Unlocking the Potential of Unconventional Reservoirs

Hydraulic fracturing treatments are performed to create a highly conductive flow path from the reservoir to the wellbore. Maximal effectiveness requires stimulating all perforations in the treated interval. However, achieving such coverage is challenging in unconventional reservoirs because fracture initiation pressures can vary widely within the perforated interval. A new fracturing service that employs a novel diverting agent improves production from established fields and allows operators to develop areas that previously were not economically viable.

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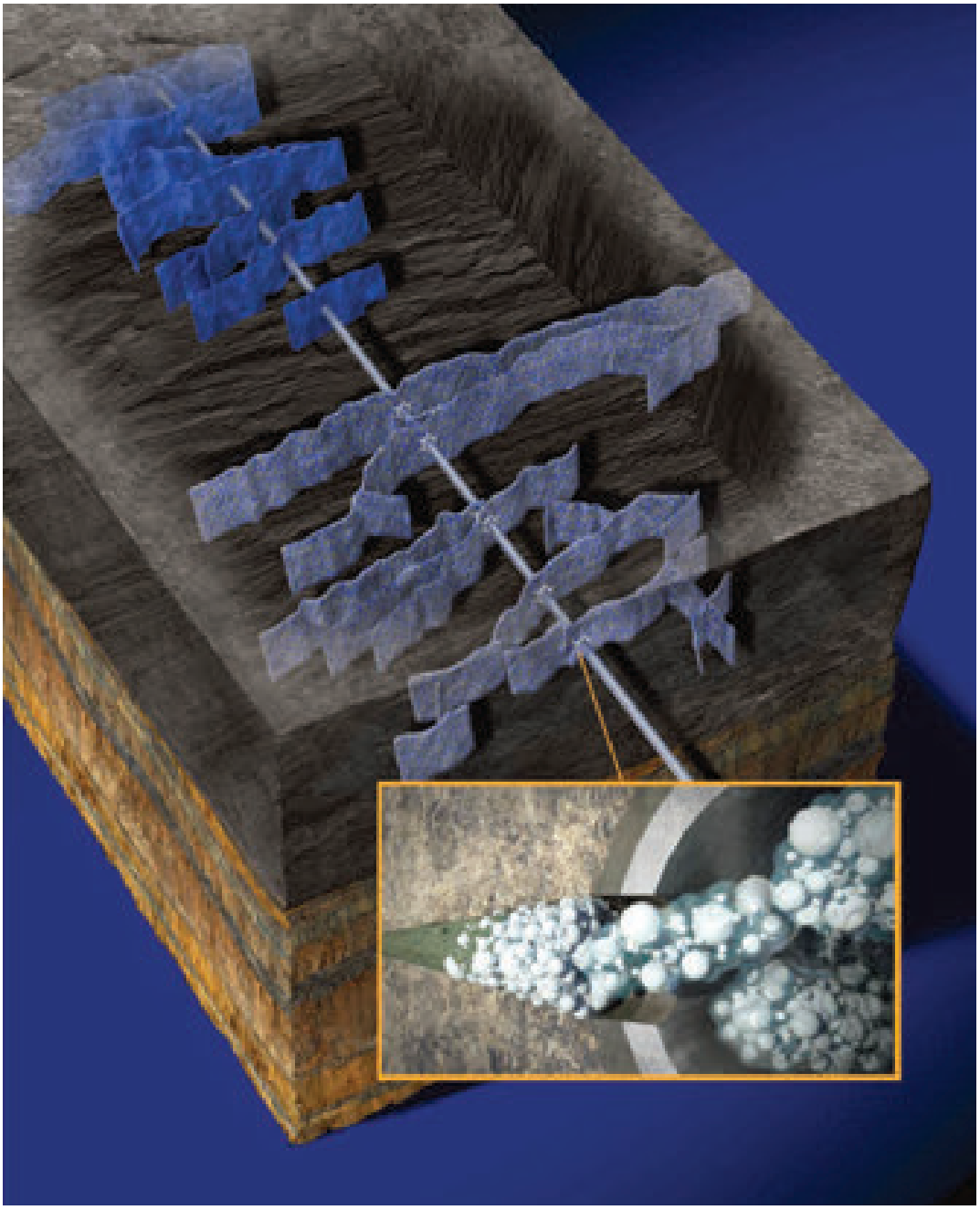
For decades, the oil and gas industry has performed hydraulic fracturing to enhance or prolong well productivity. Without fracturing, producing from many hydrocarbon reservoirs being developed today would not be technically or economically feasible.

During a fracturing treatment, specialized equipment pumps fluid into a well faster than it can be absorbed by the formation, causing pressure on the formation to rise until the rock fractures, or breaks down. Continued pumping causes the fracture to propagate away from the wellbore, increasing the formation surface area through which hydrocarbons can flow into the wellbore and helping the well achieve a higher production rate than would otherwise be possible. As a result, the volume of produced hydrocarbons increases dramatically, and operators recover their development investment costs more quickly.

Fracturing operations employ two principal substances—proppants and fracturing fluids.[1] Proppants are particles that hold the fractures open, preserving the newly formed pathways. Fracturing fluids may be aqueous or nonaqueous and must be sufficiently viscous to create and propagate a fracture and also transport the proppant down the wellbore and into the fracture. Once the treatment ends, the fracturing fluid viscosity must decrease enough to promote rapid and efficient evacuation of the fluid from the well.

Traditional fracturing treatments consist of two fluids. The first fluid, or pad, does not contain proppant and is pumped through casing perforations at a rate and pressure sufficient to break down the formation and create fractures.[2] The second fluid, or proppant slurry, transports proppant through the perforations into the newly opened fractures. When pumping ceases, the fractures relax, holding the proppant pack in place, and the fracturing fluids flow back into the wellbore to make way for hydrocarbon production. Ideally, the proppant pack should be free of stimulation fluid residue that can impair conductivity and hydrocarbon production.

For more than 60 years, chemists and engineers have sought to develop fracturing fluids, proppants and placement techniques that help produce ideal propped fractures and maximize well productivity. As a result, the chemical and physical nature of fracture fluids has evolved significantly. The industry has developed essentially residue-free fluids; an example is the ClearFRAC family of polymer-free fracturing fluids.[3] Heterogeneous proppant packs have further enhanced proppant pack conductivity, exemplified by the HiWAY flow-channel hydraulic fracturing technique.[4]



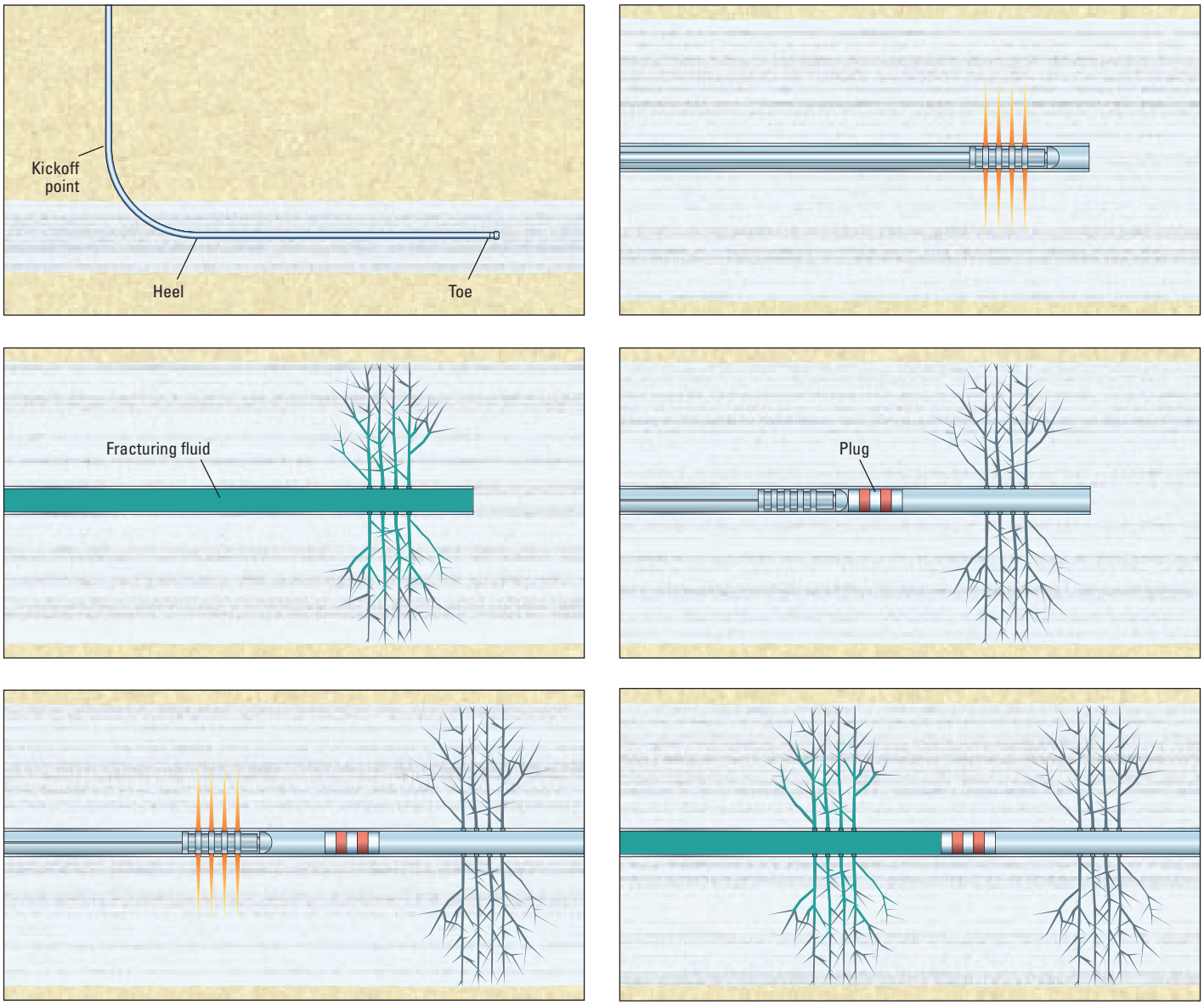
Today's proppant packs pose little resistance to fluid flow. However, achieving optimal well productivity still requires that the fracturing fluid be able to enter all of the perforations, thereby allowing maximal wellbore access to the region to be stimulated. Failure to do so may leave a large fraction of the reservoir untouched and, consequently, large volumes of hydrocarbons inaccessible.

