Orienting perforations in the Right Direction

Orienting perforations minimizes flow restrictions and friction pressures during fracturing. The resulting wider fractures permit use of larger sizes and higher concentrations of proppants along with lower viscosity, less damaging fluids to improve fracture conductivity. In weakly consolidated reservoirs or formations with large stress contrasts, properly aligned perforations maximize perforation-tunnel stability in the formation to mitigate sand production.

Operators use various perforating techniques to solve problems associated with reservoir stimulation and sand management, and to meet other well-completion objectives. Optimal phasing angles, hole spacing and orientation of perforations facilitate hydraulic fracturing and eliminate the likelihood of sand influx from perforation-tunnel collapse.

Producing companies also use oriented perforating to prevent damage to downhole well-completion components, repair channels in cement behind casing, establish communication with relief wells during pressure-control operations and avoid casing collapse in high-angle wells.

Operators employ the latest formation evaluation and interpretation techniques for integrated reservoir characterization to ensure perforating success. They also take advantage of continuing developments in well-logging tools, tubing-conveyed perforating (TCP) equipment and wireline systems that accurately align perforations in a specified direction.

The process of optimizing stimulation treatments uses oriented perforations to increase the efficiency of pumping operations, reduce treatment failures and improve fracturing effectiveness. Completion engineers also develop oriented-perforating strategies that prevent sand production and enhance well productivity by perforating to intersect natural fractures or penetrate sectors of a borehole with minimal formation damage.

Maximum and minimum horizontal stresses and vertical stress from overburden describe in-situ stress conditions in oil and gas reservoirs. Hydraulic fractures initiate and propagate along a preferred fracture plane (PFP), which is the path of least resistance resulting from differences in direction and magnitude of formation stresses. In most cases, stress is greatest in the vertical direction, so the PFP is vertical and lies in the direction of the next greatest stress, the maximum horizontal stress.

Perforations that are not aligned with the maximum stress tend to produce complex flow paths near a wellbore during hydraulic fracturing treatments. Fluids and proppants must exit wellbores, and then turn in the formation to align with the PFP. This “tortuosity” causes additional friction and pressure drops that increase pumping horsepower requirements and limit fracture width, which can result in premature screenout from proppant bridging and, consequently, less than optimal stimulation treatments.

Orienting perforations with the PFP allows completion engineers and providers of pumping services to focus on stimulation designs and treatment procedures that generate optimal fracture initiation, fracture propagation, proppant placement and final fracture geometry—width, length, height and conductivity—instead of fluid flow right at the wellbore.
In some weakly consolidated formations or competent rock with high contrasts between vertical and horizontal stresses, formation failure at the perforations causes sand to be produced. In addition, because reservoir rock must support more overburden as fluids are produced and pore pressure decreases, perforation tunnels may collapse as a formation compresses. Targeting perforations in the most stable directions with minimum stress contrasts often mitigates sand production by reducing flowing pressure drops, changing flow configurations and creating more even stress distributions around wellbores.

In vertical wells, perforations can be shot in any direction, but are essentially horizontal. In high-angle and horizontal wells or vertical wellbores through steeply inclined formations, random radial perforations can be at various orientations in the target zone, depending on wellbore inclination and formation dip. Perforations on the high side of horizontal wells often are more stable and less likely to break down or become plugged by debris. Perforations can be targeted slightly away from vertical for optimal shot density and spacing in order to increase productivity, reduce pressure drop and minimize sand production. For the same reasons, perforations in vertical wells can be aligned a few degrees away from the PFP.

This article reviews techniques to determine formation stress directions and discusses TCP and wireline systems for oriented perforating. Case histories from North America, the North Sea, South America and the Middle East demonstrate the benefits of oriented perforating for production enhancement in reservoir-stimulation and sand-prevention applications. We also discuss equipment improvements and factors driving development of new systems to enhance perforating capabilities and reduce the cycle time of hydraulic fracturing or screenless completions.
Earth Stresses

From rock-mechanics principles, we know that hydraulic fractures propagate in the direction of maximum horizontal stress ($S_h$). When perforations are not oriented with the maximum stress, fractures travel from the tunnel base or tip around casing and cement, or turn out in the formation to align with the PFP. This realignment creates complex near-wellbore flow paths, including multiple fracture-initiation points; competing fractures possibly continuing far afield; microannulus pathways with pinch-point restrictions; and fracture wings that are curved or poorly aligned with the wellbore and perforations (left).

Laboratory tests indicate that breakdown, or collapse, of perforation tunnels contributes to the onset of sand production from weakly consolidated reservoirs or formations with large stress contrasts. Various factors contribute to sand production, including rock strength, magnitude and direction of formation stresses, changing flow rates, increasing stress related to pressure drawdown or reservoir depletion, and water influx over time. Perforations properly aligned with respect to the maximum formation stress are more stable than those in other orientations around a wellbore (below left).

