THE AMERICAN OIL & GAS REPORTER
JUNE 2011
The "Better Business" Publication Serving the Exploration / Drilling / Production Industry

Pilot Wells Test Stimulation Approach

By Abhijeet Inamdar,
Tolu Ogundare,
Dave Purcell,
Raj Malpani,
Keith Atwood,
Keith Brook
and Abdunnaser Erwemi

HOUSTON–The main goal in stimulating shale formations is to maximize the reservoir contact with the hydraulic fracture face. To achieve this goal, current practices include pumping low-viscosity fluids at high rates with small mesh proppant.

A novel approach developed by an operator/service company alliance during the exploration phase was used in a well in the Eagle Ford Shale to enhance the stimulated area. Real-time microseismic hydraulic fracture monitoring (RT HFM) indicates the conventional slick water treatments were not providing adequate lateral coverage across the planned stage. To address this issue, controlled changes were made to the pumping schedule, and the effects were evaluated using RT HFM. The results indicate that a novel stimulation technique that uses a shutdown during pumping to allow pressure relaxation, or equilibration, prior to reinitiating the fracturing process proved highly successful in increasing the estimated stimulated volume (ESV) in this area.

With this approach, part of the stimulation treatment is pumped (usually the pad plus proppant slugs), followed by an extended shutdown to relax the formation. Once the surface pressure reaches a predetermined value, the treatment is resumed with monitoring for microseismic activity. The microseismic activity observed during the second part of the treatment showed a significant increase compared with the first part, with improved lateral coverage.

The resulting ESV increased significantly from this technique compared with any other specific changes tried on these wells. Production log results from well number one showed a definitive correlation between production contribution and the ESV derived from hydraulic fracture monitoring analysis, indicating that this novel approach more effectively stimulates the Eagle Ford Shale when compared with typical treatment designs in this area.

Key reservoir parameters that must be studied to evaluate the potential of any shale well include thermal maturity, adjacent water-bearing formations, mineralogy, faults, fractures, organic richness, effective porosity, matrix permeability, and thickness. Key engineering parameters are penetration rate, lateral landing point, fluid compatibility, fracture containment, fracture orientation, the presence of natural fractures, fracture complexity, and retained fracture conductivity. The relative importance of the engineering parameters varies with the shale play.

Background

Hydraulic fracture complexity is the key to unlocking the potential of shale plays. Microseismic monitoring suggests that complex fracture networks can be developed in some shale plays. Theoretically, a complex fracture should produce better than biwing planar fractures in shale plays because of the increased fracture surface area.

The Cretaceous Eagle Ford is a calcareous shale that generally is bounded by the Austin Chalk above and the Buda below. It can be divided into the upper and lower shales. The upper Eagle Ford is thicker than the lower Eagle Ford and exhibits higher calcite volumes and lower porosity. The lower Eagle Ford generally has higher organic content. Its depth can range from 4,000 to 14,000 feet and thickness ranges from 100 to more than 300 feet.

As with most shale gas plays, petrophysical analysis of the Eagle Ford is challenging. Further complicating the analysis is the presence of three distinct production windows: dry gas, wet gas and oil. It has been determined that geochemical spectroscopy is a vital measurement in shale formations that enables analysts to accurately and repeatedly calculate clay volume. When combined with a deterministic multimineral model, calibrated to core, petrophysical analyses are meaningful and enhance completion decisions. The subject wells for the pressure relaxation applications are located within the dry gas window.

