Combined Stimulation and Sand Control

Specialized fracturing treatments in conjunction with gravel packing create highly conductive propped fractures that yield sustained production increases and control fines migration in weakly consolidated reservoirs. This “frac-packing” method, which became increasingly popular in the past 10 years, bypasses formation damage and eliminates many productivity impairments that are common in conventional cased-hole gravel packs.

^Fracturing for sand control. Initial frac-pack results in the early 1990s indicated improved productivity compared with conventional gravel packing (left). As a result, frac packing now represents more than 60% of the US sand-control market (top right), and companies providing stimulation services invest heavily in research and development. These investments included construction of purpose-built vessels with high-volume mixing equipment, high-pressure pumps and sophisticated monitoring systems, such as the Schlumberger Galaxy stimulation vessel (center).
Hydraulic fracturing in high-permeability reservoirs to stop sand production is an accepted well-completion technique. Today, one of the first decisions during development planning for fields that produce sand is whether or not to frac pack—a combination of fracture stimulation and gravel packing. More than a decade of success proves that compared with conventional gravel packing, this technique significantly improves well productivity (previous page).

Frac packing as a percentage of sand-control treatments and in terms of total jobs is growing steadily. Use of this technique increased tenfold—from fewer than 100 jobs per year during the early 1990s to a current rate of almost 1000 each year. In West Africa, about 5% of sand-control treatments are frac packs, and operators frac pack at least 3% of the wells in Latin America.

Advances in stimulation design, well-completion equipment, treatment fluids and proppants continue to differentiate frac packing from conventional gravel packing and fracturing. US operators now apply this sand-control method to complete more than 60% of offshore wells.

Shell used the term frac pack as early as 1960 to describe well completions in Germany that were hydraulically fractured prior to gravel packing.1 In current usage, frac packing refers to tip-screenout (TSO) fracturing treatments that create short, wide fractures and gravel packing of sand-exclusion screens, both in a single operation. The resulting highly conductive propped fractures bypass formation damage and alleviate fines migration by reducing near-wellbore pressure drop and flow velocity.

An early application of frac packing occurred during 1963 in Venezuela, where producing companies performed small fracturing treatments using sand and viscous crude oil and then circulated screens into place downhole through sand-lateralized screens into place downhole through sand

Interest in frac packing increased after 1985, driven by activity in the Gulf of Mexico, where many conventional gravel packs do not achieve adequate productivity. Induced formation damage from drilling or completion fluids, cement filtrate, overbalanced perforating and fines migration contribute to unsatisfactory results, as does mechanical skin damage created by the redistribution of stresses after drilling.4 Formation collapse and sand influx as a result of incomplete gravel packing around screens or unpacked perforations also restrict production.

Frac packing reduces pressure drops caused by formation damage and completion restrictions, which commonly are represented by a dimensionless value called skin.5 Unlike gravel packing, frac-pack skin decreases as wells produce and treatment fluids are recovered, and productivity tends to improve over time. Consequently, the trend among operators is to apply this technique in most of the wells that require sand control.

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5. Negative skin indicates stimulation; positive skin indicates damage.
In the Gulf of Mexico, frac packing became increasingly popular beginning in the late 1980s. Amoco, now BP, performed five frac-pack completions in the Ewing Bank area during 1989 and 1990 by batch mixing up to 6 pounds of proppant added (ppa) per gallon of treatment fluid. In 1991, ARCO, now BP, performed frac packing in the South Pass area. Penzoil, now Devon Energy, used this technique in the Eugene Island area. At about the same time, Shell began frac packing inland wells from barges in Turtle Bayou field, Louisiana, USA. Later, Shell expanded the use of this technique in the North Sea and to offshore wells in Borneo, and also to onshore wells in Colombia, South America and northwest Europe.

Frac-packing success led to increased use, and this technique soon became the preferred sand-control method in the Gulf of Mexico, where several thousand oil and gas leases lie in water deeper than 3000 ft [914 m]. During 1992, BP completed frac packs in Mississippi Canyon Block 109, where water depths range from 850 to 1500 ft [260 to 460 m]. A few years later, Shell and Chevron used frac packing to develop fields in water up to 3000 ft deep.

Technology transfer and frac-packing success in other areas, such as Indonesia, the North Sea, the Middle East, West Africa and Brazil, are further expanding the worldwide application of this technique. Operators plan to frac pack Gulf of Mexico wells in more than 4000 ft [1220 m] of water, and in the North Sea and offshore Brazil, intend to push the frontier of frac packing into water as deep as 6000 ft [1830 m]. Fracture stimulation and frac packing in high-permeability reservoirs now represent 20% of the fracturing market.

This article reviews the evolution of frac packing and discusses developments in stimulation fluids, proppants, downhole equipment, design simulation, job execution and post-stimulation evaluation. Case histories illustrate application of this technique to enhance well productivity while preventing proppant flowback and sand production.

**Frac-pack completions performed by viscous-slurry and high-rate water pack (HRWP) techniques, respectively.**

**Tip-Screenout Fracturing**

Gravel packs typically have some degree of damage—positive skin—and rarely achieve low skin values consistently. Frac-pack completions, on the other hand, often result in higher productivity wells than gravel packs performed below or above fracture-initiation pressure, either by slurry packing or high-rate water packing (HRWP). Evaluations of wells completed during the past 10 years with these sand-control techniques show the dramatic impact of frac packing on total completion skin.

The permeability contrast between formations and propped fractures determines required fracture length for optimal reservoir stimulation. In lower permeability reservoirs, there is a large permeability contrast, and therefore, greater relative fracture conductivity. In high-permeability reservoirs, there is less contrast, and the relative conductivity of a narrow fracture is reduced by several orders of magnitude. This negates the value of fracture extension away from a well and underscores the need for wide fractures because conductivity is also directly proportional to propped width.

Short, wide fractures stimulate well productivity even in high-permeability formations. These highly conductive fractures alleviate sand production associated with high flow rates, perforation collapse in weakly consolidated formations and fines migration in formations with poorly sorted grain sizes by reducing near-wellbore pressure drop and flow velocity. These factors also defer critical stress conditions that crush formation grains until a lower reservoir pressure is reached.