By determining in-situ stress magnitudes and directions, completion engineers design perforating strategies for oriented fracturing that target the preferred fracture-propagation direction. In screenless completions, they target more stable sectors of the formation around a wellbore with lower stress contrasts to prevent or delay sand production. Methods for determining stress magnitudes and orientations range from accessing existing rock catalogs and interpreting borehole-imaging logs to building geomechanical earth models and conducting vertical seismic profile (VSP) surveys (see “Well-Positioned Seismic Measurements,” page 32).

Sand-management considerations. In weakly consolidated reservoirs and formations with large stress contrasts created by complex tectonic environments, perforations that target a minimum-stress plane in stable sectors around a wellbore help reduce or eliminate perforation failure and subsequent sand influx. By maximizing perforation-tunnel stability in a formation, oriented perforating plays a key role in screenless completions that prevent sand production.
Drilling-induced fractures in openhole typically form in the maximum horizontal stress direction, along the PFP; borehole breakout occurs as stress concentrations near the hole wall exceed formation strength and small pieces of rock break off while drilling (above). The borehole elongates in the minimum stress direction ($S_h$), which is 90° from the PFP. Various openhole logging tools help operators determine stress directions prior to perforating.

The borehole elongation is one of the best indications of stress direction because breakouts form in direct response to in-situ conditions. If hydrostatic pressure is high enough, the drilling process also induces shallow fractures in openholes. These drilling-induced fractures occur in the direction of maximum horizontal stress, typically propagating vertically up and down the hole. Natural fractures usually have an associated dip angle, and can be differentiated from induced fractures on borehole-imaging logs.

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Formation-stress evaluation. The DSI Dipole Shear Sonic Imager log is one of the most important formation-evaluation techniques for determining stress magnitudes and orientation. Engineers use the DSI tool to estimate stress profiles and formation mechanical properties. Data obtained from this log, such as Poisson’s ratio and Young’s Modulus (Tracks 4 and 5), are used in stimulation modeling programs like the FracCADE software to estimate fracture height, and to design, optimize and evaluate fracturing treatments.

In crossed-dipole mode, the DSI tool determines PFP orientation by detecting shear-wave anisotropy, which often results from differences in maximum and minimum horizontal stress directions. Acoustic anisotropy can be intrinsic or stress-induced. Intrinsic anisotropy can be caused by bedding, microstructure or aligned natural fractures. Stress-induced anisotropy results from depositional conditions and tectonic forces. Borehole-imaging logs help distinguish between intrinsic and stress-induced anisotropy.3

In conductive water-base fluids, the FMI Fullbore Formation MicroImager tool generates a circumferential electrical image of the borehole wall and provides quantitative information for analysis of fractures. Engineers use this tool to visualize drilling-induced fractures and borehole breakouts, and to establish their orientation (right). This FMI log reveals wellbore breakout in the upper part of the image and drilling-induced fractures in the lower section.4

Like the FMI tool, the UBI Ultrasonic Borehole Imager tool provides circumferential borehole images. However, because it generates acoustical rather than electrical images, the UBI tool can be run in nonconductive oil-base fluids to characterize drilling-induced fractures and borehole breakout (below right). Oriented four-arm caliper surveys also provide an indication of borehole breakout, but do not offer circumferential borehole coverage like the DSI, FMI and UBI logging tools. The GVR GeoVision Resistivity tool provides complete circumferential borehole-resistivity images while drilling with conductive fluids.5

The first applications of oriented perforating were in wells with dual or multiple tubing strings. Tools were developed to ensure that guns run in one string of tubing do not perforate other tubulars in a wellbore. Until recently, wireline perforating options for these types of wells were limited to systems like the Schlumberger Mechanical Orienting Device (MOD) and Powered Orienting Tool (POT).

With the MOD system, it is safe to perforate when a spring-loaded caliper measures the full inside diameter (ID) of the casing. The POT systems are motorized tools with sensors that provide real-time data as the gun string is rotated. Perforating charges are directed 180° from the caliper or aligned with a specific sensor (left). The POT-B includes a shielded gamma-ray detector to locate radioactive sources run concurrently in other tubing strings. The POT-C uses electromagnetic principles to detect metal in nearby tubing or casing strings. The POT-C was developed primarily for detecting adjacent completions cemented in a single openhole, but it has also been used successfully inside casing with two strings of tubing.

In the past, operators frequently used tubing-conveyed systems for oriented perforating. However, these operations can be more complex and costly than wireline conveyance, particularly if the well is vertical, the target interval is relatively short, and perforating is performed with wellbore hydrostatic conditions equal to formation pressure. For high-angle and horizontal wells, passive oriented-perforating systems for wireline-, tubing- and coiled-tubing conveyance use eccentric weights and swivels to orient gun strings relative to the low side of a wellbore with perforating charges facing upward (above).

