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Geomechanics Key In Marcellus Wells

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BRIDGEPORT, W.V.–Formation characterization experts have known about the relationship between regional stress orientation and hydraulic fracturing effectiveness for many years. However, the lens through which stress patterns were observed was wide, and did not offer precise targets for fracture design.

All this has changed dramatically with the introduction of a new log interpretation technique that harnesses computing power to paint a big red bull's eye on optimal fracturing targets. A combination of log measurements taken in the lateral, including both mechanical and petrophysical interpretations, are analyzed to determine optimal location for perforating targets.

Results have been consistently good, and have been confirmed by high initial flow rates in seven wells completed to date using the innovative technique. Moreover, when engineers sought further evidence they were doubly rewarded when production log comparisons with offset wells showed more than twice the number of stages were flowing in wells completed using the new technology than in those previously completed.

Engineers are trying vigorously to develop "best practices" that can be applied consistently to shale well construction and completions. But tight margins and formation complexities have combined to make it difficult to launch an all-out effort to optimize completion designs.

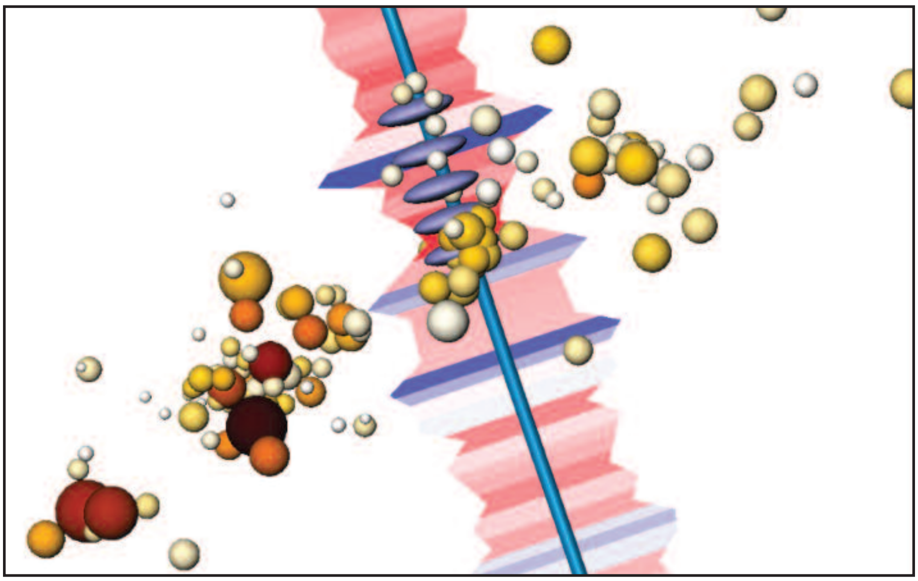
The shales themselves have added challenges, with each one different enough to prevent a standard approach from being agreed on. Some are deeper and hotter, some are shallow, and some are more naturally fractured than others, some are adjacent to aquifers that could turn a promising producer into a water well, if penetrated.

Multistage fracturing treatment designs in horizontal well penetrations have varied considerably. Conventional wisdom has shifted from a few, widely spaced fractures with long half-lengths to numerous, closely spaced fractures with moderate half-lengths. Operator preferences for completion designs have vacillated between open-hole multistage treatments and traditional plug-and-perf, cased-hole techniques, and the decision often has been influenced more by logistics than ultimate results.

Choosing the best frac technique is not easy. It may require an operator to forgo optimum post-treatment well performance to get a short frac window. Operators have made considerable investments in tests whose objectives are to determine the best practices for shale well drilling and completion.

FIGURE 1

Microseismic Mapping Showing Fractures Propagating from Lowest-Stress Interval



Fracture Propagation

PDC Mountaineer LLC (PDCM), a joint venture between Petroleum Development Corporation and Lime Rock Partners, wanted to optimize its horizontal Marcellus Shale well completions and productivity. Studying the typical drilling and completion techniques in regional use, the company's engineers noted that most operators using the plug-and-perf technique typically used geometric completion designs in which perforation clusters were spaced at equidistant intervals along the laterals. However, logic suggested that the rock would consistently fail at its weakest point, and since logs showed that stress at each perforation cluster could be vastly different, perforations at higher-stressed intervals could be unstimulated.

PDCM engineers learned that microseismic fracture mapping of many wells in the area showed that fractures did not develop equally among the evenly spaced perforation clusters, but propagated from the clusters placed in the lowest-stress zones, following the path of least resistance and leaving the majority of the perforation clusters understimulated. Figure 1 shows a microseismic mapping run while monitoring hydraulic fracturing, with fractures propagating from the lowest-stress interval (red coding).

Using knowledge of regional stress patterns, wells can be oriented in such a way that multiple stages of transverse fractures can be generated following the convention that states numerous, closely spaced fractures should yield best productivity. An advanced acoustic scanning platform that provides a fully 3-D acoustic characterization addressing both intrinsic and stress-induced anisotropy was used to identify the localized mechanical properties along the lateral production intervals.

