THE AMERICAN OIL & GAS REPORTER®
AUGUST 2014
The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Microseismic Aids In Fracturing Shale

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KINGSTON, ONTARIO–Adding to the complexity of hydraulic fracturing is that there are many options for completing a pad of wells. Examples include progressive fracturing of one well at a time, zipper frac programs that attempt to manage stress regimes in the reservoir by alternating treatment wells, and "simulfrac" methods, which treat two wells simultaneously.

Completion techniques may use sliding-sleeve or plug-and-perforate methods to define separate treatment zones, while individual stages may employ unique treatment designs by varying factors such as fluid, proppant, perforation intervals, or hesitation periods. Often, these variations in completion styles attempt to stimulate different fracture sets within a network of pre-existing fractures in order to stimulate the largest volume of reservoir while minimizing cost.

An important consideration during hydraulic fracture stimulation is how to best assess the effectiveness of various completion styles. While production decline curves and history matching are viewed as primary validation methods, these take years to realize fully. In the short term, it is important to receive reliable and rapid feedback on treatment success.

Microseismic monitoring has become a routine method for identifying overall shale fracture characteristics such as fracture geometry, stage overlap, and estimated stimulated reservoir volume. Used in conjunction with injection/engineering data, microseismic results often are used to assess stimulation effectiveness in real time.

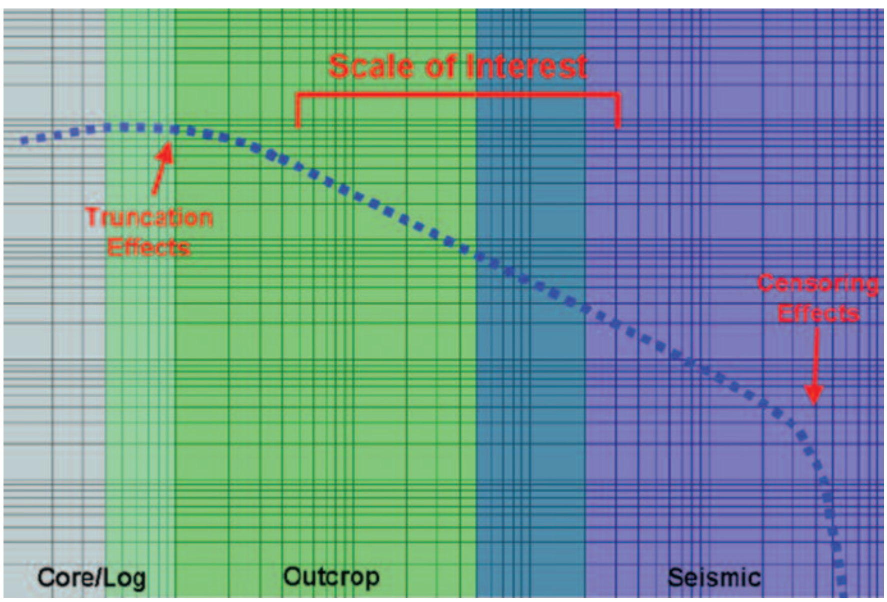
Microseismic monitoring has become an attractive option for tracking hydraulic fracture stimulations because, unlike most other monitoring techniques, it provides information about fracture behavior away from the wellbore. However, in most cases, the potential for microseismic to develop an overall picture of fracture interactions within a reservoir is not fully exploited.

Event Failure Mechanisms

Microseismic event locations provide only a finite level of feedback on reservoir stimulation. They cannot reveal definitively whether each fracture generated will contribute to production. An example of this limitation is demonstrated by the fact that early estimates of stimulated reservoir volume (SRV), which encompassed merely the envelope of microseismic events, resulted in an overestimation of the SRV. Rather, evaluating event failure mechanisms is a key aspect to understanding how the treatment programs will improve the drainage characteristics of the reservoir.

Each microseismic event can be viewed as the failure of a fracture plane (strike and dip) of a certain size that is, itself, part of a discrete fracture network (DFN) of new or pre-existing fractures. Therefore, microseismic event distributions can be used to reconstruct the DFN that is acti-

FIGURE 1



Microseismic data increase resolution in the "scale of interest" between core/log/outcrop data and larger, sparsely populated faults obtained from 3-D seismic data. Image courtesy of Reine and Dunphy, GeoConvention, 2011.