New technology is available to accurately align TCP guns across long intervals in deviated wellbores. This OrientXact system includes passive orienting weights and gun sections joined by roller-bearing swivels that handle high loads. This system orients gun sections longer than 1000 ft [300 m] to accurately shoot within 10° of a predetermined direction, such as the high side of an inclined wellbore. An innovative Orientation Confirmation Device (OCD) measures and records perforating direction within 1°, which provides valuable data about perforation orientation after retrieving the gun string.

In vertical wells, TCP techniques use gyroscopes instead of passive orientation by gravity to orient perforations. A gyroscope is run through tubing on wireline and seated in an orienting profile that includes an internal key that is aligned with the gun charges. The tubing string is rotated from surface to a required orientation, and the packer is set hydraulically to avoid additional rotation. Gun orientation is verified by the gyroscope before it is removed to prevent damage from perforating shocks.
When stress directions are not known or oriented perforating is not possible, guns with a high shot density and 60 or 120° phasing help ensure that at least some perforations will lie within 25 to 30° of the maximum stress direction. However, this random approach requires additional shaped charges and does not ensure that perforations are closely aligned with the PFP or minimum stress contrast.

The Schlumberger Wireline Oriented Perforating Tool (WOPT) system, which can be run in vertical and inclined wells, is the latest method for orienting wireline guns (below left). The WOPT system, developed initially for oriented fracturing, also is deployed to perforate for sand prevention. This tool orients standard HSD High Shot Density guns with 0°, 180° or other optimal phasing in a predetermined direction. Charge type and shot density depend on completion requirements such as sand control or sand prevention, and on fracture-design criteria such as propellant size, pump rates, treating pressures and required production flow.4

This technique relies on the fact that at a given depth, wireline tools assume a preferred orientation in a wellbore when string parameters—length, weight, mass distribution, cable speed and direction—are constant, and a swivel is used to minimize the detrimental steering effects of torque. The swivel decouples torsion

Wireline-oriented perforating. A typical Wireline Oriented Perforating Tool (WOPT) system is configured with a weighted spring-positioning device (WSPD) and indexing adapter above and below standard 0°- or 180°-phasing guns (left). The tool string includes a gyroscope and carrier, an integral Wireline Perforating Inclinometer Tool (WPIT) with casing-collar locator (CCL) and a wireline swivel to decouple cable torque from the tool. The gyroscope measures well inclination, wellbore azimuth and toolface relative bearing—orientation of the tool string—with respect to true north during an initial run with unarmed guns (top right). Perforating is performed on subsequent trips as needed without the gyroscope and after rotating, or reindexing, the guns at surface (bottom right). The WPIT remains in a tool string at all times to independently measure tool deviation and toolface relative bearing, and confirm that a tool string repeats the previously established orientation.

Verifying perforation orientation. After perforating, an oriented USI UltraSonic Imager log can be run to confirm that perforations are in the correct orientation. In this USI image, perforations appear as thin lines because of the measurement scale (Track 3). The required perforation depths are shown on the well sketch in Track 2. This well was perforated in four separate gun runs using 180° phasing and 2 shots per foot (spf)—a total of 118 holes—oriented northeast-southwest. Well inclination was about 1.7°, but the WOPT has been used in wells with inclinations as low 0.3°.

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between the wireline cable and a gun string, which allows the tool to assume its preferential, or natural, position. The observed repeatability of this “natural lie” was a key in developing the WOPT tool. The WOPT requires two trips for vertical wells with inclinations less than 8°. Perforating wellbores with less than 1° of inclination requires extra care during job execution and may require additional time to complete.

The first trip, or “mapping” run, is made with an unarmed perforating gun and a true-north-seeking gyroscope to determine the natural orientation—toolface azimuth, or direction—of the tool string. Upper and lower weighted spring-positioning devices (WSPD) help rotate tool strings toward the relative low side of a wellbore.

Several passes in each direction ensure accurate orientation data to determine the required gun rotation, or “indexing,” for oriented perforating. Single or multiple zones can be mapped during this initial trip. The Wireline Perforating Inclinometer Tool (WPIT), an integral WOPT component, provides independent, continuous and real-time measurements of tool deviation and toolface orientation—relative bearing—with respect to the high side of a wellbore.

If reliable directional-survey data are available and target zones are in well sections with inclinations greater than 8°, oriented perforating can be completed without a gyroscopic run. In this case, inclination measurements are extremely accurate and correlate to wellbore azimuth. After toolface azimuth is determined, guns are rotated manually at the surface in 5° increments using indexing adapters above and below the guns to orient the charges. The gyroscope is removed before perforating to avoid shock damage during perforating. The carrier with a dummy gyroscope and the WPIT remain in the WOPT system to maintain tool-string length and mass.