Deployed on wireline, the acoustic scanning tool must be conveyed to the toe of the lateral using a downhole tractor or on drill pipe. Despite this limitation, the tool offered the best way to acquire axial, azimuthal and radial monopole and dipole measurements to resolve formation intrinsic anisotropy using a 3-D acoustic characterization. From these measurements, stress can be characterized and mechanical rock properties can be mapped with precision. The tool can be deployed in open or cased holes, and its measurements can be applied to geomechanical solutions using the Petrel™ exploration and production software platform.

In cases where the acoustic scanning tool is unavailable, logging-while-drilling measurements can be successfully substituted.

Initially, for the first wells, log analysts systematically hand-picked precise locations for perforation. When the well was completed and stimulated, a horizontal multiphase production logging system was deployed to evaluate treatment effectiveness. The log showed that 75 percent of the stages were contributing to production compared to 25-30 percent of the stages in traditionally completed offset wells.

Reservoir-Centric Software

Encouraged by the results on the first wells, PDCM started lining up candidate wells to treat. Meanwhile, the service provider developed a field applicable technique to optimize well completions and hydraulic fracture treatments using pinpointed perforation clusters suggested from formation stress analysis. A reservoir-centric stimulation design software was created that automates the completion design process. This new workflow works as a fracture-growth simulator, primarily for unconventional reservoirs within the exploration and production software platform.

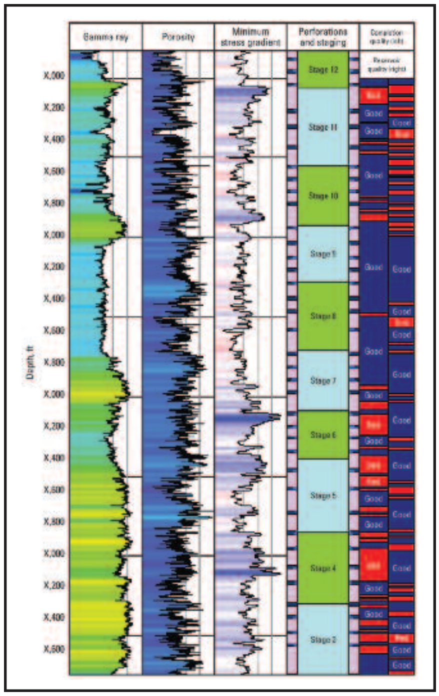
It integrates all the data available along the lateral, including geomechanical and petrophysical rock properties, as well as well bore parameters such as casing collar locations and cement bond quality, to derive an optimized completion design that helps ensure equal treatment, and thus equal flow, from all perforation clusters. The Mangrove™ reservoir-centric stimulation design software has provided a more accurate, consistent approach with vastly improved turnaround time.

The reservoir-centric software enables a seismic-to-simulation workflow specifically for unconventional reservoirs and addresses the question of how to optimize the fracture treatment once the staging and perforations have been designed. The technology allows efficient complex fracture models to capture fracture geometry and conductive surface area, which often can be calibrated with microseismic data within the same application. The explicit production modeling that avoids gross upscaling and overpredicting production is being validated.

The completion adviser workflow module within the software automates and speeds the application of lateral measurements to perforation design. Both consistent stimulation and lower breakdown pressures along the entire lateral resulted from implementing the workflow. This is to be expected, since the formation is known to fail at its weakest point. If perforations are located within these weak points, lower breakdown pressures should logically result.

FIGURE 2

Workflow Results with Completion And Reservoir Quality Data



True to its name, the completion adviser workflow helps engineers determine how many stages and perforation clusters within those stages are optimal. It then determines the best location for each perforation cluster within a fracture treatment stage. The key component provided by the adviser is identifying zones of best reservoir quality and completion quality. Reservoir quality implies the rock's ability to contribute to production, and completion quality is a measure of the rock's tendency to yield under increased pressure during hydraulic fracturing.

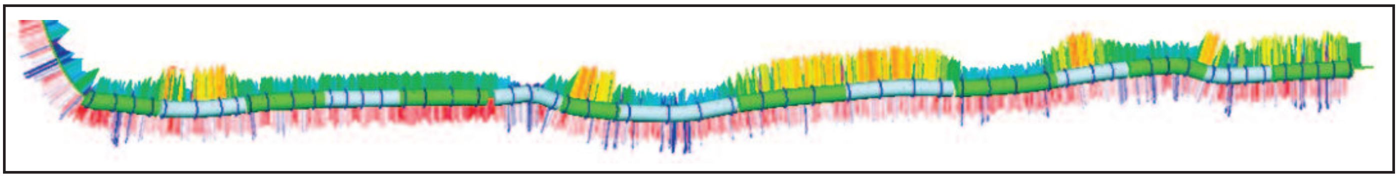
Grading Reservoir Quality

Reservoir and completion properties are considered separately and each zone is assigned a binary designation of "good" or "bad" quality. A grade of bad does not mean the zone will not produce, but rather that it is of poor quality relative to those graded as good. Reservoir properties considered may include water saturation, total organic content, and intrinsic permeability. Completion properties include mineralogical properties such as clay and silica content, in situ stress, Poisson's ratio and Young's modulus.

