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Customized Frac Stages Improve Completions In The Bone Spring

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HOUSTON–An evolving stimulation and completion strategy, building off an interconnected methodology that customizes individual frac stages to quantify permeabilities and reservoir quality throughout the lateral, continues to yield new insight into the economical drainage of the triple-bench Bone Spring formation in New Mexico's Delaware Basin.

The methodical strategy has evolved to overcome a number of technical impediments, with early results showing sequential improvements in per-well recoveries. Early on, the investigation reinforced the importance of selecting a carrier fluid based on proppant transport requirements, as well as fracture height and breaking ability to optimize conductivity placement.

The unique flow regime and cycling stresses of the Bone Spring also were found to justify using more play-compatible ceramic proppant, further illustrating the elevated understanding of the real-world trade-offs between less expensive, but equally less beneficial, technologies and practices.

One of the key learnings arising from the study was the quantifiable impact of lateral setting depth, which goes hand-in-hand with the fluid and proppant in optimizing a frac design. Accordingly, geomechanical data collected from offset wells were incorporated in a predrilling workflow model, utilizing a 3-D frac simulator to establish the optimal target zones for both the lateral and stimulation treatments.

Complementing the stage isolation component of the Bone Spring "boutique" frac design, the multifaceted analysis found that replacing basin-standard plug-and-perf completions with sliding sleeve systems enhanced completion efficiency nearly 100 percent. Along with selective stage isolation, a multistage port completion was shown to enhance production results and improve the calibration of the reservoir quality model.

Bone Spring Geology

Generally described as a thick sequence of interbedded sandstones, carbonates and shale, the Bone Spring overlies the Wolfcamp Shale, the Ellenburger group and the Morrow at depths ranging from 6,000 to 13,000 feet (Figure 1) in Southeast New Mexico's Delaware Basin, extending into West Texas. Each layer of the three benches making up the Bone Spring play consists of equally productive sand carbonate layers, although the uppermost zone is believed to seldom develop porosity and permeability.

Before the acceleration of hydraulically fractured horizontal wells, the Bone Spring source rock was largely a bypass zone for the presumably more prospective and deeper zones. When new-generation logs revealed a much thicker pay zone, the Bone Spring quickly emerged as a primary lateral target for multistage fracs, bolstered by the superb well control when landing horizontal sections between mature and deeper vertical wells.

Observed permeability from production history matching ranges from a high of 0.25 millidarcy in the second sand to a low of 0.0044 md in the third bench. Unlike other shale plays, the Bone Spring reservoir pressure gradient varies from normal to only slightly elevated at 0.443 to 0.455 psig/foot.

Because of the wide variance in permeabilities, a completion/stimulation strategy was initiated to frac each stage based on its level of permeability. Specifically, a customized workflow, in tandem with a patented fracture design and analysis software, were employed to capitalize on readily available mud log response data to precisely plot distinct permeabilities (reservoir quality) across the entire lateral. The ensuing data cleared the way for the stage-specific frac strategy, which unlike the typical homogenous approach of uniform lateral-wide stimulation treatments, was engineered to match the stimulation of each zone to its degree of permeability, thereby optimizing coverage and ostensibly increasing cumulative production rates.

Zonal permeability isolation served as the springboard for the systematic study, focusing on the second and third Bone Spring, with the objective of resolving the five remaining hurdles to a cost-effective stimulation and completion strategy.

