Shale gas plays provide valuable seismic in a low-price environment

Geophysical measurements prove their worth as shale operators opt for quality over quantity.

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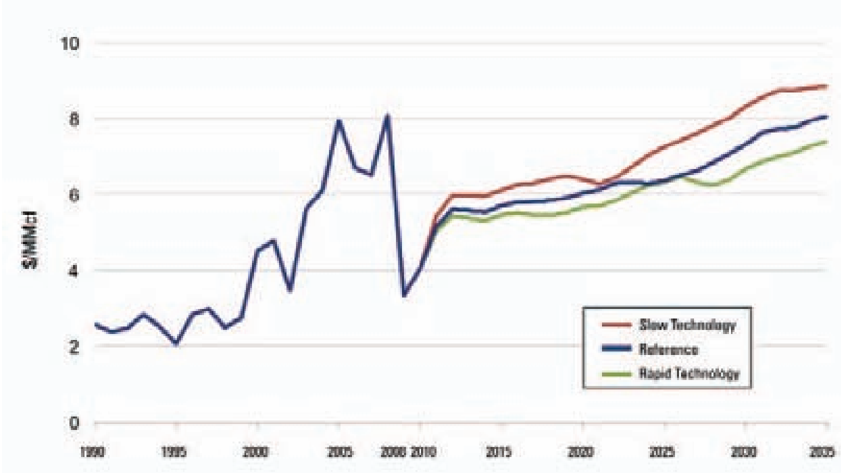
It is widely acknowledged that the economic viability of shale plays has primarily been a result of advancements in horizontal drilling and hydraulic fracturing technologies. These innovations have significantly changed the near-term natural gas supply picture, creating an overabundance of natural gas supplies in North America. The lingering effects of the recession and the surge in unconventional supply coming from accelerated drilling, driven by expiring leases, have led many government agencies and industry analysts to forecast a long-term low-price environment in North America.

Shale operators' economic success has historically been achieved by focusing on reducing the cost to drill, complete, and stimulate wells – one example of this being the significant drop in the number of days required to drill each lateral well across all plays. While incremental cost reductions are still likely to come, many in the industry suggest that these reductions are beginning to plateau, bringing up the issue of whether an acceptable rate of return can be achieved in a low natural gas price environment.

Further economic success in this environment will require a shift from a cost focus to a value focus. Enhanced reservoir characterization to better understand and predict the variability within well bores and from well to well along with customized production plans will drive this change in focus.

Wide-azimuth 3-D seismic data and microseismic monitoring will be two of the critical sources of information to enable this change.



An oversupply of natural gas in North America has many expecting a long-term price depression. (Images courtesy of ION; Source: Energy Information Administration)

Structural, geohazard imaging

To economically develop gas shale reservoirs, operators strive to maximize borehole exposure to the reservoir and create a complex fracture network to increase permeability. Most shale operators are using seismic data to map the structure and thickness of the shale reservoir unit as well as to identify possible hazards such as faults, karst zones, and collapsed chimneys, helping drilling engineers stay in zone and better geosteer long laterals.

With this structural insight, operators are able to reduce the number of lost drilling days and better design hydraulic fracturing treatment plans, helping to ensure wells have higher initial production (IP) rates and estimated ultimate recoveries (EURs).

In addition to using 3-D seismic for structural imaging, there is a growing use of seismic data to estimate and predict key geomechanical and lithological parameters. An understanding of the magnitude and directionality of *in situ* stresses and the existence and nature of natural fractures is critical for optimizing drilling, completion, and stimulation operations.

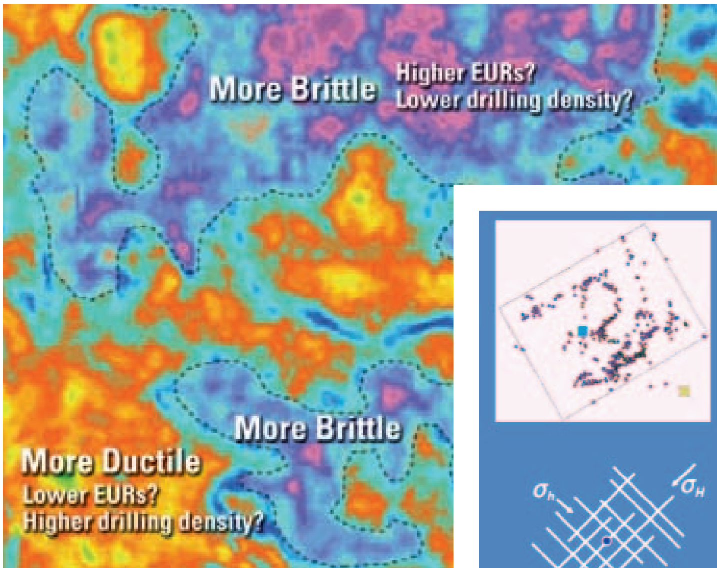
Stress insight helps with well paths, stimulation

