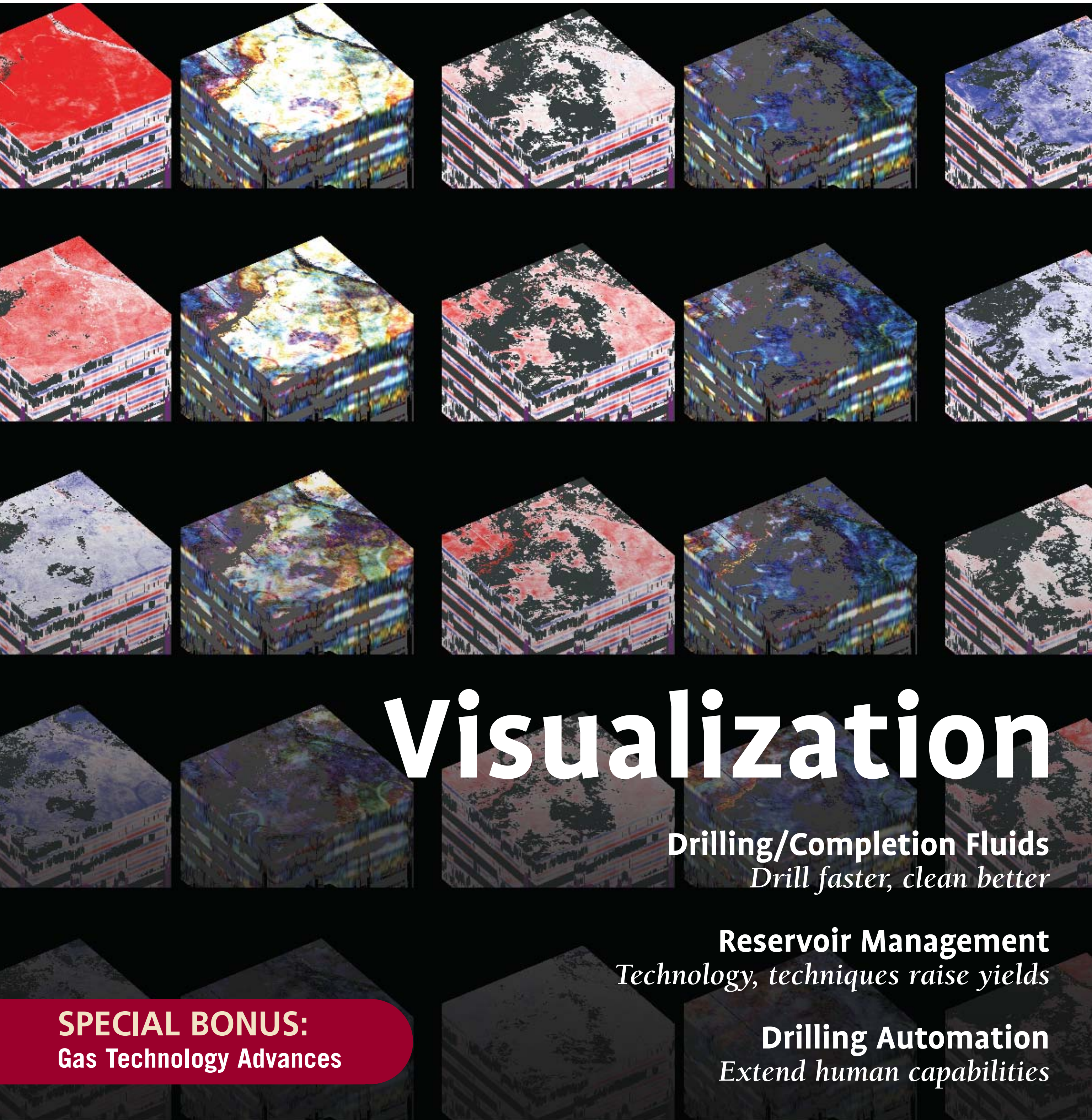
GLOBAL EXPLORATION & PRODUCTION NEWS • TECHNOLOGY UPDATES • ANALYSIS

E&P

www.eandp.info

A Hart Energy Publication

January 2007



Visualization

Drilling/Completion Fluids
Drill faster, clean better

Reservoir Management
Technology, techniques raise yields

Drilling Automation
Extend human capabilities

SPECIAL BONUS:
Gas Technology Advances

As seen in the January 2007 issue of E&P

Maximize reservoir contact

Brute frac-job force is not the solution to improved reservoir performance.

AUTHOR
Belgacem Chariag, *Schlumberger*

Hydraulic fracturing got its start when Stanolind (now BP) pumped its first job in Kansas' **Hugoton** field back in 1946, so it's appropriate that the current expansion in hydraulic stimulation is manifesting itself in North America, where it's estimated that approximately 70% of the world's fracturing activity resides.

