Live Hydraulic Fracture Monitoring and Diversion

Donald N. Burch
Aspect Abundant Shale, LP
Denver, Colorado, USA

John Daniels
Matt Gillard
William Underhill
Sugar Land, Texas, USA

Victor Ariel Exler
Poza Rica, Veracruz, Mexico

Luciano Favoretti
Pluspetrol
Neuquén, Argentina

Joël Le Calvez
Dallas, Texas

Bruno Lecerf
Dmitry Potapenko
Novosibirsk, Russia

Leonardo Maschio
Jorge Adrian Morales
Pluspetrol
Buenos Aires, Argentina

Michael Samuelson
Oklahoma City, Oklahoma, USA

Mauro Ivan Weimann
Buenos Aires, Argentina

Oilfield Review Autumn 2009: 21, no. 3.

For help in preparation of this article, thanks to Nellyana Charmelo Silva, Buenos Aires; Mario Galaguza, Rio de Janeiro; Rick Klem and John Lassek, Sugar Land; Shawn Maxwell, Calgary, Alberta, Canada; and Ed Ratchford, Arkansas Geological Survey, Little Rock, Arkansas, USA.

A propagating hydraulic fracture generates acoustic noise. Sensitive receivers in a network array detect these microseismic events and thereby locate a part of the fracture. Using new algorithms and procedures, analysis software accomplishes this within half a minute. Thus, an operator can remotely modify the fracture operation and obtain live feedback on the effect of the change.

During hydraulic fracturing jobs, operators cannot see where fractures go, but if they listen carefully, they can hear them propagate. As fracturing fluid is forced into deeply buried formations, the Earth pops and creaks in a percussive symphony whose movements follow the path of the fracture. New technologies can quickly identify the locations of these tiny seismic events and, through the use of diverting agents, direct the fracture into preferred areas.

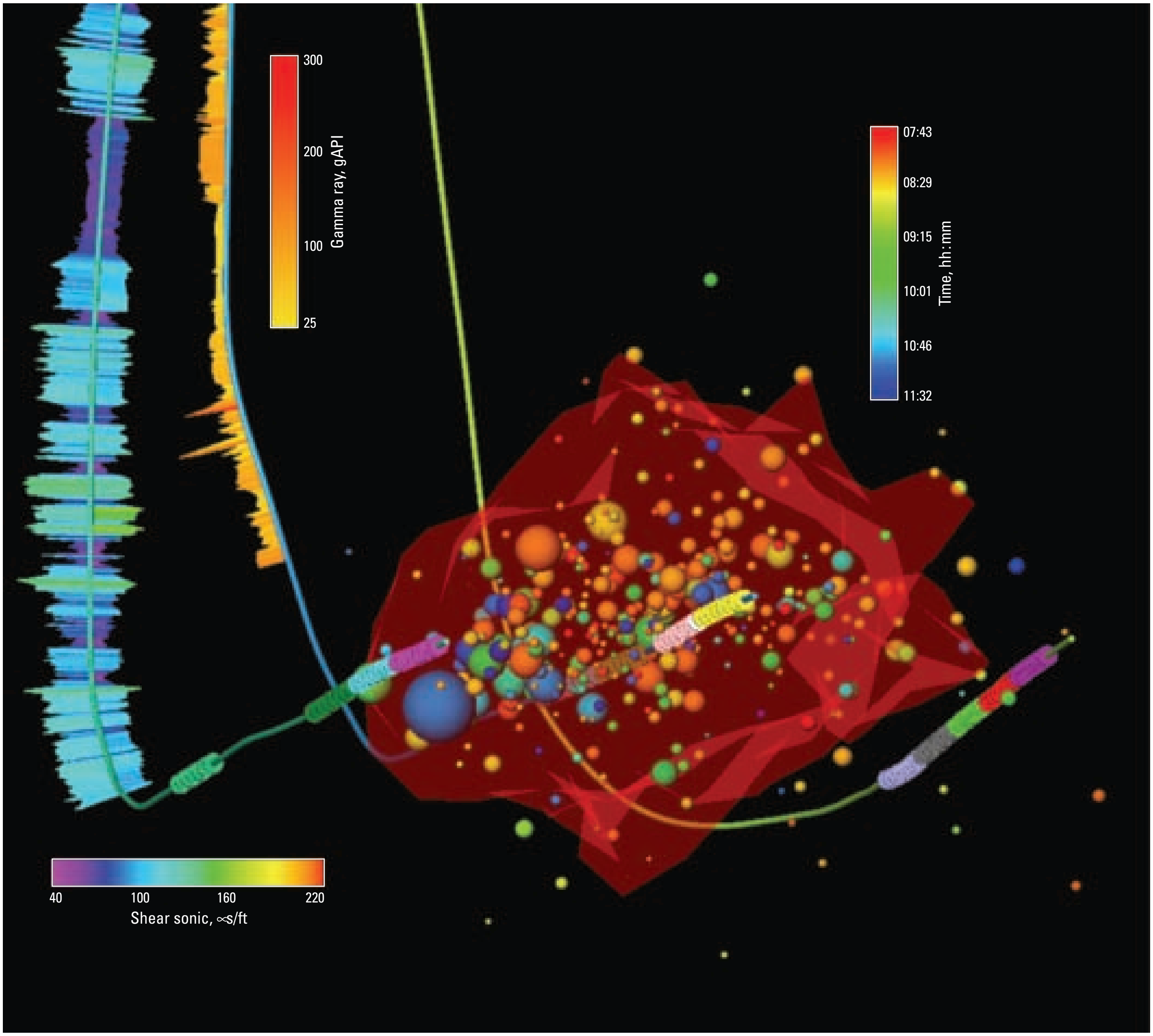
The ability to locate a fracture zone and to influence its development has huge economic significance, particularly in unconventional gas plays, such as tight gas sands and shales. Large reserves of unconventional gas are trapped within formations that have extremely low permeability and that generally do not produce at economic rates without hydraulic fracture stimulation. Most activity for fracturing gas shales has centered on the Barnett Shale in northern Texas, USA, but other formations within the USA have been produced similarly, including the Fayetteville, the Haynesville and, recently, the Marcellus Shales. Application of the technique is also expanding to other countries.

A number of methods have been applied to monitoring hydraulic fracture stimulations, including use of pressure analysis, temperature and production logging, radioactive tracers, borehole imaging, downhole video, tiltmeter mapping and acoustic—also called microseismic—monitoring.[1] In addition, well testing and production analysis give indirect indications of fracture characteristics. Most of these methods are applied or analyzed after the stimulation operation is complete. However, microseismic monitoring (MSM) can provide a live view of fracture development, so operators can proactively evaluate it and alter the result, as required.

Microseisms are acoustic events generated by minute rock movement. They can be generated during hydraulic fracturing as well as during other operating activities such as fluid production, water-, gas- or steamflooding, or formation compaction. They are essentially microearthquakes. Microseisms detected during a fracturing operation have a moment magnitude, M_w, that ranges from –1 to –3.[2]

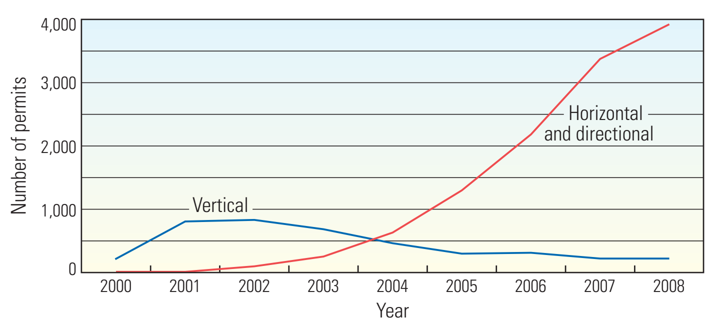
1. For more on hydraulic fracturing and an introduction to hydraulic fracture monitoring: Bennett L, Le Calvez J, Sarver DR, Tanner K, Birk WS, Waters G, Drew J, Michaud G, Primiero P, Eisner L, Jones R, Leslie D, Williams MJ, Govenlock J, Klem RC and Tezuka K: "The Source for Hydraulic Fracture Characterization," *Oilfield Review* 17, no. 4 (Winter 2005): 42–57.
2. The moment magnitude scale is a measure of earthquake strength similar to the more familiar Richter scale.
3. US DOE: "Microseismic Monitoring: Revealing What Is Going on Deep Underground," http://www.energy.gov/discovery/microseismic_monitoring.html (accessed August 3, 2009).

   For an example of results from an early test: Power DV, Schuster CL, Hay R and Twombly J: "Detection of Hydraulic Fracture Orientation and Dimensions in Cased Wells," *Journal of Petroleum Technology* 28, no. 9 (September 1976): 1116–1124; also presented as SPE paper 5626.
4. Permitting statistics for the Barnett Shale and other Texas fields are available from the Texas Railroad Commission at www.rrc.state.tx.us (accessed July 31, 2009).



The MSM currently practiced in unconventional gas fields developed from research funded by the US Department of Energy, first at Los Alamos National Laboratory and later at Sandia National Laboratories, both in New Mexico, USA.[3] Acoustic monitoring activity in unconventional gas fields began to increase significantly in the late 1990s. As a by-product of its need for fracture stimulation, the Barnett Shale has also been a testbed for these microseismic operations.

Drilling of vertical wells in the Barnett Shale peaked in 2002, and the number of horizontal and directional wells has since climbed significantly (right).[4] Many of the vertical wells first put on



^ Drilling permits filed with the Texas Railroad Commission in the Barnett Shale play. The number of permits for vertical wells peaked in 2002, while horizontal and directional well permits continued to grow through 2008.

production five to seven years ago are being refractured in response to production decline.[5] Some operators used MSM when the wells were initially stimulated, and those results are being supplemented by new microseismic maps obtained during refracturing operations. The additional mapping helps operators determine the efficacy of refracturing, particularly when it is processed with the new methods of the StimMAP Live diagnostic service. With this methodology, information is available within half a minute of event occurrence, allowing operators to adjust the operation to maximize formation contact and to avoid fracturing out of zone or into a geohazard.

The increasingly common practice of drilling horizontal wells has engendered additional techniques designed specifically for them. Fracturing in horizontal wells is typically done in stages. A portion of the well is perforated and hydraulically stimulated, then that section is sealed off and another section is perforated and stimulated. MSM with real-time mapping helps an operator determine whether each well section is properly stimulated before moving to the next stage. This rapid feedback becomes even more powerful when coupled with a means to intervene and direct, or redirect, the fracturing process. The StimMORE technology employs a diversion agent to redirect the fracture; continued StimMAP Live monitoring indicates the resulting change in fracture propagation.

This article describes live monitoring and diversion services for operations in unconventional gas formations. It includes a discussion of laboratory evaluations of the diverting agent to guide field use. Case studies demonstrate live monitoring of hydraulic fracturing in a tight gas sand in Argentina and in a shale in Arkansas, USA, and use of diversion technology to control horizontal well fracturing in Texas.

