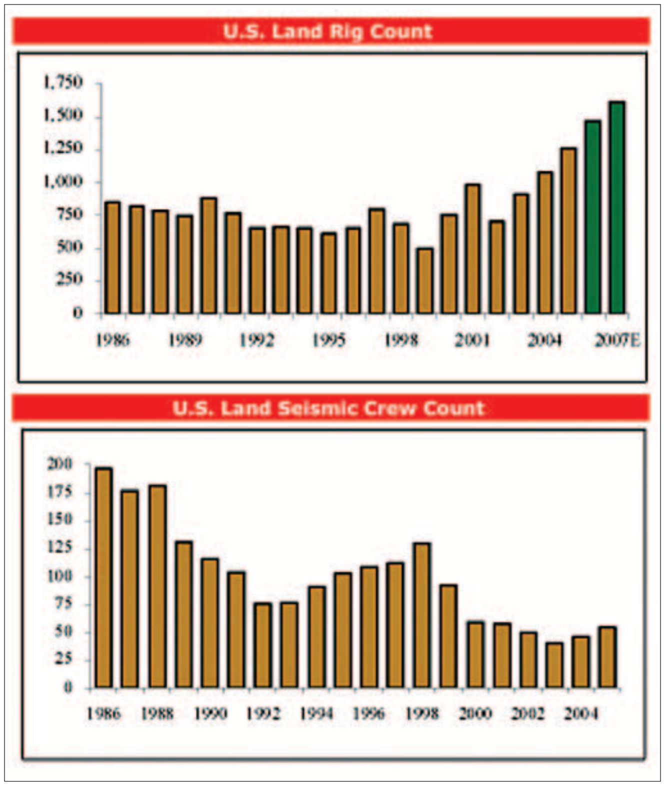

Figure 3. *(top) United States land rig count from: Baker Hughes and Lehman Brothers. (bottom) United States land seismic crew count, from:* World Geophysical News.

often obscured by random noise or coherent noise due to poor well-receiver coupling. This article presents a strategy to use microseismic multiplets to assess the quality of P- and S-wave arrival picks, and the resulting event location accuracy. Next, this article presents a methodology to examine event location error introduced by sparse velocity information, and how to mitigate the aforementioned error using multiplet analysis.

The sixth article (Potential use of resonance frequencies in microseismic interpretation) by Tary and van der Baan describes how continuous passive recordings of microseismic experiments can be used to detect and trace the modifications in resonance frequency content during hydraulic fracturing or heavy-oil steam injection. They analyze the performance of four different time-frequency representations, namely the short-time Fourier transform, the S-transform, the continuous wavelet transform, and the autoregressive method, on a real microseismic data set of intermediate quality. From this they show that time-frequency transforms provide an efficient tool to highlight time-varying resonance frequencies occurring during reservoir fracturing.

The causes of resonance frequencies in hydrofracture experiments are reviewed to identify the potential causes of the observed values and illustrate how their analysis may help in reservoir management. For the case study's monitoring array, resonance frequencies at the receiver side are anticipated to be outside the observed frequency band and as wave propagation is predominantly horizontal so resonance frequencies because path effects will be limited. Therefore, the observed resonance frequencies likely result from source effects, including resonance of fluid-filled cracks or successions of small repetitive events. The authors show that the length of a fluid-filled crack corresponding to a resonance frequency of ~17 Hz is in the order of a few tens of meters and so they conclude that this corresponds to the length of interconnected fractures representing mesoscale deformations occurring inside the reservoir because of hydraulic fracturing, from micro-earthquakes with slip surfaces of a few tens of centimeters to a few meters.

The final article (Geomechanical modeling of rock fracturing and associated microseismicity), Chorney et al. base their motivation on the fact that operators are interested in answering some key questions, the most important being: Why is failure occurring in specific locations but not others (what is the geomechanical behavior of the reservoir)? This last question is difficult to answer from the recorded seismicity alone because the geomechanical behavior depends on the in-situ stress field, the local rock properties, and any existing areas of weakness including faults, fractures, and joints. So they investigate how geomechanical modeling can offer a better understanding of deformation because of hydraulic fracturing with the use of a bonded-particle model (BPM). In short, the BPM is an aggregation of bonded spherical particles which can be calibrated to reproduce the macroscopic properties of a desired material. When these models are subjected to increasing stress, fracture mechanisms occur, resulting in microseismicity. Using this modeling approach, the complex behavior of rocks rupturing because of a set of boundary conditions can be investigated in a controlled fashion. This reveals the interaction of geomechanical reservoir behavior, rock properties, in-situ stress, existing fractures, and the resulting microseismic event locations, source mechanisms and both seismic (brittle) and aseismic (plastic) deformation. In conclusion, by simulating triaxial compression tests on calibrated sandstone models with and without the introduction of a circular plane of weakness, the authors demonstrate the utility of the BPM method.

The excellent set of articles in this special section on passive seismic and microseimic monitoring covers some of the recent technical advances in a subject that has received increasing exposure in *TLE*, as geophysicists finally take on the task of adding quantitative credibility to improving the naïve use of interpreting processed event clouds that were arbitrary dots in a box signifying little or nothing.

I acknowledge my co-editors—Julie Shemeta, Mark Willis, and Werner Heigl—for their invaluable assistance in editing this special section and for having gone beyond the call of duty in pulling together this edition on short notice as submissions for the scheduled section on Applications of Pore Pressure did not materialize. Furthermore, the original edition planned for December is fully subscribed with additional articles on Passive Seismic and Microseimic and is a testament to the ever-shifting nontraditional application of seismic remote sensing from conventional topics such as pore-pressure prediction to monitoring horizontal well hydraulic fracture stimulation of unconventional plays. TLE

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