The WOPT gun string is then run back into the well. Relative-bearing data from the WPIT confirm that the previously established tool orientation repeats. The well is perforated once gun orientation and depth are verified by repeat-analysis log (above). The WOPT system can accurately align perforations within 5° of the required azimuth. Because of the need to maintain constant tool-string parameters, a current limitation of the WOPT system is the inability to selectively detonate more than one gun per run. In vertical wells, a spent gun would alter the previously established preferential tool orientation.

Operators have run the USI UltraSonic Imager tool to verify that perforations are correctly aligned in the desired direction (previous page, right).
Post-perforating surveys indicate that perforations are consistently within about 10° of the required azimuth. The WOPT system has successfully perforated wells with inclinations from 0.3° to 58°. Operators accepted the concept of orienting perforations to improve hydraulic fracturing efficiency and effectiveness, but considered it impractical before the introduction of the WOPT system.\(^7\)

Hydraulic Fracturing
Perforating is an essential, but often-overlooked aspect of hydraulic and acid fracturing treatments. Hole size, shot density, penetration, gun phasing and perforation orientation all are important. Neglecting any of these parameters can lead to a screenout, which is detrimental to long-term production, adding completion costs for additional rig time and equipment to clean out wellbores as well as wasting expensive stimulation fluids and proppants. A premature screenout usually results in less than optimal stimulations and also can make refracturing more difficult in the future.

In any case, production response usually is less than expected because of incomplete zonal coverage, shorter fracture length and lower fracture conductivity. To deal with friction pressure from misaligned perforations and near-wellbore flow restrictions, operators often resorted to increased pump rates and pressures, higher viscosity fluids that are more damaging, prestimulation breakdown with acid, reperforating and proppant slugs pumped during early stages of a treatment to erode restrictions. All of these methods add incremental cost and, depending on existing wellbore and formation conditions, have questionable effectiveness.

\(^7\) Optimizing hydraulic fracturing. Orienting perforations in the direction of maximum horizontal stress improves the efficiency and effectiveness of reservoir-stimulation treatments. Perforations aligned with the PFP reduce or eliminate near-wellbore tortuosity and flow restrictions (top). In full-scale fracture-initiation laboratory tests on formation blocks under triaxial stress, perforations in the PFP resulted in a dominant single or biwing fracture with minimal tortuosity and reduced injection pressures (bottom left). In the same tests, perforation misalignment resulted in multiple competing fractures that initiated at various points on the wellbore radius and traveled around the cement-formation interface (bottom right).
Formation stresses control hydraulic fracture initiation and propagation. Perforations aligned with the maximum stress direction optimize the impact and effectiveness of fracture-initiation and fracture-propagation pressures by maximizing the number of holes open to a hydraulic fracture and allowing fluids to flow directly into the path of least resistance—the PFP (previous page). When perforations are not properly aligned in the stress field, flow-path tortuosity increases fracture-initiation and fluid-friction pressures during pumping operations. These losses dissipate hydraulic energy, which limits fracture geometry and increases the horsepower required to pump stimulation treatments. The consequences are possible premature screenout, reduced final proppant concentrations and volumes, and higher job costs.

An oriented perforating and fracturing strategy minimizes or eliminates near-wellbore pressure losses. Fracturing design and implementation can focus on creating wide, conductive fractures and transporting proppant rather than fluid flow in the near-wellbore region. This also allows completion engineers to design more aggressive fracturing programs with higher concentrations or larger sizes of proppant and less viscous, nondamaging fluids like ClearFRAC viscoelastic systems to improve fracture conductivity and well productivity.

Oriented perforating also helps optimize stimulation treatments when operations are constrained by pressure or pump-rate limitations and restrictions on fluid and proppant volumes. These applications include wells with smaller tubing and coiled tubing-conveyed CoilIFRAC selective stimulations.

In addition to new opportunities for fracturing with coiled tubing, oriented perforating can eliminate the need to pump down tubing and protect casing from excessive injection pressures, particularly in formations that are difficult to treat because of high breakdown pressures. In some cases, lower fracture-initiation and fracture-propagation pressures make it possible to pump down casing, which reduces the cost and complexity of fracturing through premium-grade, high-strength tubing.

In March 2000, Louis Dreyfus Natural Gas Inc. (now Dominion Exploration and Production Inc.) drilled Well ETA-4 in southeast New Mexico, USA (above right). No pressure data were available, but a bottomhole pressure of 2000 psi (13.8 MPa) was measured in an offset well. Wireline logs identified a homogeneous, high-quality, 10-ft (3-m) zone in the Morrow formation with about 14% porosity and 20% water saturation. Rotary sideway cores verified these values. A zone of this quality should produce naturally, but high permeability and low pressure make the formation susceptible to drilling- and completion-fluid damage. Significant separation between resistivity curves confirmed deep invasion, so the operator wanted to design a fracture stimulation to bypass the damage.