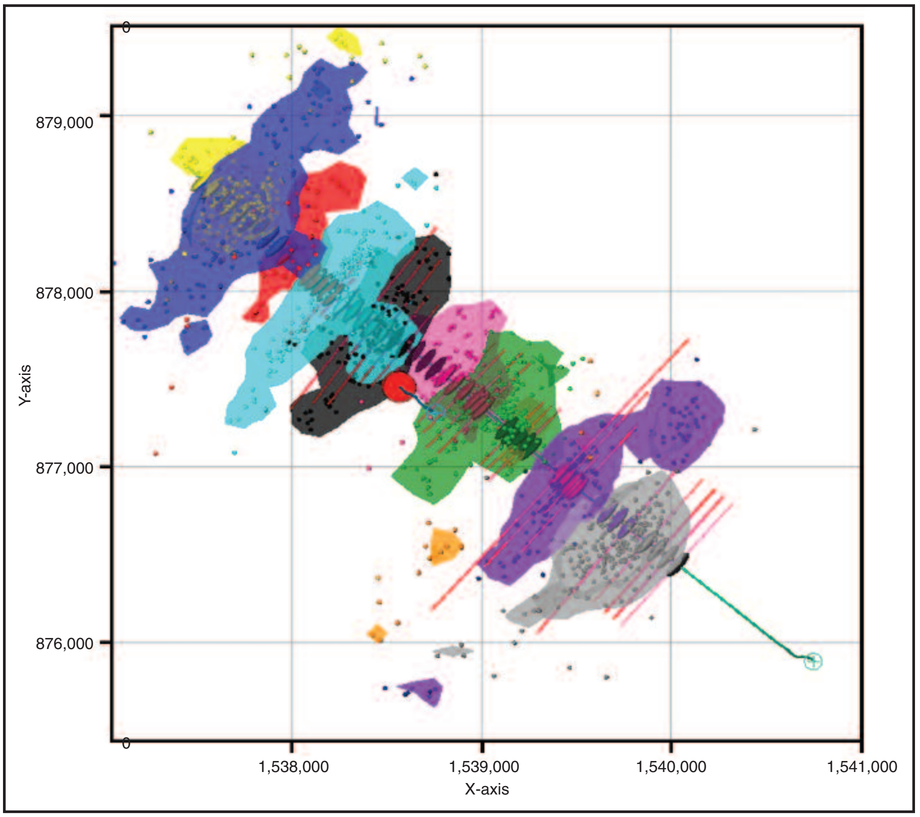
Petrohawk Energy Corporation, one of the major players in the Eagle Ford, performed a core analysis study on wells drilled in the shale. The study showed an average total organic content of 4.4-4.7 percent, 9.4-10.7 percent total porosity, 1,110-1,280 nanoDarcy average permeability, 83-85 percent gas saturation, and an estimated 180 billion-210 billion cubic feet of free gas in place per section. These measurements, if they hold true, suggest that in this particular area the Eagle Ford is one of the highest-quality shale reservoirs discovered to date in the United States.

Eagle Ford Development

The Eagle Ford was initially targeted in the 1940s by many operators in Wood, Hopkins and other counties in eastern Texas. Most of the wells were shallow

FIGURE 1

Normalized Microseismic Events, ESV and Production Log (Well Number One)



vertical oil wells. Petrohawk drilled the first Eagle Ford horizontal well in 2008, discovering the Hawkville Field in La Salle County in South Texas. The discovery well flowed at 7.6 million cubic feet of gas a day from a 3,200-foot lateral with 10 fracture stages. After this initial success, the Eagle Ford play became a hot entity, and horizontal permits increased dramatically in 2009 and 2010.

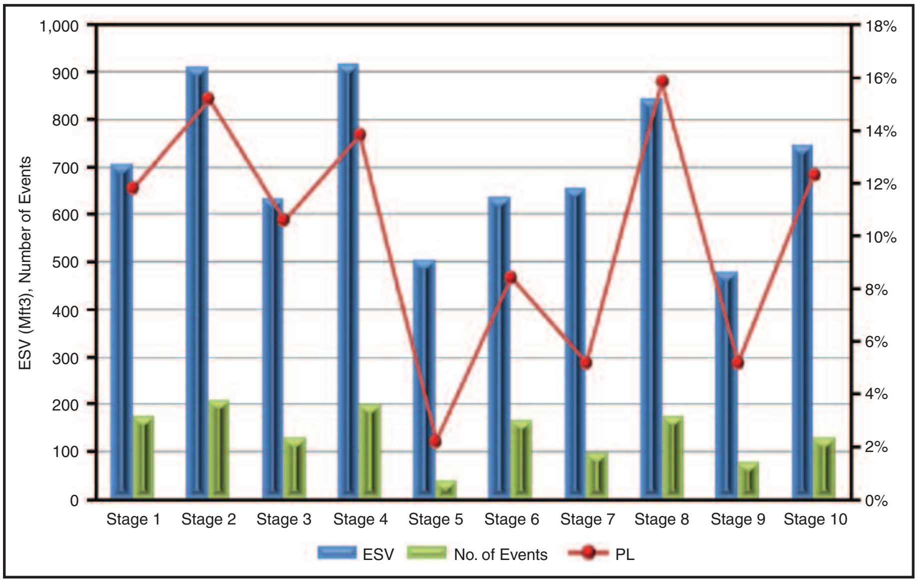
Geologists consider the Eagle Ford the source rock for the Austin Chalk and possibly other adjacent formations. One of the most attractive attributes of the Eagle Ford Shale is its high oil yield and regional infrastructure. It is a carbonaceous shale play, and as such, has a higher Young's modulus and unconfined compressive strength, compared with more argillaceous shale plays. These characteristics improve the generation and retention of fracture conductivity.

