Open-Channel Fracturing—
A Fast Track to Production

The goal of a hydraulic fracturing treatment is to improve well productivity by creating a flow path from the formation to the wellbore. Conventional fracturing treatments fill the fracture completely with proppant, which holds the fracture open to preserve the production pathway. A new hydraulic fracturing technique creates a network of open channels throughout the proppant pack, improving fracture conductivity by orders of magnitude. Performing this technique has significantly improved the economic viability of wells in several producing fields.

In 1947, Stanolind Oil & Gas performed the first experimental hydraulic fracturing treatment in the Hugoton field in southwestern Kansas, USA. Since then, E&P companies have employed this reservoir stimulation technique extensively to enhance or prolong well productivity. Indeed, many fields producing today would not be economically viable without the benefits provided by hydraulic fracturing.

During a fracturing treatment, specialized equipment pumps fluid into a well faster than it can escape into the formation. Pressure on the formation rises until it breaks down, or fractures (below). Continued pumping causes the fracture to propagate away from the wellbore, increasing the formation surface area from which hydrocarbons can flow into the wellbore. This helps the well achieve a...
higher production rate. As a result, operators recover their well development costs more quickly, and the ultimate amount of produced hydrocarbons increases dramatically (below).

During hydraulic fracturing, two principal substances—proppants and fracturing fluids—are pumped into a well. Proppants are particles that hold the fractures open and preserve the newly formed pathways to facilitate hydrocarbon production. The particles are carefully sorted for size and sphericity to form an efficient conduit, or proppant pack, which enables fluids to flow from the reservoir to the wellbore. Some proppants also feature a resin coating that binds the particles together after the proppant is placed in the well, thereby improving pack stability. Generally, larger and more spherical proppants provide more-permeable proppant packs or, in industry vernacular, packs with higher conductivity.

Fracturing treatments consist of two main fluid stages. The first stage, or pad stage, does not contain proppant. Fluid is pumped through casing perforations at a rate and pressure sufficient to break down the formation and create a fracture. The second stage, or proppant slurry stage, transports proppant through the perforations into the open fracture. The fracture closes onto the proppant when pumping ceases, holding the proppant in place both while the fracturing fluid is pumped into the wellbore. Some proppants also feature a resin coating that binds the particles together after the proppant is placed in the well, thereby improving pack stability. Generally, larger and more spherical proppants provide more-permeable proppant packs or, in industry vernacular, packs with higher conductivity.

Fracturing fluids must be sufficiently viscous to create and propagate a fracture as well as transport the proppant down the wellbore and into the fracture. Once the treatment is completed, the viscosity must decrease sufficiently to promote rapid and efficient evacuation of the fracturing fluid from the well. Ideally, the proppant pack should also be free of fluid residue, which may impair conductivity and hydrocarbon production.

For six decades, chemists and engineers have worked to develop proppants and fracturing fluids that produce the ideal propped fracture. As a result, the chemical and physical nature of these materials has changed significantly over time. Proppants have evolved from crude materials, such as nut shells, to naturally occurring sands and to high-strength spheres manufactured from ceramics or bauxite. Fracturing fluids have progressed from gelled oils to linear- and cross-linked-polymer solutions. Chemical breakers were introduced to decompose the polymer, reduce the amount of polymer residue in the fracture and improve conductivity (right). In the late 1990s, Schlumberger introduced an essentially residue-free system, ClearFRAC polymer-free fracturing fluid. The proppant pack conductivity in wells treated with ClearFRAC fluid nearly equaled the theoretical prediction.

Having maximized proppant pack conductivity, the industry began to investigate ways to further improve hydraulic fracturing results. Engineers found the answer when they focused on reducing the amount of polymer residue in the fracturing fluid.