Treating all perforations is particularly challenging when stimulating shale formations.[5] Most operators produce from horizontal wellbores that may extend for hundreds of meters through the producing formation. Therefore, to ensure adequate stimulation, completion operations are performed in steps during which the well is divided into multiple intervals and treated in stages.

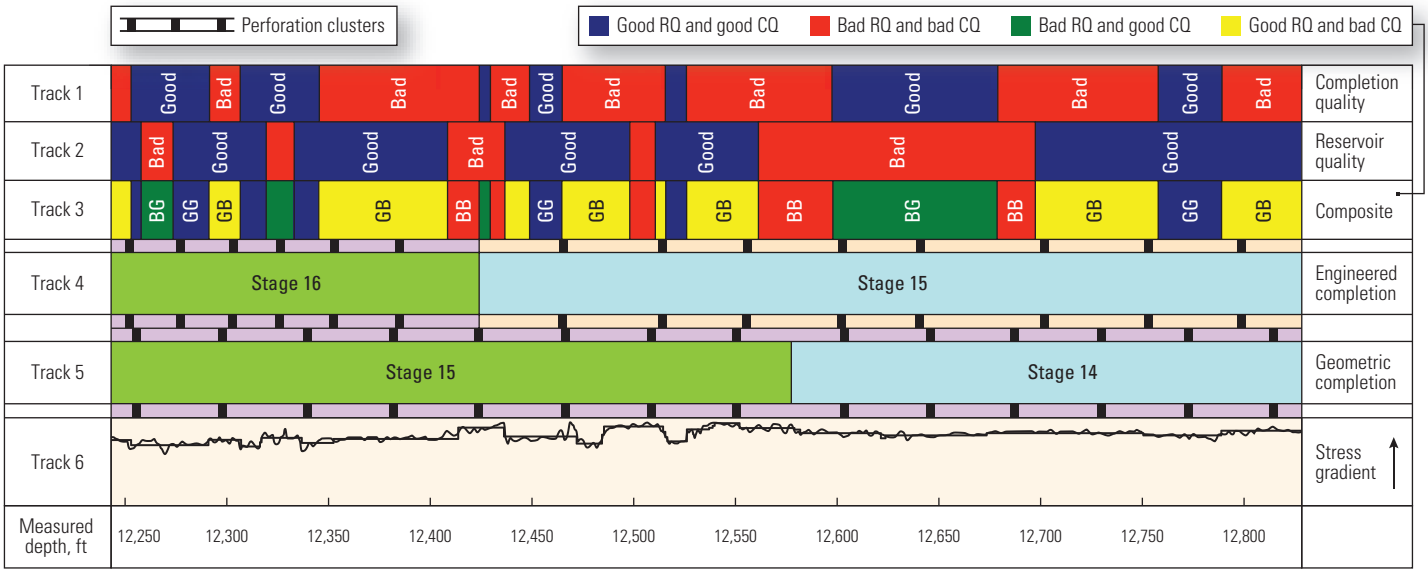
1. For more on fracturing fluids and proppants: Gulbis J and Hodge RM: "Fracturing Fluid Chemistry and Proppants," in Economides MJ and Nolte KG (eds): *Reservoir Stimulation*, 3rd ed. Chichester, West Sussex, England: John Wiley & Sons, Ltd. (2000): 7-1–7-23.
2. Perforations, holes created in the casing by guns equipped with explosive shaped charges, produce tunnels through the casing and cement sheath to provide communication between the casing interior and the producing reservoir.
3. Chase B, Chmilowski W, Marcinew R, Mitchell C, Dang Y, Krauss K, Nelson E, Lantz T, Parham C and Plummer J: "Clear Fracturing Fluids for Increased Well Productivity," *Oilfield Review* 9, no. 3 (Autumn 1997): 20–33.
4. d'Huteau E, Gillard M, Miller M, Peña A, Johnson J, Turner M, Medvedev O, Rhein T and Willberg D: "Open-Channel Fracturing—A Fast Track to Production," *Oilfield Review* 23, no. 3 (Autumn 2011): 4–17.
5. Unconventional formations include those characterized by pores that are insufficiently connected to allow oil and natural gas to move naturally through the rock to the wellbore. Economically extracting hydrocarbons from such formations requires operators to drill horizontal wells through the producing interval and perform hydraulic fracturing treatments, thereby maximizing wellbore access.

Operators frequently employ a stimulation method known in the industry vernacular as the "plug-and-perf" technique (below).[6] After the wellbore has been drilled, cased and cemented, engineers run a perforating system inside the casing toward the farthest extremity of the well—the toe. A first interval, up to about 100 m [330 ft] in length, is perforated and fractured. Next, the engineers set a plug inside the casing adjacent to the newly fractured interval to isolate the fractures from the rest of the well. A second stage is then perforated behind the plug, followed by a second fracturing treatment. This sequence may be performed many times until the entire horizontal portion of the well has been perforated and stimulated.

Traditionally, the length of each perforated interval has been the same throughout the well, and the plugs were equidistant. Such designs are called geometric completions. However, because shales are usually heterogeneous, engineers have begun using seismic and log data to determine formation mechanical properties and productivity potential along the wellbore. Operators then limit perforating and stimulation to potentially more-productive areas, forming optimized perforation clusters. This approach usually reduces the number of stages and plugs, thereby lowering costs without sacrificing well productivity (next page).[7] These designs are called engineered completions.



^ Plug-and-perf technique. Horizontal wells may extend hundreds of meters away from the vertical section of the wellbore. Most of the horizontal section of the well passes through the producing formation (gray) and is completed in stages. The wellbore begins to deviate from vertical (*top left*) at the kickoff point. The beginning of the horizontal section is the heel, and the farthest extremity of the well is the toe. Engineers perform the first perforating operation at the toe (*top right*) and follow it with a fracturing treatment (*middle left*). They then place a plug (*middle right*) in the well that hydraulically isolates the newly fractured rock from the rest of the well. A section adjacent to the plug is perforated (*bottom left*); another fracturing treatment follows (*bottom right*). This sequence may be repeated until the horizontal section is stimulated from the toe back to the heel. In a final step, a milling operation (not shown) removes the plugs from the well and allows production to commence.



^ Comparison of geometric and engineered completions. Geometric completions (Track 5) feature stages of equal length (full lengths of stages not displayed), and perforation clusters are evenly spaced. Engineered completions (Track 4) take reservoir quality (RQ) and completion quality (CQ) into account when determining the locations of perforation clusters. The Mangrove software analyzes the log data and assigns good (blue) or bad (red) ratings for both RQ and CQ (Tracks 1 and 2). The software uses the RQ and CQ grades to further determine a composite score (Track 3). The best locations have good RQ and CQ grades. In this example, Stage 15 of the engineered completion has been designed such that it spans a region with a fairly uniform stress gradient (Track 6). Furthermore, engineers avoided placing perforation clusters at locations where both RQ and CQ grades were bad.

Despite production improvements realized by the optimized cluster technique, fracture initiation pressures within an interval may still be highly variable, leading to uneven stimulation among the perforation clusters. Perforations adjacent to low–fracture gradient rock are preferentially stimulated, leaving those in more resistant rock untouched. When conventional fracturing methods are employed, up to 40% of the perforations may fail to contribute to production.[8]

Schlumberger chemists and engineers investigated the efficiency problem associated with stimulating shale formations with the goal of developing methods that tap elusive hydrocarbons and improve production results. Their efforts resulted in the development of the BroadBand Sequence fracturing service. This recently introduced service consists of pumping a unique diverting agent into a well between fracturing treatments.

This article tracks the development of the BroadBand Sequence approach from the laboratory to its introduction into the oil field. Case histories from the US and Mexico demonstrate the well productivity improvements and cost savings that have been achieved by applying this technique.

Sequenced Fracturing Technique

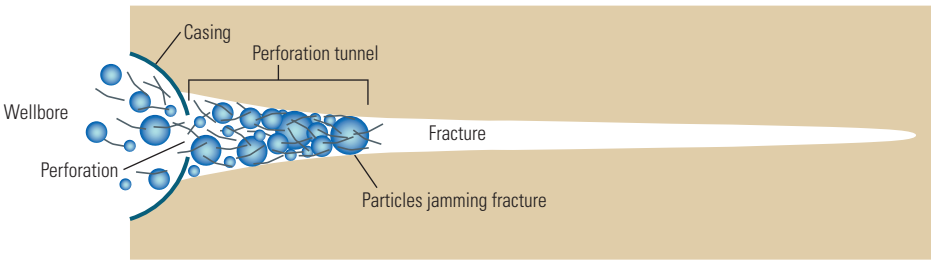
The traditional plug-and-perf completion method features one fracturing treatment, or stage, per interval. After the treatment, any unstimulated perforations are ignored as the operator proceeds to stimulate the next interval. Under these circumstances, the benefits of performing a second stage would be limited. The fracturing fluid would take the path of least resistance and flow into previously stimulated perforations.

Schlumberger engineers considered the possibility of following the first fracturing treatment with a pill containing a diverting material that would plug the initially stimulated perforations. They theorized that, during a second fracturing treatment, the fluid would be diverted away from the plugged perforations and into unstimulated perforations, thereby fracturing two distinct regions in an uninterrupted sequence and improving well productivity. However, restoring fluid flow through the initially stimulated perforations would require that the diverting material be degradable and removable.

Using diverting agents is a common practice in other oilfield operations such as matrix acidizing treatments. The agents plug the most permeable pores in the rock matrix, allowing acid to concentrate on less permeable areas.[9] For hydraulic fracturing, the diversion scale is much larger than that for matrix acidizing. The diverting agent must be able to plug fractures with near-wellbore widths between about 1 and 6 mm [0.04 and 0.24 in.]. In addition, for logistical reasons, the volume of the fluid containing the diverting agent must be minimized.