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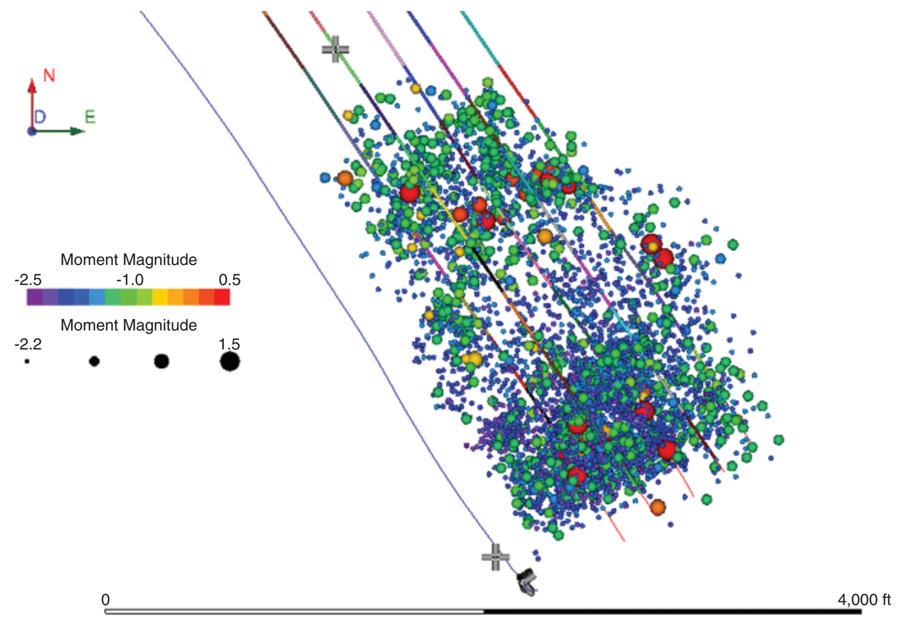
FIGURE 2



Passive seismic events detected during the stimulation of five horizontal treatment wells are colored and size-scaled by magnitude.

vating in response to the stimulation program.

Seismic moment tensor inversion (SMTI) can connect seismic observations of an event to the physical processes at the source that are causing the event, such as the event failure mechanism, principle strain axes, and potential failure plane orientations. Coupled with the dimensions of the failure planes, fracture orientations inferred from the moment tensor can generate an activated DFN model.

Key inputs for geomechanical characterization of hydraulic fracturing using DFN models include fracture length, azimuth and intensity, aperture, and transmissibility. Image log measurements and well tests may provide feedback for the last two parameters.

Microseismic monitoring can characterize the fracture distributions in the reservoir, including fracture orientations, intensity and fracture sizes, which generally follow a power law relationship.

Assessing Fracture Size

The power law of fracture size typically is assessed through core, outcrop and 3-D seismic measurements. Core data sample the smaller scales, consisting of fractures over a few centimeters in length, while outcrops may provide fracture information on the scale of meters. 3-D seismic attributes such as curvature features are limited by the resolution of the seismic imaging and typically can see features larger than 100 m.

Considering these limitations, there clearly is a gap in the observable fracture lengths ranging in scale from meters to hundreds of meters. This gap is shown in Figure 1 as the "scale of interest."

Microseismic results can help fill in this missing information using a measurement of source radii of detected events. Typical size scales for microseismic events detected on a downhole array range from one to 20 meters. Using a hybrid or broadband system, this scale increases to provide feedback on events exhibiting radii in the hundreds of meters.

Within naturally fractured formations, core data reveal that a variety of pre-existing fracture sets are found within a reservoir, often forming dense and interconnected networks.

While some fractures are dominantly vertical, horizontal fractures related to bedding planes are present also, and all surfaces exhibit considerable roughness along their interfaces. Stimulations, therefore, will cause these differently oriented fractures to fail in different ways.

