

Geophysics has a role in shale plays

Shale operators are beginning to learn that rapid development does not always equal optimal development. Reservoir characterization can help.

Rhonda Duey, Senior Editor

Sometimes it is helpful to remember that 3-D seismic was originally intended to be a development tool rather than an exploration tool. This is important in today's shale plays, where the common cry is, "We don't need seismic to find the shale. We already know where it is."

Yes, but few if any operators understand how it behaves, why one fracture stage within a well produces 10 times more oil or gas than its neighbor, or how to find sweet spots to overcome that inequity. It takes 3-D seismic back to its roots – a delineation tool that offers more information about the reservoir.

Mike Mueller, vice president of analysis for MicroSeismic Inc., said that shale plays require a completely different mindset than conventional plays. "In a conventional reservoir, you have a trap, migration of hydrocarbons into that trap, and a relatively discrete place where the hydrocarbons are going to be developed," he said. Shale plays, on the other hand, cover larger areas and contain varying amounts of hydrocarbons throughout that extent. Therefore, they require reservoir characterization.

This may seem a brash statement when one considers the amazing success many operators already are enjoying in shale plays. But those heady days may be dwindling.

"Some of these guys have drilled great wells," said Jacques Leveille, senior vice president and technology advisor for ION. "They were not using geophysics, but by golly, whatever they did, they did it well.

"But I don't think it's sustainable, and I think they know that, fundamentally."

The challenges

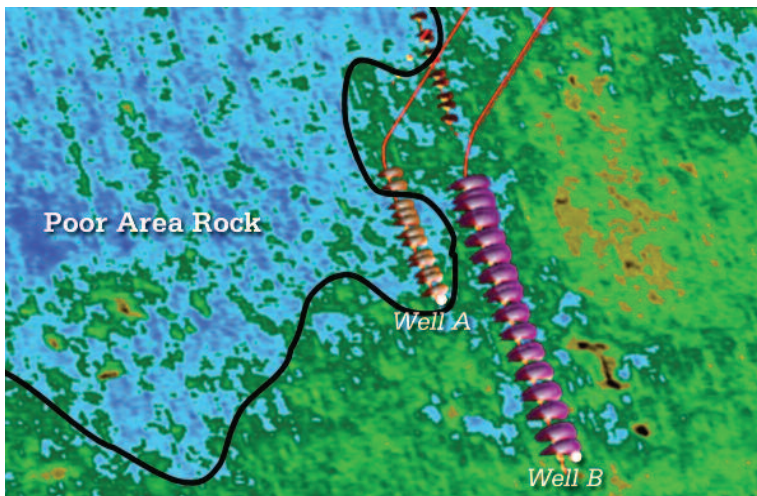
Shales present a host of issues that require something a little more subtle than brute force. Given their tendency toward nanoporosity and their fractured nature, they behave quite differently than conventional reservoirs. And each other.

"One thing I try to communicate to people is to not waste time on the analogy effort," said Ross Peebles, director of unconventional consulting for Global Geophysical Services. "It's distracting at best and lazy at worst."

