MARCELLUS MICROSEISMIC

Microseismic monitoring of the fracturing process in the vast shale is proving to be a key tool in its development.

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Throughout the long, dry summer and into the fall, with natural gas prices below $3 per thousand cubic feet (Mcf) and predictions of a further drop to below $2, the Marcellus shale play has remained an oasis of E&P activity. Rig activity is on the rise. Reports of drilling success, with enviable initial production (IP) rates, have been plentiful. Operators continue to wage bidding wars for prime acreage.

In a short couple of years, this play has become something to be reckoned with. It may turn out to be the largest unconventional resource play in the U.S., surpassing the Barnett and the Haynesville. And microseismic imaging is proving to be a key tool in its development, as it has in other shale plays.

Fracturing and productivity

Unconventional reservoirs like the Marcellus are characterized by low matrix permeability. Production rates are greatly affected by the amount of natural fracturing in the rock. The two dominant vertical, natural joint sets that occur basinwide in the Marcellus contribute significantly to its productivity. The so-called J1 joints were formed as a result of tectonic stress at the beginning of the Alleghenian orogeny that built the Appalachian Mountains. The second, younger joint set, named J2, cross-cuts the J1 joints and in most places is perpendicular to them. The J2 joints are related to hydrocarbon generation, having formed as the effective stress increased while the hydrocarbons in the rock matured.

Figure 1. Devonian shale outcrop showing the joint sets J1 and J2. (Photo courtesy of Dr. Terry Engelder)

Experience has shown that horizontal drilling and hydraulic-fracture stimulation are the best ways to exploit fracture permeability and maximize Marcellus well deliverability, just as in various other shales. Typically, the optimal orientation of horizontal wells is thought to be perpendicular to the local present-day maximum horizontal stress (S_{Hmax}) direction. In many areas of the Appalachian Basin, S_{Hmax} is parallel, or nearly parallel, to one of the joint sets. Hydro-fracturing probably activates slip along both of these joint sets.

Microseismic's role

When planning the fracing of a Marcellus well or evaluating the results of a frac campaign, several questions arise: What are the length, width, height and azimuth of the fractures that result? What is the volume of rock that has been stimulated? What is the consequent drainage area of the well? Did the operation create a new fracture parallel to S_{Hmax}, or reactivate fractures sub-parallel to S_{Hmax}? Are multiple interacting fracture trends at different orientations likely or even possible? What are the fracturing mechanisms? Microseismic monitoring of the fracturing process is often very effective in helping to answer these questions.

Microseismic monitoring involves capturing the seismic signals that are generated by the fracturing of the rock—the micro-earthquakes, so to speak—using geophones much like those used in conventional 2-D and 3-D seismic operations. The signals are then processed to find the location in time and space of the micro-events. Comparing where and when the events took place with the pressure, slurry rate and proppant density at that same time, can help reveal how effectively the formation is being treated.

The final microseismic event distribution provides data on the frac length, height, azimuth and stimulated volume that has been achieved. If the results are available in near real time, they may indicate that the frac is off course and allow an immediate remedial response. Data analysis may also determine the

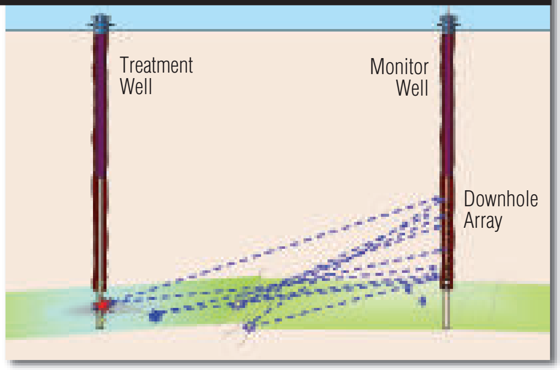


Figure 2. Schematic of downhole monitoring. The monitor array consists of between 10 and 50 3-C geophones clamped against the casing. Events in blue are located by their arrival times. The red event is the calibration shot taken in the treatment well to orient the phones and calibrate the velocity model. Accurate event location, while dependent on local conditions, is limited to about 1,500 feet from the monitor well. Source: MicroSeismic Inc.

nature of the failure mechanism that created the signal, clarifying whether the operator is breaking new rock or reactivating existing fractures.

Analysis techniques

There are basically two ways these data are analyzed to recover the event locations. The more common technique involves picking the arrival time or "first break" of the seismic event and the travel direction (azimuth and inclination) of the signal at individual receiving stations (geophones). Then, through some form of trilateration and/or triangulation, an event source location is estimated that best accounts for the distribution of arrival times and arrival angles. This is the familiar method by which government agencies such as the USGS locate earthquakes using permanent earthquake monitoring stations around the world.