Assessing fracture networks can become even more complicated when faults or geological structures are present. Fault activation stimulates considerably larger fracture lengths than typically seen in microseismic results. Inaccurate characterization of larger fracture lengths may influence dramatically the interpretation of stimulation and deformation within a reservoir. In our first case study, we discuss microseismic results from a multiwell hydraulic fracture program that activated multiple structures.

Fault Activation

ESG acquired and processed microseismic and induced seismicity data from five multistage horizontal hydraulic fracture stimulations targeting a North American shale play. Passive seismic data were collected from time-synchronized downhole and near-surface arrays using a patented approach that integrated traditional downhole microseismic with surface- and near-surface induced seismicity arrays to provide visibility for seismic events ranging from -4 to +4 in moment magnitudes (M). The surface array consisted of eight surface stations, each equipped with a 4.5-hertz geophone and a force balanced accelerometer (FBA).

Typical microseismic networks are designed to detect and analyze small-scale microseismicity. In particular, hydraulic fracturing generates thousands of microseismic events with magnitudes in the range of M-4 to M0. However, the 15-Hz geophones typically used in these networks are not optimized to record the lower frequency signals associated with larger magnitude events ranging from M0 to M4.

Incorporating near-surface arrays of lower frequency sensors, such as 4.5-Hz geophones and FBAs, will more accurately capture seismic signals for large magnitude events, effectively widening the range of magnitudes that can be evaluated accurately with a single passive seismic system.

Microseismic results recorded during the multiwell stimulation program are provided in Figure 2, where larger magnitude events measuring above zero on the moment magnitude scale are indicated by larger red dots. A number of positive magnitude events represent fractures ranging in length from 30 to 150 meters, whereas the smaller magnitude microseismic events reflect fracture lengths from five to 30 meters.

Large events were observed to separate into two clusters during the completion:

- Cluster A formed first near the toes of the wells.
- Cluster B formed later in the stimulation and further along the treatment wells.

Because the large events are recorded across a broad number of surface stations over a wide azimuthal distribution, we were able to determine the focal mechanisms for these events. Cluster 1 featured only five mechanisms; however, they all demonstrated a steeply dipping feature striking approximately east-west. Cluster 2 featured more gently dipping fractures exhibiting a southwest strike.

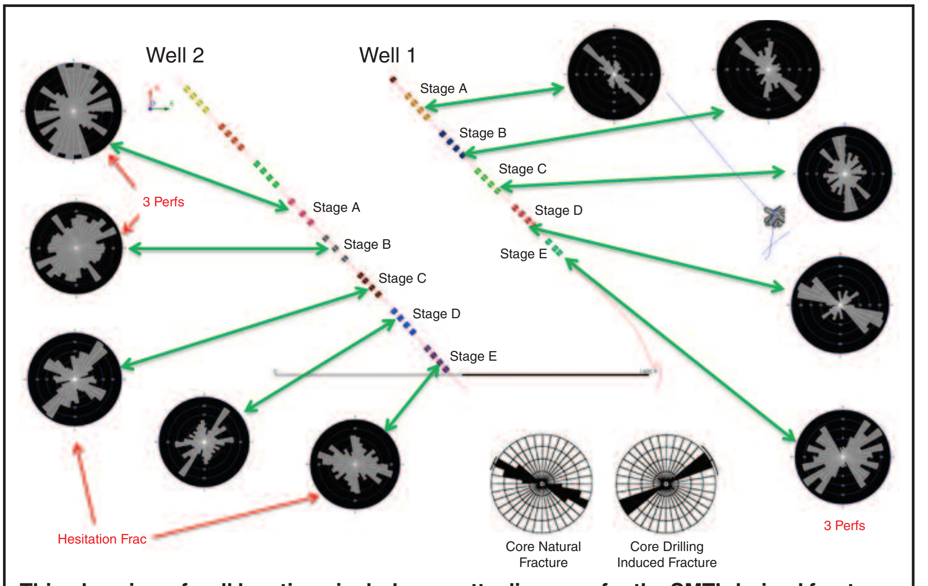
Analyzing these results suggested that the local stress conditions rotated during the fracture stimulation program, such that different fracture sets were being activated. Assessing the fracture lengths suggests the fractures were bounded by the treatment formation. Although the events were large, they did not appear to activate features that crosscut the formation and breached the cap rock.