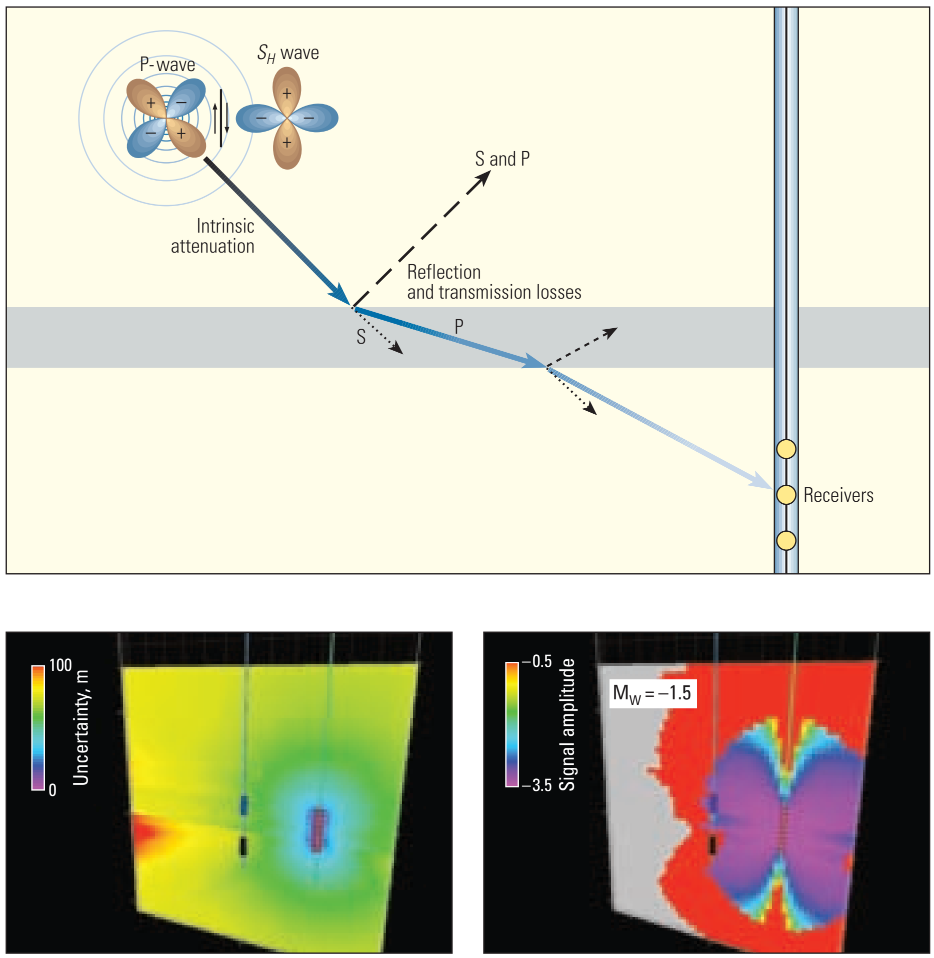
Evaluating Potential for Microseismic Monitoring

Monitoring fracture growth by detecting acoustic emissions is useful for diagnosing the success of a treatment, but it has limitations. Currently, it is not possible to monitor fracture growth from the treatment well because of the noisy environment of the wellbore, so monitoring sensors are placed in nearby wellbores.[6] And, because the acoustic signal attenuates as it passes through a formation, the treatment well and the monitoring well must be within a certain proximity that is a function of formation characteristics and equipment limitations. The probability of success can be determined through prejob modeling.

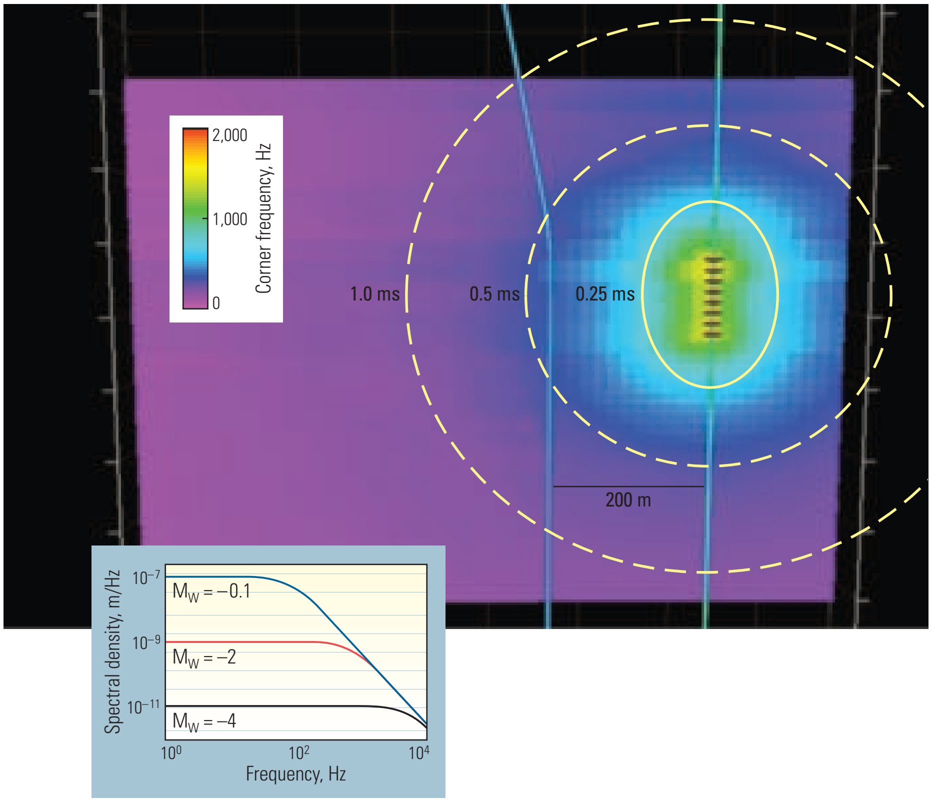
There are two key considerations for survey design and evaluation. One is the likelihood a seismic event will have sufficient magnitude for detection, called the seismogenic potential. It relates to the environment and the signal source, which are determined by the properties of the formation and the fracture and can be marginally influenced by fracture pumping pressures and rates. The second consideration is the suitability of the sensor geometry, or network, given the elastic parameters affecting signal propagation. It is defined by detection capabilities that can be designed and controlled to a greater extent than the seismogenic potential can.

A velocity model is constructed to assess the survey design. It uses NetMod simulation, an Ocean plug-in module for Petrel software (see "Feature-Rich Software, Open by Design," *page 46*). The velocity model of the subsurface can be built using compressional and shear velocities measured by a borehole acoustic logging tool.

The model provides a quantitative prediction of sensor network performance, including detectability of events in the proposed fracture zone and the level of uncertainty in inverting for their locations. Various network locations can be assessed to maximize detection capability and to minimize event location uncertainty. The model is subsequently used during the fracturing job to help interpret the events.



^ Microseismic signal and transmission losses. Emission of energy by a microseism is direction dependent. For example, microscopic slip along a planar fracture generates maximum horizontal shear energy (S_H) along the fracture plane and perpendicular to it (with an opposite polarity), while the compressional (P) energy lobes are offset by 45° (*top*). Energy from a microseism decays with distance, shown here for the compressional P-wave. The energy also attenuates as it travels because the earth is a lossy medium. At layer boundaries some energy reflects and some is transmitted. The transmission angles of reflection are different for P- and S-waves because of their different velocities. For a given receiver network location and earth model, the NetMod software predicts the event location uncertainty (*bottom left*) and the capability for detection of a magnitude –1.5 event (*bottom right*).



^ Map of frequency dependence. The spectral density plot (*inset*) indicates the frequency content at an event source for weak, medium and strong microseisms (M_w = –4, –2 and –0.1, respectively). At frequencies higher than a value termed the corner frequency, the spectral density decreases rapidly. The corner frequency for stronger events is less than it is for weaker events. In addition, higher frequency signals attenuate more rapidly, so distance from the event source to the detector is a critical factor. The NetMod map shows the ability of a receiver to detect events of a given corner frequency. The ovals indicate outer limits of utility for receivers having sampling rates of 0.25, 0.5 and 1 ms.

Microseismic signals resulting from fracture or fault movement do not radiate uniformly in all directions. Compressional and shear components have different directional dependencies, and each signal can be strong in some directions and almost nonexistent in others. This lobed transmission depends on the specific movement that generated the signal. If the movement and its direction are known, the modeling software can incorporate the specific energy transmission pattern to model the network response; if they are not known, a spherical average pattern is employed.

The NetMod software accounts for transmission losses and the effect of formation layers on the signal (previous page, bottom). A typical result based on a specified network of sensors is a 3D prediction of the minimum magnitude event that can be detected and of the maximum uncertainty in locating the source. These 3D maps help in determining the optimal placement of the sensor network and can be used to identify the best candidate wells for MSM.

The proximity of the sensor network to the microseismic source is one determinant of the frequency content of the received signal. This effect results from two complementary seismogenic properties. The first is that motions of higher frequency attenuate faster than those of lower frequency. Thus, for a given source-receiver distance, more of the original low-frequency content is able to propagate to the receiver. The second property is the spectral density of the source. Events of larger magnitude generate more content of lower frequency than do events of smaller magnitude. In conjunction with the first property, the result is a limit to the depth of investigation. A receiver sensitive to high-frequency signals is effective for events close by, but that advantage falls off with distance from the event. The NetMod software can indicate the frequency limitations for a receiver network before the fracture job (above).

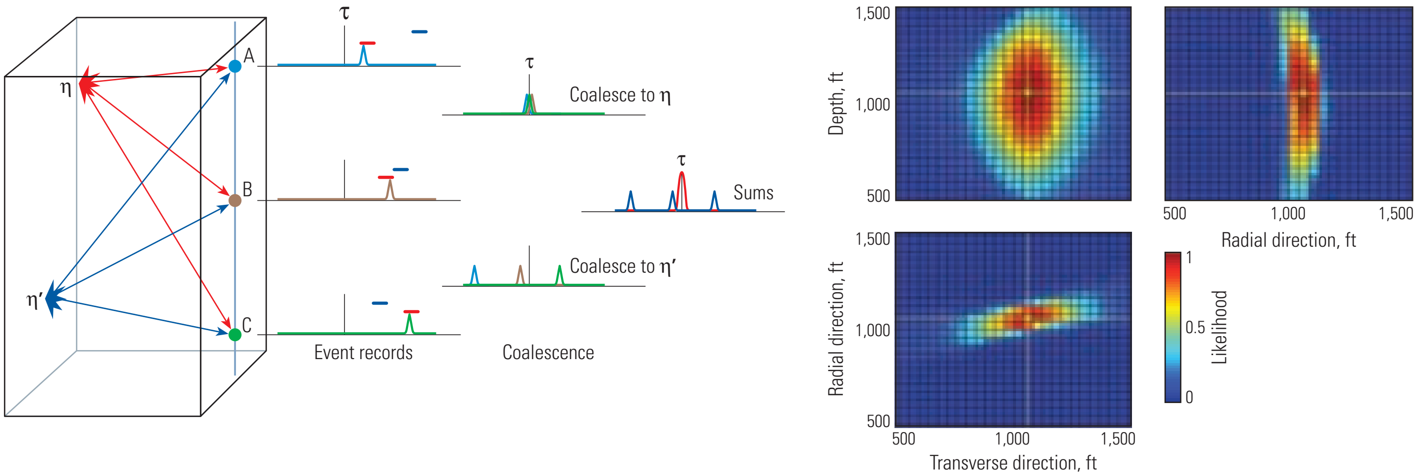
Schlumberger software can incorporate production data and fieldwide geology to screen the candidate wells for restimulation. Many wells in the Barnett Shale have been fracture stimulated over the past seven years, and fracturing of new wells continues. As time passes, the portion of the reservoir contacted by the fracture depletes and, because the permeability is so low, there is insufficient flow from other parts of the reservoir to sustain the production rate. In a three- to five-year period, gas production declines to 20% to 30% of its peak value.[7] These wells become candidates for refracturing to contact untapped regions of the reservoir from the existing wellbore.