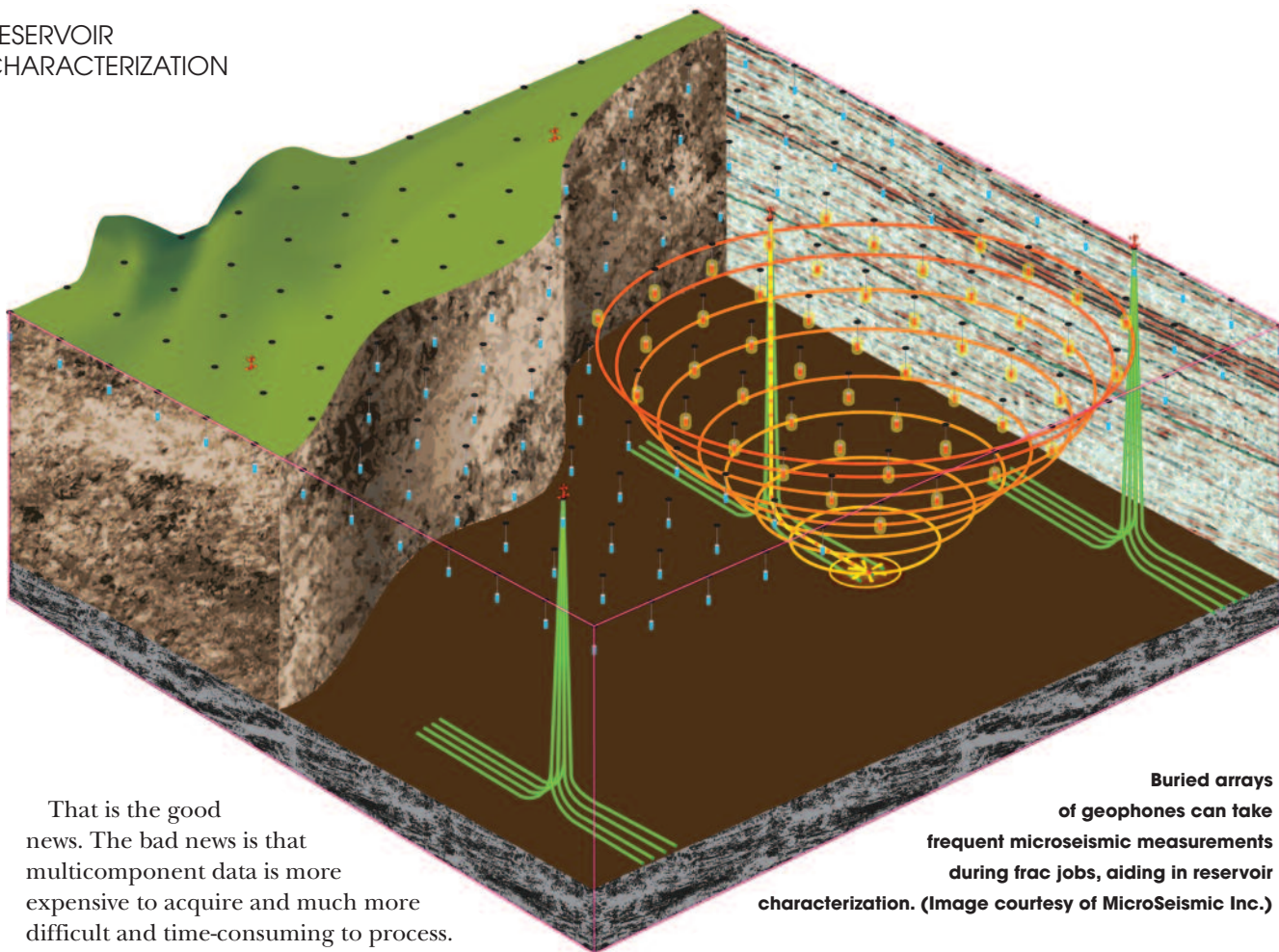
Common wisdom dictates that natural fractures in shales should be mapped, either as an aid to production or as a drilling hazard to be avoided. Borehole imaging devices can provide some fracture characterization, but the narrow depth of investigation does not provide a field-scale look. To truly map the fractures, seismic is required. But here is the rub – fractures occur on a smaller scale than seismic is able to resolve. So geophysical companies try a variety of techniques to determine fracture location and orientation from various acquisition and processing methods.

One methodology that has both proponents and detractors is the use of multicomponent seismic. This type of acquisition, which provides shear (S) as well as compressional (P) wave data, can often indicate fracture orientation through a phenomenon known as birefringence or shear-wave splitting. When they encounter open aligned vertical fractures, shear waves split into the fast and slow modes. The fast S wave is polarized in the fracture plane, while the vertically traveling slow wave is polarized perpendicular to the fractures. The difference in the velocities is proportional to fracture density.

"In the cases we've looked at, we always have better information and attribute determination with good PS data," Leveille said.