Fracturing-fluid evolution. Early fracturing treatments employed hydrocarbon-base fluids. Operators frequently added gelling agents to oil from the same producing formation. Water-base fluids, such as linear-polymer solutions, were introduced in the 1960s. However, as wells became deeper and hotter, these fluids were no longer sufficiently viscous. To improve thermal stability, chemists added metal salts, causing crosslinking reactions that increased the effective polymer molecular weight by several orders of magnitude. Today, crosslinked-polymer fluids are routinely used at well temperatures up to about 232°C (450°F). Posttreatment fluid recovery requires the addition of strong oxidizing agents, or breakers, to decompose the polymer and reduce fluid viscosity. Encapsulated breakers were eventually developed, which allowed higher oxidizer concentrations and reduced the amount of polymer residue in the proppant pack. Fluid foaming allowed lower polymer concentrations, further improving proppant pack cleanup. Including fibers improved the fluids’ ability to transport proppant, permitting further polymer concentration reductions. The most recent generation of fracturing fluids employs nonpolymeric, low-molecular-weight viscoelastic surfactants. Fluid viscosity arises from the formation of rod-shaped micelles. When the fluid contacts hydrocarbons downhole, its viscosity decreases substantially, promoting efficient recovery and virtually residue-free proppant packs.
on the proppant pack in a different way. Since the advent of hydraulic fracturing, engineers strove to fill the fracture completely with proppant—in other words, create a continuous proppant pack. What if it were possible to fill the fracture with a discontinuous proppant pack consisting of discrete proppant columns surrounded by open channels? This approach would separate the load-bearing task of the proppant pack from that of providing a fluid pathway. Engineers speculated that, if the proppant pack were properly designed, the fracture conductivity would be orders of magnitude higher than that of the cleanest conventional proppant pack (above).

2. Perforations are holes created in the casing after it has been cemented in place. The most common perforating method employs guns equipped with explosive shaped charges. Detonation creates short tunnels through the casing and the cement sheath, thereby providing hydraulic communication between the wellbore and the producing reservoir.
After several years of research and development, Schlumberger scientists have achieved this goal. The fruit of their efforts, the HiWAY flow-channel hydraulic fracturing technique, is a fundamental advance in the science of reservoir stimulation. This article describes how the HiWAY technique was developed in the laboratory and introduced to the oil field. Case histories from Argentina and the US demonstrate the well productivity improvements that have been achieved by applying this technique.

Redesigning the Proppant Pack

Scientists at the Novosibirsk Technology Center in Russia began their quest for a discontinuous proppant pack with an ambitious experimental program to confirm its feasibility and to develop the means by which such a technology could be applied. The scale of the experiments increased gradually from small benchtop laboratory simulators to full-scale testing with standard field equipment.¹

The first task was to validate the theoretical conductivity benefit expected from discontinuous proppant packs. Employing a standard American Petroleum Institute (API) test method, engineers placed a proppant pack in a fracture simulator. The simulator applies a closure stress representing overburden pressure and measures the force necessary to pump a single-phase fluid through the pack at various flow rates (left).²

The engineers then used Darcy’s law and the Navier-Stokes equations to calculate the proppant pack permeability.³ The measured permeabilities of the discontinuous proppant packs were consistent with the theoretical prediction—1.5 to 2.5 orders of magnitude higher.

Having verified the conductivity benefit of discontinuous proppant packs through experiments, scientists turned their attention to methods by which proppant columns could be created downhole in an actual fracture, withstand the stresses associated with fluid flow and fracture closure and maintain open flow channels. By performing modeling studies and experiments, engineers evaluated several concepts for creating proppant columns in a fracture. These included adding memory-alloy fibers around which proppant grains would congregate, placing encapsulated breakers in localized areas and heating the proppant slurry in a discontinuous manner. In the most promising method, engineers changed the manner by which proppant is delivered downhole.

