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Microseismic Monitoring
Increases Efficiency And Performance In Liquids-Rich Plays

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KINGSTON, ONTARIO–Growing demand for secure sources of energy and technological advances such as horizontal drilling and multistage hydraulic fracturing have led to a boom in production from unconventional reserves in North America. This trend toward unconventional resources soon will extend to Europe and the rest of the world as operators realize the potential in shale and tight sands reservoirs.

However, the increased supply of domestic natural gas in North America has contributed to lower gas prices, widening the gap between the price of crude oil and natural gas. As a result, many operators have shifted their focus to formations either containing oil or having high liquid saturations. In particular, oil bearing formations such as the Bakken, Niobrara, and northern regions of the Eagle Ford, as well as natural gas condensate producing regions of the Marcellus and Eagle Ford shales, are in high demand.

The low permeability of these oil and liquids-rich formations requires companies to use hydraulic fracturing to increase conductivity in the reservoir. However, production in many of these and similar formations is in its infancy, and fracture behavior in many of these plays remains poorly understood. While shale gas fracturing in some plays (such as the Barnett) has become relatively routine, the complex geology and lack of experience in newer oil and liquids-rich plays present a challenge for completion design.

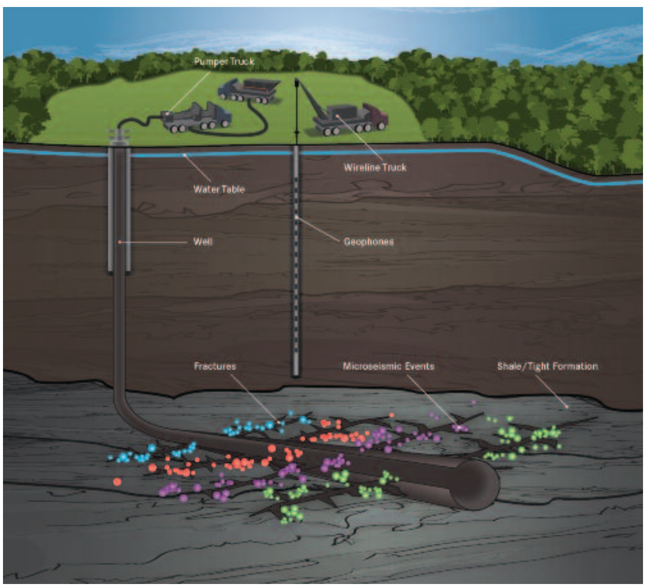
In today's economic climate, regardless whether operators are producing unconventional oil or gas, there is an even greater push to improve production economics. Implementing new technologies to enable increased recovery rates and reduced costs through improved operating efficiencies is essential to develop unconventional fields successfully.

One such technology is microseismic monitoring. When integrated with methods such as logging, 3-D seismic and engineering analysis, microseismic monitoring can improve the understanding of reservoir behavior in response to stimulation, and can help operators optimize completion efficiencies and production performance.

Micro-Earthquakes

Microseismic monitoring is probably best known in the petroleum community as a diagnostic and imaging tool for hydraulic fracture stimulations in unconventional gas production. Unlike large-scale earthquakes, which can be felt on the surface, microearthquakes (or microseisms) usually range from -4 to zero on the magnitude scale.

Micro-earthquake events are the result of a stimulation operation that alters the stress distribution in the reservoir. Rock failures in the form of fractures or shear stress slippages along preexisting faults, fluid flow paths, and fracture networks release energy that can be detected by sensitive monitoring equipment positioned near the production zone.



Sensor arrays of triaxial geophones are deployed in offset observation wells to monitor or "listen" to microseisms generally ranging from -4 to zero on the magnitude scale. Microseismic monitoring and analysis help to calibrate and verify fracture models, and to infer fracture extent, height, half-length and plane orientation.

In traditional downhole monitoring, sensor arrays of triaxial geophones are deployed temporarily in offset observation wells to monitor or "listen" to the microseismic activity generated by the stimulation. The microseismic energy generated from these failures can be processed in real time, and located and mapped in four dimensions (x, y, z and time).

Microseismic technology has been used to monitor hydraulic fracture operations in U.S. wells since the mid to late 1990s, dating to early applications such as the Devonian Shale in the Appalachian Basin and the Cotton Valley Field in East Texas. Since then, microseismic analysis has proven to be a valuable diagnostic tool for reservoir characterization, helping to calibrate and verify fracture models, and infer fracture extent, height, half-length and plane orientation.

In particular, microseismic analysis can provide tremendous value in understanding the natural fracture characteristics of a new play or help to confirm sweet spots where extensive natural fracturing is present. Evaluating microseismic data in real time also provides operators with immediate feedback about fracture generation as each stage is pumped, enabling information to be integrated into decision-making processes.