Once the separate grades are assigned, they are combined to indicate zones with both good grades that indicate the best

FIGURE 3

Optimal Perforation Locations Improve Production



spots to treat. Practical concerns such as perforation spacing, stress shadow effect, limited entry to ensure even distribution of frac fluid, etc., also are taken into account.

Figure 2 shows the results of the workflow. Completion and reservoir quality are indicated in the right-hand tracks, along with stages and perforated intervals (dark blue lines on purple background). Acoustic scanning results appear in the three left-hand tracks.

PDCM used a scientific procedure so it could accurately quantify the value of the engineered approach. Three wells were selected that already had been completed conventionally using a modified geometrical method to serve as a base case. Three additional wells then were chosen within a very short distance and with similar characteristics to those in the base case. Reservoir quality was quantified, as was completion quality. The objective was to select stages with fairly similar qualities and complete these even though they might not be evenly spaced.

Once the model was built, the wells were segmented into stages by lithology so that no stage crossed more than one lithology. Then the perforation clusters were customized for each stage so the designed injection rates were equal. To ensure that all the clusters initiated a fracture at similar pressures, all the perforation clusters within the stage were placed within similarly stressed rock. This was done to avoid the situation revealed by the earlier production log that showed many stages were underperforming on completion. By deliberately designing each stage to deliver the same production rate, it was expected that all would contribute to total flow.

TABLE 1

Completion Comparison (Engineered versus Nonengineered Wells)

Well	Completion Method	Average Treating Pressure (psi)	Average Treatment Rate (bbl/min)	Proppant Placed vs. Design
Well #1	Nonengineered	7,749	78.1	107%
Well #2	Nonengineered	7,557	76.3	55%
Well #3	Nonengineered	7,716	66.3	65%
Average		7,674	73.6	75%
Well #4	Engineered	7,308	79.2	92.8%
Well #5	Engineered	7,105	81.9	101.7%
Well #6	Engineered	7,298	82.3	100.5%
Average		7,237	81.1	98%
Average Difference		437 psi	7.5	23%

TABLE 2

30-Day Cumulative Production Normalized to Lateral Length and Stage Count

Well	Lateral Length (ft)	Stages	Max 30-Day Cum (Mcf)	Normalized 30-Day Cum (Mcf/ft of Lateral)	Normalized 30-Day Cum (Mcf/stage)
Well #1	3,375	14	63,194	18.7	4,513.9
Well #2	2,312	7	42,396	18.3	6,056.6
Well #3	2,140	7	65,039	30.4	9,291.3
Well #4	4,500	12	212,631	47.3	17,719.3
Well #5	3,950	12	162,652	41.2	13,554.3
Well #6	3,925	12	180,436	46.0	15,036.3

Improved Production

The three engineered wells delivered, on average, 57 percent more gas than the average of the three base case wells on a 30-day cumulative production basis. As shown in Figure 3, the production improvement was attributed directly to identifying and selecting optimal perforation locations based on property logs.

An unexpected benefit was realized when the reservoir-centric stimulation design software was utilized. Previously, wells stimulated traditionally experienced screen-out rates of 35 percent. Remediation costs for screen-outs averaged $300,000 per stage. When perforations were placed according to the precision stress analysis, no screen-outs were experienced. Accurate foreknowledge of expected breakdown pressures, and equal distribution of injected fluids across the perforation clusters, was the reason given for the reduced screen-out rate.

The engineered wells averaged 98 percent proppant placed versus design, whereas the base case wells only placed 75 percent of the designed proppant. In addition, the engineered wells had an average fracture pumping of 7.5 barrels/minute higher than the offsets at treatment pressures that were reduced by 437 psi, on average.

Table 1 shows the completion results for the first three engineered wells versus three nonengineered offset wells. All six well treatments were pumped with slick water at a designed rate of 80 barrels/minute. The three nonengineered wells averaged five clusters per frac stage, while two of the engineered wells averaged 4.5 clusters per stage and the other had 5.0 clusters. The pounds of proppant placed per foot of lateral ranged between 672 and 1,783 for the nonengineered wells, and between 1,002 and 1,251 for the engineered wells.

To date, seven wells have been completed using the new technique. Results have been consistently good, with 85 percent of stages shown to be contributing on two of the wells. Average stages contributing were 60 percent. Most importantly, 30-day and 90-day production results have been boosted an average of 50 percent (Table 2).

Low stress points identified by the log and software workflow can be targeted, and the stages on the completion string can be properly spaced. The new software application allows operators to effectively know where to shoot the perforations to ensure equal fracture development along the lateral. ❐

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