Building on knowledge acquired during the development of CemCRETE concrete-based oilwell cementing technology, the engineers knew that efficient plugging can be achieved when a fluid contains materials with a multimodal particle size distribution.[10] For example, a trimodal system may be designed such that the three sizes of the particle groups differ by approximately one order of magnitude. When the particles are mixed together, the small particles fit within the

6. Daneshy A: "Hydraulic Fracturing of Horizontal Wells: Issues and Insights," paper SPE 140134, presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA, January 24–26, 2011.
7. Ajayi B, Aso II, Terry IJ Jr, Walker K, Wutherich K, Caplan J, Gerdom DW, Clark BD, Ganguly U, Li X, Xu Y, Yang H, Liu H, Luo Y and Waters G: "Stimulation Design for Unconventional Resources," *Oilfield Review* 25, no. 2 (Summer 2013): 34–46.
8. Miller C, Waters G and Rylander E: "Evaluation of Production Log Data from Horizontal Wells Drilled in Organic Shales," paper SPE 144326, presented at the SPE North American Unconventional Gas Conference and Exhibition, The Woodlands, Texas, USA, June 12–16, 2011.
9. Asiri KS, Atwi MA, Jiménez Bueno OJ, Lecerf B, Peña A, Lesko T, Mueller F, Pereira AZI and Tellez Cisneros F: "Stimulating Naturally Fractured Reservoirs," *Oilfield Review* 25, no. 3 (Autumn 2013): 4–17.
10. Boisnault JM, Guillot D, Bourahla A, Tirlia T, Dahl T, Holmes C, Raiturkar AM, Maroy P, Moffett C, Perez Mejía G, Ramirez Martínez I, Revil P and Roemer R: "Concrete Developments in Cementing Technology," *Oilfield Review* 11, no. 1 (Spring 1999): 16–29.

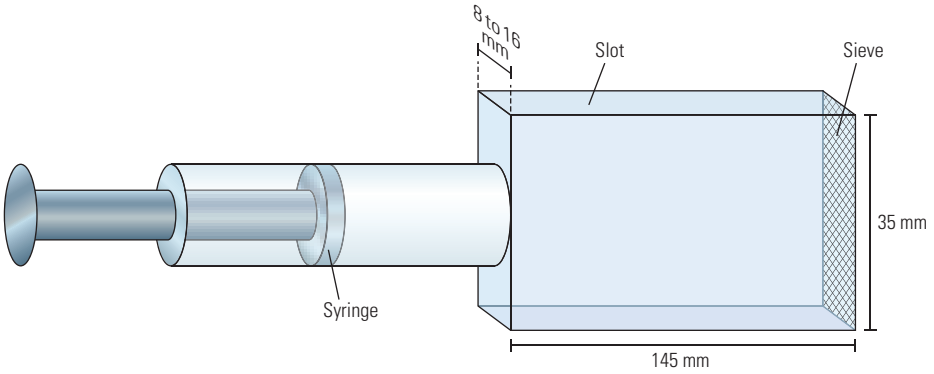


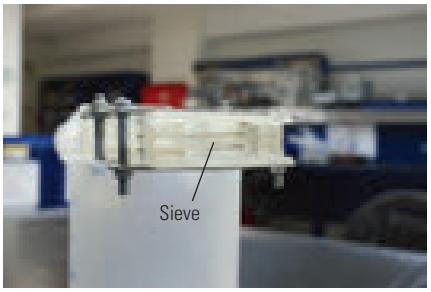
^ Fracture diversion concept. A multimodal composite fluid of degradable particles (blue spheres) and fibers forms a plug in a fracture. Ideally, the large particles do not bridge at the perforation entrance but quickly become lodged in the near-wellbore region of the fracture. A low-permeability plug forms as the smaller particles congregate in the interstices of the larger ones.

interstices of the medium-size particles, and the medium-size particles fit within the interstices of the large particles. As a result, a low-permeability plug may readily form in a fracture (above).

Using this packing principle, researchers performed diversion tests in the laboratory with a simple benchtop device consisting of a syringe connected to a slot whose width could be adjusted between 8 and 16 mm [0.31 and 0.63 in.] (below).[11] They placed a screen sieve at the end of the slot with openings that were about 0.5 mm [0.02 in.] smaller than the diameter of the largest particles but larger than those of the smaller particles. Thus, the slot and screen simulated a perforation tunnel and a fracture entrance.

Engineers varied the sizes and relative concentrations of the particles. The test slurries, called composite fluids, were prepared from a guar gum solution in water. The solutions contained multimodal mixtures of degradable particles whose sizes varied between a few microns and several millimeters.







^ Benchtop device for experiments to optimize the particle size distribution of diverting agents. The apparatus consists of a 60-mL [3.7-in.^{3}] syringe (*top*) connected to a rectangular slot whose width can be adjusted between 8 and 16 mm [0.31 and 0.63 in.]. The slot is analogous to a perforation tunnel. A sieve (*bottom left*), located at the far end of the slot, simulates the fracture entrance. During an experiment, a test slurry, or composite fluid, flows from the syringe into the slot and then through the sieve. Flow continues until the sieve becomes plugged with particles (*bottom right*). Technicians measure the volume of filtrate that passed through the sieve before plugging occurred. Low filtrate volumes are preferred. (Adapted from Kraemer et al, reference 11.)

For optimal cleanup after a diversion treatment, confining the degradable polymer plug to the near-wellbore region is usually considered the best strategy. Therefore, engineers sought to identify composite fluids that had the ability to plug the screen quickly and minimize the volume of filtrate entering fractures. After determining the most efficient particle size distribution, they learned that the composite fluids needed to contain degradable fibers to prevent particle segregation or size classification during pumping.

After placement in a fracture, the plugging material must remain intact during the time required to complete a fracturing stage—typically about four hours. To verify that the candidate compositions met this requirement, engineers built a bridging apparatus that could simulate downhole temperature and pressure conditions (next page, top). The apparatus consisted of an accumulator, a chromatography pump and a 3.4-mm [0.13-in.] slot to simulate a fracture.[12] Technicians placed the composite fluid in the accumulator and pumped the fluid into the slot until a plug formed. The pump continued to pressurize the system for four hours at 8.3 MPa [1,200 psi]. Engineers attached heating tape around the slot, enabling testing at temperatures up to 95°C [203°F].

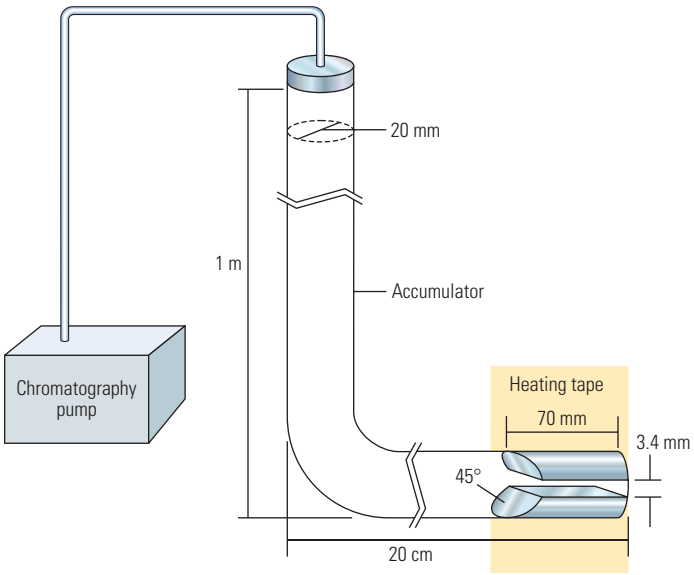
Most of the composite fluids that efficiently formed plugs during the initial syringe tests also demonstrated good plug stability. Few particles passed through the slot before plug formation, and no plug extrusion took place during the tests. Measurements showed that the permeability of the plugs was often too low to measure.

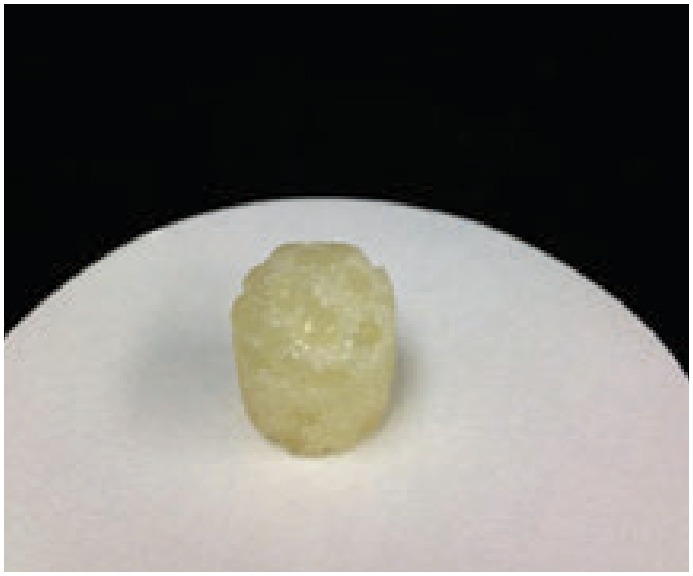
Having established that the composite fluid plugs were sufficiently resilient to withstand a fracturing stage, engineers needed to ensure that the plugs would degrade and clear the way for unobstructed hydrocarbon production. They were most concerned about the degradation rate of the large polymer particles.

Researchers performed aging tests during which they immersed the multimodal particle mixtures in water and measured polymer degradation versus time and temperature (next page, bottom). Complete polymer removal occurred within 10 days at temperatures higher than 90°C [194°F]. In many wellbore scenarios, water avail-

11. Kraemer C, Lecerf B, Torres J, Gomez H, Usoltsev D, Rutledge J, Donovan D and Philips C: "A Novel Completion Method for Sequenced Fracturing in the Eagle Ford Shale," paper SPE 169010, presented at the SPE Unconventional Resources Conference—USA, The Woodlands, Texas, April 1–3, 2014.

12. Chromatography pumps deliver fluids at accurate and precise rates. They are usually employed during high-performance liquid chromatography experiments.