Armed with these data, engineers can respond quickly and save money by refining treatment designs on the fly, avoiding geohazards, identifying faults that are redirecting fluid and proppant away from the desired fracture zone, or optimizing fracture stage spacing.

Microseismic analysis offers far more than simply identifying locations of individual fractures. The industry has begun to realize the need to move beyond traditional microseismic event mapping, and is taking advantage of the benefits provided by microseismic analysis to understand reservoir behavior in response to simulation.

SMTI Analysis

One useful method that can be used to describe the interaction of microseismic events within a reservoir is seismic moment tensor inversion (SMTI). SMTI analysis provides information about the mechanisms responsible for generating seismicity and interprets microseismic events as failures on fracture planes caused by slipping or shearing (double couple), tensile opening (mode one failures), or closures of previously open fractures.

Interpreting such mechanisms can determine temporal and spatial changes in the reservoir, and can define discrete fracture networks responsible for fracture growth. These data are particularly useful in emerging oil and liquids-rich plays where fewer wells have been stimulated and fracture complexity remains relatively unknown.

In most low-permeability reservoirs, the key to generating a high stimulated reservoir volume (SRV) is to produce complex fracture networks that maximize the contact area with the reservoir and achieve good fracture conductivity. Estimates of SRV based on seismic deformation can give some indication of future production. However, building on SRV analysis using SMTI and knowledge of fracture networks, it is possible to identify areas of increased permeability that are making positive contributions to production.

Knowledge of the fluid flow enhancement related to hydraulic fracture development is valuable for optimizing treatments, but is also useful for planning future stimulations. The information presented through advanced microseismic analysis can be incorporated into reservoir models to forecast how the reservoir will respond to subsequent injection programs.

As always, there is a delicate balance between cost reduction and well performance in hydraulic fracturing operations. Operators need to ensure that fracture stimulations are productive, while making every effort to reduce costs.

The trend in some oil-rich plays is toward longer laterals with more stages. Therefore, it is critical that each stage is completed optimally. It is one thing to design fracture treatments based on the idea that more is always better. Pumping additional fluid and proppant may increase the stimulated volume, but if the added fluid is not actually extending the fracture network, it is a waste of time and materials.

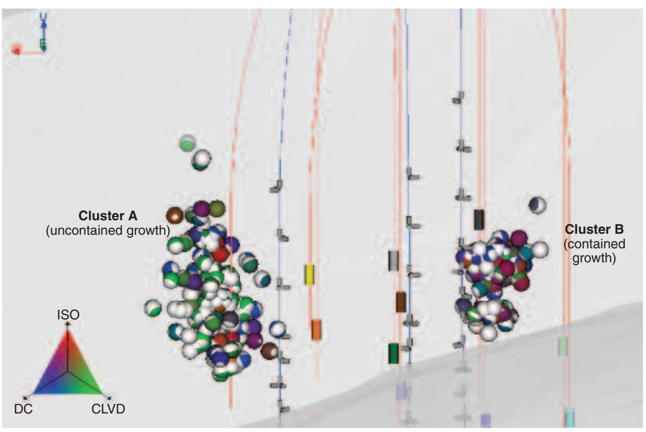
Therefore, it is important to evaluate how the fluid and proppant are interacting with the reservoir during each stage, and to identify potential changes that can be made to the treatment program in order to improve performance.

Identify Diminishing Returns

A temporal analysis of microseismic SMTI data together with engineering treatment data can be performed to identify points of diminishing returns (PDR) for various stages of a treatment program. PDR analysis aims to identify when leak-off dominates the fracture system and continued pumping using the same treatment style no longer will extend the fracture.

By analyzing the primary failure mechanisms of microseismic events in the context of the treatment program, operators can adjust their stimulation treatments to distribute proppant better and increase fracture conductivity. Operators then can use this information to optimize the design of future fracture treatments.

FIGURE 1



This depth view of the event distributions for Clusters A and B was observed during a steaming operation. Events are displayed in "beach ball" convention, with the color representing the type of failure mechanism indicated in the ternary scale in the bottom-left corner identifying isotropic, double-couple, and compensated linear vector dipole (CLVD) failures.

The versatility of the technology is such that clients rarely have to drill observation wells specifically for microseismic, even in emerging plays. It is possible to take advantage of existing well infrastructure or innovative engineering approaches such as installing a dual-monitoring array (also known as a whip array) into a single horizontal well.

The whip array deploys one wireline monitoring array in the horizontal lateral while a second array is positioned in the vertical section of the same well. Using these simultaneous dual arrays maximizes the likelihood that lower magnitude events will be detected along the entire length of the lateral, while the presence of a vertical monitoring array ensures that events can be constrained in depth. In addition, locating events on multiple arrays provides an opportunity to perform SMTI analysis.