Hydraulic fracturing in low-permeability, or tight, formations creates narrow propped fractures about 0.1 in. [2.5 mm] wide, extending 1000 ft [300 m] or more from a wellbore.

A TSO treatment generates propped fractures with widths up to 1 in. [2.5 cm] or more in soft-rock formations and wellbore-to-tip half-lengths of about 50 ft [15 m], depending on formation characteristics. For conventional treatments, final proppant concentrations in terms of fracture surface area are less than 2 lbm/ft² [10 kg/m²]. This contrasts with 5 to 10 lbm/ft² [24 to 49 kg/m²] concentrations for TSO designs.

A propped fracture increases completion radius and area open to flow. Compared with radial inflow, the resulting bilinear flow pattern reduces flow convergence and turbulence at the perforations, which enhances productivity. For example, a propped fracture with a 50-ft half-length and height of 22 ft [7 m] has 4000 sq ft [372 m²] of surface area; a gravel-pack completion in a 9-in. borehole has a maximum surface area of about 50 sq ft [5 m²] open to radial flow. The effective completion radius for each of these hypothetical frac-pack and gravel-pack completions is 50 ft and 4.5 in. [11.4 cm], respectively.

The tip of a hydraulic fracture is the final area packed by proppant during conventional fracturing of low-permeability, hard-rock formations. In contrast, TSO designs limit fracture length, or extension, by achieving fluid-leakoff rates that dehydrate the proppant slurry early in a treatment. This dehydration causes proppant to pack off near the peripheral edge, or tip, of a dynamic fracture. The hydraulic fracture inflates like a balloon as additional proppant-laden fluid is injected, creating a wider, more conductive pathway as proppant packs toward the well.
Bilinear Flow

11. Slurry-packing techniques use viscous polymer-base fluids to promote effective completion radius by establishing linear fractures and dominant bilinear flow. High-permeability formations, fracturing treatments create short, wide fractures that provide high reservoir stimulation and mitigate sand production by reducing near-wellbore pressure drop and flow velocity. In low-strength, or soft, formations, proppant concentration after fracture closure must exceed 2 lbm/ft² [10 kg/m²] to overcome proppant embedment in fracture walls.

14. Hydraulic fracturing begins with injection of a proppant-free fluid stage, or pad, at pressures above formation breakdown stress to initiate a crack in the rock and cool-down the near-wellbore region. This pad stage creates two fracture “wings” 180 degrees apart that propagate in the preferred fracture plane (PFP). The PFP lies in the direction of maximum horizontal stress, perpendicular to the least horizontal rock stress. Proppant-laden fluid stages follow to generate a required geometry—height, width and length—and pack the bioventing fracture with proppant. Proppants ensure that a conductive pathway remains open after fluid injection stops and dynamic fractures close.

Tip-screenout (TSO) fracturing. In high-permeability reservoirs, fracture stimulations require fluid systems that leak off early in a treatment. Dehydration of the slurry causes proppant to pack off at the fracture tip, halting further propagation, or extension. As additional slurry is pumped, biwing fractures inflate and proppant packs toward the wellbore. A TSO treatment ensures wider fractures and improves conductivity by promoting grain-to-grain contact in the proppant pack. This technique also generates enough formation displacement to create an annular opening between cement and formation that becomes packed with proppant. This “external” pack connects all perforations and further reduces near-wellbore pressure drop.
Fracture conductivity and reservoir stimulation do not account for all of the resulting productivity increase. Another factor is elimination of flow restrictions through the perforations. Aggressive frac packing opens a dynamic fracture up to 2 in. [5 cm] wide across all or most of the completion interval. The principles of rock mechanics dictate that the amount of subsurface movement required to generate wide TSO fractures also must create an annular opening outside of the cement sheath. This opening then is packed with proppant to form a ring, or “halo,” around the wellbore.

This “external” pack provides a more effective hydraulic connection between propped fractures and all the perforations, which further reduces pressure drop across completion intervals. Computer simulations indicate that perforations that are not aligned with propped fracture can contribute up to 50% of fluid flow into a wellbore in high-permeability formations (below). The proppant halo is a key factor in frac-pack success and the basis for screenless completions that control sand without mechanical screens and internal gravel packs (see “Emerging Technologies,” page 45).

Frac packing is a frontline defense against sand production, and properly designed TSO fracturing treatments are vital to the success of this important well-completion technique. Conventional cased-hole gravel packs often experience progressive loss of productivity, but production from properly designed and executed frac packs tends to improve over time as treatment fluids are recovered and wells clean up.17

Treatment Execution
Initially, operators performed frac packing in multiple steps—a TSO fracturing treatment followed by wellbore cleanout, installation of sand-exclusion screens and separate gravel-packing operations. However, high positive skins and limited productivity indicated damage between the propped fracture and internal gravel pack. Frac packing was simplified into a single operation to further improve well production and reduce operational costs. The TSO fracturing treatment now is pumped with screens in place. Gravel packing of screen assemblies is accomplished at the end of a treatment.

Like conventional gravel packing, fluids and proppants for frac packing are injected through tubing and a gravel-pack packer with a service tool in squeeze or circulating configuration (right). However, to withstand higher pressures during TSO fracturing, service companies adapted standard gravel-packing assemblies. Modifications include increased metal hardness, larger cross-sectional flow areas and minimizing sudden changes in flow direction to reduce metal erosion by fluids and proppants.

Squeeze configuration is used for most frac-pack treatments, especially in wells with production casing that cannot handle high pressures. Circulating position provides a path for fluid returns to surface through the tubing-casing annulus, or communication—a “live” annulus—to monitor pressure at surface independent of friction in wellbore tubulars, depending on whether the annular surface valve is open or closed. Friction pressures generated by pumping proppant-laden slurry through tubing and completion equipment often mask true downhole pressure responses when monitoring treating pressure on the tubing.

^ Perforation contributions. Inflow is not limited to the propped fracture cross-sectional area and perforations aligned, or connected, with the fracture wings. Computer simulations indicate that unaligned perforations contribute almost 50% of the inflow from high-permeability formations, underscoring the importance of TSO fracturing and creation of an external pack.