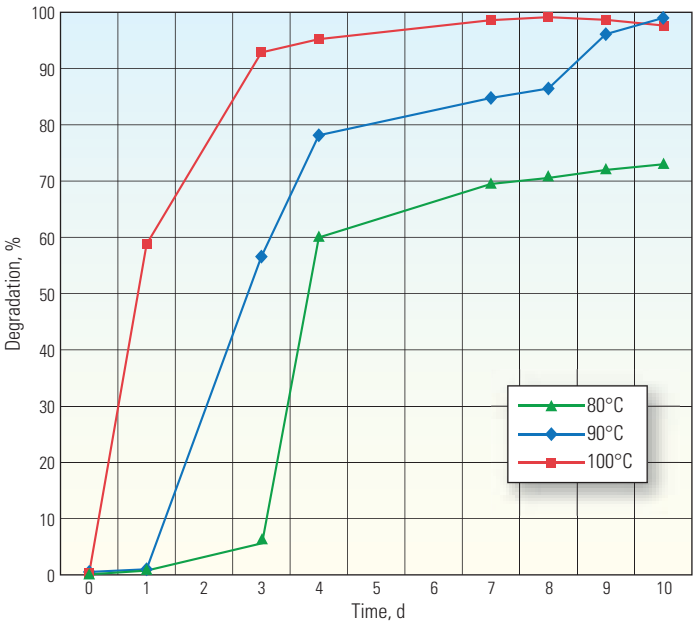


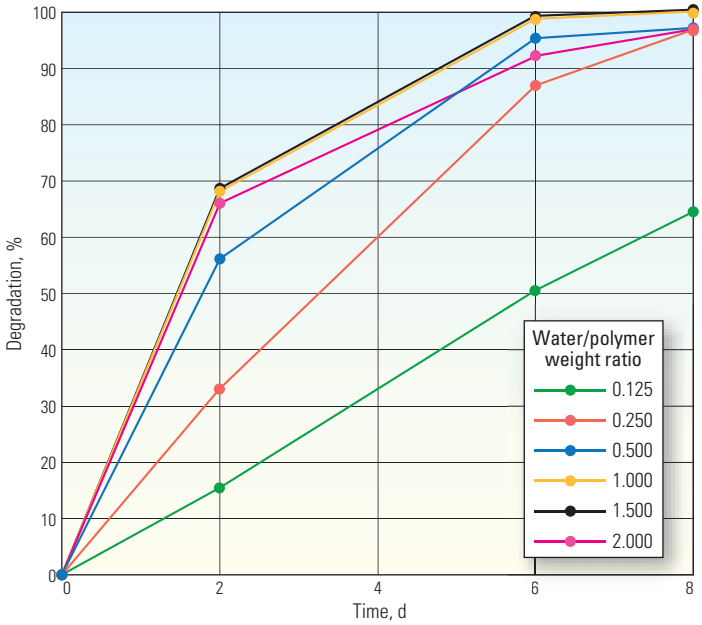


^ Diverter plug stability tests. Engineers constructed a laboratory-scale device (*left*) for determining whether plugs made from degradable particles could survive for at least four hours under downhole temperatures and pressures. A high-pressure chromatography pump forces composite fluid from an accumulator into a 3.4-mm [0.13-in.] slot that simulates a fracture. After a plug forms in the slot, the pump continues to pressurize the system for four hours at 8.3 MPa [1,200 psi]. The slot is surrounded by heating tape, allowing experiments to take place at temperatures up to 95°C [203°F]. During most tests, few particles exited the slot before a cylindrical plug formed (*right*), and no plug extrusion occurred.

ability may be limited; therefore, testing also included measuring the effect of the water-to-polymer ratio on the degradation rate. At water-to-polymer ratios higher than 0.125, complete polymer removal took place within 8 days at 90°C [194°F].

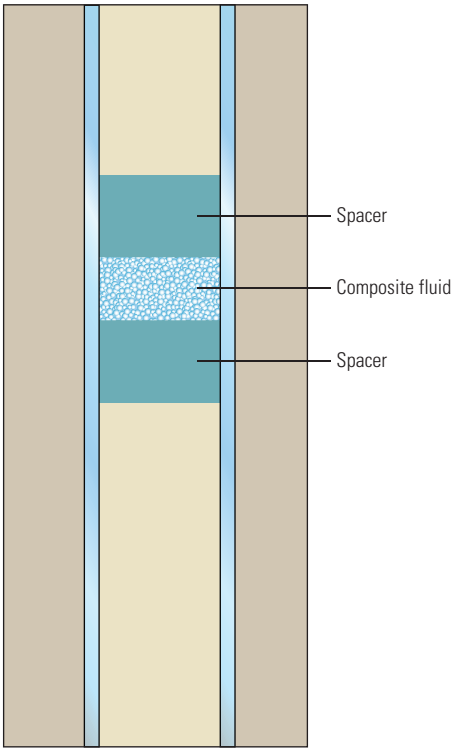
Laboratory testing demonstrated the feasibility of using degradable polymer particles for hydraulic fracturing diversion. The next task was



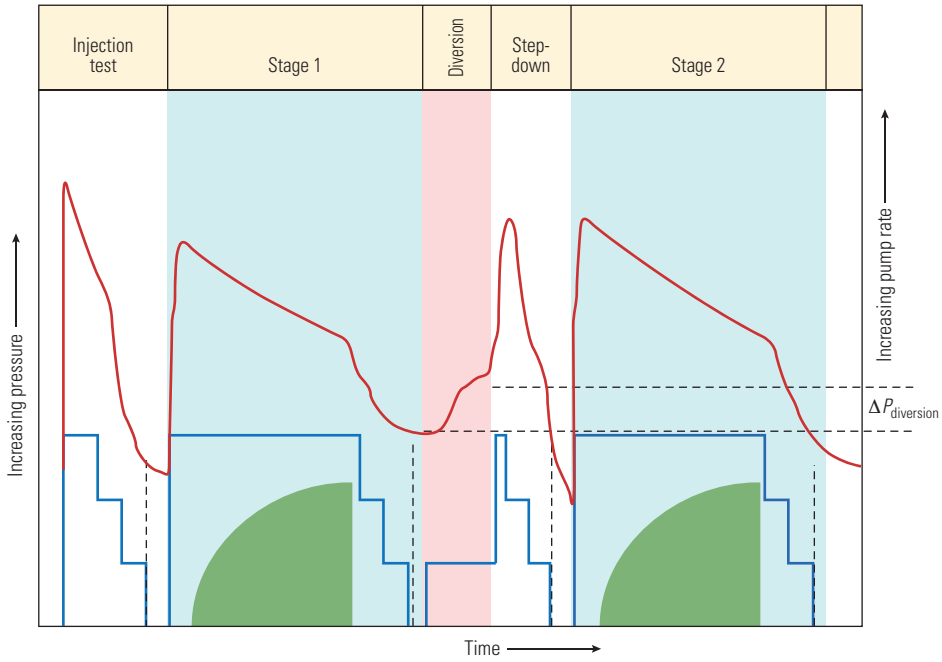


^ Diverting agent degradation tests. Researchers performed aging tests on diverter materials to evaluate the effectiveness of the treatments. Technicians placed specific amounts of multimodal polymer particles in 100-mL [3.4-oz] bottles filled with water. Next, they sealed the bottles and placed them in ovens at various temperatures. They then measured the amounts of solids remaining in the bottles versus time (*left*). Complete degradation occurred when 100% of the solids had disappeared. After 10 days, more than 70% of the solids had disappeared at 80°C [176°F]. Complete degradation had occurred within the same time period at 90°C [194°F] and 100°C [212°F]. A second series of tests investigated the effect of limited water availability on polymer degradation (*right*). Such a condition is possible in many wellbore scenarios such as dry gas wells. Technicians prepared samples at various water-to-polymer ratios, heated them at 90°C and measured the percent degradation after 2, 6 and 8 days. With the exception of the sample that had a ratio of 0.125, complete degradation occurred within 8 days. At present, three versions of the diverting agent exist, applicable across a temperature range between 38°C and 177°C [100°F and 350°F].





^ BroadBand Sequence diverter pill. The composite fluid of the diverter pill contains a multimodal mixture of degradable polymer particles (*top*). The particle sizes are between several microns and several millimeters. The pill consists of three parts (*bottom*). The diversion fluid containing the polymer particles is preceded and followed by a degradable fiber–laden spacer fluid. The spacers keep the diversion fluid intact as it flows through surface equipment and casing and prevents diversion-fluid contamination before it contacts perforations. The fluid viscosity should also be at least 20 mPa.s at a shear rate of 511/s to prevent particle bridging at the perforation entrances.



^ BroadBand Sequence pumping schedule. This schematic plot presents the timing and changes of surface pressure (red line) and pump rate (blue line) for a BroadBand Sequence treatment. First, engineers perform an injection test to verify that at least some of the perforations are able to receive fluid from the wellbore. The initial fracturing treatment, Stage 1, then commences, during which proppant (green) flows into the fractures. Next (pink), engineers pump a BroadBand Sequence composite fluid into the well. They record an initial surface pressure and monitor the pressure increase as the composite fluid flows into the well. The surface pressure levels off, indicating that the perforations treated during Stage 1 have been plugged. The difference between the final and initial pressures is the $\Delta P_{diversion}$. A step-down stage then commences, during which the pump rate is briefly increased to encourage further penetration of diverting material into the perforations, leaving the wellbore clear. The second fracturing treatment, Stage 2, is similar to the first. The pressure rise and decline indicates that additional perforations received fracturing fluid and new fractures were induced.

to scale up the technology and prove that it could be applied practically and economically in the field.

Designing and Delivering the Composite Fluid

The BroadBand Sequence service plugs perforations that were successfully treated during the first fracturing operation. To accomplish this consistently, engineers had to determine optimal composite fluid volumes and diverter material concentrations for various downhole scenarios. This task was a major challenge because no practical way exists to duplicate the downhole diversion environment in a laboratory setting. Engineers determined that testing in wells was the only way to proceed.

The Schlumberger researchers presented the BroadBand Sequence concept and laboratory data to several clients who agreed to allow experiments in their wells. Client engineers considered the risk low because if a well became plugged during an experimental treatment, the obstruction would be temporary owing to diverter material degradability. Before field testing could commence, engineers needed to determine how to prepare and deliver the composite fluid using existing field equipment.

Tests were performed to determine how a homogeneous and stable composite fluid could be mixed using existing equipment and to verify that the pill would remain homogeneous during transport from the mixing and pumping equipment to the well. Engineers validated a batch mixing technique using the tubs of standard Schlumberger cementing units. They also discovered that fiber-laden spacer fluids were necessary before and after the composite fluid to maintain pill stability and prevent contamination. Thus, the diverter pill consists of three parts (left).