Taking the deployment of downhole monitoring arrays one step further, there is a strong argument in favor of using a life-of-field approach to monitoring hydraulic fractures in emerging plays. Deploying permanent fieldwide sensors provides an opportunity for an operator to monitor all hydraulic fracture stimulations in the same field using a single, permanent monitoring system, thereby dramatically reducing the per-well cost of monitoring.

Traditionally, operators have monitored the first few fracture stimulations in a new play and applied data regarding the local fracture behavior to future fractures, assuming that the remaining wells would behave the same. However, like no two plays are alike, strong differences often are observed among wells in the same field.

Each reservoir has specific characteristics that must be accounted for in designing the completion for each well, so there is a clear advantage to being able to monitor all fracture stimulations with a permanent fieldwide system.

Permanent Arrays

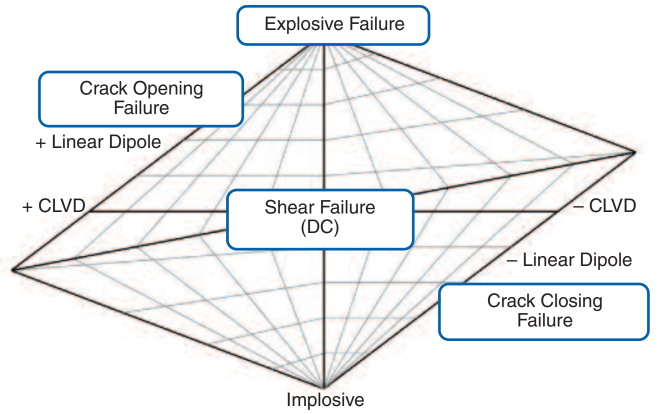
ESG has deployed permanent microseismic monitoring arrays for long-term reservoir monitoring applications, (some of which have been in operation for nearly a decade) in the heavy oil sands of northern Alberta, the diatomaceous oil fields in California, and oil fields in the Middle East. Moreover, we are finalizing what will be the world's largest fieldwide monitoring program located in Oman, which includes 26 monitoring wells across two fields.

In these longer-term reservoirs, enhanced oil recovery operations such as steam injection are commonly applied. Depending on the injection pressures or formation properties, steam modifies the stresses in the reservoir, inducing tiny fractures within the steam chest. Operators can benefit from the ability of microseismic monitoring to visualize the position and movements of a steam chamber within a reservoir, evaluate sweep efficiency, and observe how the steam is developing within the reservoir over time.

However, in some formations, such as in south-central California, large, heavy-oil-bearing diatomite reservoirs have relatively low permeability and benefit from extensive hydraulic fracturing to increase permeability prior to injecting steam. In one such diatomite formation, permanent microseismic arrays are continuously monitoring microseismicity associated with injection and production stages of a "huff-and-puff" steamflood.

Injecting steam helps to reduce the viscosity of the oil, which improves production and creates a large, contained zone of increased

FIGURE 2



This source-type plot notes the position of several failure mechanisms.

temperature and pressure. The resulting deformation in this region releases detectable seismic energy. Microseismic events are recorded using three permanently installed high-temperature downhole monitoring arrays, each consisting of 12 three-component geophones deployed in three vertical observation wells around the treatment zone.

During steaming operations, two unique clusters of seismicity (Figure 1) were observed in the reservoir. The first (Cluster A) was observed during the production cycle of one well and exhibited unconstrained vertical movement, while the second (Cluster B) was observed during the production cycle of a neighboring well.

Advanced SMTI analysis was used to further examine the specific failure mechanisms associated with each cluster. The moment tensor for each event is illustrated in Figure 1 using a "beach ball" convention, where the color and pattern represent the type of failure mechanism.

Failure Mechanism

A helpful way to display the results of SMTI analysis is with a source-type diagram (Figure 2). Several types of failure mechanisms are indicated on this plot:

- Double couple, or pure shear mechanisms, will cluster in the center.
- Isotropic, or pure opening or closing events, will be positioned at the top or bottom of the figure, respectively.
- Pure compensated linear vector dipole events will plot at the right and left sides of the figure.
- Linear dipole, and tensile opening and closing failures can be found on the upper left and lower right of the diagram.

The source-type plot for Cluster A (Figure 3A) indicated that the events were primarily shearing and tensile opening/closing events. This pattern is similar to observations of fracture propagation in hydraulic fracture stimulations, where opening events dominate early in the treatment and extend outward into the formation, followed by closing fractures nearer to the well bore.

An interpretation of the observed mechanisms is that fluid traveled through a pre-existing vertically oriented fault or fracture. By following this path of least resistance, the fluid propagated upward in an uncontrolled manner. Typically, out-of-zone growth in steaming operations is undesirable, since it may compromise the integrity of overlying cap rock, and in extreme cases may lead to a breach in the reservoir.