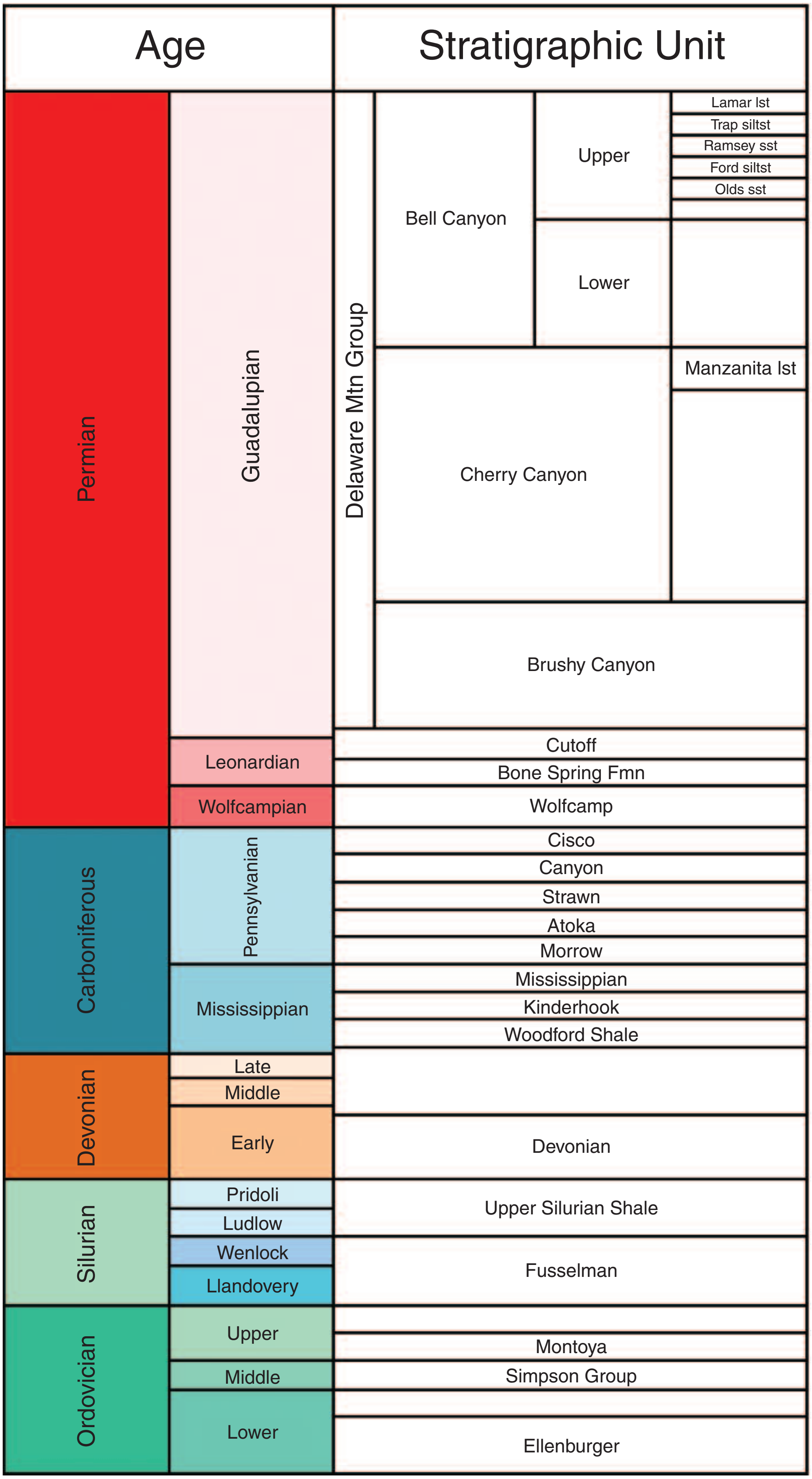
First Three Hurdles

The first hurdle to be addressed in the evolving study involved landing the lateral to accommodate the most efficient frac design. The primary considerations focused on the lateral length and azimuth, followed by determining the most effective transport fluid (the second hurdle). The third hurdle was selecting the proppant type best suited for the relatively high closure pressure gradients, ranging from 0.745 psig/foot in the second Bone Spring to 0.794 psig/foot in the third bench.

The first obstacle, however, was de-

FIGURE 1

Geographic Column of Delaware Basin And Bone Spring



termining the ideal lateral length and placement. As for lateral azimuth, play-specific geomechanical studies generally suggest that the primary horizontal stress runs relatively east-west at 8 degrees (Figure 2). Taking into account the geologically driven exceptions and low top-to-bottom permeabilities, the objective was to create a platform where multiple hydraulic fractures could be placed to enable a comparative evaluation to determine the highest possible recovery.

Earlier work held that the lateral should be drilled into a less-stressed north-south azimuth, which would afford maximum frac stages and perforation clusters, thereby generating higher reservoir contact and production. Fracture spacing continues to evolve from a beginning value equal to one cluster per three casing joints, or approximately every 120 feet.

Another offshoot of the earlier phase of the investigation was debunking long-held petrophysical contentions that classified the Bone Spring as a typical shale with a brittle and relatively isotropic stress regime, which would respond well to a fracture network-like stimulation treatment. It was that understanding that prompted completion engineers to design treatments using extremely thin water-based frac fluids with small proppant.