Where's the Fracture Right Now?

During a fracturing operation, the lag time between detecting a microseismic event and determining its location is a critical period. A processing delay of 15 or 20 minutes while continuing to pump fluids downhole means the event location information might be irrelevant to the ongoing operation. As part of the StimMAP Live service, Schlumberger engineers developed algorithms that return an event map less than 30 seconds after detection. This short lag time allows the engineers to alter the operation rapidly in response to fracture growth patterns. As soon as a hazard is detected, pump rates can be changed, proppant volumes altered or diverting agents introduced into the slurry to change the fracture geometry or to prevent fracturing into a geohazard, such as a water-bearing formation or a fault connecting to one.

Conventional methods for event location rely on picking the time of first arrival for each event at each receiver.[8] This is difficult to automate and still obtain reliable results; picking times becomes even more complicated when multiple events occur essentially simultaneously. Having an experienced interpreter pick the points increases the accuracy but is time-consuming.

5. For more on refracturing: Dozier G, Elbel J, Fielder E, Hoover R, Lemp S, Reeves S, Siebrits E, Wisler D and Wolhart S: "Refracturing Works," *Oilfield Review* 15, no. 3 (Autumn 2003): 38–53.
6. Experimental studies have been performed using receivers in the treatment well, but the configuration used is not commercial. For examples: Primiero P, Armstrong P, Drew J and Tezuka K: "Massive Hydraulic Injection and Induced AE Monitoring in Yufutsu Oil/Gas Reservoir—AE Measurement in Multiwell Downhole Sensors," *Proceedings of the Society of Exploration Geophysicists of Japan Conference*, Okinawa, Japan (2005), vol. 113: 187–190. Stewart L, Cassell BR and Bol GM: "Acoustic-Emission Monitoring During Hydraulic Fracturing," *SPE Formation Evaluation* 7, no. 2 (June 1992): 139–144.
7. Frantz Jr JH, Williamson JR, Sawyer WK, Johnston D, Waters G, Moore LP, MacDonald RJ, Pearcy M, Ganpule SV and March KS: "Evaluating Barnett Shale Production Performance Using an Integrated Approach," paper SPE 96917, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.
8. Aki K and Richards PG: *Quantitative Seismology, Vol. 1: Theory and Methods*. San Francisco: W.H. Freeman and Company (1980).



^ Coalescence of signals from multiple receivers. Three receivers, A, B and C, record the same microseism at slightly different times because of the different traveltimes from the event location to each receiver (Event records, *left*). To determine the location of the source event, the coalescence software tests every gridblock in the detection volume. In this example, two grid locations, η and η′, are tested for an event occurring at time τ. Based on the traveltime from η to Receiver A and allowing for uncertainty, the expected signal should occur within a certain time window (red bar). Traveltime from η′ to Receiver A is longer, so the window is later (blue bar). The expected arrival times at the other two stations are determined similarly. The amplitude in this calculated window is summed over all the receivers in a process called coalescence. This is equivalent to translating each event record backward in time by an amount equal to the modeled traveltime from each location to each receiver (Coalescence), then summing the translated receiver signals (red for η, blue for η′). Thus, a likelihood value will be assigned to each location at each time. The maximum coalesced amplitude represents the most likely place and time for the source event; for this case it is location η at time τ. Using the software, analysts can examine slices of the 3D detection volume showing calculated likelihoods (*right*).

Although it seems counterintuitive, a faster way to determine event location and timing is to model the whole detected space and check the likelihood that each location in the space was the signal source at a corresponding moment in time (above).[9] This process, called coalescence, yields a maximum signal at the most likely point in both time and space for the event's occurrence. Thus, picking first arrivals is not required.

In addition to the location information provided by signal timing, the StimMAP Live software looks at vector information contained in the compressional or shear wave. This analysis further constrains the location of the microseism. Although the process assigns the event to the point of maximum coalescence, it also implicitly provides a probability volume around that location to indicate uncertainty, constrained both by the timing and the compressional-wave vector information.

The StimMAP Live console is available at the wellsite or through a secure InterACT connection at any location around the world. The console displays the events within seconds of detection. The uncertainty map is also available in real time. This is particularly useful for events approaching a zonal boundary or a geohazard because it helps assess the probability of the fracture growing into that zone. The results can be displayed with the NetMod model to determine if there is any observational bias in the measured geometry. In addition to providing information for avoiding geohazards, the software also displays a parameter that relates to improved production.

This parameter is based on a correlation between production after hydraulic fracturing and stimulated-reservoir volume.[10] The original correlation showing an increase in production with increased reservoir contact was based on identifying each fracture in the complex of fractures detected through MSM. The NetMod program uses a proprietary diagnostic tool based on this principle that evaluates the event density and provides a measure of the effective stimulated volume (ESV) (next page, top). This is a "shrink-wrapped" volume around the microseisms that excludes sparse outliers. This approach is more conservative than putting a box around all microseismic events, and it more clearly distinguishes an increase in the volume of formation that is fracturing.

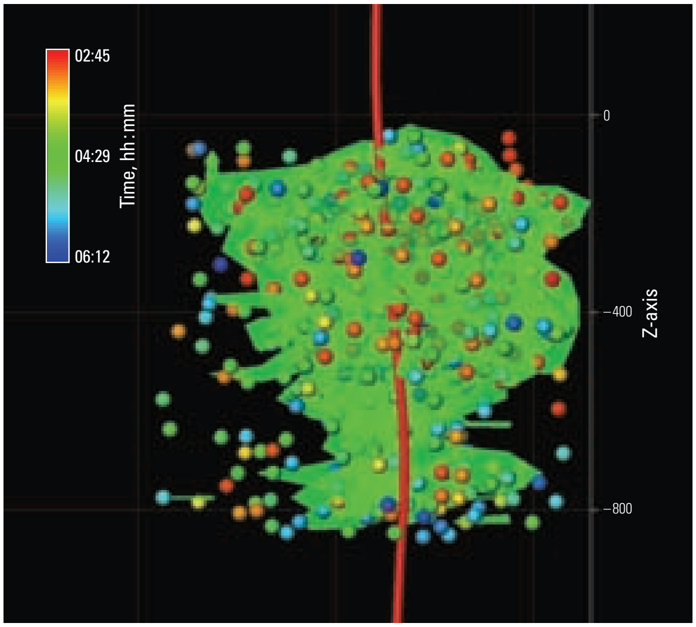
StimMAP Live software records all the event information and can play it back at any time; the operator can review the progress of the fracture operation either as it progresses or later. Interpretation is aided by coloring or sizing the events by event time or some calculated attribute such as event magnitude, signal/noise ratio or ratio of compressional- to shear-wave amplitudes.

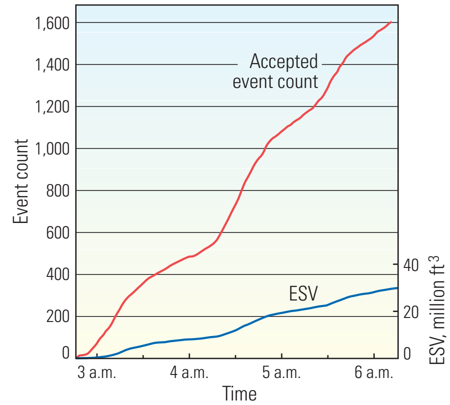
Determining Stress Anisotropy

The Centenario field in southwestern Argentina is highly faulted, which can cause the local horizontal stress direction to vary. Since hydraulic fractures tend to grow in the local maximum-stress direction, uncertainty about that direction could lead to inefficiencies in placement of future wells and in the general field development plan, which tries to minimize overlap between individual-well drainage areas. Pluspetrol, operator of the field, used StimMAP Live monitoring during a fracturing operation to confirm the stress direction.

The field, 15 km [9 mi] west of the city of Neuquén, produces both oil and gas from several formations. One, Los Molles Formation, comprises several gas-bearing sands intercalated with shales. The formation has four sections: Molles Superior, Molles Intermedio, Molles Basal and Molles Pelitico. The upper three sandy bodies with shale intercalations are considered reservoir-quality tight gas sands with permeabilities of 0.1 mD and less. Wells are fractured to increase their productivity.

Extensional faults that developed initially during a late Triassic rifting phase divide the field into nine blocks and influence the local stress direction within each block.[11] Pluspetrol uses dipole shear sonic logging, breakout directions from six-arm caliper measurements and borehole





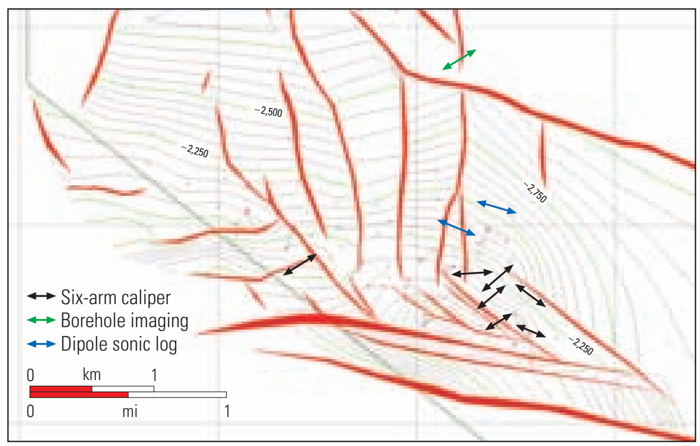
< Effective stimulated volume. Analysis of the event cloud density provides a measure of the effective stimulated volume (ESV) of rock within the formation (*left*). The irregular surface excludes outlying events. This analysis provides a real-time diagnostic tool (*above*). An increase in the cumulative number of events (red) with a simultaneous increase in ESV (blue) indicates growth in the volume of the fractured-rock zone.

imaging to estimate the stress direction (right). However, because of the shallow depth of investigation, these methods measure anisotropy only in the immediate vicinity of the logged well. A StimMAP Live monitoring operation both indicated the direction of fracture growth much farther from the wellbore and confirmed the logged near-well stress orientation.[12]

The treatment and observation wells are vertical within the target zone, separated by about 600 m [1,970 ft] at that depth. The microseisms were detected using a VSI imager with eight stations spaced 30.5 m [100 ft] apart. This tool measures compressional and shear waves and transmits the full waveform to surface for immediate analysis.[13] The treatment well was perforated over a 10-m [33-ft] interval near the base of Los Molles Superior section. The perforations were about at the depth of the middle receiver station.