The Eagle Ford play is evolving at a similar pace to the Haynesville Shale, with the average lateral lengths eclipsing 5,000 feet and the number of stages at 10-17 per lateral. An average Eagle Ford hydraulic fracture stage consists of 12,000 barrels of slick water with 300,000 pounds of proppant at an average injection rate of 80 barrels/minute. The average reported well cost is $5 million-$6 million.

In the best parts of the shale that produce oil, Texas Railroad Commission data show that wells have initial rates as high as 1,000 bbl/d, and estimated per-well reserves of 500,000 barrels of oil equivalent (oil equivalents factor in the casinghead gas along with the oil produced). Wells in the best parts of the shale that produce natural gas have initial rates around 5 MMcf/d with estimated per-well reserves of 6 Bcf of gas equivalent (gas equivalents factor in the condensate along with gas produced).

FIGURE 2

ESV and Production Log Comparison



Pilot Program

Developing the play was a twofold challenge for the operator, SM Energy Company, because it was a new shale play and the first shale project for its particular asset team. To speed the learning curve, the operator sought value by having a service company aid in defining and capturing key measurements to determine optimal horizontal well design. The operator saw value in having a single service company work closely with its asset team to acquire, integrate and evaluate the data with a systematic approach.

The pilot program consisted of two horizontal wells and two vertical monitoring wells. A wide range of data were acquired, including surface seismic, vertical and horizontal logs, cores, microseismic data and a production log. In addition, some unique completion design approaches were planned and tested in a controlled manner to better understand the Eagle Ford reservoir's response to various completion strategies. Alterations were made to lateral length, staging, and perforation location and spacing based on petrophysical and geomechanical log measurements. Stimulation design changes included multiple proppant cycles, injection rate changes and pressure relaxation during fracturing.

The first well was landed and completed in the lower Eagle Ford. The monitor well was placed near the center of the horizontal lateral to increase the chances of locating the microseismic events in all stages. Figure 1 displays in map view the results of hydraulic fracture monitoring (yellow is stage one, blue is stage two, red is stage three, aqua is stage four, black is stage five, pink is stage six, green is stage seven, orange is stage eight, purple is stage nine, and gray is stage 10). The microseismic events showed good coverage along the lateral.

The figure also shows microseismic events (colored dots) along the lateral in map view, corresponding ESV (colored opaque envelopes) and the production log from each perforated interval (red lines). The effective ESV for each perforated interval was calculated based on the coverage and overlap of events.

Downward growth was a concern because of the presence of hydrogen sulfide in formations below the lower Eagle Ford Shale. None of the stages showed significant downward acoustic growth, but there were considerable numbers of events in the Austin Chalk formation above the upper Eagle Ford, possibly related to faulting and/or an excessive injection rate. Based on microseismic activity from the first and second stages, the decision was made to adjust the perforations of stage three to increase the spacing between the second and third. In addition, the rate was restricted to 80 bbl/minute to avoid unwanted upward height growth.

In later stages, the pump rate was slowly increased to achieve width and lengths while continuing to contain the acoustic fracture in the target zone. Slurry rates were varied from 80 to 120 bbl/minute and minor changes were made in the proppant schedule for stages three through nine. Acoustic activity was well contained in the target formation during these stages. Based on the microseismic activity from previous stages, the perforation strategy was adjusted to increase the space between stages six and seven. A similar strategy was followed in later stages, leading to reducing the perforation clusters from five to four for stages nine and 10.

Soon after completion, a production log was run in the well to quantify the contribution from each perforated interval and stage. Microseismic events were normalized based on the magnitude of the events. The ESV was calculated using proprietary software based on the density and magnitude of microseismic events for each perforated interval, and then correlated to the results of the production log.

Figure 2 plots the number of microseismic events, ESV and production log data for the 10 stages. The better gas production was coming from higher ESV intervals. Production for stages one through three was extrapolated based on the ESV/PL correlation because the production logging tool was unable to reach total depth.