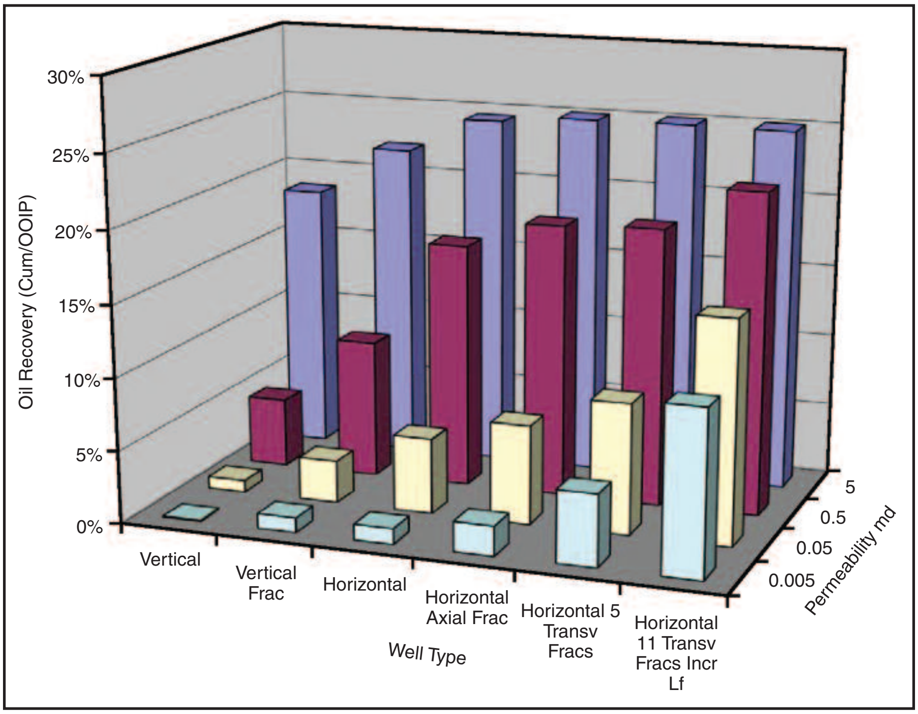
Microseismic mapping has revealed the Bone Springs fracture geometry to be largely planar, with subsequent geomechanical studies showing the threshold pressure to dilate any natural fractures to be more than 10 percent above closure gradient, making creating a natural fracture network difficult at best. The previous fracturing fluid and small-mesh proppant selection was deemed ineffective for maximum recoveries.

Owing to the planar fracture geometry and a frac height greater than 200 feet, the evaluation settled on a low-viscosity and nondamaging frac fluid formulated with an extremely low-loading, guar-based cross-linked gel. Linear gel was used in the early stages in tandem with excess breakers and a nanosurfactant package to enhance load recovery.

Complementing the redesigned fluid stream was a wholesale analysis of the proppant selection. Along with closure pressures, another data point used to select proppant was the gas-to-oil ratio coupled with high initial flow rates, which raised concerns about the presence of multiphase flow compounded by non-darcy flow issues.

FIGURE 2

Well Planning Guide used in Determining Lateral Azimuth



Logically, it can be maintained that the producing pressure exerted a net load within the operating capacity of the commonly used natural frac sand. However, results of the study found that the combination of multistage frac treatments, frequent shut-ins caused by a subpar local gas gathering network, and multiphase high-flow rates mandated the higher-conductivity of ceramic proppant–a recommendation that was verified by independent third-party investigations.

Lateral Setting Depth

The fourth hurdle in the evolutionary process centered on identifying the lateral setting depths that would best exploit the capacities of the high-conductive proppant and medium-thin fracturing fluid. Therefore, a simulated landing study was initiated using a 3-D frac model that incorporated the frac fluid, proppant, offset vertical well data, and subsurface mapping inputs. The 3-D model was incorporated in developing a workflow to independently test four candidate landing depths in a representative second-bench Bone Spring well. The aim was to identify and isolate the zones delivering the highest-quality reservoirs.

Myriad and often-interrelated factors affected the eventual selection of the targeted lateral depth setting, including the total fracture height; low to medium stress barriers; permeability between the landing depth and the high stress barrier; the carrier fluid's proppant transport capability; frac fluid leak-off characteristics; the proppant's density, shape and sphericity; and the permeability changes and resulting pay quality from the vertical aspect. It was assumed that the total frac height would be confined between two hard lime streaks with roughly 243 feet of pay, and that these boundaries would not be breached with the medium-thin carrier fluid and lateral placement just above the hard streaks.

These low to medium stress barriers typically crop up intermittently in the third bench between the Red Hills and upper sand body (Figure 3). Accordingly, landing the lateral above the hard streaks facilitates forcing frac fluid through the lateral and into the Red Hills. While this hard layer is considered a modest barrier, pressure data are inconclusive in regard to its capacity to help deflect proppant upward to cover more of the Bone Spring upper sand body.