^ Downhole tools. In gravel packing and frac packing, a service tool directs fluid flow through a gravel-pack packer and around the screen assembly. Squeeze configuration is established by closing the annular blowout preventer (BOP) and the tubing-casing annulus surface valve (left), or by closing the ball valve downhole (right). Shutting in the annulus with the downhole ball valve open allows bottomhole pressure to be monitored independent of friction in the tubing. Closing the downhole valve prevents fluid returns to surface and protects weak casing from high pressures; pressure also can be applied to the annulus to offset high pressure in the tubing. Mechanical devices such as flapper valves or the FIV Formation Isolation Valve system prevent excess fluid loss into formations after the service tool is retrieved.
Early service tools used a conventional check valve, which prohibited pressure declines from being observed after fracturing. More recent designs of QUANTUM gravel-pack packer tools eliminate the check valve, replacing it with an improved downhole ball valve that allows pressure fluctuations to be monitored in real time during treatments when the ball valve is open. A live annulus allows more accurate evaluation of treatments.16

Frac packing usually begins in squeeze configuration. After tip screenout occurs, establishing circulating configuration ensures complete packing of the screens and grain-to-grain proppant contact. The service tool then is shifted to clean out excess slurry by pumping fluid down the annulus and up the tubing. The amount of upward movement required to shift some service tools pulls reservoir fluids into a wellbore. This swabbing effect can bring formation sand into perforation tunnels before a fracture is completely packed or reduce conductivity between fractures and the internal gravel pack, which can limit frac-pack productivity.

Set-down service tools, such as the QUANTUM gravel-packing system, close the downhole ball valve and shift tool configuration with upward movement. This type of tool also is used for deep completions and treatments conducted from floating rigs or drillships.

In addition to a variety of reservoir conditions and of fracturing and gravel-packing requirements, treatment execution must address the complexity of completing multiple zones and long intervals. Even the best frac-pack designs end in failure if excess fluid loss into formation causes proppant bridges to form between screens and casing, restricting or blocking annular flow. Annular proppant packoff, or bridging, results in early treatment termination, low fracture conductivity and an incomplete gravel pack around screens.

Placing proppant with sand-exclusion screens in place requires close attention to annular clearances. As frictional pressure increases, there is potential for fluid from slurry in the screen-casing annulus to pass through the screens into the washpipe-screen annulus. Fluid bypass worsens as the slurry dehydrates, and proppant concentration increases to an unpumpable state, causing proppant to bridge in the screen-casing annulus.

Annular blockage near the top of a completion interval prevents continued fracturing of deeper zones or zones with higher in-situ stress and inhibits subsequent packing of the screens. Even a partial flow restriction in the annulus increases frictional pressure drop, restricts rate distribution and limits fracture-height growth across the remainder of the completion interval. Annular voids below a proppant bridge increase the likelihood of screen failure from erosion by produced fluids and fine formation sand.

For homogeneous reservoirs where pay intervals are less than 60 ft [18 m] thick, fracture-height growth typically covers the entire zone. In longer intervals, the probability of complete fracture coverage decreases, and risk of proppant bridging increases dramatically. Long intervals can be split into stages and treated separately. This requires more downhole equipment, such as two stacked frac-packing assemblies, and additional installation time, but increases frac-packing effectiveness (see “Conventional and Alternate Path Screens,” next page).

Alternate Path technology is also available to gravel pack and frac pack longer intervals (right). AllFRAC screens use hollow rectangular tubes, or shunts, welded on the outside of screens to provide additional flow paths for slurry. Exit ports with carbide-strengthened nozzles located along the shunt tubes then allow fluids and proppant to exit below annular restrictions, which allows fracturing and annular packing to continue after restrictions form in the screen-casing annulus. AllFRAC screens for frac packing use slightly


larger shunt tubes than AllPAC screens for gravel packing to accommodate higher injection rates for fracturing.

Shunt tubes provide conduits for slurry to bypass collapsed hole and external zonal isolation packers as well as annular proppant gravel bridges at the top of intervals or adjacent to higher permeability zones with high fluid leakoff. If annular restrictions form, injection pressure increases and slurry diverts into the shunt tubes, the only open flow path. This ensures fracture coverage and complete gravel packing around screens across an entire perforated interval.

**Conventional and Alternate Path Screens**

In the late 1990s, Saudi Aramco chose frac packing to control sand in oil wells about 200 km [124 miles] southeast of Riyadh, Saudi Arabia (below). This new field in the Central Province encompassed two heterogeneous Permian-age reservoirs comprising high-permeability sandstones at 8700 to 9000 ft [2650 to 2740 m] that are interbedded with shale and siltstone.

The deeper B reservoir was a high-quality sandstone interbedded with thin, low-permeability siltstone. Reservoir thickness varied from 20 to 65 ft [6 to 20 m]. Well tests indicated permeability from 0.5 to 2 darcies; air-derived core permeabilities were 3 to 4 darcies. The A reservoir was a sequence of slightly more heterogeneous individual sandstones between lower permeability siltstone strata. This overlying reservoir was up to 200 ft [61 m] thick with net pay up to 75 ft [23 m]. Permeabilities from well tests were 0.1 to 2.5 darcies; air-derived core permeabilities were about 2 darcies.

A well completed without sand-control measures produced for less than six months before sand influx and suspected perforation collapse stopped production. If completion practices induced a significant pressure drop downhole, it would be difficult to control sand at oil rates and wellhead pressures that met production targets while allowing wells to flow naturally into existing facilities 50 km [31 miles] away. Frac packing satisfied well-completion requirements for both the A and B reservoirs.

Long completion intervals necessitated different frac-packing techniques for each reservoir (next page, top). Saudi Aramco used conventional screens in the B reservoir where pay zones were less than 60 ft thick. For longer perforated intervals in the A reservoir, the operator chose AllFRAC Alternate Path screens with three shunt tubes, each designed for 6 bbl/min [1 m³/min], to achieve required injection rates (next page, bottom).

Wells with an oil-water contact near the bottom perforations required close control of fracture height to avoid early water breakthrough. In other wells, perforations extended over long intervals and individual zones were spaced far apart. Engineers selected a stacked-screen completion to meet frac-packing objectives in these wells. Dividing the productive interval into two sections allowed Saudi Aramco to optimize treatment designs for each zone and avoid fracturing into water-bearing zones.