Evaluating Completions

In a second example, microseismic monitoring was used to evaluate the success of various completion methods, including a hesitation approach to successfully stimulate multiple known fracture sets. Hesitation stimulation is an approach used by a number of producers that attempts to stimulate a complex, dendritic (branching) network of pre-existing fractures to enhance well productivity.

The well is stimulated initially with fluids and proppants, after which it is shut in for a period, allowing for flow back before the well is stimulated a second time. The flow-back period is believed to relax the state of stress in the reservoir sufficiently to enable a secondary fracture set to become more optimally oriented for failure, ultimately enhancing well productivity.

FIGURE 4



This plan view of well locations includes rosette diagrams for the SMTI-derived fractures for each stage. In addition, the mapped natural and induced (secondary) fractures described by Gale, et al, (2007) also are shown on rosette diagrams. Unless indicated, each stage consisted of four perforations. North is toward the top of the figure.

Advanced microseismic assessment based on SMTI analysis provided information about the orientations of the stimulated fracture sets.

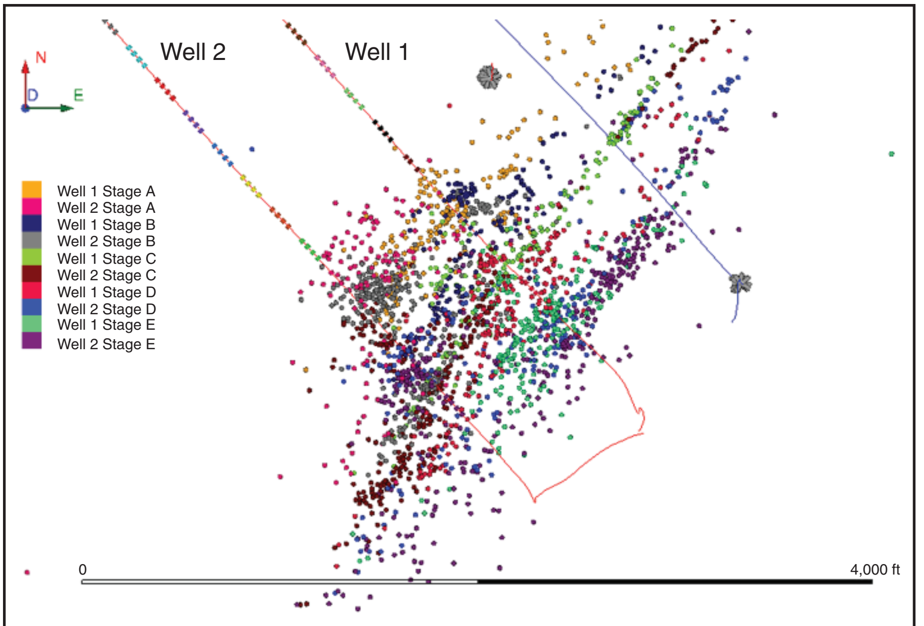
A secondary goal of the program was to evaluate the effect of modifying injection pressures, slurry rates, perforation strategies, etc., on the resulting microseismic-based DFN. Both fracture intensity and fracture orientations were used to assess the complexity of the fracture network generated in response to the dynamic behavior of in situ stresses in the reservoir.

Microseismic events generated during a multiwell, multistage hydraulic fracture stimulation in a North American shale play were monitored using a 24-level vertical geophone array and a 24-level whip array. The whip array is a unique sensor configuration where sensors are deployed in both the horizontal and vertical sections of an adjacent lateral well. Figure 3 illustrates the microseismic results for 10 of the stages.

The fracture stimulation program evaluated a number of completion approaches. With the exception of stage E, all stages in well 1 were completed with at least four perforation clusters. A slightly more varied program was used for well 2, which employed either three or four perforation clusters, as well as a hesitation approach in two stages.