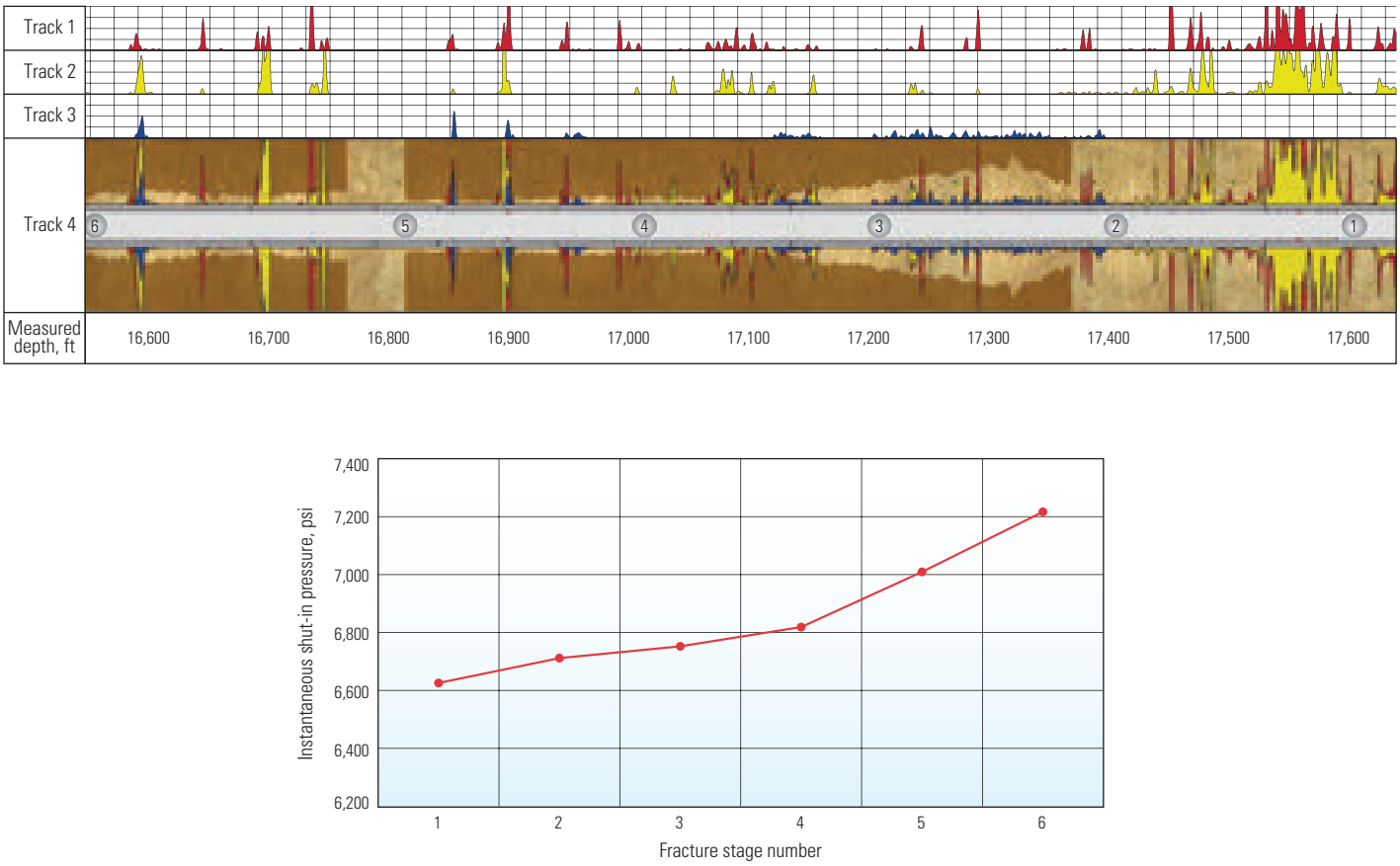
The particles larger than 4 mm [0.157 in.] were also a major concern for the members of the design team because they were uncertain if the large particles would be able to pass through the pump truck valves without causing damage. Engineers determined that a dedicated fracturing pump that had modified valves would be required for all BroadBand Sequence treatments.

Next, engineers assembled the equipment at client wellsites and initiated field testing. The principal objective was to establish guidelines for achieving diversion using composite fluids that had maximal diverter-material concentrations and minimal total volumes. Testing commenced based on an idealized pumping schedule (previous page, top right).

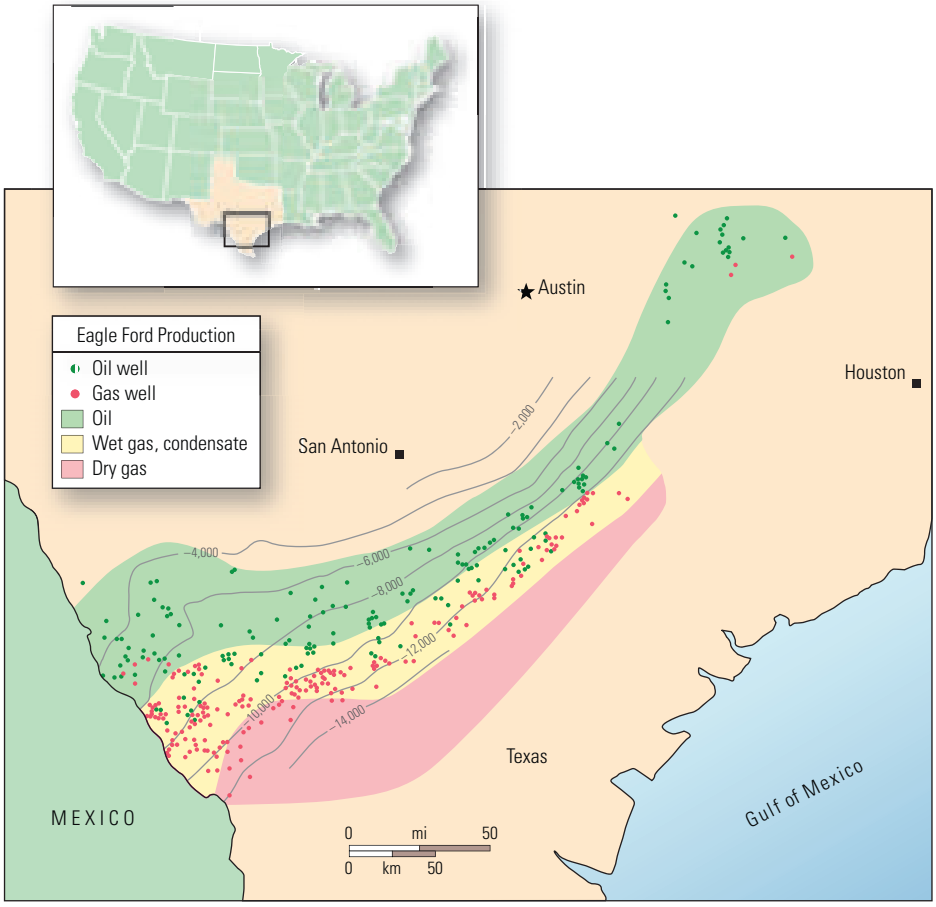
This scenario calls for engineers to perform an injection test then execute a first fracturing treatment and monitor the surface pressure. A pressure increase followed by a drop in pressure indicates that formation breakdown and fracture initiation have occurred. The surface pressure gradually declines during proppant placement. Pumping ceases before the BroadBand Sequence composite fluid is placed. The pressure rises during the composite fluid placement and begins to level off, indicating that previously stimulated perforations have been plugged. A second fracturing treatment is then performed, during which another pressure increase occurs, followed by a pressure drop, indicating that fracture initiation has occurred at the previously unstimulated perforations, allowing additional proppant placement. Subsequent diversion treatments may be performed until optimal stimulation has been achieved.

One series of treatments took place in south Texas, USA. Engineers treated a perforated interval with six fracturing stages separated by BroadBand Sequence composite fluids (below). Three radioactive tracer logs acquired during the treatments allowed personnel to verify the diversion and creation of new fractures. In addition, the operator recorded the ISIP after each fracturing stage. During this series of treatments, the volume of each diverter pill was 20 bbl [3.18 m^3], and the amount of diverting material varied from 50 to 75 lbm [23 to 34 kg]. The tracer logs indicated that the composite fluids were working as designed. The instantaneous shut-in pressure (ISIP) increased from 6,600 psi to 7,200 psi [44.5 to 49.6 MPa].

Schlumberger engineers formulated guidelines for the BroadBand Sequence service after the field trials. The composite fluid volume and diverter material concentration depend on the length of the treated interval and the number of perforations. The default formulation allocates 1.4 kg [3 lbm] of diverter material per perforation hole, and sufficient material is added to plug half of the holes. As an operator gains experience in a particular field, formulation adjustments may be made to optimize results.



^ BroadBand Sequence field test. During a field trial, engineers pumped six fracturing treatments into a perforated interval. Tracer logs were generated to analyze the results (*top*). Track 1 shows the results of an iridium log (red) after the first fracturing stage and before the first BroadBand Sequence pill was pumped. Track 2 is a scandium log (yellow), taken after the third fracturing stage. Evidence of fracture plugging may be seen at 16,950 ft, where no scandium had entered the previously created fracture. A third tracer log employing antimony (blue), measured at the end of the sixth fracturing stage, is shown in Track 3. The amount of diverting agent had been increased to 75 lbm [34 kg], and the log shows evidence of fracture plugging at 16,650 to 16,750 ft, 17,000 to 17,100 ft and 17,400 to 17,650 ft. New fractures appeared between 17,300 and 17,350 ft. Engineers also measured the instantaneous shut-in pressure (ISIP) following each stage (*bottom*). Following the BroadBand Sequence treatments, the ISIP increased, particularly after Stages 5 and 6. Track 4 presents another view of the tracer data, superimposed onto a lithology log. The lithology log, generated from gamma ray data, provides information about the relative clay content.



^ Eagle Ford Shale play. This formation, located in south Texas, USA, produces gas as well as relatively large volumes of oil and condensate. It is the source for the oil and gas found in the prolific Austin Chalk reservoir. Because the Eagle Ford has a high carbonate content, it is brittle and amenable to fracturing treatments. (Adapted from Kraemer et al, reference 11.)

Stimulating the Eagle Ford Shale

The Late Cretaceous-age Eagle Ford Shale formation underlies much of south Texas (above). The formation has an average thickness of 250 ft [76 m] at depths between 4,000 and more than 14,000 ft [1,200 and 4,300 m]. This formation became an active play in 2008 after the first horizontal well was completed using the plug-and-perf technique. By 2012, the Eagle Ford Formation had become one of the most prolific shale plays in the world.