³ Measuring the conductivity of a proppant column network. A standard API conductivity cell (top) features two steel platens, driven by a hydraulic press to apply closure stress. The proppant pack is placed between two sandstone slabs (usually Berea Sandstone), and the resulting “sandwich” is placed between the two platens of the hydraulic load frame. After installing the platen assembly inside an enclosure equipped with flowlines, technicians pump a single-phase fluid (usually water or brine) through the proppant pack at 1 to 10 mL/min, measure the resulting pressure drops and calculate the proppant-pack permeability. The enclosure may also be heated to simulate reservoir temperature. Technicians created a discontinuous proppant pack by placing four proppant columns between the two slabs of sandstone (middle). Conductivity measurements were performed at closure stresses between 1,000 and 6,000 psi [6.9 and 41.4 MPa] (bottom). The permeabilities of continuous proppant packs prepared with 20/40-mesh sand (blue diamonds) and 20/40-mesh ceramic proppant (green triangles) were less than 1,000 D. Permeability generally decreased with closure stress due to proppant crushing and proppant embedment into the sandstone. The discontinuous proppant packs were formed from 20/40-mesh sand and, in agreement with the theoretical prediction (red line), the measured permeabilities (black squares) were orders of magnitude higher.
In the conventional method, proppant is present throughout the entire proppant slurry volume. However, if the proppant slurry stage consisted of alternating fluid pulses—with and without proppant—a series of proppant slugs could settle in the fracture and form columns (right).

For the pulsing method to succeed, it was essential that the proppant slugs not disperse during their journey down the tubulars, through the perforations and into the fracture. In the first experiments to test this concept, engineers observed the static settling behavior of proppant slugs in a transparent slot filled with a fracturing fluid. After injecting a sample of proppant-laden fluid into the top of the slot, engineers could visually assess the settling behavior over time. Scientists quickly learned that proppant slugs prepared with conventional fracturing fluids readily dispersed as they traveled down the slot. Eventually, they discovered that proppant slug stability could be dramatically improved by integrating fibers (below right).

The next series of experiments evaluated the dynamic stability of proppant slugs. The apparatus featured up to 33 m [108 ft] of 0.78-in. [2-cm] ID pipe—a geometry that allowed scientists to test flow rates, fluid velocities and proppant concentrations consistent with flow through a fracture. An X-ray registration system measured proppant slug stability. The X-ray absorbance across the pipe diameter is linearly proportional to the proppant concentration; therefore, stability measurements could be obtained by recording

\[ \text{Absorbance} = \frac{\text{proppant pack absorbance}}{\text{proppant pack thickness}} \]


6. Darcy’s law may be represented by the following equation: \[ q = kfw \Delta \frac{\rho}{L} \] where \( q \) is the flow rate, \( k \) is the proppant pack permeability, \( w \) is the proppant pack width, \( \mu \) is the fluid viscosity and \( \Delta \rho \) is the pressure drop per unit of proppant pack length. The Navier-Stokes equations are a set of coupled differential equations that describe how the velocity, pressure, temperature and density of a moving fluid are related. For more information: Zimmerman RW and Bodvarsson GS: “Hydraulic Conductivity of Rock Fractures,” Transport in Porous Media 23, no. 1 (1998): 1–30.
7. One may question how well the circular pipe geometry represents the slot geometry of an actual fracture. Since the relative cross-sectional area of a pipe is larger than that of a slot, destabilizing influences are more pronounced. Therefore, the pipe geometry provides a more conservative stability assessment.

\[ \text{Comparing the HIWAY technique with a conventional fracturing treatment.} \]

During the proppant stage of a conventional fracturing treatment (red line, top), all of the slurry contains proppant, and operators usually increase the proppant concentration stepwise. The proppant stage of a HIWAY fracturing treatment (green line) features alternating pulses of proppant-laden (dirty) fluid and clean fluid. The proppant concentration in the pulses may also be increased stepwise. Engineers monitor proppant pulses during actual fracturing treatments (bottom). Proppant concentrations are commonly expressed in pounds per gallon added, or ppa. One ppa means that one pound of proppant is added to each gallon of fracturing fluid. It must not be confused with the more common pounds per gallon, or lbm/galUS. During hydraulic fracturing treatments, ppa better reflects field practice. There is no recognized SI equivalent to ppa.

\[ \text{Design Versus Actual Proppant Concentration} \]

\[ \text{Pump time, s} \]

\[ \text{Proppant concentration, ppa} \]

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X-ray absorbance before and after the proppant slugs traveled through the pipe. The results confirmed that fibers enhance proppant slug stability (left).

