On a warm summer evening in South Texas, a Schlumberger hydraulic fracturing fleet works at an Eagle Ford shale wellsite south of San Antonio. Image: Schlumberger.
Flow-channel fracturing raises production in the Eagle Ford

Studios in the Eagle Ford shale show that flow-channel fracturing delivers gains in oil and gas production and recovery while reducing water and proppant usage.

JOHN THOMPSON and ALEJANDRO PEÑA, Schlumberger

In the five years since the industry first set its sights on the Eagle Ford shale, the play has emerged as one of the world’s most prolific oil- and gas-producing regions, with thousands of horizontal wells now operating across a wide swath of South Texas. Advances in hydraulic fracturing methods have been pivotal to this success. Among the most important innovations is a hydraulic channel-fracturing technique that creates a network of open channels, or pathways, inside the fracture, optimizing connectivity to the reservoir and significantly improving fracture conductivity while using less proppant and water.

The HiWAY flow-channel fracturing technique has proved to be highly effective in unlocking the Eagle Ford, starting with a single well in 2010 that is still producing today. That initial success has since been repeated in more than 1,000 liquid- and gas-producing wells in the Eagle Ford, which have provided well production data for a unique and far-reaching study, conducted over a multi-year period. Findings document that wells stimulated with this technique perform better than those stimulated with conventional treatments short-term, and, more significantly, over an extended period of time. The incremental production, and the savings realized by the reduced use of water and proppant, have translated into billions of dollars of enhanced value for Eagle Ford operators.

Hydraulic fracturing relies on filling a fracture with proppant, to create a continuous proppant pack. The proppant pack stabilizes and holds the fracture open, providing a porous medium through which hydrocarbons can flow, from the formation to the well. The technique, which has been used by the industry for decades, emerged from its niche about 20 years ago, when it was adapted for multistage horizontal fracturing operations in low-permeability reservoirs, such as shales and tight sandstone and carbonate fields across North America.

Over the years, the industry has improved hydraulic fracturing technology through the development of sophisticated, robust proppant materials and water-based fracturing fluids, from low-viscosity (slickwater) to highly viscous, polymer-laden cross-linked fluids and hybrid formulas. Fluid formulations are tailored to promote proppant transport and placement throughout the fractures that are induced hydraulically to render them conductive for oil and gas. The introduction of chemical breakers further improved conductivity by decomposing molecular structures that thicken the fluids and reduce the amount of residue left in the fracture.

Despite these developments, significant technical opportunities remain for stimulation treatments being pumped today, for unconventional hydraulic fracturing operations. It has been understood, and agreed by the industry, that only the effective portion of the fracture (or stimulated reservoir volume) matters to production and well performance. Rigorous production modeling exercises indicate that only 30% to 40% of the average hydraulic fracture length that is created contributes to production, in most cases. Conventional fracturing treatments and techniques have limited capacity to transport proppant across the fractured networks. Most proppant accumulates near the wellbore region. Many fractures that are open initially, beyond the near-wellbore area, eventually close, due to lack of proppant placed within. Also, as hydrocarbons are drained, closure pressure on the fractures increases, and the effective conductivity of the fractures diminishes as the proppant packs are compressed.

Recognition of those limitations led to the application in unconventional reservoirs of flow-channel fracturing, which is based on the concept that proppant can be: a) transported more effectively across the fractured network with the use of fibers; and b) placed discontinuously, or intermittently, to engineer a network of open channels within the proppant pack, itself. This technique provides a highly conductive pathway for the flow of fluids, which

More than 90% of fracturing operations currently performed by Schlumberger in the Eagle Ford shale apply the HiWAY flow-channel fracturing technique with the goal of increasing well production, making more effective use of proppant and water. Image: Schlumberger.
renders higher residual effective fracture conductivity over time. The approach had been used previously to stimulate vertical wells in conventional sandstone reservoirs, and to improve production in vertical wells, in heterogeneous tight gas reservoirs.

ENHANCED TRANSPORT/NON-UNIFORM PLACEMENT

In 2010, Schlumberger introduced the HiWAY flow-channel fracturing technique, after five years of laboratory and field testing for its qualification. Job execution and well performance data, from thousands of wells worldwide, show that the approach results in average initial and long-term well productivity, and flowing pressures that consistently meet or exceed those of wells stimulated with conventional treatments. Experience also shows that this technique contributes to a low occurrence of near-wellbore screen-outs, or early job terminations, as it mitigates excessive accumulation of proppant in the near-wellbore area, and enhances transport of proppant within the formation.

The flow-channel fracturing treatment fundamentally changes the way proppant fractures generate conductivity by promoting the formation of stable voids within the proppant pack. These voids serve as highly conductive channels, for transporting oil and gas throughout the fracture. Instead of flowing through the proppant pack, the hydrocarbons move through the channels, between pillars of proppant that are created, resulting in an infinite degree of flow capacity.

The key to the technique’s effectiveness is the use of non-uniform proppant placement, achieved by implementing a pumping protocol whereby proppant-laden fluid, or slugs, and proppant-free fluid are delivered in alternating, short pulses. Throughout the operation, degradable fibers are added to mitigate the dispersion of the proppant-filled pulses, as they move throughout the surface equipment and casing, along the lateral and throughout the fractures.