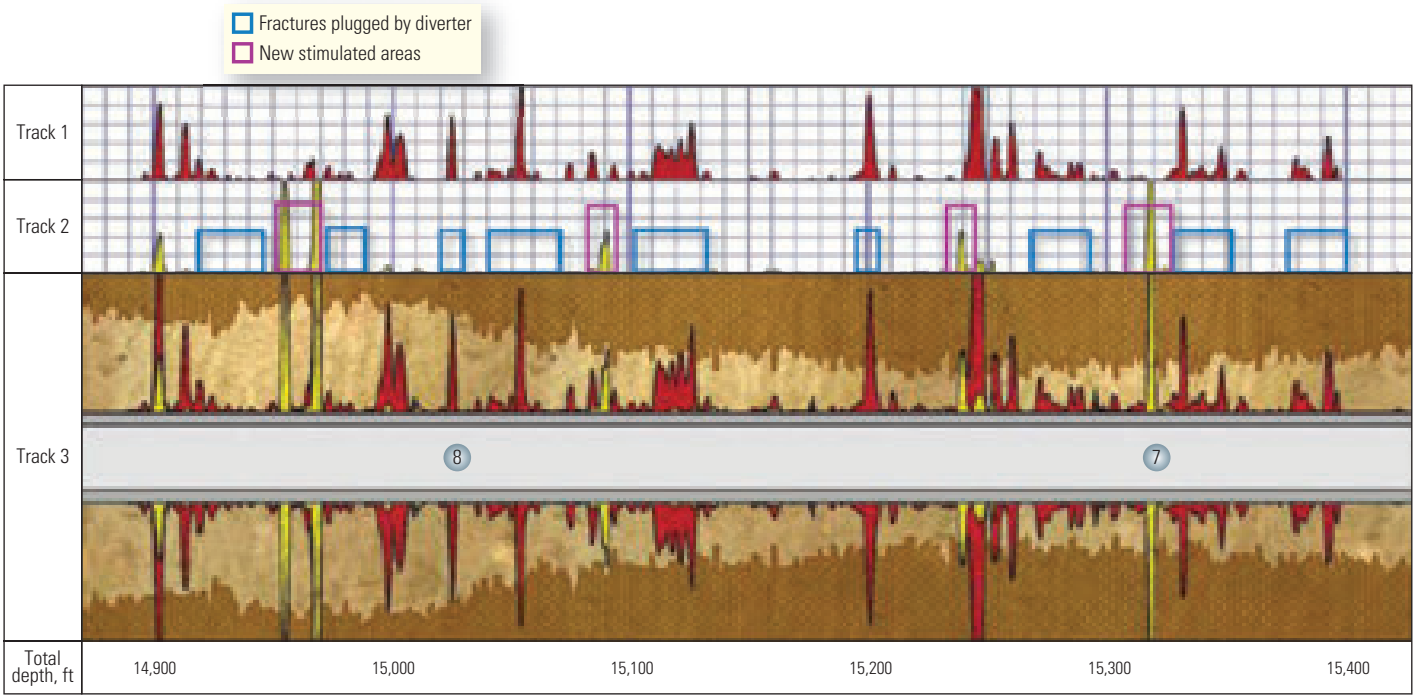
Initial fracturing treatments were performed at high pump rates using low-viscosity water-base fluids containing friction reducers. Proppant concentrations were usually lower than 3 ppa.[13] Completion practices in many wells changed in 2010 with the successful introduction of channel fracturing techniques such as the HiWAY service, which creates heterogeneous proppant packs.[14] The HiWAY method also features fiber-laden fracturing fluids that enhance proppant transport and reservoir coverage. Such fluids allow operators to increase the fluid viscosity and proppant concentrations, thereby reducing the volume of water required to perform a treatment.

Most wells in this region were stimulated using geometric completions. A recent study revealed that only 64% of the perforation clusters were contributing to overall production.[15] In an attempt to improve results, several operators increased the differential pressure across perforations by reducing the number of perforation clusters per stimulation stage. This approach required a higher number of wireline interventions to place additional bridge plugs as well as longer milling operations to remove the plugs. Not only did completion costs and times increase, but each intervention increased operational risks.

In view of the successful BroadBand Sequence field trial in the Eagle Ford Shale, BHP Billiton Petroleum opted to evaluate the service's impact on production.[16] The operator selected three wells from an eight-well, three-pad project for stimulation. The bottomhole static temperature was approximately 300°F [150°C], the average true vertical depth (TVD) was 12,000 ft [3,700 m] and lateral well lengths varied between 4,800 and 5,000 ft [1,460 and 1,520 m].

The completion design strategy for all wells on the pad included 300-ft [90-m] intervals with six perforation clusters spaced 50 ft [15 m] apart. The stimulation fluid and proppant volumes were equal in the BroadBand Sequence and offset wells. Engineers employed the HiWAY channel fracturing technique during all stages, using a borate-crosslinked guar fracturing fluid.

The operator performed conventional one-stage stimulation treatments in the offset wells, whereas the BroadBand Sequence treatment consisted of two fracturing events—each employing half the fluid volume of the offset treatments—separated by the composite diverter fluid. The treated interval lengths were equal, allowing a realistic comparison. Engineers



^ Tracer logs across a section of Eagle Ford Shale stimulated by the BroadBand Sequence technique. Two perforation clusters (7 and 8, Track 3) received two fracturing treatments. During the first fracturing treatment, indium tracer (Track 1, red) entered perforations in both clusters. After the BroadBand Sequence composite fluid, scandium tracer (Track 2, yellow), pumped during the second fracturing treatment, entered perforations that had been missed during the first treatment. The new fractures created during the second treatment are indicated by the presence of the scandium tracer. Track 3 presents the tracer data superimposed onto a lithology log. The lithology log, generated from gamma ray data, provides relative clay content.

monitored surface pressure during the treatments. The pump rate was 15 bbl/min [2.4 m^3/min] during placement of the composite fluid. The measured diversion pressures ($\Delta P_{diversion}$) during each stage varied from 143 to 3,700 psi [1.0 to 25.5 MPa].

Engineers acquired tracer logs to monitor the diversion arising from the BroadBand Sequence treatments (above). The logs showed that 80% of the stages experienced near-wellbore diversion. The operator also recorded ISIPs before and after each treatment stage for each well. Compared with offset wells that experienced an average net pressure gain of 263 psi [1.81 MPa], the wells treated by the BroadBand Sequence technique showed a pressure gain of 313 psi [2.16 MPa].

BHP Billiton engineers then measured production rates of all the wells and normalized the results according to the lateral length of each well. After 140 days, the BroadBand Sequence wells were 20% more productive than the conventionally treated offset wells. As a result, BHP Billiton has continued to employ the BroadBand Sequence service in this field.

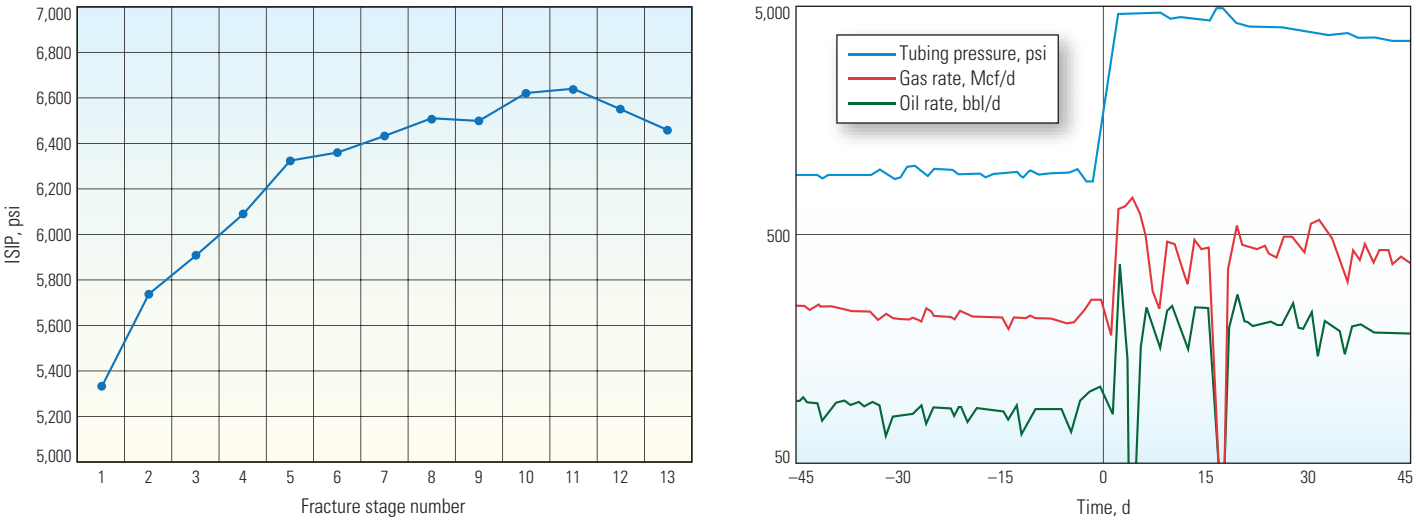
Remedial Stimulation in South Texas

Another Eagle Ford Shale operator has been engaged in restimulating older wells in the region. The company's goal is to accelerate and increase oil and gas recovery by reestablishing conductivity in old hydraulic fractures and stimulating new reservoir volume.

The wells are in the high-pressure, high-temperature (HPHT) category and have fracture gradients between 0.85 and 0.95 psi/ft [19.2 and 21.5 kPa/m], TVDs between 12,000 and 13,500 ft [3,700 and 4,100 m] and bottomhole temperatures between 300°F and 345°F [150°C and 174°C].

A key challenge for these refracturing operations is achieving effective stimulation along the length of the laterals—4,000 to 6,000 ft [1,200 to 1,800 m]. Since some of the perforations are

13. Proppant concentrations are commonly expressed in pounds of proppant added—abbreviated as ppa. One ppa is defined as one pound of proppant added to each gallon of fracturing fluid. There is no recognized SI equivalent to ppa.
14. Gillard M, Medvedev O, Peña A, Medvedev A, Peñacorada F and d'Huteau E: "A New Approach to Generating Fracture Conductivity," paper SPE 135034, presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, September 20–22, 2010.
15. Slocombe R, Acock A, Fisher K, Viswanathan A, Chadwick C, Reischman R and Wigger E: "Eagle Ford Completion Optimization Using Horizontal Log Data," paper SPE 166242, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 2, 2013.
16. Viswanathan A, Watkins H, Reese J, Corman A and Sinosic B: "Sequenced Fracture Treatment Diversion Enhances Horizontal Well Completions in the Eagle Ford Shale," paper SPE 171660, presented at the SPE/Canadian Society for Unconventional Resources (CSUR) Unconventional Resources Conference—Calgary, September 30–October 2, 2014.