The treatment objective was to create a fracture of 100-m [333-ft] half-length, with limited height, to stimulate the 10-m [33-ft] interval. However, in the design stage a simulation model showed vertical growth would be extensive because there were no effective bounding barriers. The simulation indicated that in order to achieve a 112-m [367-ft] half-length, the fracture height should be 120 m [393 ft] high.

In six stages of the operation, the proppant concentration was increased from 0 to 6 lbm of



^ Stress directions in Centenario field. A series of faults divides the basin into blocks with varying directions of maximum principal stress. The MSM operation was used to confirm these near-well interpretations of stress direction.

9. Drew J, Leslie D, Armstrong P and Michaud G: "Automated Microseismic Event Detection and Location by Continuous Spatial Mapping," paper SPE 95513, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.

   Michaud G and Leaney S: "Continuous Microseismic Mapping for Real-Time Event Detection and Location," *Expanded Abstracts* 27: Society of Exploration Geophysicists (2008): 1357–1361.

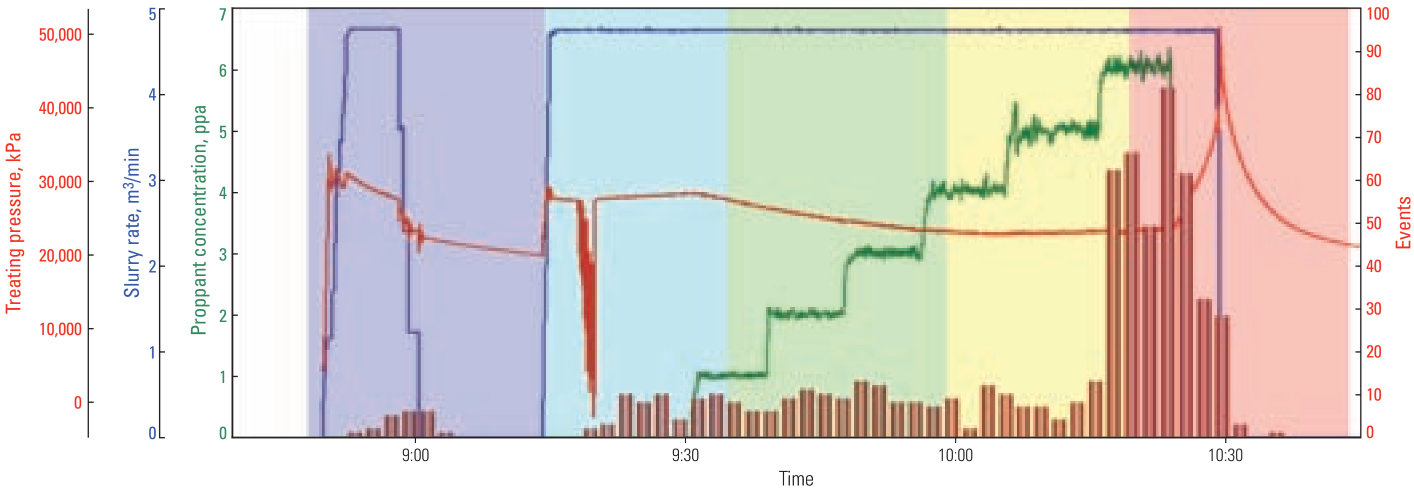
   For use of this technique in earthquake mapping: Kao H and Shan S-J: "The Source-Scanning Algorithm: Mapping the Distribution of Seismic Sources in Time and Space," *Geophysical Journal International* 157, no. 2 (2004): 589–594.

10. Mayerhofer MJ, Lolon EP, Warpinski NR, Cipolla CL, Walser D and Rightmire CM: "What Is Stimulated Reservoir Volume (SRV)?" paper SPE 119890, presented at the SPE Shale Gas Production Conference, Fort Worth, Texas, USA, November 16–18, 2008.

11. For more on stress orientations near faults: Yale DP: "Fault and Stress Magnitude Controls on Variations in the Orientation of In Situ Stress," in Ameen M (ed): *Fracture and In-Situ Stress Characterization of Hydrocarbon Reservoirs*. London: Geological Society of London, Special Publication 209 (2003): 55–64.

12. For more on use of sonic logging to determine stress anisotropy: Brie A, Endo T, Hoyle D, Codazzi D, Esmersoy C, Hsu K, Denoo S, Mueller MC, Plona T, Shenoy R and Sinha B: "New Directions in Sonic Logging," *Oilfield Review* 10, no. 1 (Spring 1998): 40–55.

13. Blackburn J, Daniels J, Dingwall S, Hampden-Smith G, Leaney S, Le Calvez J, Nutt L, Menkiti H, Sanchez A and Schinelli M: "Borehole Seismic Surveys: Beyond the Vertical Profile," *Oilfield Review* 19, no. 3 (Autumn 2007): 20–35.

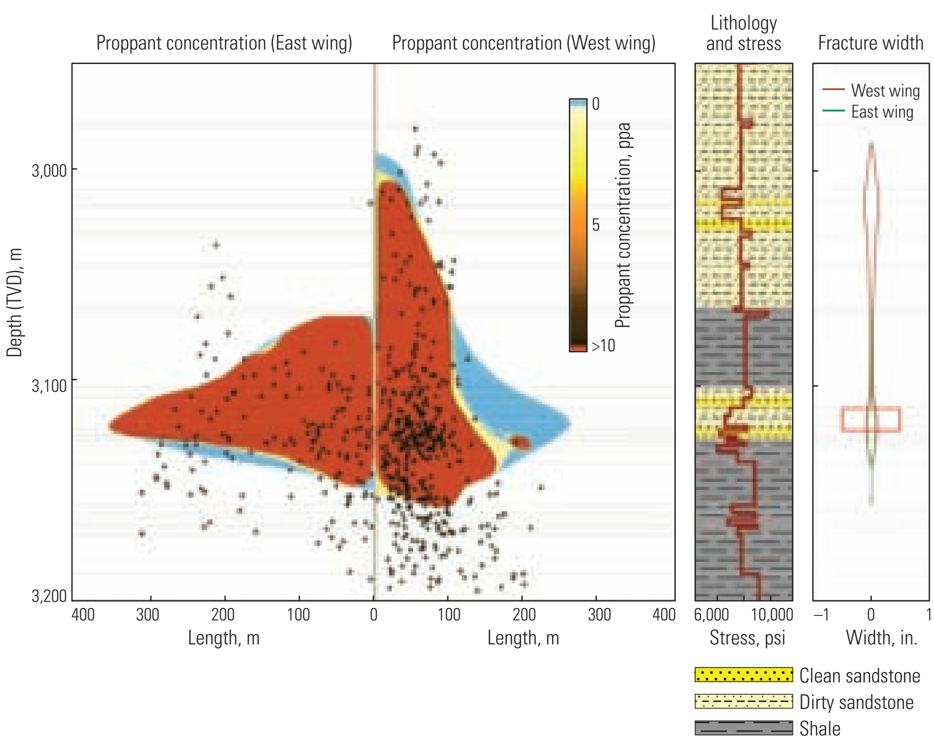


^ Microseismic events during fracturing treatment. Following the pad, the proppant concentration (green) was increased in six steps, while the slurry rate (blue) was kept constant. The treating pressure (red) increased near the end of the job, indicating tip-screenout behavior. The microseisms (maroon) occurred at a fairly consistent rate until the final step in concentration, when the rate increased significantly. The background shading corresponds to the colors of the five stages shown in other figures of this case study.

proppant added (ppa) (above). The pumping rate was about 5 m^3/min [30 bbl/min] with an average pressure of 27.6 MPa [4,000 psi]. The treatment used 340 m^3 [2,130 bbl] of fluid to deliver 92,400 kg [203,800 lbm] of proppant.

During the operation, 640 microseismic events were recorded over about a 2-h period. At the end of the job, when the highest concentration of proppant was being pumped, the event rate increased dramatically. Most of those late events occurred near the wellbore. A FracCADE net-pressure analysis confirmed that this behavior indicated tip screenout, a technique that provides good proppant packing in the fracture.

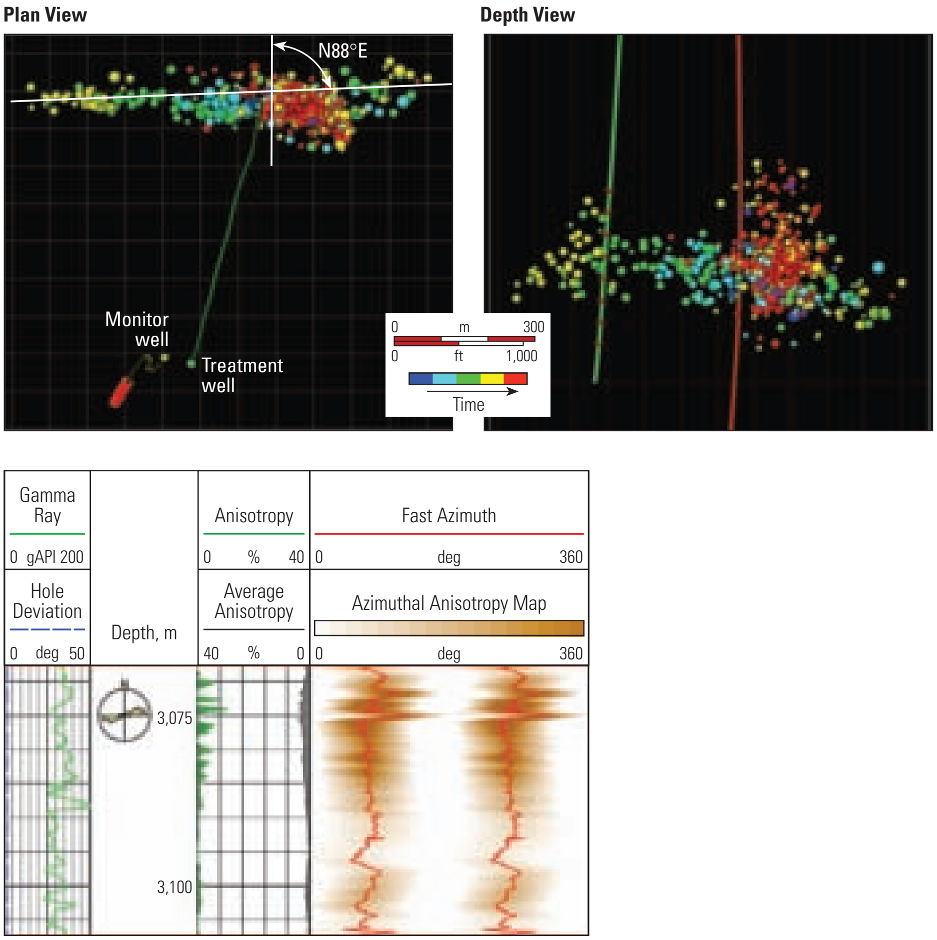
The microseisms define a fracture plane with an azimuth of N88°E, which compares well with the direction predicted by the dipole sonic log over the fractured interval. The events indicate the fracture was not symmetric in either height or extent (left). The propped fracture in the western wing was about 334 m long by 84 m high [1,096 by 276 ft], while the eastern wing was shorter in length but taller at 238 m long by 167 m high [781 by 548 ft]. This asymmetry may be due to the nearby faults. Pluspetrol engineers use the sum of the measured fracture half-lengths in their ECLIPSE reservoir models for forward simulations.