Early fracture stimulations with water-base fluids in this formation were marginally successful because these gas sands are low pressure and potentially water sensitive, with a wide range of permeabilities. If possible, wells are completed naturally without stimulation, but those in low-permeability areas of the reservoir must be hydraulically fractured, often with marginal results. Operators approach Morrow stimulation treatments cautiously. To address water sensitivity and avoid a screenout, less viscous foam fluids with low proppant concentrations that yield narrow, low-conductivity fractures are frequently used.

Studies suggested that poor results were due to water-sensitive clays or capillary-pressure effects that reduce permeability when zones are exposed to fracturing fluids. Low reservoir pressure exacerbates capillary effects. These issues were addressed by pumping nitrogen \([\text{N}_2]\) or carbon dioxide \([\text{CO}_2]\) energized treatments and using methanol in fracturing fluids. However, stimulation results with foam systems have been inconsistent. In higher permeability zones, small fracturing treatments using foams effectively bypass near-wellbore damage, but in lower permeability zones where fracture length is critical for optimal productivity, results with foam systems are inconsistent.

These treatments address water sensitivity, but low viscosity, high friction pressure and chemical requirements increase costs and the risk of screenout. Lower proppant concentrations and frequent premature screenout leave wells producing considerably below their full potential. Fracture-treatment designs that develop adequate hydraulic width and transport higher concentrations and volumes of proppant were needed to maximize production.

Reservoir quality in the ETA-3 well, completed two months earlier, was similar to that of the ETA-4 well, but with half as much pay. This offset well was perforated conventionally with 4-in. carrier guns with 4 shots per foot (spf) at 60° phasing and fracture stimulated down 5-in. casing with \(\text{CO}_2\) foam and high-strength, man-made ceramic proppant. Surface treating pressure was 5000 psi (34.4 MPa) with a maximum proppant concentration of 4 pounds of proppant added (ppa). Increasing pressure near the end of the job indicated a possible screenout. Post-stimulation production stabilized at 1.7 MMscf/D [48,700 m³/d] and 500-psi [3.4-MPa] flowing tubing pressure (FTP) at surface.


The operator decided to use the Schlumberger WOPT system to align 3¾-in. HSD High Shot Density gun systems with 6 spf at 180° phasing along the PFP. Using FMI log data, engineers determined that the maximum stress direction was northwest to southeast in the ETA-4 well. Higher proppant concentration—6 versus 4 ppa—to increase fracture width was possible because oriented perforating reduced risk of premature screenout caused by near-wellbore tortuosity.

Because reservoir quality was equivalent to the ETA-3 well and the pay was twice as thick, the operator expected ETA-4 to be an excellent well, but production after perforating was only 500 Mscf/D [14,300 m³/d] with 220-psi [1.5-MPa] FTP. This rate was equivalent to an extremely damaged completion with a positive 45 skin. To take full advantage of reservoir quality, the operator wanted to design a more conductive fracture using a higher proppant concentration. However, fracture-treatment pressures in the offset well indicated a possible screenout at 4 ppa, so this would not be easy.

At 6 ppa, the FracCADE simulation shows a fracture half-length of 300 ft [91 m] and a width of 0.15 in. [3.8 mm], more than twice as wide as a 4-ppa design (below). This treatment appears over-designed, but local experience suggests that a 300-foot design target may be necessary to obtain an effective 200-ft [60-m] conductive fracture, considering the potential for fracture-conductivity damage after the fracture closes and production begins.

Treatment pressures highlight the positive impact of oriented perforations on job execution (next page, top left). Pump rates for the two stimulation treatments are identical at 30 bbl/min [4.7 m³/min], but the conventional fracture stimulation had a treating pressure of 5000 psi, while pressures for the oriented fracturing treatment range between 3000 and 4000 psi [20 and 27 MPa].

Another important indicator of the benefits of oriented perforating is pressure response after pumping stops. On the conventional job, it took 15 minutes for pressure to reach 3000 psi, suggesting that net pressure was increasing and this job was close to screenout. For the oriented fracture, pressure stabilized almost immediately, suggesting that higher proppant concentrations could have been placed.

Early production history for Well ETA-4 indicated a successful stimulation. Post-fracturing production was 3.5 MMscf/D [1 million m³/d] with 1280-psi [8.9-MPa] FTP compared with 500 Mscf/D and a flowing pressure of 220 psi before stimulation. The goal was to bypass drilling damage, so skin is a good measure of fracturing success. The post-stimulation production rate of 3.5 MMscf/D indicates that skin was reduced from 45 to ~4.