It is estimated that nine of every 10 frac jobs are performed in gas wells. But gas production is no longer limited to conventional sandstone reservoirs. Operators are pursuing production in carbonates, tight sandstones, shales and coal beds, some with intrinsic permeabilities measured in nanoDarcies (10^{-9} Darcies). With extremely low permeability in the matrix rock, natural fracture networks can act as conduits and completion strategies seek to exploit these high conductivity paths.

But producing from natural fractures alone is not enough.

A natural conclusion seemed be to drill more wells. Although the number of wells drilled in US land has more than doubled over the last 6 years, average daily gas production has remained flat at about 50 Bcf (1.42 Bcm). Obviously, drilling lots of additional wells was not a feasible way to solve the problem, so the industry sought relief by creating conductivity through hydraulic fracturing.

In vertical wells, hydraulic fracturing can improve reservoir contact several hundredfold, but when applied in horizontal wells the improvement is exponential (Figure 1). Results have been encouraging, and the practice has evolved to multistage fracturing, whereby several levels are stimulated in rapid succession in an attempt to increase reservoir contact. Today, operators are completing multiple thin zones distributed over gross intervals of several thousands of feet (Figure 2). According to Schlumberger records, in a span of just 3 years the percentage of US land wells receiving multizone treatments has blossomed from 33% to 50%, with 25% receiving two treatments and 30% receiving more than two stages. And with individual zonal isolation, it is now possible to selectively re-frac under-performing zones.

Technology on all fronts

Improvements in fracturing technology are advancing on every level. Today operators can select from an impressive menu of frac fluids containing sophisticated diverting agents and breakers. With a look to the future, scale inhibitors are now integrated into the fluid to ward off the long-term formation of scale in the rock and in the well bore. Proppants are treated with novel material to prevent unwanted flowback and to bridge off fines and sand production. Solutions have been postulated to ward off recently discovered diagenetic effects on the proppant grains that reduce permeability over time. And the inclusion of millions of microfibers to the proppant mix has mitigated the slumping effect whereby proppant falls to the bottom of the fracture once pumping is terminated.

New techniques involving sophisticated isolation devices are benefiting multistage fracturing, first by locating the fracture point with precision, and second by allowing each stage to be individually treated according to its requirements. External packers and

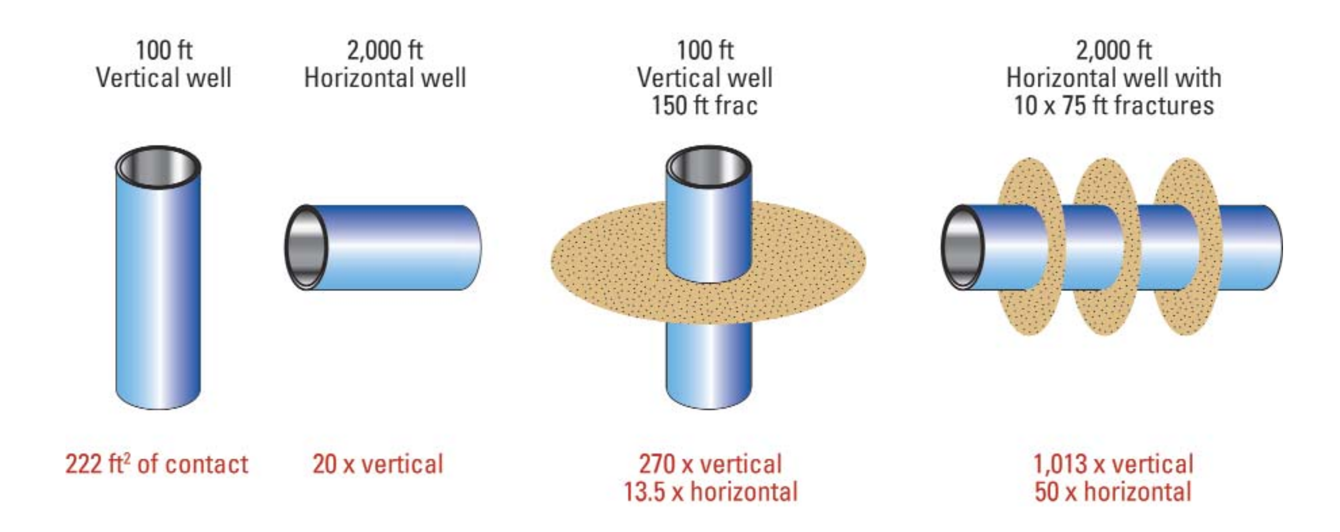


Figure 1. Reservoir contact for a typical 8½-in. borehole grows significantly when hydraulic fracturing is employed. When combined with horizontal drilling the growth is exponential. (All graphics courtesy of Schlumberger)

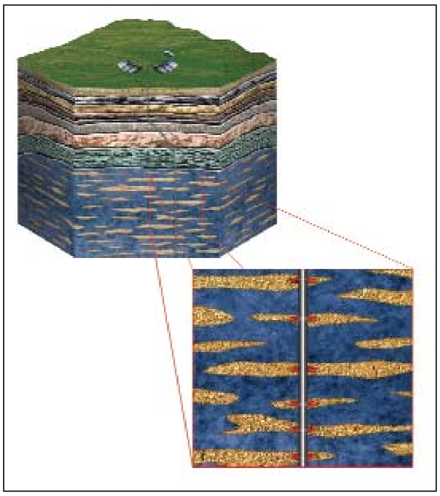


Figure 2. Maximum formation conductivity can be achieved when precisely placed fractures are staged along a borehole, but the real challenge is steering them into high-potential reservoir blocks like this typical gas play in the Rockies.

expandable elastomeric seals provide hydraulic isolation in lieu of cement, so precious near wellbore permeability is not sacrificed.