The fibers also strengthen the system’s proppant-moving capacity, by transporting the proppant farther into the formation and reducing its settling within the fracture, a phenomenon that can result in narrow fracture width, and a reduction in the number and quality of the channels. This capability maintains the heterogeneous placement of proppant and optimizes vertical coverage of the fracture. Intermittent pumping of the proppant-free and proppant-filled slugs also provides the dual benefit of reducing the amount of proppant, and preventing proppant from accumulating in the near-wellbore area, mitigating the risk of screen-outs.

The introduction of the flow-channel fracturing technique occurred at the same time as the Eagle Ford shale was starting to be developed. The play sits in an Upper Cretaceous formation, which extends about 50 mi wide and 400 mi long, from the Maverick basin and San Marcos Arch to the East Texas basin. The region is geologically heterogeneous, with the northern regions rich in liquids, while the section to the south features predominantly gas reservoirs. The predominantly calcareous formation has a carbonate rock content greater than 70%, and clay content of about 10%.

FROM SLICKWATER TO FLOW-CHANNEL FRACTURING

One of the earliest, and most active, production areas in the Eagle Ford is Hawkville field, a predominantly limestone section with 100 to 600 nanodarcy permeability and 7% to 10% total porosity. Nearly all of the initial stimulation treatments in the field were done with slickwater, with an average of 12 stages pumped per well. Each stage involved pumping at high rates, typically 60 bbl-to-100 bbl/min., between 13,000 bbl and 18,000 bbl of low-viscosity fracturing fluid, and 200,000 lb to 400,000 lb of natural sands at concentrations of 0.5 lb to 3 lb of proppant added per gal (ppa).

As laterals in the Eagle Ford became longer, operators began implementing hybrid treatments, which delivered modest production enhancement, but reduced fluid volumes per well significantly over slickwater treatments. An average 16 stages per well were stimulated, each stage requiring 6,500 bbl to 8,500 bbl of fluid, and 200,000 lb to 400,000 lb of natural sands at 0.5 ppa to 4 ppa.

The first application of the flow-channel fracturing technique in the Eagle Ford shale was in October 2010, on a horizontal dry gas well in Hawkville field, in LaSalle County near Cotulla, Texas (well Heim 2H, API # 42-283-32314). In a comparison study, with three offset wells stimulated with slickwater that were identified prior to the treatment of this well, as a reference for performance, the flow-channel fractured well has demonstrated markedly better production performance over a 4.5-year period, Fig. 1.

The subject well has rendered over 4 Bcf, whereas the referential offsets have rendered about 2.5 Bcf over such period. A modeling study normalizing results from these wells over their first six months of production rendered a 51% average increase in output. Importantly, this well was treated with the lowest amount of water, and with less proppant than one of the offsets.

50-WELL STUDY

Based on the success of the initial trials, a subsequent 50-well comparative field study was launched, between October 2010 and February 2011, over a broader section of Hawkville field encompassing LaSalle and McMullen counties. In this case, 30
wells had been treated with a slickwater fracturing method, eight had been completed with a hybrid method, and 12 wells were stimulated, using the flow-channel fracturing technique. The wells, a mix of dry gas and gas condensate, provided a statistically significant representation of early production rates over a 90-day period, and were later assessed over a one-year period, Fig. 2.

In both cases, the ratios of cumulative production per unit of lateral length, fracturing fluid volume and proppant usage were included, to take into account the relative effects of the completion and stimulation techniques. Throughout the study, average production was consistently higher for the flow-channel fractured wells, both when looking at overall production, and also when the numbers are normalized by lateral length, and by the amount of water and proppant usage.

For all completion techniques, a distribution of cumulative production results was observed, for which the data were analyzed probabilistically. All samples exhibited good correlation with a Gaussian log-normal distribution, as evidenced by relatively good linear correlations in the log-probability plot shown in Fig. 2 for one-year cumulative production. The progression of datasets from left (slickwater) to middle (hybrid) to right (flow-channel fracturing) indicates improved overall performance by completion technique from worst to best, in that order. The same trends were observed at 90 days.1 Importantly, the average cumulative production at 90 days, for the wells completed with the flow-channel fracturing technique, was 32% and 67% higher than those of the datasets for hybrid and slickwater completions, respectively. After one year, such differences had increased to 34% and 91%, respectively. Therefore, the flow-channel fracturing technique mitigated production decline more effectively than conventional techniques, leading to higher oil and gas recovery.

On average, the wells completed with the flow-channel fracturing technique required the least amount of proppant and water, with respect to wells completed with conventional hybrid or slickwater methods. The technique enabled more efficient utilization of resources for these hydraulic fracturing operations.

Rigorous single-well modeling studies performed on Eagle Ford wells, including several wells from the studies referred to above, show that enhanced effective fracture half-length increases by more than 30%, and fracture conductivity increases by more than 40% with the use of the flow-channel fracturing technique.2 These benefits are consistent with improved proppant transport, due to the use of fibers and heterogeneous proppant placement, enabling a secondary, but dominant, conductivity mechanism—flow through open channels within the hydraulic fracture.3,4 With better proppant distribution within the reservoir and much higher initial average conductivity, and with the same percentage of conductivity reduction during the production period, output from wells fractured with the flow-channel fracturing technique holds up longer, which generates better long-term well performance, and oil and gas recovery.