Results show that stimulation programs can be optimized based on rock properties from seismic data. Well B produced twice the production per foot of Well A. (Image courtesy of ION)



Buried arrays of geophones can take frequent microseismic measurements during frac jobs, aiding in reservoir characterization. (Image courtesy of MicroSeismic Inc.)

That is the good news. The bad news is that multicomponent data is more expensive to acquire and much more difficult and time-consuming to process. So companies like Geotrace and ION are processing wide-azimuth data rich in azimuthal and offset sampling. As with so many debates about shales, the real answer to this question is, “It depends.” Lee Bell, chief geophysicist for Geokinetics, said that good and well-calibrated P-wave data can suffice in some shales. But the S wave data, he added, have a greater sensitivity to fracture orientation.

Another debate surrounding fractures is the use of curvature analysis. Mueller said that more curvature can be indicative of more natural fractures. But not always. Curvature analysis is useful in finding structural fractures, but shale plays tend to be characterized by regional fractures, which are not caused by curvature.

“Curvature is good, but it’s part of the story,” he said. “We don’t have great proven 3-D seismic methods to identify noncurvature-related regional fractures.”

Toward this end, Ilya Tsvankin at the Colorado School of Mines is researching other ways to characterize small-scale fractures. “We cannot see such fractures directly on seismic images,” he said. “But they influence the effective medium properties and, therefore, seismic velocities and amplitudes.”

Tsvankin’s group is developing seismic inversion methods based on realistic azimuthally anisotropic models of fractured formations. He emphasizes that it is highly beneficial to combine 3-D wide-azimuth data with

walkaway vertical seismic profiling surveys.

“Case studies have shown that valuable, although not always unambiguous, information about the dominant fracture orientation and sweet spots of high fracture density can be obtained from the azimuthal variation of P-wave moveout parameters, reflection amplitudes, and attenuation coefficients,” he said.