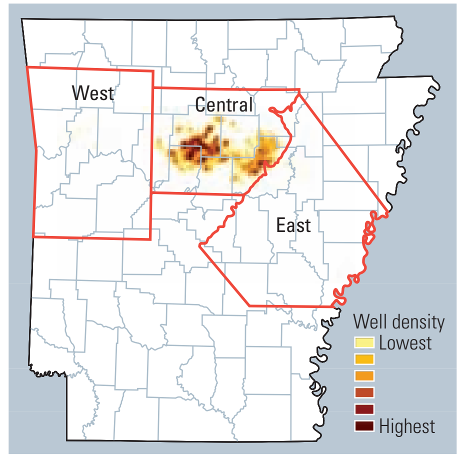
^ Modeling Los Molles fracture. Using FracCADE fracturing design and evaluation software, analysts fit the pressure profile and microseisms to a fracture that is longer on the east but taller on the west (*left*); its asymmetry is possibly due to nearby faults. A large portion of the fracture received a high proppant concentration (red), but the extreme wings received a much lower concentration (blue). Although seismic events were measured in the lower shale, analysis indicates they do not represent a through-going fracture. The shale (lithology chart, gray) was unable to contain upward fracture growth on the west. The fracture is wider in the sands than in the shales (*right*).

Los Molles Superior and Intermedio sections were both stimulated by this fracture. The fracture grew beyond the anticipated height because there is low stress contrast between the formation and the upper bounding layer. However, the bounding formation is also gas bearing, although the reservoir quality is poorer than that of the target zone. Since Pluspetrol was interested in obtaining a long fracture, the engineers allowed the fracture to grow into the poor-quality reservoir.

The primary result of the evaluation was agreement between the maximum horizontal principal stress direction from the sonic logs obtained on a few wells in each block and the fracture strike determined by the more definitive microseismic monitoring, which might be used only once in each fault block (next page, top left). This agreement helps Pluspetrol plan future well locations to maximize the effectiveness of frac-



^ Event location and stress azimuth. The microseismic events outline a planar fracture with an orientation of N88°E (*top left*), which agrees with the maximum horizontal principal stress direction from the dipole sonic tool (depth track, *bottom*). The receivers spanned the region of the fracture growth and provided good coverage of events on both sides of the fracture (*top right*). Most of the late events were near the wellbore.

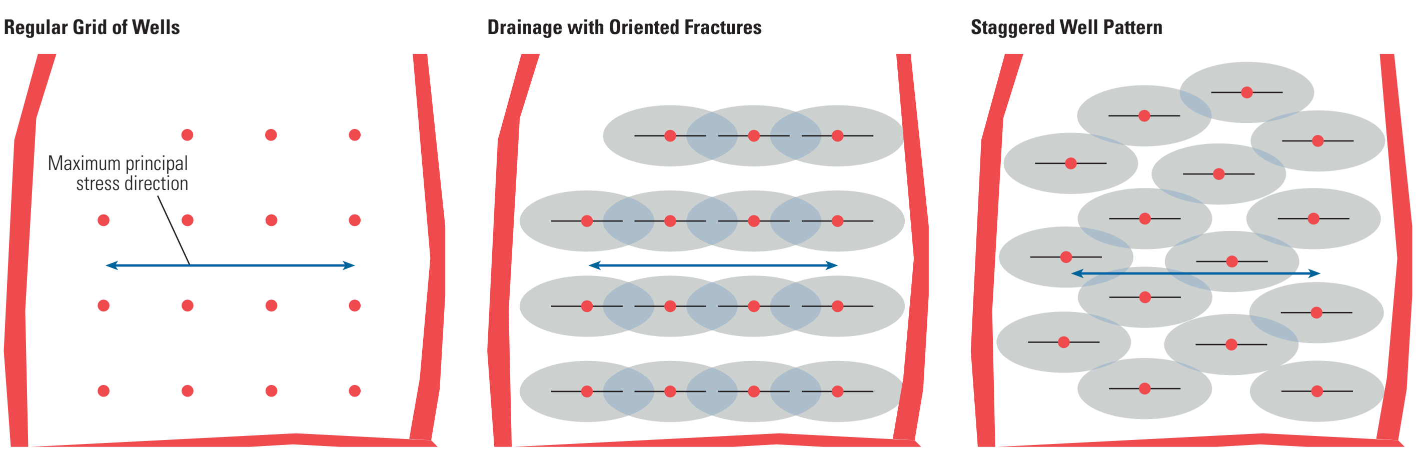


^ Drilling activity in the Fayetteville Shale. (Copyright Arkansas Geological Survey, used with permission.)

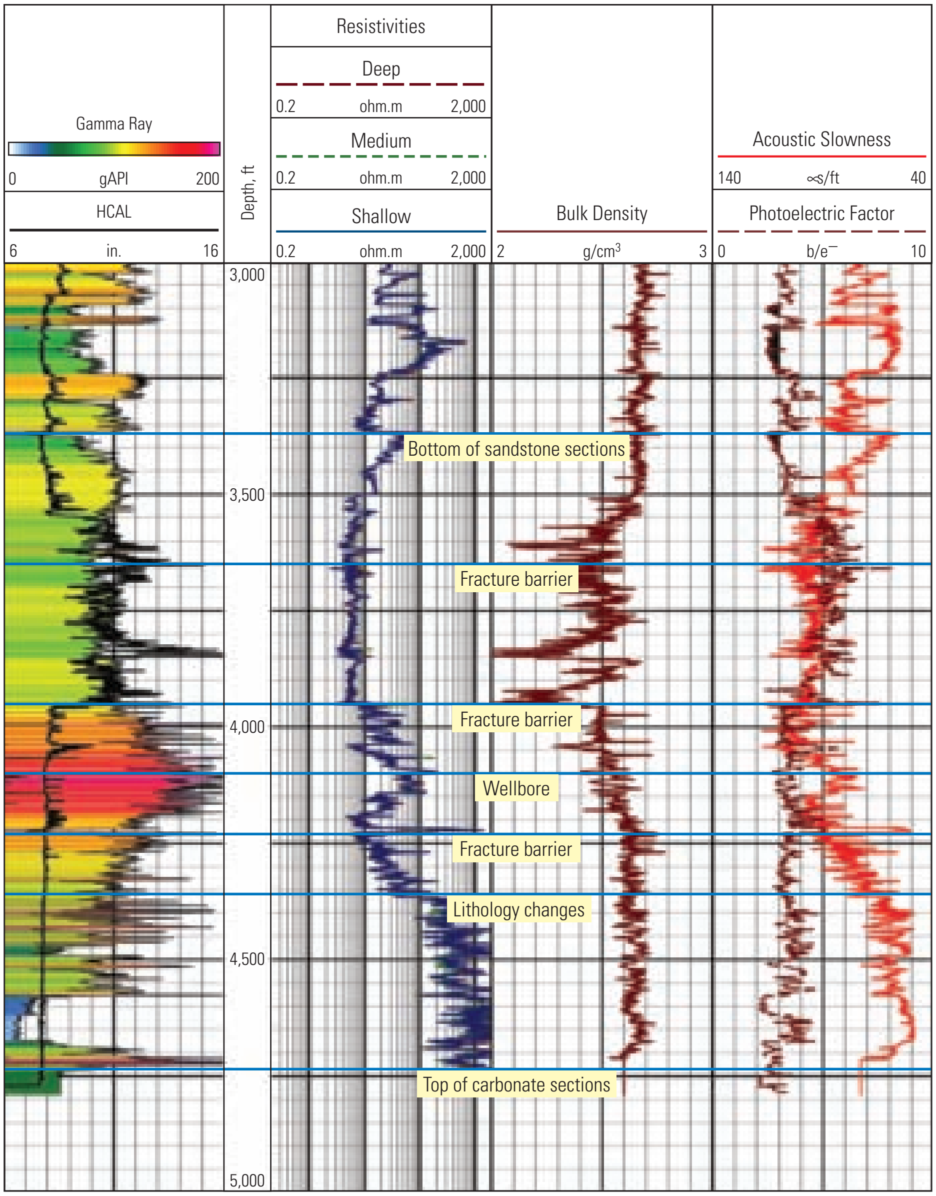
turing to improve the recovery factor. Wells can be staggered to take advantage of the fracture orientation, rather than being placed in a set pattern (below). Well separation can be optimized because the company knows the desired fracture length is achievable.

Confirming Fault Geometry in the Fayetteville Shale

Operators have extended practices first developed in the Barnett Shale to other shale gas provinces. The Mississippian Fayetteville Shale, with production in central Arkansas, is one of these (above). Although porosity in this formation ranges from 7% to 12%, the permeability is typically less than 1 nD. Fracturing is necessary to achieve economic production.



^ Placing wells. A standard grid (*left*) may not provide efficient drainage when the fracture drainage pattern is taken into consideration (*middle*). To take advantage of the fracture length and orientation, which are based on the maximum horizontal principal stress direction (blue), wells should be staggered within a fracture block (*right*).