Second Well

Well number two was landed in the lower Eagle Ford Shale and completed in 17 stages. Throughout the stimulation operations, different techniques were applied and differences in microseismic activity were observed and documented for optimizing the treatment design for future wells.

FIGURE 3

Stage 10 Microseismic Events and Treatment Data (Well Number Two)

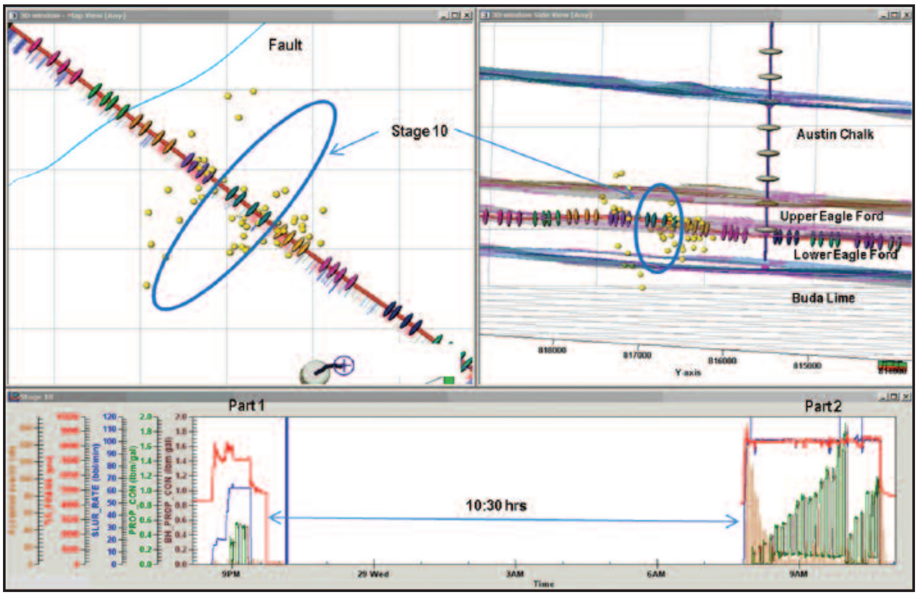
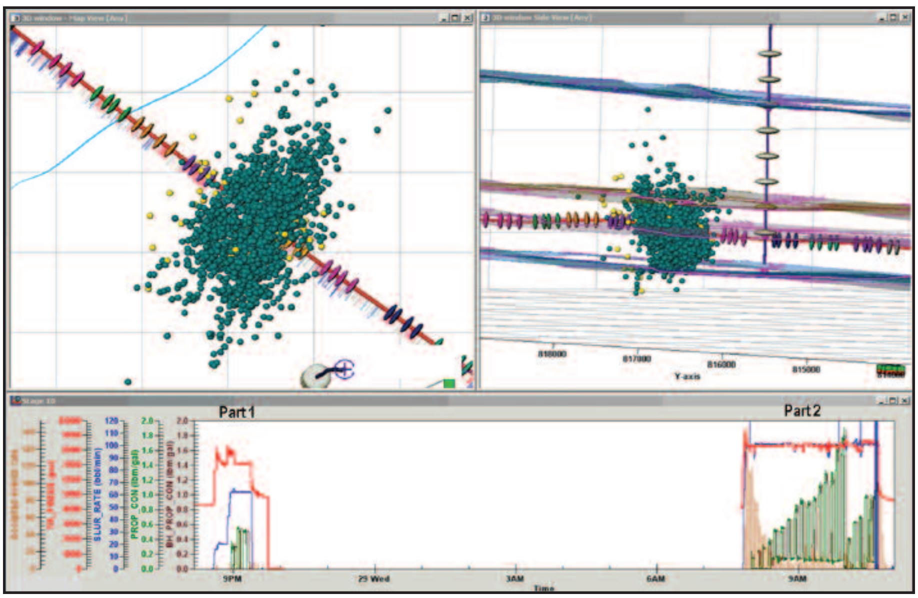


FIGURE 4

Complete Job Microseismic Events and Treatment Data (Well Number Two)



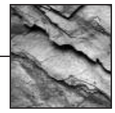


FIGURE 5

Treatment Data and Event Rate for Stages 9, 16 and 14 (Well Number Two)