Typically, these frac-packing treatments included the pad, an initial low-concentration stage with 0.5 lbm/gal [0.06 kg/L], or pounds of proppant added (ppa) per gallon of fracturing fluid, and additional proppant stages ramped up to 3, 6 or 9 ppa [0.36, 0.72 or 1 kg/L]. In a few wells, 9-ppa stages were pumped successfully. Higher proppant concentrations were difficult to place in more permeable zones, but placing 3 and 6 ppa in the formation yielded good results.

Saudi Aramco and Schlumberger modified initial fracturing designs based on minifracture analysis using the Schlumberger DataFRAC fracture data determination service (see “Design and Implementation,” page 38). Fracture-closure stress, fluid-leakoff coefficient and fracture height from these pretreatment injectivity tests helped ensure that the main treatments achieved a tip screenout. The operator adjusted pad and proppant stages as needed and accounted for high fluid leakoff in the B sand by increasing the maximum injection rate to 18 bbl/min [2.9 m³/min]. Engineers also restricted pump rates to 16 bbl/min [2.5 m³/min] for the A reservoir Alternate Path completions to limit friction pressure in the shunt tubes.

The operator performed post-treatment hydrochloric (HCl) acid jobs on some wells to reduce cleanup time. Other wells cleaned up within two months without acid treatments. Overall well productivity continued to improve as treatment fluids were recovered. Experience from the first wells helped optimize frac-packing procedures. Saudi Aramco reduced polymer concentrations in treatment fluids and included slow-release encapsulated breakers to optimize fracture placement and post-treatment cleanup.

![Sand-control completions onshore. In the late 1990s, Saudi Aramco began frac packing new oil-well completions in central Saudi Arabia about 200 km [124 miles] southeast of Riyadh. These frac packs controlled sand influx and reduced downhole pressure drop, allowing the wells to flow naturally into facilities 50 km [31 miles] away under existing intake-pressure conditions.](image-url)

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<B-sand completions. A typical well log indicates a maximum pay interval of about 65 ft with closely spaced perforations in the B reservoir (left). Relatively short perforated intervals allowed Saudi Aramco to install a single completion and frac pack these lower sands using standard screens (right).

>A-sand completions. A typical well log shows perforations across a 180-ft [55-m] interval of the A reservoir (left). Saudi Aramco performed two separate treatments using a stacked-screen assembly to frac pack these longer intervals (right). Standard screens were used for the lowest zone, which was shorter. AllIFRAC screens with shunt tubes were installed to complete the longer upper zone.
The initial group of wells included five completions with conventional screens in the B reservoir and five completions in the A reservoir with AllFRAC screens that successfully treated intervals up to 200 ft. Two completions in the A reservoir used stacked-screen assemblies. Treatments were pumped through 9000 ft of 3-in. outside diameter (OD) tubing at surface injection pressures below 10,000 psi [69 MPa] and pump rates of 14 bbl/min [2.2 m³/min] to 18 bbl/min.

The operator performed well tests by flowing through surface facilities or with downhole production logging tools to evaluate 12 frac-packing treatments on the first 10 completions in this field (left). Except for two, these frac-pack completions yielded low completion skin and good sand control in formations with up to 3-darcy permeability.

A positive frac-pack skin is caused by inadequate connectivity between propped fractures and wellbores, incomplete zone coverage or failure to achieve a high-conductivity TSO fracture. If these conditions produce a completion skin of 8 or more, well productivity may be no better than that of a conventional gravel pack. Achieving optimal frac-pack performance, as in the case of these Saudi Aramco wells, requires detailed preliminary designs, careful proppant and fluid selection, accurate pretreatment injectivity testing and treatment optimization as needed.

**Design and Implementation**

During the initial design of frac-packing treatments, completion engineers determine required fracture geometry based on reservoir conditions, rock properties and barriers to fracture-height growth. Fracture length and, more importantly for high-permeability formations, fracture width enhance well productivity. Operators select an optimal TSO fracture design by maximizing the net present value (NPV) from enhanced well productivity (left).22

**Proppant selection**—The type of proppant chosen to keep fractures open and form a granular filter is an important design consideration. Frac-packing success is due, in part, to larger proppant sizes than those commonly used in gravel packing. High concentrations of large, spherical proppants minimize embedment and offset the effects of turbulent flow in propped fractures.

Operators use various grain sizes and proppant types, including natural sand, custom-sieved sand, resin-coated sand and intermediate or high-strength man-made ceramic proppants, depending on formation stress and fracture-closure pressure. Proppants for frac packing should accomplish four fracturing objectives:
• provide an effective permeability contrast
• control sand influx and fines migration
• minimize proppant embedment in soft rock
• maintain fracture conductivity without proppant crushing.

In the past, gravel-packing considerations dominated proppant selection. Gravel packs require gravel, or sand, sized to prevent formation particles and fines from invading the annular pack. The widely accepted Saucier rule dictates that sand, or gravel, particles be five to six times the mean particle diameter of formation grains. Fracture permeability and conductivity improve as proppant sizes become larger, but production of formation sand grains and fine particles that reduce pack permeability also increases. Frac packs require proppants sized to optimize fracture permeability.

In the early 1990s, operators began evaluating larger sizes of stronger proppants to increase fracture permeability and relative conductivity in high-permeability reservoirs. For example, larger 20/40-mesh proppants were used for frac packing instead of smaller 40/60-mesh proppants often required for gravel packing. Experience indicated that proppant sizes dictated by gravel-packing criteria could be increased to next larger size for frac packing.

Saucier criteria for sizing proppants in relation to formation grain size were relaxed in frac-pack designs because the large flow area of hydraulic fractures mitigates formation failure and sand influx. Balancing the mechanisms of sand production—flow velocity, proppant particle sizes, and fluid properties—allows operators to increase fracture conductivity and improve frac-pack performance by using larger proppant sizes.