Fracture propagation can now be monitored by a combination of surface or downhole techniques like microseismic arrays used in conjunction with a myriad of pressure, volume and flow sensors that feed job data, which is compared with a fracture design model and pumping schedule constructed using log, seismic and geomechanics information.

Today's conventional wisdom

Among the shortcomings of traditional fracturing techniques listed by many operators is too much complexity, leading both operators and service company personnel to become preoccupied with the activities they are performing rather than the results they both expect. Fracturing is considered a stepchild to well construction, with all focus on the number of pounds of proppant pumped, or the number of days it takes. Lack of a scientific approach and the inability to quantitatively relate cause and effect has led many to accept any improvement as evidence of success. There is a reluctance to deviate from traditional ways, and this is limiting the ability to achieve a well's true potential.

So what's the solution? Can the industry look into its crystal ball and picture future trends?

Location is everything

Just as precise well placement has become the critical factor in improving reservoir performance, fracture placement is looming as the biggest contributor toward connecting the well with the reservoir. A properly placed hydraulic fracture can maximize reservoir contact, enhancing conductivity between the well and the far reaches of the reservoir, thus ensuring sustainable production rates, which are key to economic viability.

And therein lies the problem. It's easy to say where you want a fracture to go, but not so easy to make it go there.

Accordingly, maximum reservoir contact will result from the application of an integrated portfolio of complementary technologies whose main objective is to "steer" the fracture to high-potential reservoir blocks, while avoiding depleted zones or aquifers. To accomplish this requires real-time knowledge of fracture propagation and direction. Among other things, this will require the ability to acquire and process microseismic data in real-time to provide accurate understanding of fracture orientation (Figure 3). Secondly, it will require the ability to judiciously apply diverters to direct the hydraulic energy appropriately to achieve the objective. Lastly, to let the operator know when the objective has been reached, the system must allow an immediate true test of the well's post-frac performance so results can be quantified. In this way, the operator can apply just what it takes to maximize reservoir contact — no more and no less.

A scientific approach

All wells are not alike, so it is fundamental that decision capability supported by a portfolio of options and placement solutions be developed to take the complexity and conjecture out of the operation. The use of pre-existing information such as logs or seismic data, intrinsic stress analyses, and geomechanical models that can be merged with incoming dynamic data from the fracturing operation facilitates understanding of what's happening downhole, simplifying and streamlining the decision-making process. Not only will this facilitate the decision related to accurate placement and fracture diversion, but it will base each decision on supportable scientific principles and measured data, leading to predictable results and minimized risks. E&P

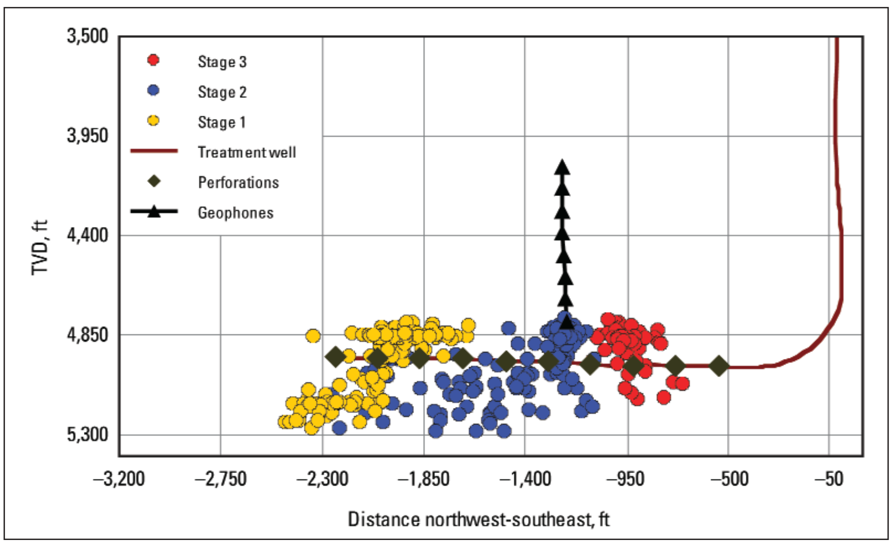


Figure 3. Real-time microseismic imaging and processing can indicate fracture orientation and progress so diverters can be employed in a timely manner. Example from a three-stage fracture in Fayetteville shale.