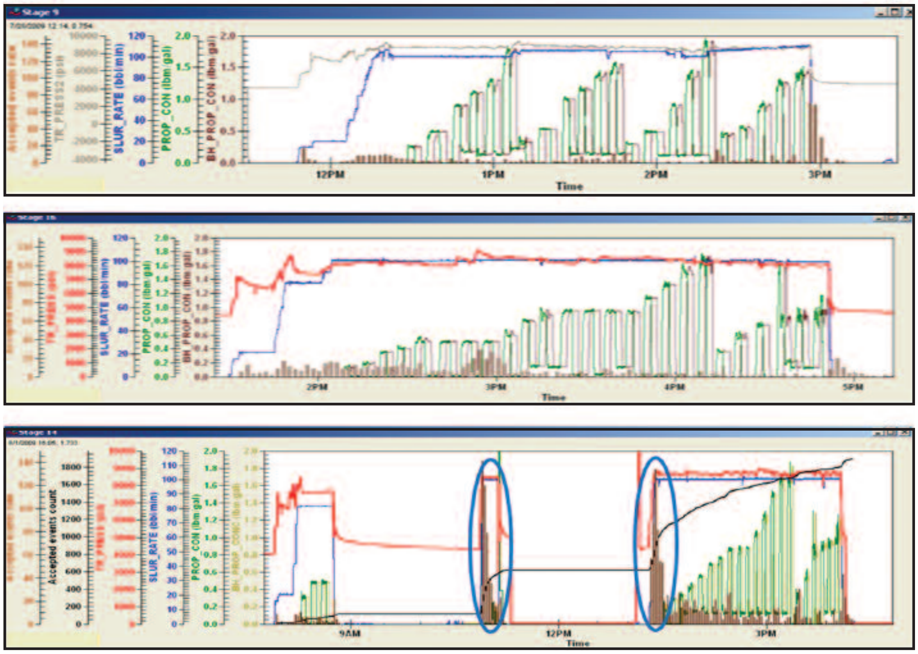
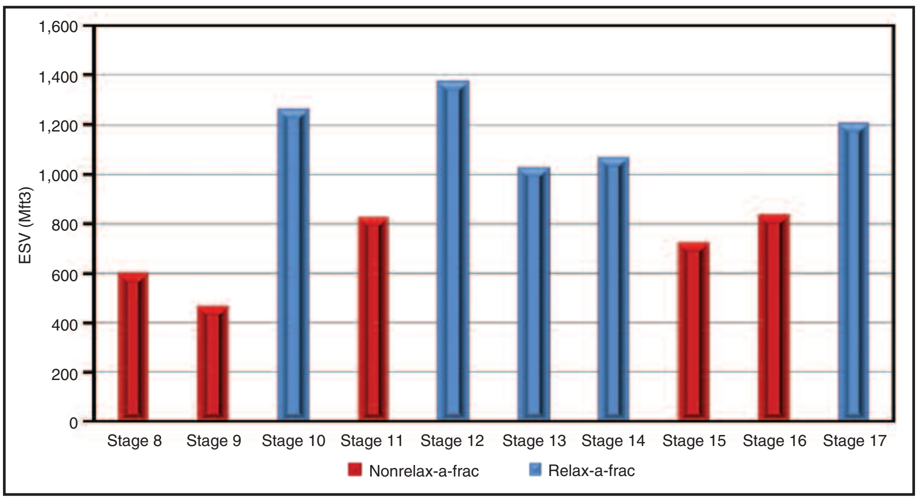


FIGURE 6

ESV for Pressure Relaxation Stages versus Other Stages



One of the changes made along the lateral included using 100-mesh sand in the pad beginning with stage five in an effort to shift microseismic activity away from previously stimulated areas to focus it on the current perforated interval. Multiple proppant cycles also were pumped in a couple stages.

In addition, the technique to allow pressure relaxation during the fracturing process was employed on stages 10, 12, 13, 14 and 17. Each stage was split into two parts. The first part consisted of the pad portion along with 100-mesh slugs. The well then was shut in (between two and 14 hours). The second part consisted of the main body of the treatment and contained all of the 40/70-mesh and 20/40-mesh proppant stages. This technique resulted in much higher microseismic activity levels and ESV compared with other stages.

Fracturing Results

Figure 3 shows the map view and side view of microseismic events, along with the event rate and treatment data for the 10th stage. Events colored in yellow are during the first part of pumping. The treatment was shut down because of operational issues for a few hours. After resuming treatment, there was an 1,800-percent increase in microseismic events within the first 10 minutes. The event rate in orange is plotted in the bottom treatment graph.