Completing deeper wells with high fracture-closure stresses led operators to use more man-made ceramic proppants because they are stronger and their consistent spherical shape reduces embedment, which also increases fracture conductivity (above right). The majority of frac packs use ceramic 20/40-mesh intermediate-strength proppant (ISP) when reservoirs have good pressure support and closure stresses are not excessive.

Fluid selection—After evaluating reservoir characteristics, engineers choose an optimal fluid for combined stimulation and gravel packing. The polymer-based hydroxyethylcellulose (HEC) fluids used in gravel packing, hydroxypropyl guar (HPG) fracturing fluids with a borate crosslinker for additional viscosity, and more recently, viscoelastic surfactant (VES) fracturing fluids, all are applicable. Frac-packing fluids must have a variety of properties.

Fluid selection depends primarily on TSO fracturing criteria. Unlike massive hydraulic fracture stimulations in low-permeability formations, a low leakoff rate, or high fluid efficiency, is less desirable for frac packing. In fact, a somewhat inefficient fluid helps achieve tip screenout and promote grain-to-grain proppant contact from fracture tip to wellbore.

However, frac-packing fluids also must maintain sufficient viscosity to create wide dynamic fractures and place high proppant concentrations that ensure adequate conductivity after fracture closure. After tip screenout, fluid systems transport proppant in the low-shear environment of a wide dynamic fracture, but also must suspend proppant under higher shear rates in tubing, around screen assemblies, through the perforations and during fracture initiation and propagation.

Fluid viscosity should break easily to minimize formation and proppant-pack damage after treatments. Optimal fluids need to be compatible with formations and chemicals such as polymer breakers; they must also produce low friction and clean up quickly during post-treatment flowback. To maximize retained fracture conductivity, operators exercise great care with viscosity breakers or acid treatments after frac packing to optimize post-treatment cleanup for maximum productivity and hydrocarbon recovery. Finally, frac-packing fluids should be safe, cost-effective and easy to mix, especially in offshore applications.

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Fluid viscosity should break easily to minimize formation and proppant-pack damage after treatments. Optimal fluids need to be compatible with formations and chemicals such as polymer breakers; they must also produce low friction and clean up quickly during post-treatment flowback. To maximize retained fracture conductivity, operators exercise great care with viscosity breakers or acid treatments after frac packing to optimize post-treatment cleanup for maximum productivity and hydrocarbon recovery. Finally, frac-packing fluids should be safe, cost-effective and easy to mix, especially in offshore applications.

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Fluids based on HEC have many preferred frac-packing characteristics, but also several drawbacks. Systems based on HEC exhibit increased friction pressures compared with delayed crosslinked HPG or VES fluids, and frictional losses become significant in deeper wells or smaller diameter tubulars. In addition, proppant transport characteristics for HEC fluids are not as good as those of crosslinked HPG or VES fluids. High temperatures cause HEC fluids to thin, and viscosity is not as high at low shear rates.

High-viscosity crosslinked HPG systems leave some polymer residue, but maximize fracture height growth in moderate- to high-permeability formations. They also perform well in longer intervals and transport higher proppant concentrations for greater fracture conductivity. Pumping pressures increase with HPG systems, but service companies can used a delayed crosslinker to reduce tubular friction.

Delayed-crosslink HPG fluids start at a lower viscosity and require less hydraulic horsepower to pump downhole. Prior to reaching the perforations, temperature in the wellbore and fluid pH cause the viscosity of these fluids to increase in order to achieve low fluid-leakoff rates. The majority of frac packs are pumped with crosslinked or delayed-crosslink HPG fluids.

Viscoelastic ClearFRAC polymer-free fracturing fluids, introduced in the mid-1990s, use a VES liquid-gelling agent to develop viscosity in light brines. This type of fluid provides low friction pressures while pumping, enough viscosity at low shear rates for good proppant transport, adequate leakoff rates to ensure tip screenout and high retained permeability for better fracture conductivity. Field data also indicate that fracture confinement using VES fluids is better than with conventional fracturing fluids, which is an advantage when frac-packing near water-bearing zones.

These VES systems mix easily and do not require additives such as bactericides, breakers, demulsifiers, crosslinkers, chemical buffers or delayed-crosslink agents. Systems based on VES also are not susceptible to bacterial attack. If wells must be shut in for extended periods before flowback and cleanup, solids-free ClearFRAC fluids are recommended to avoid precipitation of damaging polymer materials.

Fluids based on HEC and VES systems minimize formation damage in zones with low to moderate permeability, but high leakoff rates and deeper invasion often result in slower recovery of treatment fluids. Adding enzyme or oxidizing breakers to frac-packing fluids reduces formation damage and improves well cleanup. Slow-release

\[ \text{Fluid viscosity versus typical shear rate (blue) in laboratory tests.} \]

Under frac-packing conditions of fracture extension and tip screenout in an Amoco, now BP, Matagorda Island field in the US Gulf of Mexico, a 35-ppt crosslinked HPG fracturing fluid (green) exhibited adequate viscosity behavior, while 40- and 45-ppt systems (red and gold, respectively) had unnecessarily high viscosities.

\[ \text{Improving frac-pack productivity. Production from frac-pack completions in a field of the Gulf of Mexico Matagorda Island area doubled after Amoco, now BP, began using an optimized 35-ppt crosslinked HPG fluid (Wells 5–7) instead of an initial fluid system with 50-ppt polymer concentration (Wells 1–4). Well 7 also had a high productivity ratio, but output was limited by small production tubing.} \]
encapsulated breakers deposited in the proppant pack allow higher breaker concentrations to be used without sacrificing fluid efficiency.

In addition to fluid leakoff and friction pressure considerations, shear rate and temperature are critical in selecting frac-packing fluids and polymer concentrations. The first frac-pack treatments were performed using the same HEC fluid systems as gravel-packing operations. Later, a shift to more conventional fracturing fluids occurred because of increasing temperature requirements and the need to maximize fracture conductivity in high-permeability formations.

Initially, selection criteria for these fluids were similar to those of conventional fracturing applications in which narrow hydraulic fractures in consolidated, low-permeability formations create high shear rates with low fluid-leakoff rates. These factors result in breakdown of fluid viscosity and less cooling of formations, and greater polymer concentrations are required to maintain viscosity throughout a treatment. The use of higher polymer concentrations carried over into fracturing and frac-packing designs for high-permeability reservoirs.