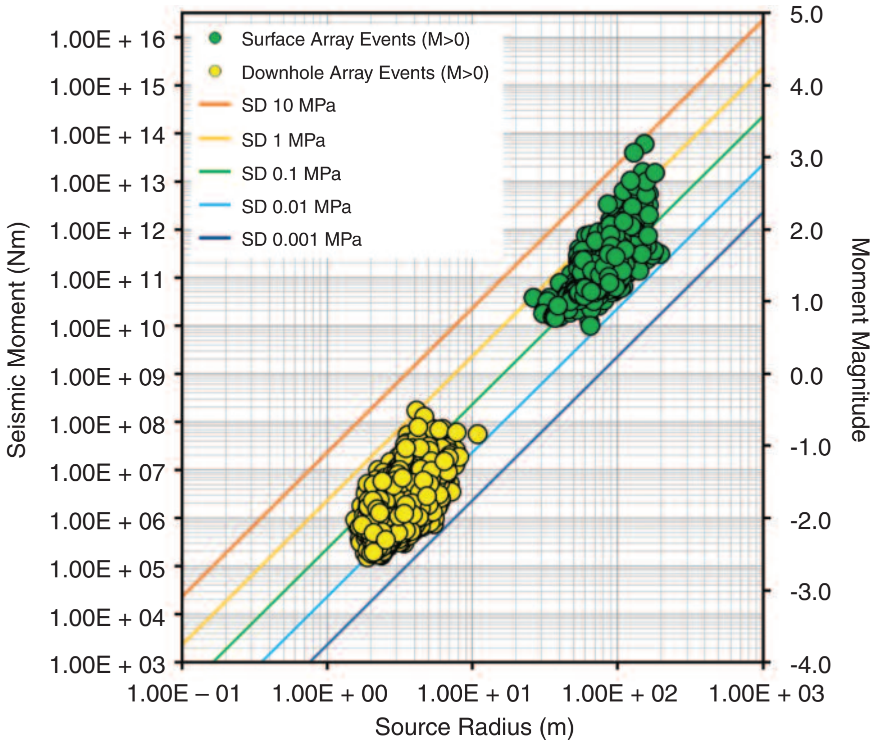
Assessing the resulting orientations of the SMTI-derived fractures is summarized in rosette diagrams in Figure 4. Also included in Figure 4 are the fracture orientations mapped from a core taken just to the south of the study area.

FIGURE 3



The microseismic events shown here were detected for 10 stages of a multiwell hydraulic fracture stimulation in a North American shale play.

FIGURE 5



This image plots log source radius versus moment for two datasets. Green data represent larger magnitude events recorded from a near-surface regional seismic network, while the yellow data represent smaller microseismic events recorded with a downhole array. Although there is some scatter, each dataset appears to follow a self-similar distribution. However, the two datasets are not self-similar, since they each release different levels of stress.

Two groupings were identified within these core fractures: those referred to as natural fractures developed during paleo-stress conditions, and those induced by core drilling (secondary fractures) are responding to the current stress regime. In general, the natural fractures trend NW-SE, whereas the induced fractures are to the NE-SW.

In most stages in well 1, the fractures resembled those of the mapped natural fracture network. In contrast, stages with three perforation clusters succeeded in generating increased fracture complexity, activating both the natural fracture network and initiating secondary fractures. The hesitation regime also appears to increase the level of fracture complexity resulting from a local reorientation of the stress field.

Self-Similar Scaling

The power law shown in Figure 1 gives the impression that the frequency of fractures follows a uniform power law over a range of fracture scales. Such behavior is indicative of self-similar scaling processes. In other words, the behavior of the reservoirs at the smaller scales is a scaled down version of the response of the larger features.

In the context of microseismic events, this implies there is a given relationship between the moment magnitude of the event and the size of the fracture that it is activating, described by a constant release of stress (stress drop). However, over the range of the scales of fractures present in the reservoir, there may be different processes to which the microseismicity is responding (fluid-induced versus stress-triggered), as well as lithological controls on the fracture sizes present (large scale fractures may be bound by lithology).

Understanding these relationships gives additional insight into the behavior of the reservoir and the triggering processes responsible for controlling the seismicity.