The map view and side views in Figure 4 depict the complete job with all the acoustic activity. The green events are located during the second part of pumping. The majority of these microseismic events occurred during the first 10-15 minutes after pumping was resumed.

Figure 5 shows the microseismic event rate and treatment data for three stages in well number two pumped with and without pressure relaxation during fracturing. Stage nine was pumped in three proppant cycles, while stage 16 was pumped traditionally with a higher proppant tail-in, and stage 14 was stimulated using the pressure relaxation method. It is apparent from this plot that stage 14 had the most acoustic activity. Overall job size was similar in all stages. Based on the results from well number one, better production would have been anticipated from stage 14 than stages nine and 16.

By temporarily shutting down pumping during treatment, it is believed that stresses on the rock are relaxed during the shut-in period. After pumping is resumed, secondary fractures are created that are connected to primary fractures.

The greatest impact on ESV was observed on the stages where the pressure relaxation method was used, and other stimulation design changes had minimal impact. Figure 6 shows ESV for stages eight through 17 on well number two. For a fair comparison, only stages close to the monitoring well were considered. The pressure relaxation stages are in blue.

Production analysis of well number one showed that the higher the ESV in the Eagle Ford, the higher the production. By applying the ESV/PL correlation on well number two, production was forecast to be higher from stages 10, 12, 13, 14 and 17 where the pressure relaxation technique was applied. Because of operational issues, the operator unfortunately, was unable to run the production log. However, overall production was 23 percent higher per lateral foot as compared with well number one for the best month.

The operator/service company alliance successfully applied a novel stimulation technique in the Eagle Ford Shale. The results show that the ESV highly correlates to production in the Eagle Ford, and ESV has the potential to be used as a predictive model for Eagle Ford production forecasting. The pressure relaxation technique increased the total number of microseismic events and improved ESV, which implies improved fracture surface area and complexity. Stimulation design changes, including traditional techniques, multiple proppant cycles and injection rate changes, had minimal impact on ESV. ❒

ABHIJEET INAMDAR *is a reservoir engineer for SM Energy in Houston, and is responsible for developing the Eagle Ford Shale. He has seven years of experience in the oil and gas industry. Inamdar worked as a production and completions engineer at Schlumberger before joining SM Energy. He holds an M.S. in petroleum engineering from the University of Alaska Fairbanks.*

TOLU OGUNDARE *is a senior production/operations engineer with SM Energy for the South Texas and Gulf Coast region. He is involved in completing and producing SM Energy's Eagle Ford Shale wells, including production optimization, completion optimization and artificial lift applications. Before joining SM Energy, Ogundare worked for BP America. He has an M.S. in petroleum engineering from the University of Oklahoma.*

DAVE PURCELL *is chief geophysicist at SM Energy in Houston. He has 30 years of experience with a range of oil and gas companies, from Shell to small independents and private ventures. Purcell holds a B.S. and an M.S. in electrical engineering from Texas A&M University.*

RAJ MALPANI *is a senior production stimulation engineer with Schlumberger in Houston. He has designed and evaluated numerous horizontal wells in shale and tight sand formations over the past five years. Malpani is also engaged in production data analysis and hydraulic fracture treatment evaluation. He holds an M.S. in petroleum engineering from Texas A&M University.*

KEITH ATWOOD *is an unconventional ID petrophysicist for the unconventional reservoir optimization team at Schlumberger Consulting Services. Previously, he was lead petrophysicist and completion specialist for Schlumberger Consulting Services. Prior to that assignment, Atwood served as a production enhancement engineer working with Schlumberger clients to optimize their completions and production. He has 30 years of experience working in a number of unconventional and tight gas reservoirs, and is a graduate of the University of Texas.*

KEITH BROOK *runs Schlumberger's microseismic hydraulic fracturing monitoring processing and interpretation group for U.S. operations in Houston. He joined Schlumberger in 1977 and has held various operational, technical and management roles both internationally and in the United States. Brook holds a master's in chemical engineering from the University of Cambridge.*

ABDUNNASER ERWEMI *is a senior geophysicist and microseismic processing manager for Schlumberger in Denver. He started his career as a geophysicist in 1997 with the petroleum research center of Libya's national oil company, and moved to Schlumberger 1998. Erwemi has held geophysical positions in 2- and 3-D surface seismic acquisition and processing, bore hole seismic processing and microseismic processing. He holds a B.S. in geophysics.*