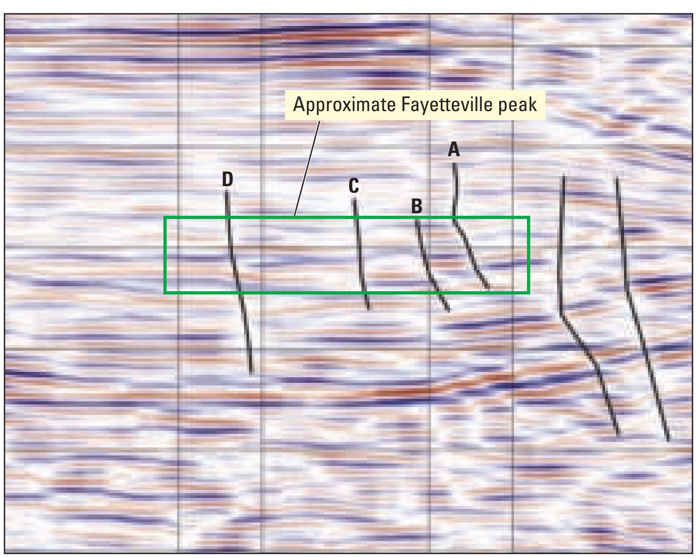


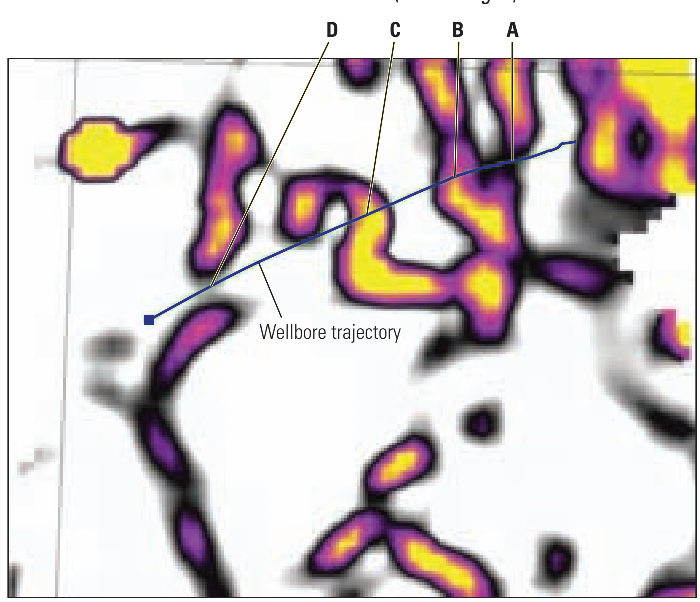
This shale comprises mud-sized particles—less than 0.06 mm diameter—of clay minerals, fine-grained quartz and feldspars, and organic material. The depositional environment was the calm water of a seafloor below the storm-wave base. The pay is bounded above and below by stronger formations that act as barriers to fracture growth (left). Seismic interpretation indicates subvertical faults, although the data resolution is poor.

Operator Aspect Abundant Shale drilled a horizontal well through a faulted section of the shale.[14] The faults represented geohazards to fracturing—thief zones that allow the stimulation of nonreservoir rock or the possibility of opening flow to the underlying Penters Formation, which can be water bearing. To monitor the slickwater fracturing operation, Aspect used the StimMAP Live service. It provides real-time feedback on fracture progression, determination of the induced fracture geometry and additional inferences regarding subseismic-scale information on faults.

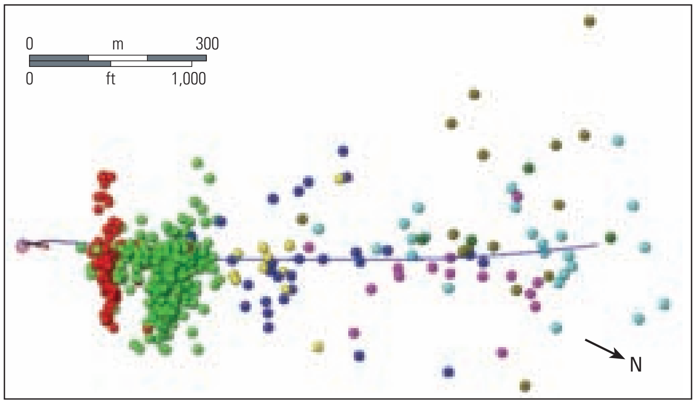
Stimulation of the horizontal well was planned in nine stages from toe to heel. The pilot well was used to monitor the microseisms. The anisotropic velocity model was calibrated using results from acoustic monitoring of the perforation shots in each stage and from wireline and surface 3D seismic data.

< Fayetteville Shale geology and faults. A typical log indicates high gamma ray response in the shale (*top*, Track 1, orange to red). Fracture barriers and lithological changes are indicated in Track 2. The seismic section (*bottom left*) shows four faults (A, B, C and D) in the region of the horizontal well; they are indicated as geohazards in the 3D model (*bottom right*).

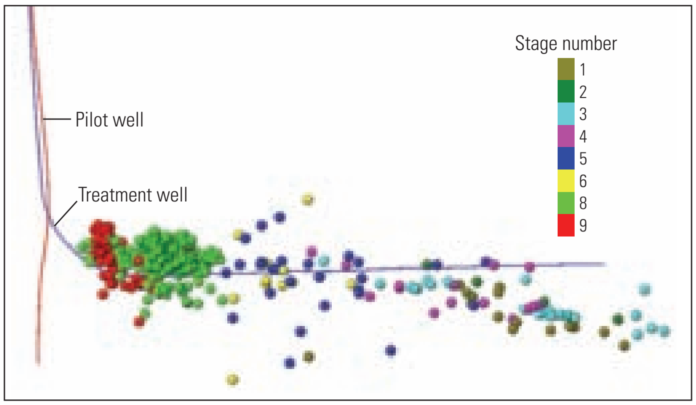




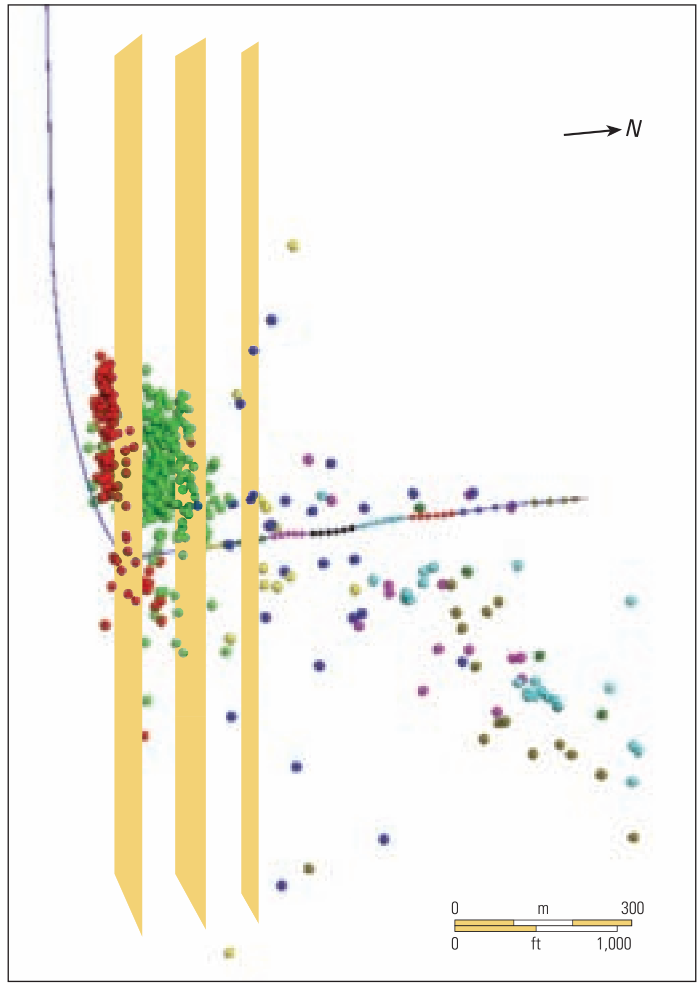
Plan View



Depth View



^ Microseismic events in the Fayetteville well. Most of the detected events occurred during Stages 8 (green) and 9 (red). The fracture azimuth is defined by the cluster of events from these stages (plan view, *top*). The sparse data from the other stages are consistent with the azimuth from those stages. The events at the toe of the well extended downward (*bottom, right side*), but the activity moved upward as the stages moved toward the heel.



^ Fault orientation. MSM events in Stages 8 and 9 are subvertical and may have opened existing faults (gold) seen on the seismic section.

The first six stages had few acoustic events (above). There are three possible reasons: distance to the monitor well, energy loss during transmission through the fault system and variable rock characteristics in the area. Aspect tested various pump rates to see which ones gave the best performance, and these different rates likely contributed to differences in observed stimulation geometry. The events that were recorded indicate the fractures from the first four stages extended downward. Based on these live measurements, the operator decreased the pumping rate in time to avoid fracturing into the water zone below.

Microseismic events indicate that fractures propagating during Stages 5 and 6 extended upward from the well. Although the data are sparse, this upward movement from toe toward the heel indicates a fractured-zone dip from southwest to northeast.

The microseismic behavior seen in Stage 6—possibly activating a fault system—led the operator to cancel Stage 7. This prevented a potential fluid loss into the fault system and also avoided overlapping the stimulated volume of the rock from Stage 6. Making the decision would not have been possible without the real-time feedback from the live MSM.

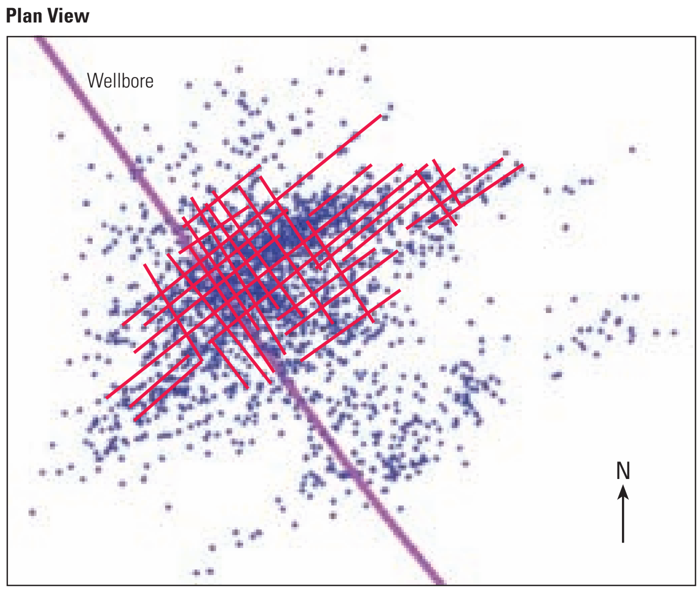
Stages 8 and 9, the final two, had significantly more acoustic events than the previous ones. These events show well-defined upper and lower bounds for the fractures, but there was a small amount of overlap between these two stages. The fractures grew upward out of the target zone along faults identified in the 3D seismic data, but because the higher zone did not present a danger of water encroachment, Aspect chose to continue the operation. Although fracturing in this zone was less than ideal because of the lower gas saturation in the shale, the stages were pumped to completion.

Both these final stages created fractures with the same well-defined azimuth. In addition, the sparse events from the earlier stages were consistent with the azimuth defined in these heel stages. The azimuth confirms the near-vertical fault planes interpreted from the seismic sections (above). The Aspect scientist entered the updated fracture geometry into the company's 3D reservoir model during the operation, providing a calibration of the results to the model. Recalibrating the model extended the benefits to Aspect operations throughout the field.