In frac packing, however, fractures are wider with lower fluid velocities and shear rates. Pretreatment fluid injection also decreases formation temperature near the wellbore. Pumping large volumes of treatment fluid decreases heat transfer from a reservoir, resulting in cooler temperatures inside a fracture. Failure to consider these effects results in use of higher polymer concentrations than actually required. This increases the potential for formation damage and decreases the likelihood of a tip screenout.

For example, because of differences in shear rate, a crosslinked fluid with a polymer loading of 20 lbm/1000 gal (ppt) [2.4 kg/m³] of base fluid can have the same viscosity in a high-permeability formation as a 40-ppt [4.8-kg/m³] fluid in a low-permeability formation. Proper fluid selection and specification dramatically increase frac-packing efficiency and well productivity.

In 1996, Amoco, now BP, completed four Matagorda Island wells in the western Gulf of Mexico by frac packing. The reservoir temperature was 300°F [150°C], so the operator chose a high-viscosity 50-ppt [6-kg/m³] crosslinked HPG fluid that was also used in fracture-stimulation treatments for low-permeability reservoirs. Production from these frac-pack completions was comparable to that of gravel-packed wells. The operator attributed the relatively poor performance to lack of tip screenout because of improper fluid design.

The operator and Schlumberger evaluated the effects of shear rate on fluid properties in order to remedy poor performance (previous page, top). Based on the results of this investigation, frac-pack treatments on the next three wells used a 35-ppt [4.2-kg/m³] fluid. Fluid efficiency decreased because of lower viscosity, allowing better slurry dehydration, which achieved desired TSG results. Average daily production from these wells doubled compared with the initial four wells (previous page, bottom).

Pretreatment testing—Laboratory testing and history matching of previous treatments provide insight into stress profiles and the performance of treatment fluids, but in-situ formation properties vary significantly in high-permeability unconsolidated reservoirs. After developing preliminary stimulation designs, engineers perform a pretreatment evaluation, or minifrac, to quantify five critical parameters, including fracture-propagation pressure, fracture-closure pressure, fracture geometry, fluid efficiency and leakoff.

This procedure consists of two tests, a stress test and a calibration test, performed prior to the main treatment to determine specific reservoir properties and establish the performance characteristics of actual treatment fluids in the pay zone. A stress, or closure, test determines minimum in-situ rock stress, which is a critical reference pressure for frac-pack analysis and proppant selection (above).

A calibration test involves injecting actual fracturing fluid without proppant at the design treatment rate to determine formation-specific fluid efficiency and fluid-loss coefficients. Fracture-height growth can be estimated by tagging proppants with radioactive tracers and running a post-treatment gamma ray log. A pressure-decline analysis confirms rock properties and provides data on fluid loss and fluid efficiency.

An integral part of pretreatment testing is live-annulus monitoring and real-time measurements from downhole quartz gauges to obtain pressure responses independent of frictional pumping pressures. Accurate analysis using DataFRAC services ensures that the current frac-pack design and subsequent treatments achieve wide fractures with a tip screenout for optimal results.

Surface data from pretreatment tests combined with bottomhole injection pressures are history matched using a computer simulator, such as the SandCADE gravel-pack design and evaluation software, to calibrate the fracturing model and finalize treatment design. Calibrated data from DataFRAC analysis are also used to assess stimulation effectiveness during post-treatment evaluations.

Treatment design, particularly TSO fracture stimulation, is critically important to successful frac packing. If premature screenout or failure to achieve a tip screenout results in insufficient fracture width to overcome proppant embedment in the formation, well productivity may, at best, be equivalent to that of a conventional gravel pack. Standard frac-packing practice is to redesign treatments on-site after minifracture testing and analysis are complete.

**Treatment design—Previously, frac packs, which sometimes failed because of premature fracture screenout or early annular packoff, were designed solely using hydraulic-fracturing simulators that neglected gravel-packing and completion equipment inside the wellbore, such as crossover ports in gravel-pack packers, blank pipe, screens and washpipe. With the SandCADE simulator, engineers now specify tip-screenout designs and simulate frac-packing treatments using coupled wellbore and hydraulic-fracturing simulators.** This software also simulates slurry flow including the effects of well inclination, gravel setting and bridging around screens, and fluid flow through packer and screen assemblies.

The fracture simulator supports tip-screenout designs in high-permeability formations. Inducing gravel packoff in wellbores by deliberately reducing pump rate or shifting service tools to circulate at the end of a treatment also can be modeled. The SandCADE simulator also models fracturing of multiple layers and shunt-tube flow.

**Well-Completion Applications**
Fracturing designs based on TSO technology, larger proppant particle sizes, advances in fracturing fluids and improved treatment evaluation combined with more robust and versatile pumping equipment and downhole tools make frac packs a viable completion alternative in many wells. Experience from more than 4000 Gulf of Mexico frac packs in formations with permeabilities ranging from 3 mD to 3 darcies helps oil and gas producers identify frac-pack candidate wells. Frac-packing well-completion applications include the following:

- wells prone to fines migration and sanding
- high-permeability, easily damaged formations
- high-rate gas wells
- low-permeability zones requiring stimulation
- laminated sand-shale sequences
- heterogeneous pay zones
- low-pressure and depleted reservoirs.

Today, operators select sand-control methods by determining first if conditions justify frac packing. There are 11 major advantages to frac packing:

- bypass formation damage
- increase completion radius and flow area
- reduce pressure drop and fluid velocity
- connect individual laminated zones
- re-stress borehole relaxation after drilling
- alleviate fines migration and sand production
- improve well productivity
- achieve consistent low-skin completions
- sustain increased production
- maintain completion longevity
- reduce the likelihood of sand-control failure.