Analysis showed that with 4-ppa maximum proppant concentration and 0.06-in. [1.5-mm] fracture width, the ETA-4 well should produce 2.2 MMscf/D [63,000 m³/d] at 1280-psi FTP. If the fracture width is 0.15 in., production increases to 3 MMscf/D [85,000 m³/d] with 1280-psi FTP. The well actually produced more, suggesting a slightly wider fracture. Oriented perforating allowed a higher proppant concentration to be used while avoiding premature screenout and the need to clean out wells after fracturing. This resulted in an additional 1.3 MMscf/D [34,000 m³/d] and a three-day payout for incremental perforating costs.

In some areas, fracturing applications include completion objectives other than just fracturing to enhance productivity. Operated by Amerada Hess, the Scott field in the central North Sea UK sector is subject to impaired productivity from scale and asphaltene deposits in and around the wellbores.12 Reperforating, injecting scale dissolvers, and creating short fractures with explosive propellants were unsuccessful remedial treatments due to the severity of this damage. A fracture stimulation, which is expensive in offshore environments, was the only remaining option to bypass formation damage.

This challenge, however, encouraged investigation of new methods and novel technologies to ensure success. A joint Amerada Hess and Schlumberger Production Enhancement Group (PEG) identified Well J9 as a fracture-stimulation candidate based on existing production versus potential productivity, drainage area, pressure
support from a nearby injection well and wellbore access.\textsuperscript{13} Oil production peaked at 5700 B/D [906 m$^3$/d], but declined steadily in spite of increasing reservoir pressure. Pressure in the fault block rose from about 4000 psi [27.6 MPa] to more than 9000 psi [62 MPa] after water injection began.

A production log spinner survey and cased-hole caliper revealed that production was primarily from an upper zone and there was water holdup as well as scale buildup across lower perforations. The operator suspected a combination of sulfate-scale buildup prevalent in other parts of the field, fines migration and possible asphaltene deposition. Reperforating the entire interval had no effect on production. Hydraulic fracturing was the only practical option remaining. However, the complex faulted structure and extreme tectonic forces create conditions for potentially narrow hydraulic fractures and possible premature screenout. High wellbore deviations further exacerbate near-wellbore restrictions and complicate fracturing operations.

A limited interval was reperforated using the WOPT system to align guns with 180$^\circ$ phasing in the maximum stress direction to minimize pressure losses from fracture tortuosity. A PFP azimuth of 46$^\circ$ was obtained from shear-wave anisotropy, four-arm caliper measurements in openhole and borehole-imaging logs. The operator selected big-hole PowerFlow charges at 6 spf to reduce uncertainty about perforation alignment with the PFP and minimize perforation friction. This choice also helped ensure the widest possible fracture to mitigate post-stimulation skin from flow turbulence during subsequent production.

Even with a wellbore azimuth across the target interval of 40$^\circ$, engineers estimated that a hydraulic fracture would propagate almost in-line with the wellbore. Despite a favorable wellbore azimuth, Amerada Hess decided to mitigate the possibility of a screenout due to narrow fracture width or multiple fractures near the wellbore. This was accomplished by reperforating only 10 ft and plugging back to reduce the injection interval, even though this could result in convergent, possibly turbulent, flow under producing conditions (above right).

Achieving adequate fracture conductivity and maintaining productivity were major concerns given the high propensity for scale deposition in wellbores and the formation matrix. Hydraulic fracture treatments reduce pressure drops during production, which reduces the potential for scale deposits to form. In addition, a special proppant impregnated with a scale-inhibiting
North Sea stimulation success. The productivity of Amerada Hess’s Well J9 in the Scott field, a central North Sea development, increased as the result of an optimized fracture treatment that included oriented perforating of a limited interval and injection of scale-inhibitor-impregnated proppant. Production rose from 120 B/D [19 m³/d] to more than 2500 B/D [397 m³/d] of sustained output. This intervention paid out within 14 days.

Screenless completions. When combined with oriented perforating and fracturing strategies, novel technologies, such as resin-coated and scale-inhibitor-impregnated proppants (left), and PropNET fibers (right), control proppant flowback and sand production to provide effective sand prevention without downhole mechanical screens and gravel packing.

Sand Prevention

Although sand-control methods are required in many completions, restricted flow rates may make mechanical screens and gravel packing for sand control impractical or uneconomical in high-productivity wells. In some weakly consolidated reservoirs and formations with anisotropic stresses, oriented perforating and specialized screenless technologies can maximize perforation-tunnel stability and reduce or eliminate sand production without restricting well output.


and directions, completion engineers target more stable areas of the formation around a well with minimum stress contrast and avoid less stable sectors with large contrasts between horizontal and vertical stresses.