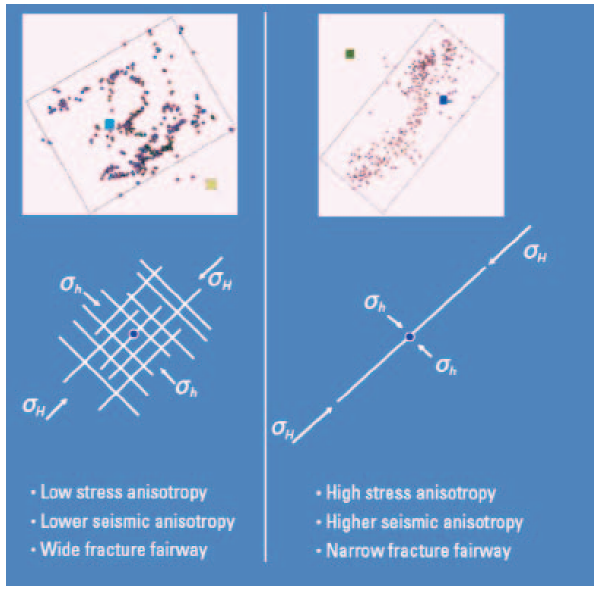
The orientation of the *in situ* stress field relative to wellbore orientation is an important factor that can significantly influence production rates. In general, high horizontal stress anisotropy (stress being directionally dependent, as opposed to more similar in all directions) results in narrow fracture fairways, whereas low horizontal stress anisotropy results in wider, more complex fracture fairways. Microseismic data from various shale plays support this relationship.

Azimuthal velocity analysis of wide-azimuth 3-D seismic data can be used to estimate the *in situ* stress state. These seismic attribute volumes, when calibrated with other geomechanical data, generally enable operators to steer wells perpendicular to major stress orientation and assist in defining cost-effective stimulation treatments. A larger number of hydraulic fracturing stages, spaced closer together, would be appropriate where narrow fracture fairways are predicted, whereas wider fracture fairways would allow pumping fewer stages, spaced farther apart with larger treatments, to maximize fracture complexity.

Prioritized drilling with fracture characterization

When hydraulic fracture stimulation is used to enhance the recovery of naturally fractured reservoirs, the interplay between the *in situ* stress field and any existing natural fractures (i.e., pre-existing planes of weakness) becomes an important factor. Often there is a reactivation of the natural fractures during hydraulic stimulation. Depending upon the density and orientation of the natural fractures relative to the *in situ* stress field direction (and anisotropy), the combined effect can either enhance or degrade the resultant fracture fairway width.





ABOVE: Seismic inversion can determine the brittleness of a shale reservoir unit. **RIGHT:** Stress anisotropy is related to fracture fairway width in the Barnett shale. (Source: Journal of Petroleum Technology, September 2008)

Variations in seismic velocity and amplitude with azimuth can be measured from wide-azimuth 3-D surveys to predict the fracture density and orientation within the shale reservoir. The mapping of natural fracture systems, when integrated and calibrated with existing core, well, and production logs and other geomechanical knowledge, can help operators high-grade drilling locations and acreage.

The business benefits to operators include increased cash flow from drilling wells with high expected IPs and the opportunity to reduce the risk of over-drilling or under-producing the acreage.

Targeting sweet spots

Along with the *in situ* stress field and natural fracture systems, the brittleness of the shale reservoir unit also is an important factor in how effectively rocks will fracture during hydraulic fracture stimulation. The more brittle the rock, the more easily it will fracture under stress. In shale units, brittleness usually is affected by mineralogy. Higher silica and/or carbonate content results in more brittle rock, whereas higher clay content results in more ductile rock.

Seismic inversion provides a means to estimate physical rock properties such as brittleness from seismic data. Brittle rock would be expected to fracture more easily, thereby resulting in wells with higher IP rates and EURs as well as possibly lower well densities via increased spacing. Thus, like stress fields and natural fracture systems, estimation of rock properties such as brittleness from seismic data can be used to identify sweet spots for the high-grading of drilling locations and acreage.

Looking ahead

The use of seismic data as an information source to assist in estimating *in situ* stress field conditions, characterizing natural fracture systems, and understanding rock brittleness is growing. These seismic technologies are enabling operators to prioritize acreage based upon expected IP/EUR, design cost-effective well plans and stimulation programs, and prevent over-drilling and/or under-producing of acreage by optimizing the drainage strategy and well spacing.

Looking ahead, an increasing reliance on a methodical, scientific approach will be needed for the profitable development of these plays in a low-price environment. Geophysics is one of the disciplines in which much opportunity exists beyond the growing seismic data applications and the use of microseismic monitoring as a means to quantify hydraulic fracturing effectiveness and calibrate existing reservoir models. New and emerging seismic attributes and combinations of attributes, which estimate properties such as closure stress, density, total organic content, and pore pressure, promise increased reservoir geomechanical and lithological understanding. That, combined with cost-effective advances in microseismic monitoring, will help reservoir engineers accurately predict the behavior of shales. With this insight, operators will have the opportunity to more judiciously deploy their capital and create value for shareholders. E&P