^ Results of refracturing treatment. After each fracturing stage, engineers measured the ISIP (*left*). The progressive ISIP increase demonstrated the ability of BroadBand Sequence technology to reinvigorate a depleted well. The operator monitored the gas and oil production rates and the tubing pressure before and after the refracturing treatments (*right*). During the 45 days following treatment, the oil (green) and gas (red) production rates doubled, and the tubing pressure quadrupled (blue).

open, mechanical aids such as bridge plugs and mechanical packers cannot be used. The BroadBand Sequence service had potential as a solution because of its ability to establish temporary isolation of perforation clusters. The operator decided to evaluate the new technology.

The candidate well, originally one of the best producers in the field, had been stimulated two years earlier. The original completion strategy consisted of 13 fracturing stages. For the refracturing operation, engineers followed a similar 13-stage strategy using the HiWAY fracturing technique. They pumped BroadBand Sequence composite pills between each of the fracturing stages to enable temporary isolation of previously stimulated clusters.

All 13 refracturing stages took place within 36 hours. The ISIP measurements performed at the end of each stage showed a progressive increase toward values that are characteristic of untreated rock in the area, indicating that the diverter pills were opening new paths as planned (above). Following refracturing, the operator placed the well into production. After 45 days, oil and gas production rates had doubled, and tubing pressure increased fourfold. Calculations for the well's productivity index (PI), which take into account both rates and pressures to normalize production, indicated a PI increase greater than 600% after the restimulation operation.[17]



^ The Burgos basin in northeast Mexico. The Pimienta Formation in the Burgos basin is of Jurassic origin. It is a lithologically heterogeneous organic-rich mudstone that includes thin-bedded dark gray to black shales.

Sequenced Fracturing in Mexico

In 2010, exploration of gas- and oil-rich shale reservoirs began in northeast Mexico. The Pimienta Formation, located in the Burgos basin is a heterogeneous mudstone that contains thin shale beds (left). During the initial development, Petróleos Mexicanos (PEMEX)

17. The productivity index (PI) is a mathematical means of expressing the ability of a reservoir to deliver fluids to the wellbore. The PI is usually stated as the volume rate delivered per unit of drawdown pressure (for example, bbl/d/psi).
18. Valenzuela A, Parra PA, Gigena LD, Weimann MI, Villareal R, Acosta NL and Potapova E: "Novel Dynamic Diversion Applied in Stimulation of Shale Plays in North Mexico," paper SPE 170902, presented at the SPE Annual Technical Conference and Exhibition, Amsterdam, October 27–29, 2014.
19. Ajayi et al, reference 7.

drilled 19 horizontal wells and employed the plug-and-perf completion method. The wells were cased and cemented in their horizontal sections and stimulated from toe to heel in 12 to 16 geometrically spaced 100-m intervals. Unfortunately, these wells experienced an undesired trend of increasing completion costs that, combined with lower than expected production rates in some cases, threatened future development plans.[18]

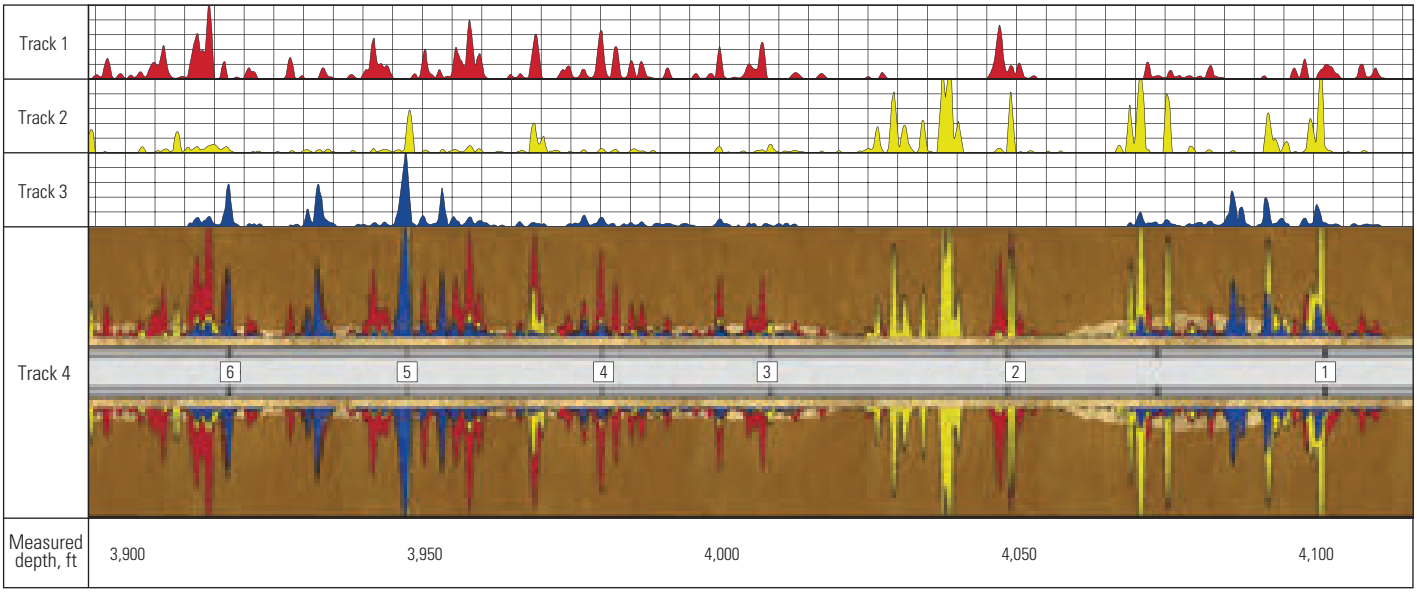
The initial BroadBand Sequence program consisted of three wells. Engineers performed reservoir characterization utilizing the Mangrove stimulation design advisor.[19] The advisor software considers two parameters and determines the optimal locations of stages and perforation clusters. Reservoir quality (RQ) is a prediction of how prone the rock is to yield hydrocarbons; the relevant criteria include organic content, effective porosity, intrinsic permeability, fluid saturations and hydrocarbons in place. Completion quality (CQ) is a prediction of how effectively the rock may be stimulated by hydraulic fracturing and is influenced by mineralogy, mechanical properties, in situ stress and the presence of natural fractures.

Engineers used the Mangrove completion advisor to create an engineered completion design that confined perforation clusters to regions with good reservoir and completion quality. As a result, the operator was able to extend the average stimulation intervals in one well from 100 m to 228 m [748 ft] (above). This reduced the number of bridge plugs and wireline interventions by 45% compared with those needed for the conventional completion design technique.

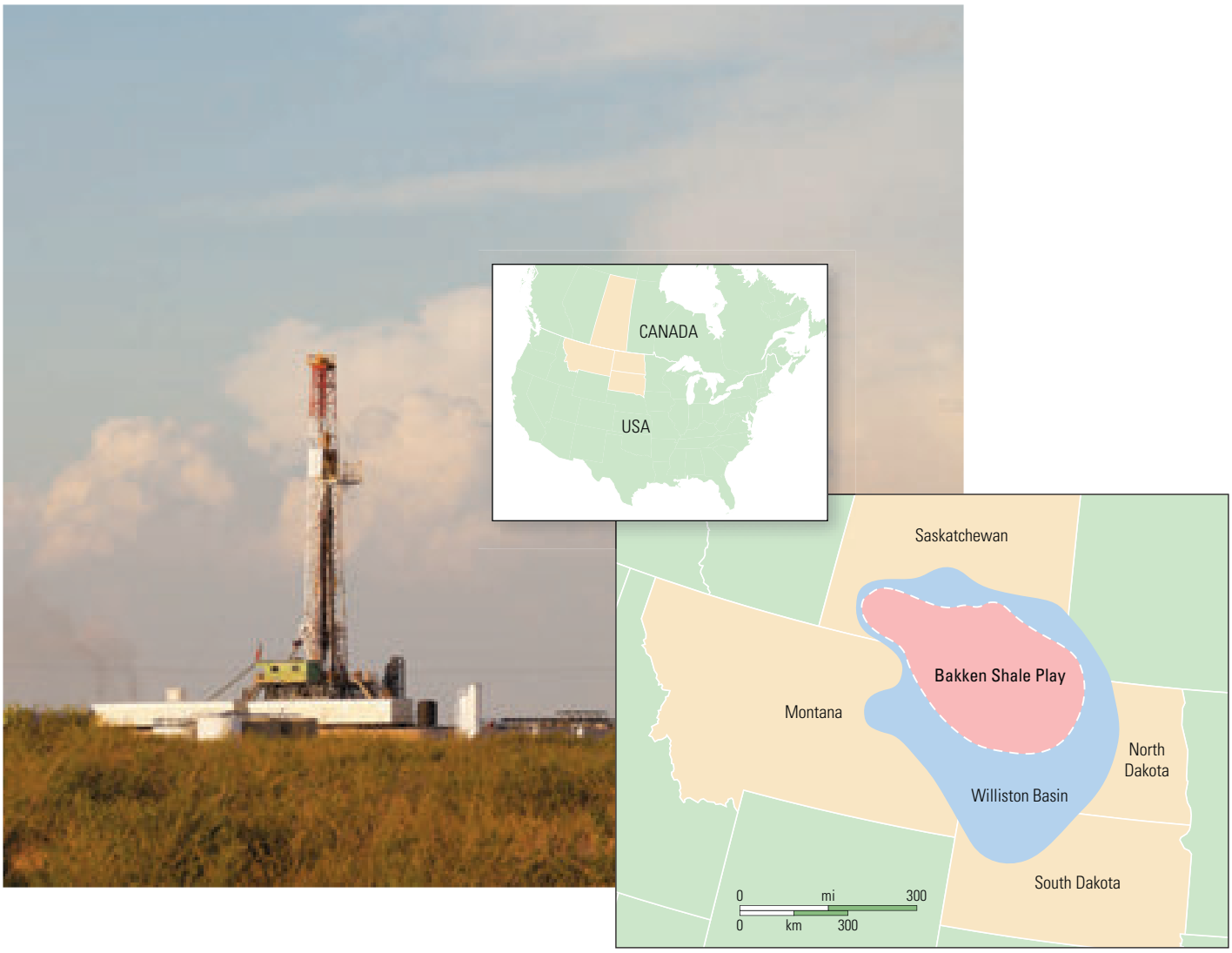
	Well A	Well B	Well C
TVD of perforated interval, m [ft]	2,740 [8,990]	2,270 to 2,300 [7,448 to 7,546]	2,414 to 2,462 [7,920 to 8,077]
Horizontal section length, m [ft]	1,565 [5,134]	1,600 [5,249]	1,500 [4,921]
Bottomhole static temperature, °C [°F]	122 [252]	102 [216]	100 [212]
Number of stages	16	13	15
Number of perforation clusters per stage	3	3	7
Total perforations	48	39	46
Number of intervals treated by Broadband Sequence technique	9	7	9
Average interval length, m [ft]	174 [571]	228 [748]	167 [548]

^ Pimienta Formation well data. Using the Mangrove completion advisor, Schlumberger engineers designed engineered completions for three wells. The perforation clusters were spaced around regions of maximal completion and reservoir quality. The design allowed treatment of more than one cluster during each fracturing stage. As a result, the average treated interval length could be extended from 100 m in previous wells to as long as 228 m [748 ft], resulting in a significant cost reduction per completion.