For Cluster B, the source-type plot (Figure 3B) indicates the failure mechanisms are primarily explosive and implosive in nature, coupled with pure shearing. This pattern is very typical of how steam chambers develop, and may be related to the inflation and deflation of the production zone as steam interacts with the pore spaces of the diatomite. The microseismic activity as-

FIGURE 3A

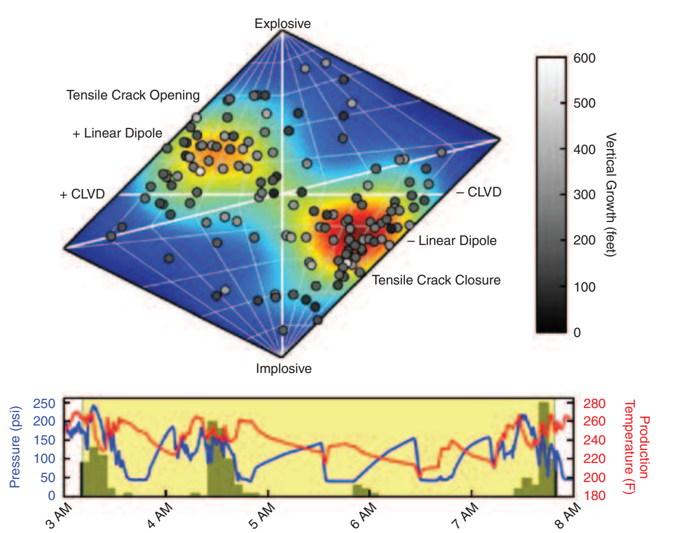


FIGURE 3B

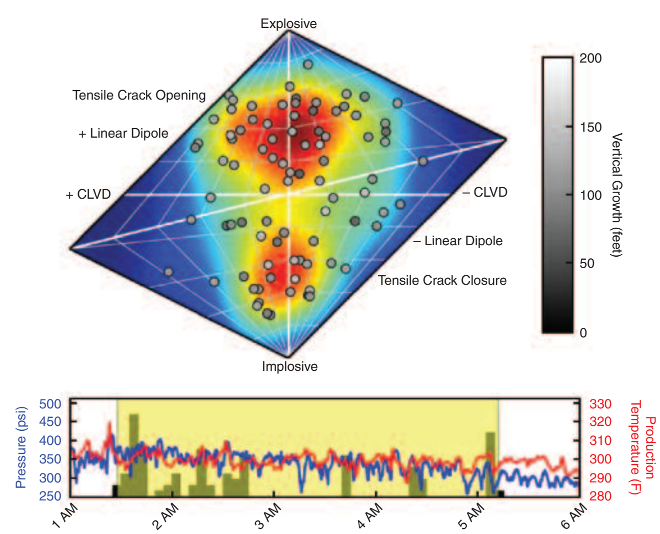


Figure 3A shows a source-type plot and production parameters (temperature in red, pressure in blue, and event rate histogram) for the events depicted in Cluster A for uncontained fracture growth. Figure 3B shows a source-type plot and production parameters for the events depicted in Cluster B for contained fracture growth. The events are gray scaled by vertical growth over a density plot for the distribution.

sociated with Cluster B was well contained and represented optimal steam chamber development.

As cost reduction and completion efficiency become ever more critical, operators require methods to help them achieve production goals in unconventional reservoirs. Microseismic methods continue to develop beyond mapping event locations, and have proven to be a valuable tool for optimizing production from complex unconventional plays.

Advanced SMTI analysis can provide insight into the failure mechanisms associated with reservoir stimulation, and demonstrates that the true value offered by microseismic monitoring comes from the enhanced understanding of reservoir behavior achieved by integrating microseismic information with other geophysical, geological, engineering and geomechanical data. ❐

TED URBANCIC

Ted Urbancic is a founder of ESG Solutions and holds the position of executive vice president for ESG's Global Energy Services. With more than 25 years of experience examining and interpreting microseismicity associated with mining and petroleum applications, Urbancic is a pioneer in developing microseismic monitoring for industrial applications. In recent years, Urbancic's primary focus has been using seismic source techniques to constrain numerical models for reservoir optimization and in evaluating hydraulic stimulation and enhanced oil recovery-induced seismicity. His work examines using microseismicity to characterize and understand fracture development. Urbancic holds a Ph.D. in seismology from Queen's University in Kingston, Canada.

KATHERINE MOUNTJOY

Katherine Mountjoy is an engineer at ESG Solutions, and has spent the past three years in various technical and marketing roles. She currently holds the position of marketing analyst. 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. Prior to joining ESG, Mountjoy completed her M.Sc. in engineering at Queen's University in Kingston, Canada.