Following the promising laboratory experiments, full-scale tests were performed at the Schlumberger Kellyville Learning Center (KLC) in Oklahoma, USA. These experiments were designed to test the stability of proppant slugs traveling through surface lines, wellbore tubulars and perforations at flow rates similar to those experienced during an actual fracturing treatment. The layout included a field blender and approximately 198 m [650 ft] of 7.6-cm [3-in.] treating line connected to the blender discharge (below). Five sets of perforations were arranged along the treating line. Each set consisted of ten 0.95-cm [0.374-in.] holes—five at 0° phasing and five directly opposite at 180° phasing. Fluid escaping from the perforations was collected in ten 1.04-m³ [275-galUS] tote tanks. Two densitometers—one at the blender discharge, the

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other at the end of the treating line—measured proppant concentrations and provided an indication of slug stability. A unique feature of the Schlumberger blender is a programmable mixer that precisely controls the proppant concentration in the fracturing fluid, which is coupled with an array of dry- and liquid-additive feeders and a unique fiber-additive system.

The first set of KLC experiments, performed with the perforations closed, measured the stability of proppant slugs traveling through the treating line at 11.6 m/s [38 ft/s]. This velocity corresponded to a pump rate of 2.7 m³/min [17 bbl/min]. The carrier fluid was a borate-crosslinked guar system, with a guar concentration of 3.6 kg/m³ [30 lbm/1,000 galUS], and a fiber concentration of 5.0 kg/m³ [42 lbm/1,000 galUS]. The proppant concentration in the slugs was 10 ppa, and the fiber concentration was 10.0 kg/m³ [84 lbm/1,000 galUS]. The results showed that the proppant slugs were stable after passing through the treating line (above right).

The second set of KLC experiments evaluated the ability of proppant slugs to pass through the perforations and remain intact. In addition, the scientists wanted to verify that the proppant slugs could fractionate and distribute themselves among all of the perforations. During each test, technicians measured the accumulated fluid volumes in each of the tote tanks connected to the five sets of perforations. The first perforation set was equipped with a densitometer that continuously recorded fluid density, and fluid samples were manually collected from the last perforation set. When fibers were present in both the clean-fluid and proppant-laden pulses, the fluid volume distribution among the tote tanks was uniform. The fluid density variations measured by the densitometer and by manual sampling also matched, further confirming the feasibility of the proppant slug method for creating a discontinuous proppant pack (right).

Last, engineers attempted the HiWAY placement technique in an experimental well. Under these circumstances, it was impossible to directly observe the behavior of the fluid pulses. Instead, engineers recorded surface- and downhole-pressure measurements during pumping and employed a mathematical model to reconstruct
Evaluating Proppant Column Durability

Having shown that proppant columns can be constructed using available blending and pumping equipment, the scientists turned their attention to the postplacement stability of discontinuous proppant packs. Following a fracturing treatment, the columns must be strong enough to withstand formation closure pressure as well as erosive forces arising from fluid flow during well cleanup and production.

To investigate the effects of closure stress, technicians manually prepared proppant columns and placed them in a hydraulic press equipped with sensors for monitoring the distance between the press rams. The apparatus subjected the proppant columns to compressive loads as high as about 228 MPa [33,000 psi]. Measured parameters included column height and diameter and proppant particle size distribution.

As expected, proppant column height decreased with closure stress; however, it is notable that more than 80% of the column shrinkage occurred during the first 6.9 MPa [1,000 psi] of compression. As loads increased, further shrinkage was minimal. Inspection of the proppant columns revealed that the initial shrinkage resulted from carrier fluid leakoff and proppant consolidation. Additional column shrinkage at higher pressures was due to proppant compaction and crushing. The median size of the proppant particles decreased with increasing pressure. Ultimately, at 228 MPa closure stress, sufficient proppant column height remained for efficient fluid flow (middle left). This closure stress is approximately two times higher than that which occurs in the deepest oil or gas wells, indicating that the HiWAY technique would not have a depth limitation owing to pressure.