One difficulty is that the seismic signals generated by the tiny stimulation-induced earthquakes are very small. To accurately pick the first breaks for these small events, the geophones must be placed close to reservoir depth near the treatment well. That requires drilling a monitor well in which to place the geophone. In fact, triangulating the source location requires several geophones distributed around the source point. Ideally, that would mean having several monitor wells, which increases costs. The compromise solution is to put a string of geophones over as long a length as possible in the single monitor well drilled.

Other issues involved in this monitoring approach are: limited distance of event detection due to signal absorption; increased location uncertainty with distance from the monitor well; and poor failure mechanism inversion with this vertical antenna geometry.

A better geometric solution can be obtained from a large areal distribution of geophones around the treatment well. Economics require that this distribution be at or near the surface of the earth, yet that is where the signal size is small and the noise is large.

The solution is to use a different analysis technique—full waveform stacking—similar in concept to a dish microphone. But in this case, the dish is the array of geophones. Pointing the dish at target locations is done computationally, and is often referred to as beamsteering or beamforming. In fact, the technique is well known to geophysicists as "migration" and is commonly used for conventional seismic imaging.

The stacking process enhances the signal-to-noise ratio in the data and allows an accurate estimate of the event location. The large aperture sampling of the seismic wavefront also allows a high-confidence estimate of event magnitude and the source or failure mechanism that generated the event. The downside to this technique is that the size of the array is typically about twice the depth to the target events, which requires surface-access permits over a large area. If the geophones are set out on the surface, which is the faster route, the number of geophones deployed can be in the tens of thousands. That usually requires a crew of about 20 to lay out and pick up the phones.

The number of phones required can be reduced to hundreds by placing them at a shallow depth away from the noisy free surface of the earth. However, this incurs the expense of drilling a hole several hundred feet deep and planting the phones permanently. A buried array can have real technical and economic advantages in the monitoring of a significant fraction of wells in a developing field, but it is not practical for monitoring just one treatment well.

Evaluating and using the data

After data analysis and estimates of the event locations, still images of the event distribution are used to evaluate the treatment's effectiveness. Was the entire length of the well stimulated? Did the frac stay within the reservoir? What frac length was achieved? At what azimuth do the fracs take off? Was the well drilled at the right azimuth? What reservoir volume was stimulated? What well spacing should be used in the future?

Comparing the results for different pumping, water, gel and proppant programs will shed light on how the reservoir is responding and guide adjustments to the treatment of future wells. Movies of the treatment can be useful for

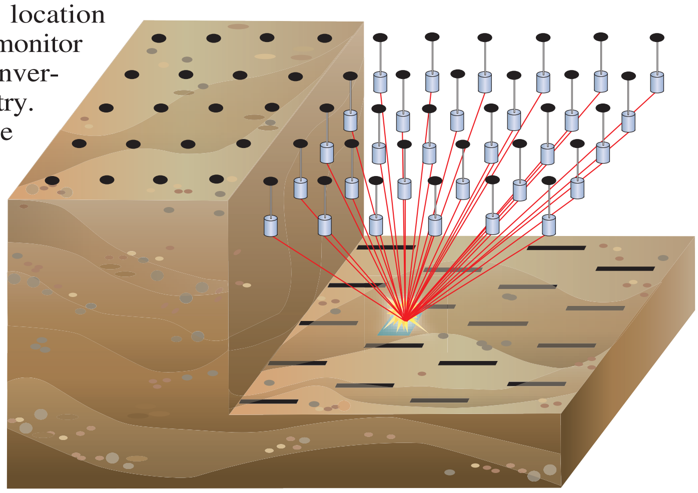
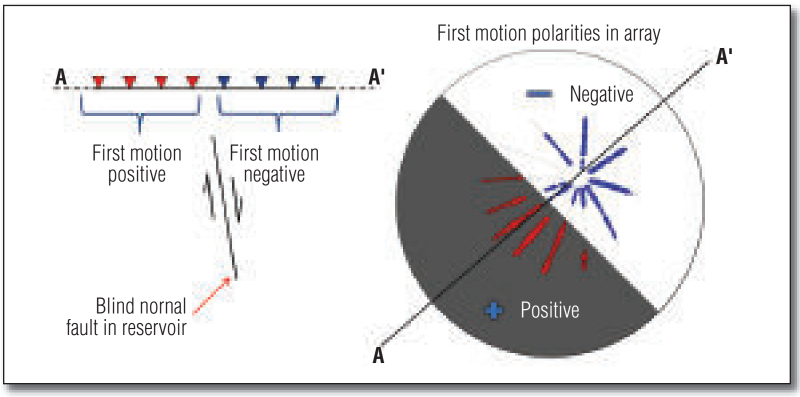


Figure 3. Schematic of a near-surface monitoring array and the beamsteering to detect an event at depth. The array shown would cover at least 25 square miles and would be capable of monitoring the treatment of all the wells within its boundary at a greatly reduced unit monitoring cost. Source: MicroSeismic Inc.