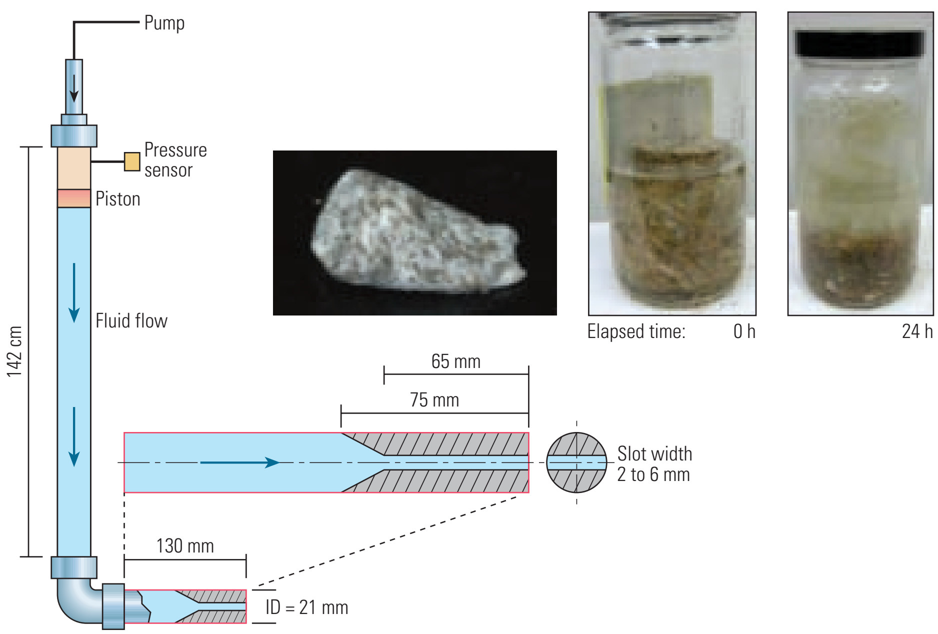
Making a Temporary Diversion

Fracturing results in the Barnett Shale are not easy to interpret; treatment operations are likely to reactivate natural fractures that form a complex network. Experts in this area envision a natural network characterized by a main, roughly

14. Burch DN and Le Calvez JH: "Integration of New Technologies to Map Structural Features and Improve Stimulation Treatments in Shale Gas Plays: Coupling Surface Seismic, Microseismic Mapping, and Wireline Logs in the Fayetteville Shale Formation," presented at the AAPG International Conference and Exhibition, Cape Town, South Africa, October 26–29, 2008.



^ Complex fracture patterns. Interpretation of fracture patterns in the Barnett Shale can be difficult. Detailed interpretation based on microseisms during one fracturing stage suggests a pattern of primary and secondary fractures (red).



^ Diversion testing. The laboratory setup for testing fibers in proppant slurries used a long tube with a removable, adjustable slot (diagram). After each test, the slot was disassembled and a visual check of the fiber and proppant bridge that formed in the slot (photo, *left*) confirmed the pressure increase seen during the test. Photos of the laboratory vials show degradation of the plug begins within one day.

parallel set that can be extensive and shorter fractures that intersect with, and often terminate at, the primary set (left).[15] The simple conceptual model suggesting that hydraulic stimulation generates a penny-shaped fracture extending in both directions from a wellbore is often incorrect in the Barnett. Although some planar features can be located in the MSM results, acoustic events show an extensive zone of fracture activation around the wellbore.

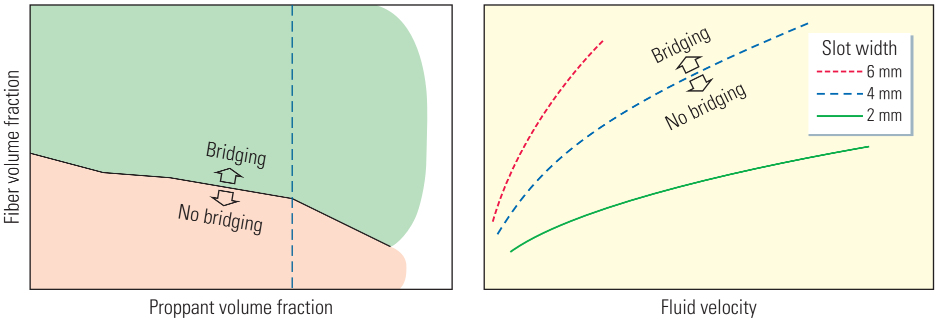
This complexity makes control of the fracture difficult. Expansion of a fracture network might occur far from the perforations that are open to the treatment. If growth in that location is unacceptable, then an operator will try to divert the fluid elsewhere. Gels and foams have been used as diverting agents, but they leave residues that can impact long-term producibility.

The StimMORE diversion service takes a different approach. Fibers introduced into the slurry are carried into the formation and create bridges of proppant and fibers across fracture openings. The fiber has a low specific gravity that prevents it from settling, allowing the fiber to be delivered more effectively to the desired location. The fiber shape can bridge over open channels and fractures with much lower solids content than possible for particulates alone.

This temporary barrier created while pumping allows the bottomhole pressure to increase enough to initiate a fracture elsewhere in the formation. A few days or weeks later, the fibers dissolve, leaving no damage. The fiber material is inert polyester that leaves only a water-soluble weak acid when it dissolves.

Extensive laboratory tests provided guidelines for use of this fiber treatment in the Barnett Shale. The laboratory equipment included a flow device with a slot whose opening size could be controlled (left). In addition to the slot width, the variables covered by the 400 tests were fiber concentration, proppant size and concentration and fluid velocity. The evaluations used carriers of three varieties: low- and medium-temperature viscoelastic fluids and linear gels. Researchers could determine which slurry and fiber combinations bridged across the slot (next page, top).

The laboratory results provide the basis for the StimMORE Advisor software that Schlumberger engineers use to design diversion treatments. Before a job, a StimMORE engineer enters information about the well, completion, previous fracture stimulations and natural frac-



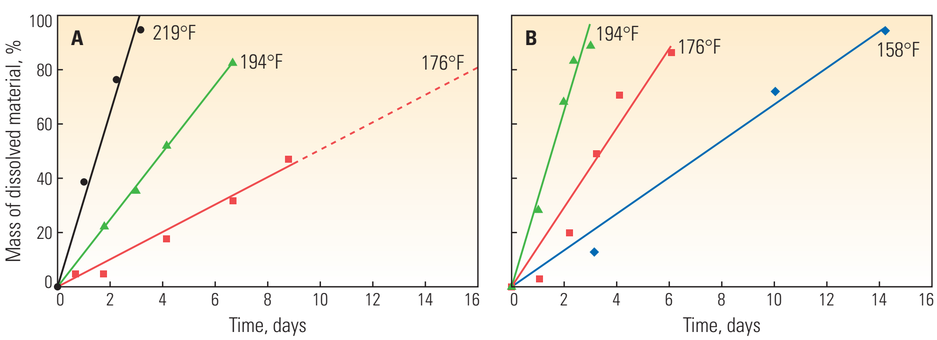
^ Bridging the slot. All the parameters tested affect the bridging point; only two relationships are shown here. Both proppant concentration (*left*) and fluid velocity (*right*) influence the concentration of fiber needed to create a bridge.

ture networks. This information is used to calculate treatment volumes based on the laboratory-scale results. Information about the current hydraulic fracture operation, including the proppant size and concentration, the fiber concentration and the placement rate, are then used to calculate volumes of the diverting slurry. The Advisor provides the volumes for all three base carriers. The design engineer can alter the input specifications if overriding concerns require deviation from standard recommendations.

The fibers are mixed into the slurry at surface, generally while pumping at a slower rate than used during fracturing. Then the injection rate is increased to its previous value until the diversion treatment reaches its delivery point; the rate is then decreased to cause a plug to form in a fracture at a desired distance from the wellbore. In addition to determining the effective delivery rate, the design software makes sure the slower rates of mixing and delivery are still high enough to avoid proppant settling in the wellbore.

Because the fracture opening width is unknown, experience with the geographic area provides the initial value. The Schlumberger approach, and StimMORE Advisor implementation, is to be conservative with the first diversion treatment. If that treatment does not provide adequate diversion, the engineer iterates to an effective concentration; gradually increasing the estimated fracture width is one way to do this. The simultaneous use of the StimMAP Live service is critical for determining the success of the diversion. Typically, 5 to 10 min is sufficient to assess the results of the diversion stage. If the microseismic events remain in the same part of the reservoir and the ESV indicates no new rock volumes are being treated, a more aggressive treatment is planned for the next diversion stage.

The laboratory tests also evaluated the degradation of the fibers. The breakdown from the original polymer to a water-soluble weak acid occurs over a period of days or weeks, depending on the formation temperature. This period can be shortened by putting additives in the diversion fluid that prevent a drop in pH during degradation (below left).



^ Fiber degradation in the presence of additives A and B. Over time, the polyester comprising the fibers degrades into shorter-chain polymers, eventually leaving only a safe, water-soluble weak acid.