Proppant column diameter, or footprint, increased with closure stress. However, closure test results showed that with each increase in the proppant column diameter, the relative footprint increase became less pronounced (left). The laboratory tests investigated column diameters of several centimeters. However, column diameters in an actual fracture would be of the order of several meters; therefore, engineers did not expect that the conductive pathways between columns would be lost as a result of closure stress.
Fluid flow during cleanup and production, other potentially destabilizing events, also required investigation. To evaluate this risk, the scientists constructed an erosion cell that could be inserted between the rams of a hydraulic press (above). The cell accommodated two sandstone cores, between which a proppant column could be placed. While the hydraulic press exerted closure pressure, technicians pumped a fluid past the column at various flow rates corresponding to and exceeding normal well production. They assessed erosion visually and by measuring column weight loss (right).

The results demonstrated that nearly all proppant erosion occurred within the first few minutes of proppant exposure to fluid flow. In addition, the amount of erosion decreased with increasing closure stress, particularly above about 69 MPa [10,000 psi]. Visual analysis revealed that all of the erosion took place along the sides of the columns, not at the surfaces directly facing fluid flow.

Following these experiments, the scientists were confident that proppant columns placed in a hydraulic fracture would survive the rigors of subsequent well operations.

Effects of flow rate and closure stress on proppant column erosion. The initial, uneroded proppant columns were 1.38 mm [0.05 in.] high and 36 to 42 mm [1.42 to 1.65 in.] in diameter, and the closure stress was 16.6 MPa [2,400 psi]. Technicians increased the fluid flow rate incrementally and measured the amount of proppant collected in the filter at the erosion cell outlet (top). Most of the erosion occurred during the first few minutes, at lower flow rates (blue line). Proppant column erosion decreased significantly at higher closure stresses (bottom).
Selecting Field Testing Candidates

Engineers designed a conservative field testing approach that considered several important formation and well design parameters. At first, they decided to limit the technique to vertical wells and, to ensure adequate proppant column separation in the fracture, they initially arranged the perforations in clusters rather than in the conventional, even-spaced configuration (below).

Engineers also needed to consider the nature of the producing formation. How would the fracture walls respond to the presence of void areas in a discontinuous proppant pack? If the rock is too soft or flexible, the walls might bend or flow into the voids, compromising the fracture conductivity. For guidance, the scientists turned to a related discipline—mining engineering. Proppant conglomerates are analogous to columns in an underground mine, and mining engineers must consider the relationships between the columns and the overlying rock.

Conventional and HiWAY perforating schemes. Arranging perforations in clusters enhances the separation between proppant slugs entering the fracture and ensures an optimal conductive pathway from the fracture to the wellbore.

HiWAY field study results. The Loma La Lata field, operated by YPF, S.A., is located in southwest Argentina (top). The field’s wells produce oil (green dots) and gas (red dots). The initial (30-day) average production rate from gas wells stimulated by the HiWAY technique (bottom, blue) was 8.2 MMcf/d, while those stimulated conventionally (orange) averaged 5.4 MMcf/d. The wells are grouped on the plot according to their proximity and reservoir property similarity.
The principal parameters governing the stability of an underground mine are column strength, the overburden pressure and the Young's moduli of the columns and the overlying rock. The scientists judged that the initial applications of the HIWAS technique should be performed in fields where the ratio between the formation Young's modulus and the fracture closure stress is higher than about 1,000. Such formations tend to be hard and inflexible. Once HIWAS technology was validated in these formations, engineers would consider lowering the limit incrementally.

Scientists and engineers spent many years preparing theoretical models and conducting tests to reach this point in the development of HIWAS technology. Now, with the well candidate selection guidelines in mind, they were ready to leave the experimental world and apply their new technique in producing oil fields.

Improving Gas Production in Argentina
The Loma La Lata field, operated by YPF, S.A., is located in southwest Argentina. With more than 300 wells, this field produces 26% of the country’s natural gas. Three producing zones lie in fine- to coarse-grained sandstone of the Sierras Blancas Formation in the Neuquen basin, at depths between 2,896 and 3,200 m [9,500 and 10,500 ft]. The bottomhole temperature and pressure vary between 113°C and 118°C [235°F and 245°F], and 24.1 and 31.0 MPa [3,500 and 4,500 psi]. Reservoir permeabilities and porosities are moderate—between 0.08 and 5 mD, and 12% and 17%, respectively. The Young’s modulus of the formation is between 27,600 and 48,300 MPa [3,500 and 6,000 psi]. Closure stresses vary between 27.6 and 41.4 MPa [4,000 and 6,000 psi].