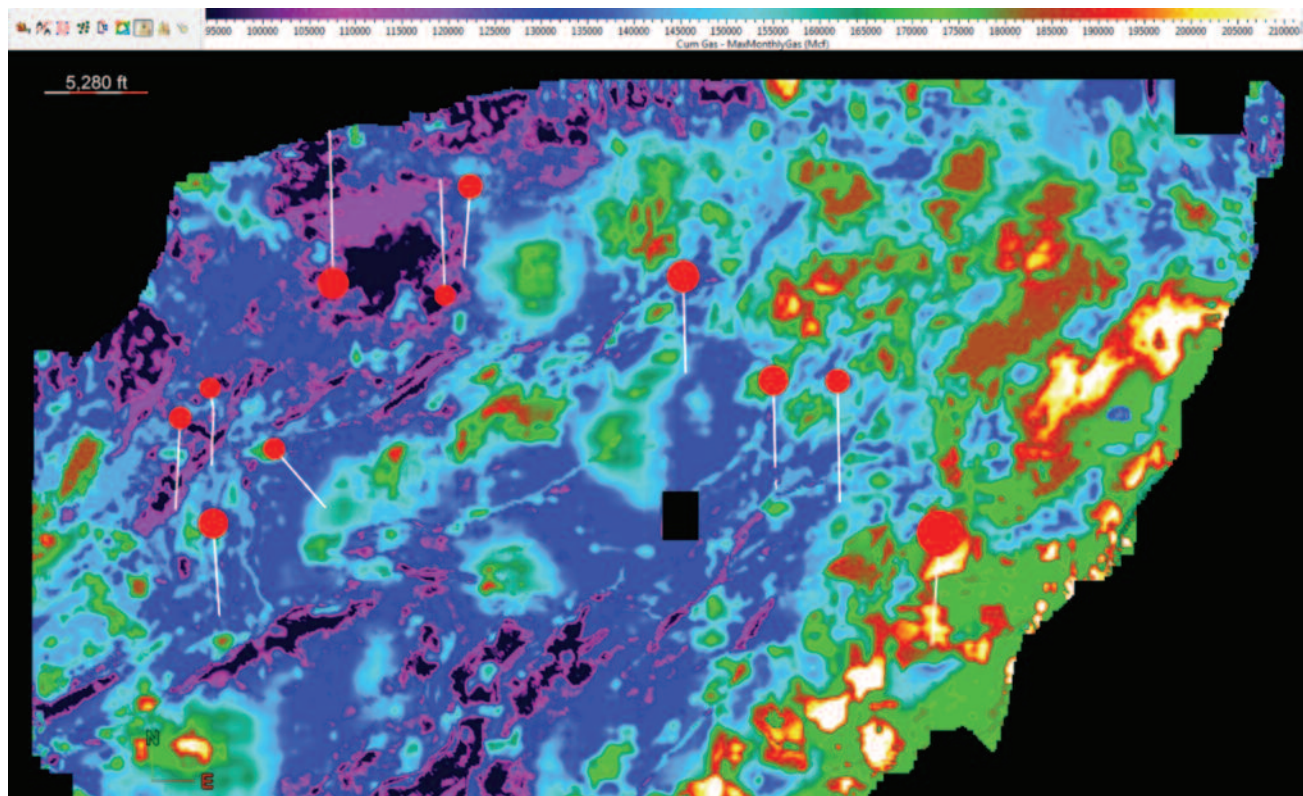
Sweet spots

Shale operators are chasing sweet spots to help them optimize well and perforation placement, but the jury is out about what exactly constitutes a sweet spot and how geophysical techniques might identify them.

One area of intense interest revolves around the brittleness of the rock, brittleness being a good indicator of how well the rock will fracture during stimulation. In certain situations, seismic attributes are capable of determining rock brittleness. Is this enough?

“Brittleness is very popular these days,” Bell said. “Even with the P-wave data we can make estimates of the shear by the partitioning of energy at reflector interfaces. From the V_p/V_s ratio we can estimate Young’s modulus and Poisson’s ratio as those apply to brittleness. But that’s not the only thing you can characterize.” He added that porosity and mineralogy also can be studied.

Mueller is a fan of the brittleness approach. “The idea



This map view shows the predicted monthly gas production in 207 sq km (80 sq miles) of the Eagle Ford generated from the multivariate nonlinear regression with the more prospective areas in the warmer colors (higher values). Horizontal well bores are shown with the amount of gas production displayed as red bubbles at the wellhead. (Image courtesy of Global Geophysical)

that we want to bias ourselves toward developing brittle shales is probably the right bias,” he said. “This will tie into geological and engineering information.” His company is working with NSI Technologies to study how prolific brittle rocks have been to date in shale development.

For Leveille, brittleness is one of many characteristics that might help determine sweet spots, and again it varies from shale to shale. The Barnett shale, for instance, has very loud microseismic events because the rock is very brittle.

“Brittleness is a very important attribute there because the formation cracks very well,” he said. “But if you go to the Montney shale, things are different. You have to determine the optimal set of attributes for each shale play.”

Ultimate characterization

Global applies this concept in its multiclient datasets, Peebles said. “We take the approach that we don’t really know what’s going to be useful in any particular development area,” he said. “We use a statistical

approach, and we analyze seismic attributes, look at geological indicators, integrate microseismic, and look at engineering datasets and determine which ones are most relevant to well performance and productivity in a particular development.”

Global has the largest modern full-azimuth multiclient library in unconventional plays, including more than 10,400 sq km (4,000 sq miles) in the Eagle Ford, and has done a tremendous amount of study in that play. Peebles said that while his company is studying and modeling the entire 6 million acres of the Eagle Ford, “We believe that each operator’s development benefits from a customized, local analysis.”

Leveille added that ultimate characterization will come when people stop using conventional reservoir characterization techniques in unconventional plays. “I think that is the wrong way to look at it,” he said. “These are totally different rocks and behave differently seismically.

“People will need to find better ways to predict where the sweet spots are. It’s a challenge for geophysics. But I think it’s a healthy challenge.” **ESP**