More Stimulating in Real Time

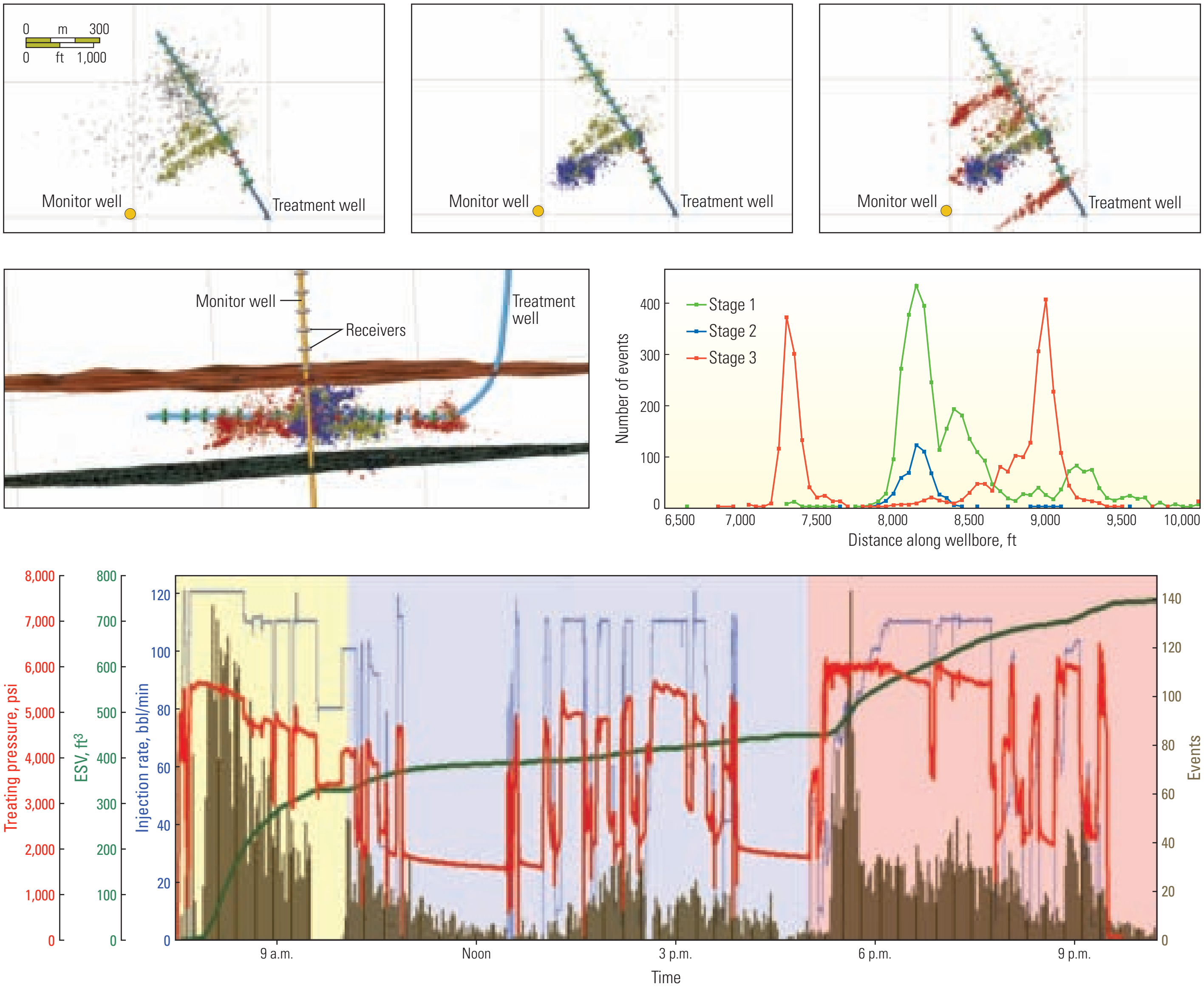
The extensive laboratory studies associated with the StimMORE diversion optimization system were designed for its use in the Barnett Shale. This Mississippian marine shelf deposit lies unconformably atop the Viola Limestone of the Ellenburger Group.[16] The Marble Falls Limestone is above it. The formation thickness ranges from 200 to 800 ft [60 to 240 m].

The shale is its own source rock for the gas in place.[17] Matrix permeability ranges from 70 to 500 nD, a flow capacity so low that production generally is not economic without fracture stimulation.[18] Even with stimulation, the production declines after a period of time. Many companies are now restimulating wells.

A cased and cemented Barnett well was originally fractured in 2003.[19] The well had 12 clusters of perforations in the interval between 8,025 and 9,853 ft [2,446 and 3,003 m] MD, with two other clusters in the heel at 7,396 and 7,560 ft [2,254 and 2,304 m] MD. Microseismic monitoring of that original slickwater operation indicated the heel and lower midlateral sections were the ones predominantly stimulated.

In late 2007 well production had declined by a factor of four from the original value. The operator refractured this well, using the StimMORE procedure to monitor the operation and divert fracturing fluid from the area already stimulated. The first step was to add two more perforation clusters at 7,711 and 7,866 ft [2,350 and 2,398 m] in the gap between the previously perforated areas.

15. Olsen TN, Bratton TR and Thiercelin MJ: "Quantifying Proppant Transport for Complex Fractures in Unconventional Formations," paper SPE 119300, presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, January 19–21, 2009.
16. Potapenko DI, Tinkham SK, Lecerf B, Fredd CN, Samuelson ML, Gillard MR, Le Calvez JH and Daniels JL: "Barnett Shale Refracture Stimulations Using a Novel Diversion Technique," paper SPE 119636, presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, January 19–21, 2009.
17. For more on gas shales as source rocks: Boyer C, Kieschnick J, Suarez-Rivera R, Lewis RE and Waters G: "Producing Gas from Its Source," *Oilfield Review* 18, no. 3 (Autumn 2006): 36–49.
18. Potapenko et al, reference 16.
19. Potapenko et al, reference 16.

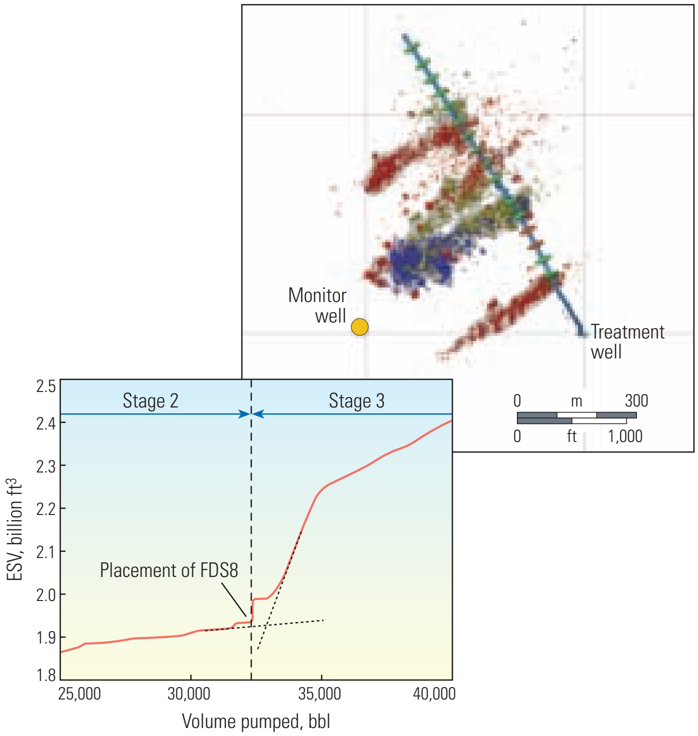


^ Restimulation with diversion in the Barnett Shale. Microseismic events were recorded in a horizontal well during the original completion and three stages of restimulation. Stage 1 events (gold, *top left*) are shown in the plan view with the events from the original completion (gray). Events during Stage 2 (blue, *top center*) stimulated the same middle and lower portions of the well as did Stage 1. After an aggressive diversion treatment, Stage 3 (red, *top right*) stimulated new sections around the well (*middle right*). The depth view of the microseismic events from all three stages (*middle left*) also indicates the bounding formations, with the Marble Falls Limestone above and the Viola Limestone below. These injection stages included several fiber diversion stages, which affected the injection rate (blue, *bottom*) and treatment pressure (red). The rapid increase in ESV (green) occurred after the aggressive diversion treatment at about 5:30 p.m. The background colors match event colors for the three stages.

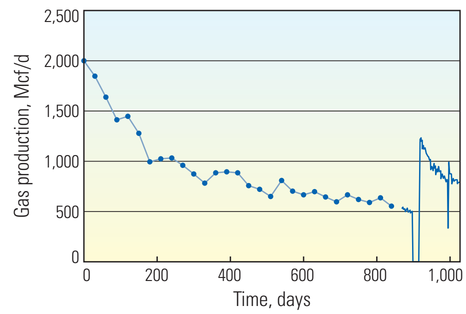
The operation used 2 million galUS [7,571 m^3] of slickwater and 1 million lbm [454,000 kg] of sand including 100-, 40/70- and 10/40-mesh proppants. The treatment included 3 stages of proppant injection in which a total of 11 stages of fiber diverting agent were applied.

The observation well used in the original fracture monitoring operation was used again. The geophone array in that well had eight stations at 100-ft [30.5-m] intervals. During the first injection stage, microseismic activity indicated fracture stimulation in the lower to upper midlateral region of the wellbore (above). Injection Stage 2 began with two conservative fiber diversion stages (FDS), followed later in this stage by five others. The iterations of fiber content and slug size were designed using the StimMORE Advisor software. The injection continued to stimulate the same zone in the reservoir, as indicated by the monitored events.

The third stage began with a more aggressive fiber diversion treatment, which was designed assuming a larger fracture opening width. This stage, FDS8, used a slurry with higher solids loading than the previous ones. The treating pressure increased by about 500 psi [3.4 MPa], indicative of closing fracture pathways and opening new ones. The StimMAP Live monitoring showed activity in new segments near both the heel and the toe of the well. These new fracture areas follow the same azimuth as the earlier fractures in this well, which was N55°E. As indicated by continued monitoring, three additional treatments did not succeed in diverting the fracture into other areas.



^ ESV in Barnett restimulation. Microseisms from the original stimulation (small dots, *top*) are shown along with the restimulation results. Stage 1 events (gold) are shown with the ESV envelope surrounding them. Stage 2 events (blue) added some stimulated volume in the same area of the wellbore as that treated by Stage 1. The first diversion stage during injection Stage 3 diverted the proppant to new areas of the wellbore. Placement of this diversion stage caused a rapid increase in the ESV, and the continuing rate of increase was greater than that during the previous stage (*bottom*).



^ Increase in gas production after restimulation. The gas production rate declined almost to a quarter of its initial value before the well was restimulated; the rate subsequently increased to more than 1,200 Mcf/d [34,000 m^3/d].

The ESV indicates increased contact during injection Stage 1, but only slow growth of the system during Stage 2. A rapid increase in ESV occurred when FDS8 was injected, followed by a higher rate of ESV increase during Stage 3. The StimMAP Live display can also show the ESV as a surface around the microseismic events (above left).

The restimulation was successful (above right). The gas production rate roughly doubled, and an analysis by the operator indicated a potential increase in recoverable reserves of 0.25 Bcf [7 million m^3].

Stimulating Future Directions

MSM is a relatively new measurement and interpretation techniques are still developing. The industry is realizing its potential and striving to make use of MSM in several areas:

- understanding geohazards (e.g., active faults) for planning new wells
- understanding fracture growth and complexity and incorporating that into a context of seismic attributes and stress maps
- incorporating measurements of induced fractures based on MSM into reservoir engineering and production workflows.

The increasing number of horizontal wells in reservoirs such as the Barnett Shale eventually will lead to their use as monitoring wells. Most of the MSM analysis methods assume a near-vertical monitor well, so they will need to be altered to account for the geometry.

The methods used in MSM are also applied in other areas of production activity. Passive seismic monitoring uses permanently mounted acoustic receivers to detect microseismic events over an extended period of time. Acoustic events detected over this time frame come from reservoir changes associated with fluid pressure changes, with thermal change in the reservoir and with production-related formation compaction and subsidence.

An industry goal is to be able to place receivers in a treatment well and avoid the need for a separate monitor well. Some success has been achieved in detecting events immediately after pumping stops, capturing the last microseisms caused by elevated pressure still in the fracture and pores. However, the noise of fluids flowing through the treatment well has frustrated the effort to monitor during treatment. The quiet microseismic symphony is overwhelmed by the louder movements in the wellbore.

Overall, the industry has made remarkable strides in microseismic monitoring techniques during the past decade. The ability to process and display the events rapidly has transformed the method into a useful tool for directing the fracture movement in real time. —MAA