Despite ongoing drilling and fracturing activity, gas production for the field had recently begun to decline. This situation, combined with the increasing energy demand in Argentina, prompted the operator to consider novel well-stimulation methods. Engineers conducted a 15-well field study wherein seven wells received the HIWAS treatment, and the remaining offsets were stimulated conventionally. To ensure an optimal comparison, all of the wells received the same fracturing fluid and proppant. The initial 30-day production rate from the wells stimulated by the HIWAS channel-fracturing technique exceeded that from the offsets by 53%.

Engineers continued to monitor production from some of these wells for two years (above). Cumulative gas production from the HIWAS well was 29% higher than from the offsets, equivalent to about US$ 4.8 million additional revenue at today’s prices. Thus, the HIWAS wells not only delivered higher initial production rates but also sustained significant production gains over time. The results also showed that the oil production from the discontinuous proppant pack remained in place for an extended period of time. For these reasons, YPF, S.A., is continuing to incorporate the HIWAS technique in its well development activities.

The Argentina study demonstrated that the HIWAS technique is effective in moderately permeable reservoirs. Following this success, engineers decided to execute the new technology in low-permeability, gas-bearing formations.

Channel Fracturing in Tight-Gas Reservoirs
Encana Oil and Gas (USA), Inc. operates the Jonah field in Wyoming, USA. Most production originates from the Lance Formation, which consists of fluvial sand intervals with permeabilities between 0.005 and 0.05 mD, and gas saturations of 33% to 55%. Bottomhole temperatures range from 79°C to 118°C [175°F to 245°F], and the formation Young’s modulus fluctuates between 24,130 and 41,400 MPa [3.5 and 6.0 million psi]. Closure stresses range between 35.9 and 49.6 MPa [5,200 and 7,190 psi]. Because the sand-interval thicknesses vary between about 3 and 61 m [10 and 200 ft], at depths between 2,290 and 4,115 m [7,500 and 13,500 ft], and are interbedded with siltstones and shales, stimulation treatments must be performed in multiple stages.

Typically, the wells consist of 20 to 50 stacked sand sequences, and Encana usually divides them into 10 to 14 stages. Each stage requires its own perforating and fracturing treatment. Engineers begin with the deepest stage and allow several days of fluid flowback and cleanup before continuing upward to the next stage. After engineers perforate and stimulate the last zone, well production may proceed.

Implementation of the HIWAS fracturing technique commenced with a 12-stage well containing 191 m [626 ft] of net pay. A nearby 12-stage offset well with 204 m [669 ft] of net pay received conventional fracturing treatments. Engineers pumped the same borate-crosslinked guar fracturing fluid and 20/40-mesh sand proppant into both wells at proppant concentrations between 4 and 6 ppa. Because of the formation of open channels, 44% less proppant was necessary.
in the HiWAY well. The operator tracked production from both wells for 180 days (above). Cumulative production from the HiWAY well was 26% higher than that of the offset well. This encouraging result led Encana to embark on a more ambitious comparative well study.

Thirteen wells were stimulated in the same section of the field—five by the HiWAY process and the other eight by conventional means. As before, all wells received the same borate-cross-linked guar fluid and sand proppant. The program consisted of 135 fracturing stages. Because of the open fracture channels, cleanup occurred more quickly, and the recovered-fluid volumes were 48% higher than those of the offset wells. After 30 days, the normalized production from the wells treated by the HiWAY technique was 23% higher than that from the offsets. Models predict that, after two years, the cumulative production was 54% higher than that from the conventionally stimulated wells.