Smaller diameter perforations, higher shot density, optimal gun phasing and maximum spacing between holes, and oriented perforating aid in preventing sand production from weakly consolidated reservoirs. When high shot densities are required, gun phasing is adjusted to orient perforations slightly to either side of the minimum stress contrast direction to maximize perforation-to-perforation spacing. This optimizes well productivity and helps prevent or delay sand production throughout the life of a well. Geomechanical models and laboratory testing determine the acceptable deviation from a target azimuth, typically about 25° to 30°, or less.

Using knowledge about the in-situ stress distribution and directions from a detailed geomechanical study, Petróleos de Venezuela S.A. (PDVSA) applied optimal phasing and oriented perforating to prevent sanding. Sand production is a major problem in the Eocene C reservoir of Lake Maracaibo, Venezuela. This sandstone is competent and consolidated, but as a result of complex tectonics, maximum horizontal stress is significantly greater than the vertical stress, which is similar in magnitude to the minimum horizontal stress. The large contrast between maximum and minimum horizontal stresses generates significant produced sand in vertical wells.

During the 1990s, PDVSA used several techniques, including hydraulic fracturing and high-angle drilling, to reduce sand production. Production averaged 1500 B/D (240 m³/d) per well, but sand influx remained at about 14 lbm/1000 bbl (4 kg/100 m³) per well, which was still considered excessive. To address this problem, PDVSA turned to oriented perforating for sand prevention in vertical wells.

Faults and tectonic effects influence stress direction variations in the Eocene C reservoir. PDVSA used borehole-image data and laboratory core measurements to estimate maximum horizontal stress directions. Investigators also evaluated the stability of a single perforation tunnel using an elastic-plastic model, finite-element analysis and material-failure criteria. The critical angle from the direction of maximum stress where perforation tunnels remain stable was used to select gun phasing and perforation orientation.

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Geomechanical studies by PDVSA and experiments at the Schlumberger Reservoir Completions (SRC) Center in Rosharon, Texas, USA, resulted in the following perforating strategies and recommendations:

- Determine stress magnitudes and directions.
- Define the critical angle at which perforations are stable.
- Select appropriate deep-penetrating PowerJet charges.
- Use sufficient shot density for optimal productivity.
- Use a shot phasing for maximum perforation-to-perforation distance.
- Avoid shooting in directions where perforation tunnels are less stable.
- Perforate with a sufficient pressure underbalance.

Initially, four jobs were performed using oriented TCP techniques. In all of these wells, sand production was reduced significantly compared with the field average of more than 14 lbm/1000 bbl (above). Because of the sand-prevention success in these Eocene C wells, PDVSA performed additional oriented perforating in other fields using TCP and WOPT systems.

Shot densities below 6 spf reduced productivity. Above 8 spf there was essentially no productivity increase, but the risk of perforation failure and sand production increased. PDVSA selected 6 to 8 spf to satisfy all the above conditions. The first three wells were perforated with conventional guns using 6 spf. The fourth well was perforated with a customized gun to provide 8 spf while still satisfying the original requirements of maximum perforation-to-perforation distance, and more uniform distribution of perforations within the allowable perforation angle.

Sand production is a problem in many areas. During 1995, Saudi Aramco began extensive development of nonassociated gas reserves in Ghawar field. The Jauf reservoir was part of the endeavor. This unconsolidated sandstone produces sweet gas from 13,500 to 14,400 ft (4115 to 4390 m) deep, has low to moderate permeabilities and a high potential for sand production at elevated pressure and temperature—8750 psi (60 MPa) and 300°F (150°C).

Jauf wells produce 10 to 60 MMscf/D (28,600 to 1.7 million m³/d), but it is difficult to achieve these high rates without producing significant volumes of formation sand. This sand influx results in repeated workover interventions to clean out wellbores and creates severe pipeline corrosion by stripping away chemical inhibitor from the inside of gathering and transmission lines.

Some Ghawar field wells were completed with 4½-in. casing, which ruled out rate-restricted, gravel-packed mechanical screens. Frac packing was considered, but low permeabilities from core analysis and openhole well-testing data indicated a need for longer high-conductivity fractures to achieve target gas rates. As a result, Saudi Aramco decided to pursue screenless technologies with hydraulic fracture stimulations.
The newly built Hawiyah gas plant, with a total capacity of 1.6 Bscf/D [46 million m³/d], required 400 MMscf/D [11.5 million m³/d] of sand-free, sweet gas from Jauf wells. However, four fracture stimulations pumped in 1999 and 2000 failed to prevent sand production, and consequently were largely ineffective. With plant startup less than a year away, the operator assembled a team of experts in petrophysics, geology, reservoir engineering and stimulation design under a Saudi Aramco manager and a Schlumberger coordinator. Along with representatives from field operations, this group addressed proppant flowback and sand production, optimizing fracture treatments and improving wellbore cleanout procedures.