As with vertical wells, designing frac treatments for horizontals should consider out-of-perforated-field permeability as a superb blockade to frac height growth. The only issue is the ability to map and evaluate the stress barrier in a lateral, but it is logically assumed that increased footage of permeability equates to a more effective barrier mechanism.

Proppant Transport

A predominate consideration in setting the lateral depth is the lifting capacity of the carrier fluid. At deeper landing depths, and especially with a thin fluid, the Dar-

FIGURE 3

Type Log of a Third Bone Springs Vertical Section

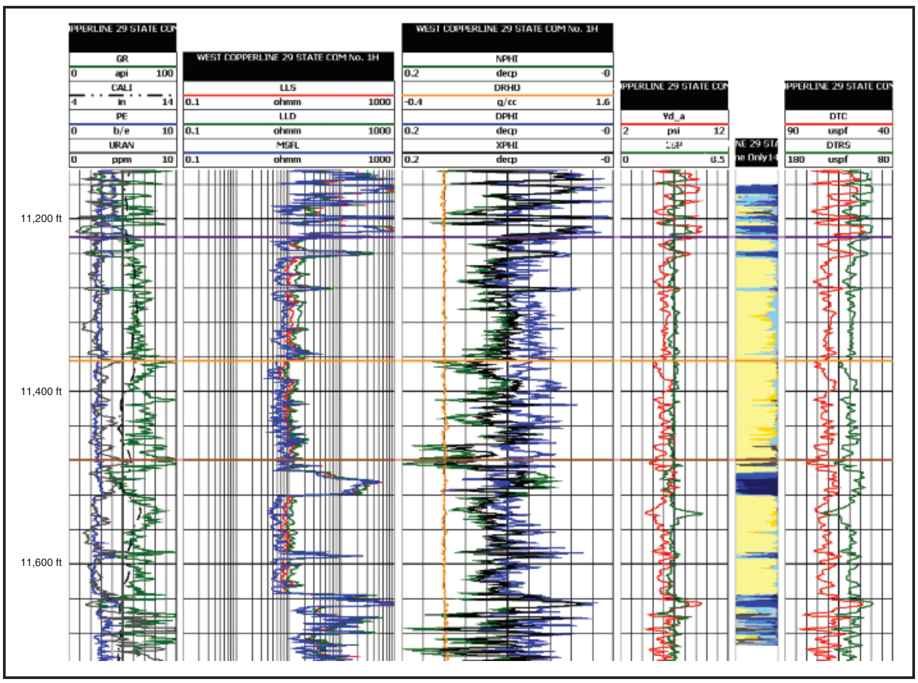


TABLE 1

Results of Four Placement Simulations with Selected Landing Depths (Red)

Setting Depth (TVD ft)	Frac Length (ft)	Propped Length (ft)	Frac Height (ft)	Propped Height (ft)	Dimensionless Fracture Conductivity (F_{cd})
10,480	592.5	545.3	286.5	263.6	2.461
10,520	576.3	529.5	272.2	250.2	2.476
10,553	**568.6**	**520.0**	**276.7**	**253.2**	**2.526**
10,590	555.2	502.6	305.6	276.9	2.563

TABLE 2

Summary of Generic Case Study Wells with Milestone Events and Comparative Production

Well	Bone Spring Interval	Start Date	Milestone Event	Best 60-Day Oil (bbl)	Best 60-Day Gas (MMcf)
A	3rd	5/27/14	Proppant and fluid	24,878	31.381
B	3rd	7/7/14	Lateral setting depth	43,871	69.764
C	3rd	12/23/14	Multistage port	33,242	30.332
D	2nd	7/21/14	Proppant and fluid	32,433	12.987
E	2nd	9/22/14	Lateral setting depth and multistage port	51,107	49.796
F	2nd	12/9/14	Multistage port	83,737	136.144

winesque theory that it is easier to prop down with gravity than prop upward with force generally holds true. On the other hand, running a more viscous fluid at a shallower setting aggravates the risks of breaching the upper hard streak.

The transport capacity and minimizing gel damage dictated the choice of a medium-thin frac fluid. The minimally damaging issue also is closely aligned with the density, shape and sphericity considerations of the ceramic proppant, which plays a significant role in determining the horizontal landing depth. Specifically, the proppant and frac fluid properties, together with the injection rate (frac velocity), control propping of the pay zone above the lateral.