PEMEX elected to stimulate the three new wells using the BroadBand Sequence service. The operator performed tracer log surveys to verify stimulation of all perforations (below). The evaluation confirmed that 95% of the perforation clusters received proppant. Modeling



^ Tracer logs of an engineered completion of a Pimienta Shale well. The logs show a section from Well B, which received three fracturing treatments. Iridium tracer (Track 1, red), pumped during the first fracturing treatment, entered Perforation Clusters 2, 3, 4, 5 and 6. After the first BroadBand Sequence composite fluid, scandium tracer (Track 2, yellow), pumped during the second fracturing treatment, entered Perforation Clusters 1, 2 and 5. After the second composite fluid, antimony tracer (Track 3, blue) entered Perforation Clusters 5 and 6. The tracer data are superimposed on a lithology log (Track 4) for comparison.



^ Bakken Shale play. As of 2013, the Bakken Shale produced more 10% of all US oil production, exceeding one million bbl/d [159,000 m^3/d]. The US Geological Survey has estimated that the total volume of oil in the Bakken Shale may be between 271 billion and 503 billion bbl [43 billion and 80 billion m^3].

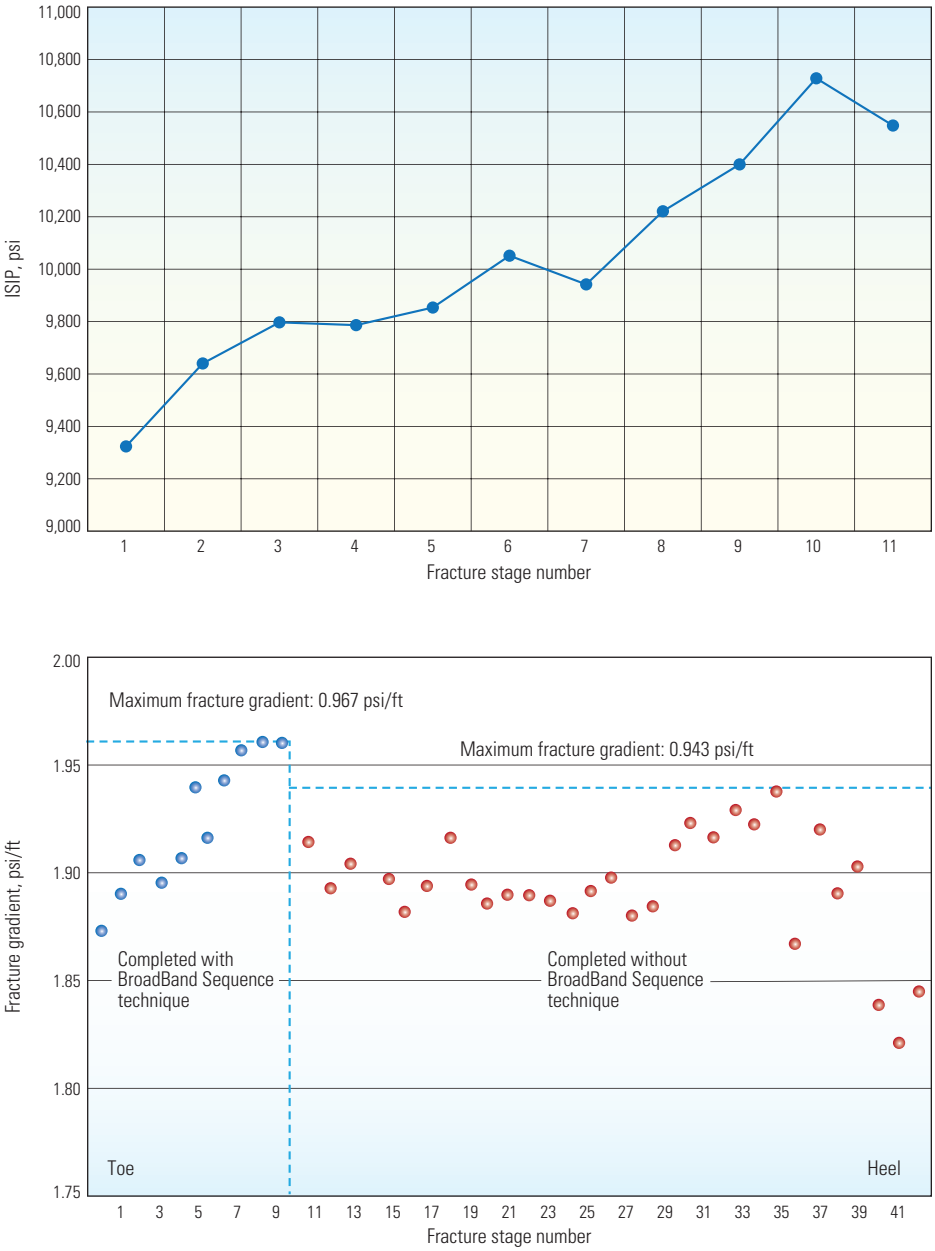
one-year cumulative production with a numerical reservoir simulator showed that one of the wells stimulated using the BroadBand Sequence service would be 8% more productive than if it had been completed conventionally. In addition, the stimulation time per well was 65% shorter than that of the conventional completions, resulting in significant cost savings. Based on these results, PEMEX engineers have continued to apply the combined use of the BroadBand Sequence service with the Mangrove completion advisor in the first phase of development of the field.

Openhole Completion in North Dakota

An operator manages approximately 330,000 acres [1,340 km^2] of the Bakken Shale play in North Dakota, USA (above). This play has emerged in recent years as one of the most important sources of oil in the US.

New wells are completed to total measured depths exceeding 21,000 ft [6,400 m] with TVDs between 9,800 and 11,200 ft [3,000 and 3,400 m]. Fracture gradients are between 0.85 and 0.95 psi/ft [0.020 and 0.022 MPa/m], and bottomhole temperatures are between 220°F and 250°F [104°C and 121°C]. Typical horizontal completions employ noncemented casing.

In one well, the operator had difficulty while running casing. The planned TD was 21,200 ft [6,460 m]; however, the end of the casing became stuck at 20,610 ft [6,280 m]. After several unsuccessful attempts to move the casing farther downhole, the operator decided to investigate alternative stimulation options. Initially, the operator considered leaving the toe unstimulated or pumping a conventional stimulation treatment that might have limited success. Schlumberger engineers proposed addressing the problem by applying the BroadBand Sequence service across the openhole interval.



^ Results of openhole stimulation using the BroadBand Sequence technique. After each fracture stage, engineers measured the ISIP (*top*). The progressive ISIP increase demonstrated the ability of the BroadBand Sequence technology to stimulate openhole areas that would otherwise remain untreated by conventional fracturing techniques. After the well began producing, the operator measured fracture gradients along the well (*bottom*). The openhole portion of the well achieved a higher maximum fracturing gradient (blue dots) than that of the stages that were completed conventionally (red dots).

Engineers lowered a swellable packer to 20,299 ft [6,187 m], leaving a 901-ft [275-m] interval open at the toe. The openhole treatment consisted of 11 fracturing stages separated by 10 BroadBand Sequence composite pills. Operations were completed within 14 hours without the use of bridge plugs or inflatable packers.

A shut-in period followed the placement of each composite pill, allowing the operator to monitor fracture gradient changes. The ISIP measurements captured at the end of each stage showed progressive pressure increases (above). After the openhole interval had been treated, engineers set a bridge plug at the end of the casing and then completed the rest of the well using the plug-and-perf technique.

After the well began producing, engineers determined that the long openhole portion of the well treated by BroadBand Sequence technology was more productive than the portion that had been treated conventionally.

Expanding the Scope of Dynamic Diversion

More than 1,500 BroadBand Sequence treatments have been performed in the US, Mexico and Argentina. As engineers gain experience with the technique, they are making further refinements to improve the service.

The BroadBand Sequence service is compatible with either conventional or fiber-laden fracturing fluids. However, field experience indicates that using fiber-laden fluids achieves superior results because such fluids provide enhanced proppant transport capabilities as well as optimal reservoir coverage and well productivity. Consequently, most BroadBand Sequence treatments today employ the HiWAY fracturing technique.

Dynamic diversion techniques are continuing to evolve. Recently, Schlumberger introduced a stimulation service for unconventional formations that does not include perforating. The BroadBand Precision integrated completion service features the placement of casing fitted with sliding sleeves along the intervals to be treated. After the casing is cemented in place, the sleeves are opened to provide access to the formation. During stimulation treatments, engineers pump composite fluids between fracturing stages. The technique eliminates wireline interventions, placement of bridge plugs and milling operations, resulting in significant rig time and completion cost savings.

Hydraulic stimulation treatments have revolutionized unconventional reservoir plays and changed the dynamics of the oil and gas industry, especially in North America. However, stimulation practices are still evolving as both service companies and operators search for more effective and efficient techniques to access hard to produce resources. Innovations such as BroadBand Sequence treatments promise to enhance developments in unconventional reservoirs that have underperformed or were ineffectively completed. Operators deploying these systems in new resource plays may find that marginal wells and fields are economically viable from the outset, unlocking needed hydrocarbons for the world and providing secure energy resources for the future. —EBN