Stimulating the Eagle Ford Shale

The Eagle Ford Shale in the US is of significant importance because of its ability to produce both gas and relatively large volumes of oil and condensate. The shale has a high carbonate content, making it brittle and amenable to fracturing treatments. The formation extends from Mexico northeast into east Texas, and is roughly 80 km [50 mi] wide and 644 km [400 mi] long. The average thickness is 76 m [250 ft] at a depth of approximately 1,220 to 3,660 m [4,000 to 12,000 ft] (next page, top left). Engineers at Petrohawk Energy Corporation, which operates the Hawville field near Cotulla, Texas, investigated whether the HiWAY fracturing technique could improve production of both gas and condensate.11

The formation is extremely tight, with permeabilities between 100 and 600 d and porosities between 7% and 10%. The bottomhole temperatures and pressures are also elevated—132°C to 166°C [270°F to 330°F] and 48.3 to 69.0 MPa [7,000 to 10,000 psi]. Young’s moduli are lower than those described earlier—between 19,800 and 31,050 MPa [2.0 and 4.5 million psi]. These are challenging conditions for the successful execution of fracturing treatments, regardless of the technique.

Wells in this section of the Eagle Ford formation are usually horizontal, presenting additional challenges for the HiWAY fracturing method. Schlumberger scientists had not yet performed extensive modeling studies of open-channel formation in deviated wellbores; nevertheless, Petrohawk decided to try the new technique. The operator selected two wells for an initial assessment: Well 1, located in a gas-producing region, and Well 2, in a condensate sector. Offset wells were available to provide a valid comparison (next page, bottom left). The operator had stimulated the offsets with fracturing fluids consisting of either slickwater or a hybrid system that employed slickwater during the pad stage and a crosslinked-polymer fluid during the proppant stage.12 Schlumberger engineers chose a borate-cross-linked guar fluid to stimulate the HiWAY wells.

For Well 1, the initial gas production rate was 411,000 m³/d [14.5 MMcf/d]—37% higher than in the best comparable offset well. After 180 days, the cumulative gas production was 76% higher than for the same offset well. Ultimate gas production from this well is expected to be 252 million m³ [8.9 Bcf]. Well 2 initially produced 130 m³ [820 bbl] of condensate per day—32% higher than the best comparable offset. After 180 days, the cumulative condensate production was 54% higher than that from the comparable offset well.


12. Slickwater fracturing fluids are composed of water and a polymer (usually polyacrylamide) for lowering the friction pressure when pumping the fluid through tubulars. The pump rate during slickwater fracturing treatments is high—up to 15.9 m³/min [100 bbl/min]. Consequently, large amounts of water are required to stimulate a well.
Based on these results, Petrohawk has increased its utilization of HiWAY technology. Ten additional wells were completed using the new technique, showing production trends consistent with the initial test wells. The technique has increased gas production from the Eagle Ford Shale by 51% and condensate production by 46%.

Expanding the Scope of HiWAY Service

As of this writing, more than 2,600 HiWAY fracturing treatments have been performed in eight countries, with a placement-success rate higher than 99.8%. This statistic confirms that the years of theoretical and experimental work clearly resulted in robust design and execution criteria.

Creating discontinuous proppant packs significantly reduces the cost and the environmental footprint of fracturing treatments. Engineers estimate that, on a global basis, operators have saved more than 86,180,000 kg [190 million lbm] of proppant compared with what would be used in conventional treatments. This corresponds to about 7,000 fewer road trips and about 900 fewer railroad trips hauling proppant to the wellsites. Accordingly, diesel fuel consumption declined by about 283.9 m³ [75,000 galUS], and CO₂ emissions dropped by about 725,750 kg [1.6 million lbm].

The scope of the HiWAY service is still expanding. For example, engineers are looking for ways to broaden the types of reservoirs for which the technique is applicable. Field experience has demonstrated that the initial guideline for the ratio between the formation Young’s modulus and the closure stress was too conservative. The limit has been reduced from 1,000 to 350, thereby opening HiWAY service to a wider range of formations, particularly shales.

The initial success with horizontal wells in the Eagle Ford formation led scientists to perform additional modeling and experimental work to tailor the HiWAY technique to a deviated well environment. As a result, horizontal wells account for 69% of the treatments performed to date. Work has also begun to extend HiWAY service from a cased hole to an openhole environment. As operators perform the technique successfully in a wider range of well types, it is conceivable that discontinuous proppant packs will become standard industry practice. —EBN