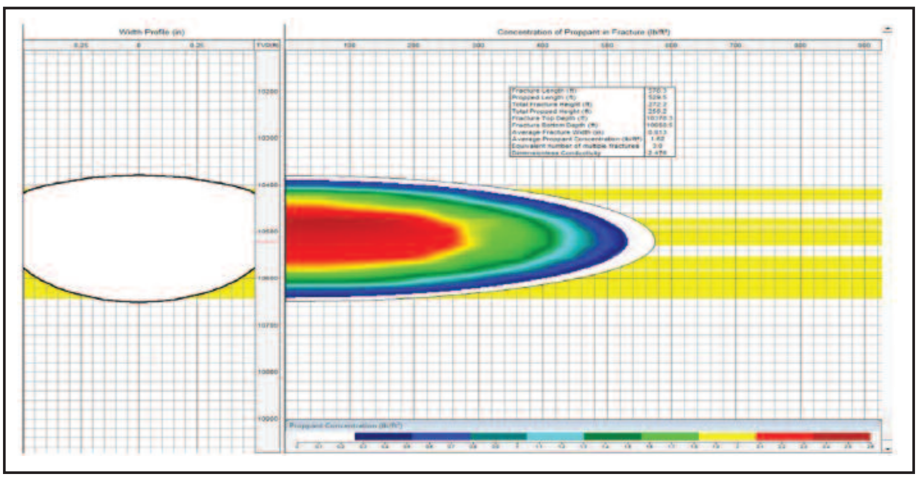
As part of this evaluation, proppant transport was defined by a simplified Navier-Strokes equation relating to settling rates. The drag coefficient and proppant area were the key elements in the transport analysis, since they characterize the drag of spherical versus nonspherical proppant. Considering that ceramic rods settle faster in fluid than spheres of the same density, spherical ceramic proppant was deemed preferable.

In addition, sphericity was considered to account for both high potential flow rates and frac fluid cleanup, thus the selection of a proppant with the lowest beta factor to accommodate drag from Forchheimer porous-flow forces.

The four depth simulations (Table 1, with selected landing depths shown in red) employed the same frac design, injection rate and proppant ramp schedule, making the only variable the source of the frac entering the pay section. Justification for the selected depth setting (Figure 4) was based on proppant mapping showing higher coverage of proppant concentrations in all three pay sections, and the low to modest net pressure trend during the treatments, improving the ability to repeat each stage along the lateral.

FIGURE 4

Selected 10,553-Foot Landing Depth Simulation



Multisleeve Frac System

The fifth barrier to be addressed (and which continues to be studied) was optimizing the operational components–specifically relating to fracture spacing–monitoring back-stress, and developing a permeability model from mud logging data. The subject wells were perforated with limited-entry tools using three evenly spaced clusters with 20 perforations at the farthest (toe) measured depth, 15 in the middle depth, and 12 at the shallowest (heel) depth. Absent microseismic mapping, net pressure matching–especially when step-rate tests were employed–suggested a perforation efficiency issue.

Consequently, with perforation cluster efficiency lower than 74 percent, concern was raised that entire clusters were being eliminated, thereby restricting stimulation treatment to only two and perhaps one of the three targeted fractures. Accordingly, a multisleeve frac system was employed in the completion, allowing each sleeve port to be opened individually during frac treatment. While the straightforward process is similar to using one perforation cluster per stage, the ability to use coiled tubing with less water and eliminating plug drill-outs reduced the time and cost appreciably, even with up to a threefold increase in the number of stages.

Throughout the ongoing study, production rates of example wells were evaluated relative to instituting the various technology and/or best practice enhancements (Table 2). Results from the study wells, which were not benchmarked for reservoir quality, showed the best 60-day oil and gas production rates after incorporating all the hurdles, either singularly or in combination.

The study accentuates the inherent value of comprehensive diagnostic assessments in the well planning stage to modify lateral placement and ensure the thickest and richest pay zones are thoroughly covered and exploited. Furthermore, the increased understanding of the changes in reservoir quality along the lateral in both vertical and horizontal aspects have been confirmed as significant elements in designing the drilling and completion programs, and essential in optimizing overall well spacing. ❒

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Lyle Lehman is director of fracture design and evaluation for STRATAGEN, a CARBO business. He leads a team that utilizes the company's matrix- and shale-based reservoir stimulation workflows. Lehman's experience includes optimizing fracturing treatments in low-permeability reservoirs around the world. Before joining STRATAGEN in 2007, he worked for Halliburton Energy Services, including serving as North American regional practice manager for drilling and completion optimization. Lehman holds seven U.S. patents related to fracture stimulation. He has a B.S. in chemistry from the University of Oklahoma.