**Fig. 2.** Cumulative hydrocarbon production for 50 wells stimulated in Hawkville field. Image: Schlumberger, data source Ref. 1 and IHS Enerdeq.

**Fig. 3.** Plot showing widespread utilization of the HiWAY flow-channel fracturing technique in the Eagle Ford. The amount of wells completed with the HiWAY technique in this shale play now numbers over 1,000 and shows increased production, with more efficient utilization of water and proppant. Image: Schlumberger, data source IHS Enerdeq.

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**EXPANDING THE ANALYSIS**

The evaluation of the flow-channel fracturing method has expanded into a field-wide study, to include production performance and treatment size from a public database that comprises more than 11,000 horizontal wells between October 2010 and December 2014.

One study involved a direct comparison of the best three-month barrels of oil equivalent per day (B3 boed) and the best 12-month (B12 boed) production performance, on 621 flow-channel fractured wells and 6,074 conventional wells, to
assess both the short-term and long-term effectiveness of the flow-channel fracturing method, compared to conventional treatments. These are all the wells listed in the database with at least 12 months of production.

The flow-channel fractured wells outperformed the conventional wells, short-term, by 33%, with an average 716 B3 boed, as compared to an average 537 B3 boed. The flow-channel fractured wells also outperformed conventional wells in the long term, averaging 460 B12 boed, 38% more than the conventional wells, which averaged 334 B12 boed. In regard to water and proppant utilization for the same sample, wells completed with the flow-channel fracturing technique utilized 32% less water and 37% less proppant than those completed using conventional fracturing methods, Fig. 3.

A different type of analysis was conducted to highlight the overall incremental impact that the flow-channel fracturing method has on production and revenue. This study involved 1,024 HiWAY wells and 8,566 conventional wells over a 3¼-year period (October 2010 to June 2014). These included oil, gas condensate and dry gas wells. The year-on-year average production difference shows the flow-channel fracturing method performed 40% better than conventional treatments. During this period, the 1,024 flow-channel fractured wells produced 176 MMboe.

Had these wells been treated conventionally, the estimated cumulative production would have been 126 MMboe. This equates to an incremental 50 MMboe, due to the implementation of flow-channel fracturing. The incremental production generated an additional $2.9 billion, or 37%, increase in gross revenue—$10.6 billion for flow-channel fractured treatments versus $7.8 billion for conventional treatments, Fig. 4.

In a more extensive evaluation to assess water and proppant usage, Schlumberger looked at well data over a 4¼-year period, from October 2010 through December 2014. Overall, flow-channel fractured wells used 39% less proppant and 33% less water compared to conventionally-treated wells. This led to savings of 2.7 billion lb of proppant and 2.1 billion gal of water on 1,146 flow-channel fractured wells. The savings in fluid and proppant use allowed completion of 564 to 730 additional flow-channel fractured wells from water and proppant savings, respectively, Fig. 5.

These Eagle Ford studies comparing the performance of flow-channel fracturing with conventional stimulation methods provide a comprehensive and long-term analysis that goes far beyond the scope of typical production performance studies. The in-depth analysis paints a compelling picture, demonstrating the effectiveness of the flow-channel fracturing technique to optimize reservoir connectivity and enhance both short- and long-term production while reducing environmental footprint through reduction of proppant and water requirements.

The flow-channel fracturing method has expanded to other unconventional U.S. and international shale plays, enabling the use of local sands instead of more costly proppants for effective well stimulation. The technique has also expanded to comprise use of low and high viscous fluids that can be formulated with all practical water sources. 

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JOHN THOMPSON is a technical advisor for Schlumberger PetroTechnical Geoscience & Petroleum Engineering Services in North America, based in College Station, Texas. He has 30 years of industry experience with production, completion, and stimulation optimization in conventional and unconventional reservoirs. Mr. Thompson has authored/co-authored more than 20 technical publications in his career. His focus in recent years has been on integrated reservoir projects in shale basins, encompassing single-well to field-wide studies, to optimize field development and maximize the value of the operations. Mr. Thompson holds a BA degree in marketing and management from Southwest Texas State University and a BS degree in petroleum engineering from Texas A&M University.

DR. ALEJANDRO PEÑA is the integrated completion services manager for Schlumberger, overseeing the global development, integration and implementation of well stimulation technologies. These include breakthrough hydraulic fracturing technologies for efficient and responsible recovery of hydrocarbons from unconventional reservoirs. He previously held operational, engineering and technology management positions with Schlumberger in South and North America. Dr. Peña is an inventor with nine granted patents, and he has authored 30 publications on interfacial phenomena and reservoir stimulation technologies. He holds a BS degree in chemical engineering from Universidad de Los Andes, and earned his PhD in chemical engineering from Rice University in Houston, Texas, where he attended as a J. W. Fulbright scholar.