Most wells requiring sand control benefit from frac packing. Exceptions include locations where high-pressure pumping equipment is unavailable, wells with casing sizes that are less than 5 in., wells with weak casing when there is a risk of failure and loss of wellbore integrity or completions with a possibility of fracture-height growth into water or gas zones. Frac packing also may not be economical for low-rate wells, water-source or injection wells that do not produce revenue directly, and reservoirs with

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^ Modeling frac-packing treatments. The Schlumberger SandCADE simulator is the only commercially available software that accounts for completion and gravel-packing equipment. A hydraulic-fracturing simulator that calculates fracture geometry, proppant distribution in fractures, and two-dimensional fluid flow as boundary conditions is coupled to wellbore simulator, which models fluid and slurry flow in the screen-casing annulus and Alternate Path shunt tubes. A special feature simulates fracturing of multiple layers with or without shunt tubes. This example illustrates simultaneous frac packing of three zones. Without shunt tubes, the treatment places most of proppant in the middle zone (left). Alternate Path screens ensure treatment of the entire completion interval as well as more uniform fracture lengths and widths (right).
limited reserves or homogeneous thick zones where horizontal gravel packing in openhole is more appropriate.36

In more prolific reservoirs, flow turbulence associated with perforated casing restricts production, so operators often drill and complete openhole horizontal wells to optimize productivity. Stand-alone screens, openhole gravel packs or expandable screens are sand-control options in these settings, especially for thick reservoir sections. Frac packing in openhole completions is the next logical step to provide long-term sand control without sacrificing productivity.

Openhole Frac Packing

Widuri field, operated by Repsol YPF, lies offshore in the Java Sea, Indonesia (above). Drilled in an area scheduled for waterflooding, Well B-28 targeted a thin sandstone of the Talang Akar formation at 3500 to 3600 ft [1067 to 1097 m] with 29% porosity and 1- to 2-darcy permeability.37 Original reservoir pressure was 1350 psi [9.3 MPa], but solution-gas drive and weak aquifer support resulted in rapid depletion to 600 psi [4 MPa]. Moderate consolidation and a tendency to produce sand mandated sand-control completions. Initially, wells were completed as cased-hole gravel packs. Because of lower reservoir pressure, the operator planned cased-hole frac packs for new wells.

Openhole frac packing. Repsol YPF chose to frac pack an openhole completion located north of Jakarta, Indonesia, in the offshore Widuri field to maximize well productivity.
An unexpected low bottomhole pressure of 390 psi [2.7 MPa] resulted in complete fluid loss while drilling the B-28 well. A high-pressure, reactive shale above the pay zone required that the operator set 7-in. casing to isolate this potentially unstable section. Hole collapse caused this casing string to be set high, leaving 70 ft [21 m] of shale exposed after drilling deeper. Repsol YPF suspended the well temporarily after attempts to run a screen assembly failed.

After five months of waterflooding, reservoir pressure increased enough to hold a water column and maintain hole stability. Repsol YPF decided to attempt an openhole frac pack because running 5-in. casing was too restrictive for an internal gravel pack. This approach presented several challenges, including openhole stability, screen deployment, fracturing a long high-permeability section, proppant slurry contamination in exposed shale and annular packing efficiency in a 70° inclined wellbore. Incomplete packing and completion failures on other completions raised concerns about frac-packing effectiveness in high-angle wells.

Repsol YPF chose an innovative combination of Alternate Path screens and a multizone (MZ) isolation packer to avoid fluid contamination, facilitate effective fracturing and ensure complete packing of the long openhole section. Two large shunt tubes designed for pumping 15 bbl/min [2.4 m³/min] extended through the packer, bypassing the reactive shale section and the entire pay interval. The design incorporated an inner washpipe that conveyed drilling fluid to a drilling motor. This motor could rotate a bit on the bottom of the assembly if required to deploy the completion equipment. An outer shroud with holes protected screens from damage in the openhole.

Elastomer cups on the MZ packer prevented annular flow and diverted fluid to the shunt tubes. Exit nozzles on the shunt tubes did not begin until just above the screens to avoid any injection across the shale. Slurry bypassed the shale section, exiting through nozzles along the screens to fill gaps in the pack below proppant bridges that might form. This configuration preserved fracture and proppant conductivity by eliminating fluid contamination from the reactive shale.

Frac-pack execution went smoothly despite concerns about the high-angle wellbore, multiple competing fractures and excessive fluid leakoff through 225 ft [69 m] of openhole interval with 47 ft [14 m] of high-permeability net sand.
Treatment simulation indicated a final fracture half-length of 18 ft [5.5 m] with a propped width of 1 in.

Initial production of 2000 B/D [318 m³/d] total fluid with 500 B/D [79 m³/d] of oil from an electrical submersible pump exceeded operator expectations. Post-treatment skin was not measured by pressure-buildup analysis, but a sensor on the electrical submersible pump monitored downhole flowing pressures, which indicated a small pressure drop at the completion face.

Well performance was evaluated by calculating a productivity index (PI) based on net reservoir thickness from flowing bottomhole pressures, reservoir pressure and production rates (below). Well B-28 outperformed most wells in the field and compared favorably with wells completed by openhole horizontal gravel packing. Considering the excessive fluid losses during drilling, this level of productivity demonstrates the feasibility of openhole frac packing as a sand-control alternative in extremely permeable reservoirs with high mobility ratios.

Emerging Technologies

New developments continue in all aspects of frac packing, from improved sand prediction and treatment modeling, to new fluids that reduce damage in both propped fractures and annular packs. New placement techniques improve frac packing by applying new downhole equipment or eliminating subsurface hardware entirely. Fluid additives that are in testing promise to minimize production declines by reducing fines migration and preventing scale deposition.

Frac-pack placement data generally indicate creation of a fracture and subsequent tip screen-out, but post-treatment pressure data often indicate positive skin values and some remaining damage, raising questions about the effectiveness of propped fractures. More realistic models have been developed to resolve discrepancies between geophysical evaluations, well-log interpretation, fracturing data from frac-packing treatments and well-test pressure analysis (right). Generating consistent solutions and resolving discrepancies require measurement of multiple parameters within a discipline, and integration across disciplines.

Differential stresses make uniform hydraulic fracture diversion and complete coverage difficult in long intervals of heterogeneous formations, even when Alternate Path technology is used. This is particularly true if stress profiles vary significantly when high-permeability zones with lower stresses occur at the top of a long interval. Preferential propagation of fractures in zones with lower in-situ stresses results in suboptimal reservoir stimulation.