Figure 4. In the star-shaped surface array on the right, the event first motion on one side of the array is negative (blue) while positive (red) on the other. Event marker size is proportional to event magnitude. These observations allow for an estimate of the failure mechanism that created the event. In this case, it is a normal fault, striking along the white-to-black interface, down to the right. Such analysis improves the understanding of the geomechanics of the reservoir. The analysis requires a reasonably well-dispersed sampling of the focal sphere as depicted by the circle. Source: MicroSeismic Inc.



visualizing the dynamic nature of the frac growth and its timing relative to the treatment program.

It is becoming more common to actually watch the microseismic data in real time (or nearly real time) in order to respond immediately to what is happening in the reservoir. In the Fort Worth Basin's Barnett shale, for example, operators watch closely to see if the frac starts heading down into the Ellenberger formation, a prolific aquifer that could cause serious water problems in the well. If that happens, they can curtail the treatment.

Operators in the Marcellus have expressed similar concerns with respect to the Onondaga Lime, which lies some 200 feet below the Marcellus. In other cases, real-time observation might reveal that the frac has grown enough, allowing the operator to shut down and save money.

A more rigorous interpretation of these data involves turning the "dots in the box" that are the event location estimates into a model of the fractures actually created, or what is known as a discrete fracture network. Estimating this network and assigning flow-permeability properties to the fractures provides information to flow simulators for production design, prediction and optimization.

The process is helped along by estimating the type of movement that occurred on the fracture. To do so requires observations of the signal polarity and amplitude over a significant portion of the wavefront generated by the event. This is more accurately achieved with a large areal array than with a sparse, downhole deployment.

Marcellus applications

In the Marcellus shale, with its significant network of existing natural fractures, understanding the mode of fracturing is even more important in characterizing the frac's effect and predicting flow properties resulting from the stimulation. Fracturing accompanied by a microseismic response may only represent a relatively small percentage of the pathways that were stimulated by the frac treatment; slip on some planes may cause aseismic dilation on existing fracture planes in other orientations.

The number of wells monitored so far in the Marcellus is small compared to that in the Barnett. Early results indicate that the formation responds well to treatment and produces readily detectable microseismic events. Frac half-lengths range from 1,000 to 2,000 feet. Frac azimuths are typically east-northeast, in many cases almost parallel to the Appalachian Basin's J1 joint sets.

Strike-slip failure along these joints, as determined with large areal-array data, shows that the fracture-failure mechanism is reactivation of the preexisting joints by the frac treatment, which greatly enhances permeability in the natural fracture network. Connectivity between the J1 Appalachian joints and the intersecting joint sets creates a stimulated reservoir volume connected to reservoir rock via a real-world version of the discrete fracture network. Individual stages can stimulate as much as 10,000 acre feet.

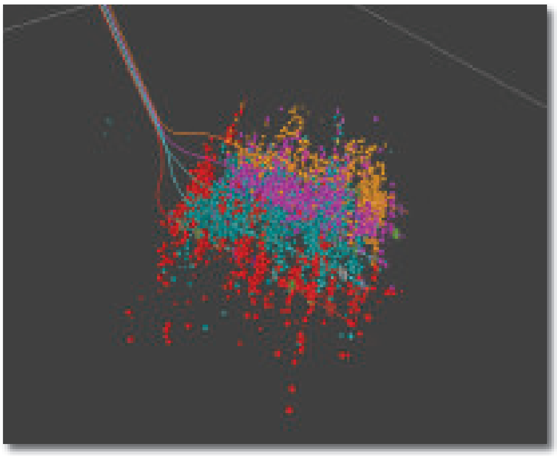


Figure 5. Perspective image of the microseismic events associated with the fracing of multiple stages in a series of five Marcellus horizontal wells drilled from a common pad. The toes of the wells are to the lower right. Events are colored by treatment well. Frac half-length is greater than 1,000 feet.The monitoring was done with a surface array. Source: Range Resources Corp. and MicroSeismic Inc.

Microseismic monitoring is proving to be a useful tool and its applications are growing. Most monitoring to date has been done with small downhole arrays. Recent results with surface arrays have proven very successful and operators can be expected to move quickly to increased use of permanent, near-surface buried arrays, which offer lower environmental impact, lower costs and superior technical results. □

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For more on the Marcellus and other shale plays, see UGcenter.com.