In Figure 5, the relationships between moment and source radius are plotted against lines of constant stress drop for two datasets. Green data represent larger magnitude events recorded from a near-surface regional seismic network, while the yellow data represent smaller microseismic events recorded with a downhole array.

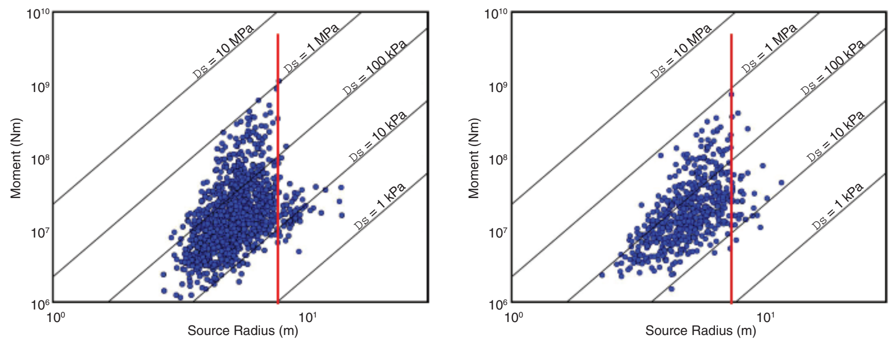
Each dataset appears to follow a self-similar distribution, as shown by their tendency to follow lines of constant stress drop, albeit with a significant degree of scatter. The two datasets seem to fall along lines of constant stress drop, but the larger events may have a slightly higher stress drop, indicating that there are potentially higher stresses driving these failures.

This difference in overall stress release supports the interpretation that the higher-magnitude events are responding to a stress transfer process on nearby faults, whereas the smaller magnitude events all are associated with a stage of a hydraulic fracture treatment, and their lower stress drops are more characteristic of the fluid-induced events typically seen in these injections.

Horn River Data

The same analysis was performed

FIGURE 6



In these scaling plots for two stages during a hydraulic fracture treatment, the red line indicates that there is a critical fracture length, beyond which it takes significantly more energy to activate a fracture, contrasting the observation of self-similar scaling.

using two groups of downhole microseismic data acquired from separate stages of a hydraulic fracture stimulation in the Horn River Basin (Figure 6). There appears to be a fracture radius (around eight m) that is a firm–but not absolutely hard–limit on the observed fracture sizes. The effect of this barrier is to locally divert the self-similar scaling relationship.

For these fracture sizes, there is an increase in moment for events of equal radius, indicating that in this case, the microseismic response shows some deviation from the consistent power law behavior. In this case, above the fracture limit of eight meters, the formation requires significantly more energy to activate a fracture of the same size.

Here, we suggest that lithological controls play a role in determining fracture sizes (fractures bound to certain lithological units need to have a higher energy to transition out of that unit into adjacent units), and in yielding larger fracture sizes. This lithological constraint to the scaling relationship and power law relationship is an important feature to be incorporated into any geomechanical DFN to ensure accurate modeling of the reservoir.

The stimulation of naturally fractured shale formations was used to emphasize how different fracture sets of different sizes are activated by different completion programs and in varying lithologies. SMTI-derived fracture planes can be used to define the distribution of the size scales of fractures in the form of a power law, providing direct input to help constrain and validate reservoir models. ❐

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Adam Baig is a seismologist with ESG Solutions, managing research and development for its global energy services division. He joined the company in 2008, and has led its efforts to understand the dynamics of hydraulic fracturing and other injection processes through the seismicity associated with moment tensor inversion of signals to reveal underlying fracture sets and the dynamic in situ stress/strain conditions. Baig obtained a B.S. and an M.S. in geophysics from the University of Alberta, and a Ph.D. in geosciences from Princeton University, studying diffraction and scattering effects on seismic wave propagation.

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Katie Jeziorski is an engineer at ESG Solutions, and has spent the past five years in various technical and marketing roles. She currently holds the position of technical marketing coordinator. Her primary focus has been examining the integration of microseismics with fracture engineering and geomechanics to create a higher level of understanding about the applications of microseismics in unconventional oil and gas production. Jeziorski holds an M.S. in engineering from Queen's University in Ontario.