Ocean Energy used an innovative technique in the Gulf of Mexico to ensure uniform stimulation and annular packing across long intervals in a field in the Eugene Island area. The operator pumped more than one pad-slurry sequence during a treatment without shutting down to sequentially increase the resistance to fracture extension, or fracture stiffness, in each zone from lowest to highest in-situ stress. As proppant packed toward a well, fractures became more difficult to propagate, and the next pad-slurry sequence diverted into other zones of long heterogeneous intervals.

In this application, AIFRAC screens improved frac-pack treatment diversion across long intervals. Multiple temperature gauges with electronic memory placed strategically in the washpipe monitored slurry diversion through

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shunt tubes to other zones (above). Temperature decreases indicated fluid flow past a gauge, and temperature increases corresponded to reduced flow or no fluid movement at a gauge. Temperature responses at the gauges confirmed complete interval coverage and diversion of treatment fluids into individual target zones. Net pressure developed during the treatment indicated a tip screenout.

Individually frac packing multiple zones in a single wellbore is time-consuming and expensive. An alternative to stacked frac-pack completions uses Alternate Path screens and MZ isolation packers with bypass shunt tubes to complete more than one zone in a single pumping operation with the same gravel-pack packer (next page, left). This diversion technique uses pressure drop in the shunt tubes to control fluid flow. Changing the number and length of shunt tubes going to each zone controls pressure drop. Engineers vary shunt-tube configurations to achieve the desired rate distribution. This system potentially allows up to three zones to be completed at reduced cost and improved profitability.

Operators often bypass many marginal, or secondary, pay intervals. These zones may never be exploited because of the mechanical risk of extending the frac-pack interval length up or down and the cost of mobilizing a rig to recomplete the well, especially offshore where the vast majority of frac packs are performed. Recently, new technologies have been introduced that promise to speed routine application of “rigless” completions.

Coiled tubing-conveyed fracturing technology, including CoilFRAC stimulation through coiled tubing service, is rapidly becoming a viable tool for exploiting bypassed pay.4 This new technology has been applied successfully onshore in multilayered, low-permeability reservoirs, but the next step is to take this technology offshore. Accessing offshore wellbores in a workover environment and placing a frac pack or screenless completion in a new zone without using a costly conventional drilling or workover rig opens up countless future opportunities. Significant friction reduction with VES fluids may increase application of coiled tubing-conveyed fracturing by allowing this type of rigless completion to be performed at greater depths.

Operators recently began evaluating and installing sand-exclusion screens that expand against the borehole wall. An annular gravel pack is not required to achieve wellbore stability. Expandable compliant screens also could be installed after frac-packing treatments to eliminate internal annular packs.

Emerging screenless techniques potentially produce completions with a negative skin and reduce completion costs while maintaining effective sand control.4 It is assumed that TSO fracturing and the proppant ring around a wellbore act as a sand filter. However, any area not covered leaves perforations open to produce sand. This technique requires various combinations of oriented perforating, injection of organic resins to hold formation grains in place and resin-coated proppants or fiber technology to prevent proppant flowback (next page, right). Porous ScalePROP scale-inhibitor-impregnated proppants can improve inhibitor placement and ensure uniform chemical release for extended protection against scale buildup in completion equipment and tubulars.
**Future Trends**

Engineers recognize that conventional fracturing simulators based on linear elastic fracture mechanics do not adequately model frac packing. Current research is evaluating new modeling concepts that account for differences in elastic and plastic behavior between hard and soft formations. Effects of fluid injection during pretreatment minifracture tests on potential fluid loss during the main treatment also are being studied. Future frac-packing simulators will account for fluid-injection behavior to further improve frac-pack designs.

A better understanding and modeling of fluid rheology, with control of fracturing net pressure, may help companies fracture small zones without breaking into nearby barriers or into water and gas zones, especially when combined with frac-pack designs that control net-pressure increase.42

Recent advances in fluids promise additional improvement in frac-pack productivity. These include low-polymer crosslinked HPG, delayed-crosslinker and polymer-breaker improvements, and extension of temperature limits for solids-free VES systems beyond 300ºF. Alternatives to current polymer systems are also being evaluated. Finding or creating new polymers may be the key to developing a completely new fracturing fluid.

MudSOLV filter-cake removal services currently used for simultaneous gravel packing and cleanup in openhole gravel packs may find similar application in openhole frac packing.43 Incorporating aggressive breakers and filter-cake removal chemicals into fracturing fluids without affecting base properties would be advantageous during frac-pack treatments to ensure chemical contact with the entire openhole section and provide a uniform production profile.

The increasing use of synthetic oil-base mud, especially in high-permeability reservoirs, will require compatible fracturing fluids. This need will become increasingly important as operators perform more openhole frac packs. Fluid compatibility, formation wettability and filter-cake cleanup have to be addressed in the context of expensive displacement to water-base systems and oil-base fluid handling.

Some of these techniques require further development, but as frac-packing treatments are implemented in a wider range of reservoirs and subsurface conditions, new ideas and techniques will be developed to fully realize the benefits of combined stimulation and sand-control techniques. —MET

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^ Frac packing and gravel packing multiple zones in a single trip. Multizone (MZ) isolation packers with shunt tubes allow more than one interval to be treated with the same gravel-pack packer during one pumping operation in a single trip into the wellbore. Treatment fluids pass through shunt tubes in MZ packers located at the top and bottom of a completion interval to isolate individual zones. Shunt-tube size and configuration balance flow between the zones to create two or three fractures simultaneously. This capability reduces the incremental cost to access additional reservoirs.

^ Screenless completions. Combined with frac packing, resin consolidation, resin-coated proppants or PropNET hydraulic fracturing proppant-pack additives (top right) potentially control proppant and sand production without sand-exclusion screens and internal gravel packs (top left). Cost savings include elimination of the screens, associated rig time for screen installation and placing an annular pack. In addition, porous ScalePROP scale-inhibitor-impregnated proppants contain a solid phase of scale inhibitor (bottom left). This method distributes the chemical throughout a proppant pack to avoid loss of inhibitor and scale protection during initial well flowback and cleanup of treatment fluids; slow dissolution ensures uniform inhibitor release during production (bottom right).