This team identified 10 wells that were candidates for screenless completions. To achieve a step change beyond conventional designs, a PowerSTIM well-optimization process was implemented to integrate petrophysics, formation evaluation, reservoir characterization and well testing with stimulation design, execution and post-treatment evaluation. In addition to better formation evaluation and reservoir characterization, recommendations for improving hydraulic fracture stimulations included oriented perforating to reduce treating pressures and create wider fractures, which reduce turbulent, nondarcy flow during production. Perforations properly aligned with the PFP also eliminate unpacked tunnels that contribute to sand production.

Borehole breakout identified on FMI logs confirmed an east-west maximum stress and PFP orientation in the Jauf formation at an azimuth of about 80°, or 260°. The current perforating strategy is to orient perforations along the preferred fracture plane using guns with 180° phasing and 6 spf. This approach helps prevent solids production and reduce near-wellbore friction pressures during fracturing operations.

Typical wellbore breakout in the Jauf formation. FMI logs identified north-south borehole breakout of about 25% in the Jauf formation of Saudi Arabia. This confirmed a maximum formation stress direction of approximately east to west at azimuth 80°, or 260°. The current perforating strategy is to orient perforations along the preferred fracture plane using guns with 180° phasing and 6 spf. This approach helps prevent solids production and reduce near-wellbore friction pressures during fracturing operations.

If not addressed, problems associated with sand influx adversely affect well and reservoir productivity, jeopardize future remedial-intervention options and limit field profitability. Ensuring that perforation tunnels and the surrounding formation remain stable over the life of a well is an important element of sand management. Improved sanding models, enhanced risk assessment and increasingly sophisticated perforating techniques address these problems by providing alternative strategies to manage and eliminate sand production.

**Additional Applications and Developments**

Is premature screenout common during fracture-stimulation treatments? Are injection pressures higher than expected? Is treatment implementation rate or pressure limited by casing conditions or the use of coiled tubing for selective stimulation of individual zones? Should less damaging fluids be used? Are final proppant concentrations too low? Do wells have sand-production or proppant-flowback problems? Are there indications of scale and asphaltene deposition? If the answer to any of these questions is yes, oriented perforating may be a key element of the oilfield services solution.


Carefully planned oriented perforating delivers optimal results, in most cases, at negligible incremental costs compared with the additional value generated. Detailed analysis and candidate selection are vital parts of the planning process for oriented perforating (above). The latest logging tools and interpretation techniques facilitate this process by measuring and evaluating rock properties beyond drilling-induced formation damage. Combined with integrated reservoir characterization, these services provide data and input for developing accurate earth models to simulate, design and evaluate stimulation optimization and sand-management solutions that oil and gas operators need to enhance production.

Oriented-perforating operations are technique-sensitive, and currently require more time than conventional perforating, particularly in vertical wells with little inclination. Because the WOPT relies on repeatability of tool-string orientation, care must be taken during each step of job execution. In addition, if the tool assumes a different orientation during a perforating run, the guns must be pulled back out of the well and reindexed accordingly.

A system that allows rotation, or indexing, of guns downhole would greatly reduce technique sensitivity and further improve the overall efficiency of oriented perforating. Downhole reorientation would be particularly beneficial in wells with inclinations greater than 3° where inclination measurements are more reliable. The additional capability to selectively fire more than one detonator, and therefore, several guns in a single trip also will drastically reduce the number of runs required to perforate longer intervals or multiple zones. In any case, a gyroscope run is required when directional-survey data are not available.

The need to perforate without damaging cables, control lines and other hardware in increasingly complex, instrumented wells is a growing application for wireline-conveyed oriented perforating. The number of intelligent completions being deployed is expected to increase at a rate of about 30% per year. Installation of fiber-optic systems that allow operators to monitor downhole well performance and evaluate stimulation-treatment effectiveness over time is growing even faster. Techniques to detect and map downhole completion components, and monitor gun orientation while perforating will help meet this need.

Other applications for oriented perforating include intersecting natural fractures or borehole sectors with minimal formation damage for enhanced well productivity, repairing channels in cement behind casing and activating relief wells during pressure-control operations. Oriented perforations that avoid exposing perforation-weakened casing to extreme stress concentrations also prevent casing collapse in high-angle wells or wells drilled in tectonically active areas. In the future, this technique also may find applications in complex, highly faulted geological structures where in-situ stress conditions complicate fracture design, treatment implementation and stimulation effectiveness.

These requirements and increasingly demanding well completions are driving development of the next generation of perforating systems and techniques, aimed primarily at increasing wellsite efficiency and reducing the time required to implement perforating services and solutions. When commercial, these tool enhancements and the new perforating systems that use them will further expand the flexibility and effectiveness of oriented perforating.

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