Clear Fracturing Fluids for Increased Well Productivity

Hydraulic fracturing treatments can greatly improve well productivity by decreasing wellbore skin. Residue from conventional polymer-base fluids, however, may clog pore spaces in the proppant pack, reducing fracture permeability. A new fracturing fluid offers a solution by not using polymers. This viscoelastic surfactant fluid requires no chemical breakers, yet cleans up better than crosslinked polymer fluids, leading to a lower skin and greater well productivity.
A successful hydraulic fracturing treatment has too long been defined as one that was pumped without problems. Rather, the true measure of a successful fracture treatment is increased production or injectivity. The objective is to improve fluid communication between the reservoir and the well. One of the most significant developments in hydraulic fracturing has been the realization that many stimulation treatments might not produce a negative skin or decrease the skin as much as desired. Laboratory testing indicates that unbroken residue from solids-base polymer fluids can plug the pores in the proppant pack. Some of this polymer residue can remain in the well indefinitely, hindering production.

The ideal fracturing fluid should show minimal pressure drop in the pipe during placement, have adequate viscosity to carry proppant effectively and degrade after the fracture closes so as not to leave residual material.

From a historical perspective, fracturing fluids have evolved significantly since the first fracture stimulation was performed in 1947. Early stimulation treatments used surplus napalm added to gasoline to create a viscous fluid capable of initiating and propagating a fracture. During the 1950s, viscous oils and gelled oils were the fluids of choice, as it was generally believed that water introduced into oil reservoirs would cause formation damage. With the realization that water did not cause as much damage as originally thought, engineers began pumping water gelled with guar and guar derivatives (linear gelled water) in the 1960s.

As fracturing grew in popularity in the 1970s, wells were also being drilled deeper and hotter formations were encountered. There was an increasing need for fluid viscosities greater than those offered by linear gels. To attain sufficient viscosity and increased thermal stability in higher temperature reservoirs, linear gels were crosslinked with borate, zirconate or titanate ions.

In the 1980s, foamed fracturing fluids grew more popular as engineers became more aware of the permeability damage caused by polymeric fluids. The use of foams decreased the amount of guar introduced into the fracture, thereby reducing the amount of residue and, hence, the extent of damage. In a foam fluid, the gas phase typically occupies more than half of the total fluid volume, so less liquid, and hence less guar, is pumped into the well. Foams also enhance cleanup after a fracturing treatment. The liquid volume is lower, and the entrained gas offers significantly more energy to evacuate the fracturing fluid from the well.

The quest for cleaner fluids continued into the 1990s, when advanced breaker technology and lower polymer concentrations became effective tools for reducing and limiting damage from guar.

The next step was the development of a polymer-free aqueous fracturing fluid. This fluid is unlike guar or hydroxyethyl cellulose (HEC) fluid systems; rather, it belongs to a new class of fracturing fluids—those based on viscoelastic surfactants. This article discusses the new polymer-free fracturing fluids and, with specific case studies, details how they may be used most effectively to increase well productivity.

2. Skin is a zone of reduced permeability near the wellbore. Skin damage causes an excess pressure drop around the wellbore and reduces formation fluid flow into the wellbore.
Viscoelastic Surfactant Development

In 1983, The Dow Chemical Company introduced fatty amine quaternary ammonium salts containing alkyl groups longer than C14 as thickeners in consumer products, such as bleach, liquid dishwashing detergent and topical cosmetics. These viscoelastic surfactants belong to a class of compounds that form micelles in an aqueous system containing certain anions. The deformation of such systems is time dependent; the system acts as a solid unless a sufficient amount of shear has been applied for a certain length of time. When the system deforms, the rheological behavior is nearly Newtonian.

A viscoelastic surfactant fluid provides excellent particle suspension. Dowell applied this fluid technology first as a gravel-pack fluid, PERMPAC fluid. The surfactant is added to common completion brines—potassium chloride, ammonium chloride, calcium chloride or calcium bromide—to suspend gravel effectively. The surfactant concentration varies from 2.5 to 6% by volume, depending on the anticipated temperature in the well. The main advantage of this fluid, unlike polymer-base systems such as guar or HEC, is that little residue is left upon breaking. This type of treatment results in a gravel pack with significantly higher conductivity.

The principal advantages of viscoelastic-surfactant fluids are ease of preparation, minimal formation damage and high retained permeability in the proppant pack. The fluids are typically prepared by continuous mixing of the surfactant into the brine before it passes through a high-shear blender. The blender provides sufficient shear for complete dispersion of the surfactant and fluid viscosification. Viscoelastic surfactant fluids can also be used in frac pack and in conventional high-permeability fracturing treatments. The original PERMPAC surfactant works well in these applications, but cost and temperature limitations—less than 140°F [60°C]—prevented widespread use in hydraulic fracturing applications. Recent modifications to the chemical structure of the surfactant have reduced the fluid cost and increased the temperature limit to 200°F [93°C], opening the door to hydraulic fracturing applications.

The ClearFRAC surfactant is a blend of a quaternary ammonium salt, erucyl bis (2-hydroxyethyl) methyl ammonium chloride (derived from rapeseed oil), with isopropanol. ClearFRAC fluid is a mixture of this surfactant in brine. The preferred brine compositions include 3% by weight of ammonium chloride and 4% by weight of potassium chloride solutions. At temperatures greater than 150°F [66°C], sodium salicylate is added as a stabilizer. The surfactant concentration varies from 0.7 to 4% by volume.

Breaking ClearFRAC fluids. No additional chemicals are usually needed to break ClearFRAC fluids. Dilution by formation water or contact with hydrocarbons will disrupt the rod-shaped micelles, breaking the fluid.
Tail groups are on the inside, and the hydrophilic groups are on the outside. Such structures are called micelles. In the case of ClearFRAC fluid, the micelles are rod-shaped or worm-like (previous page, top). If the surfactant concentration is above a critical concentration, the micelles entangle and hinder fluid movement. Such interactions produce the fluid’s viscosity.

The viscosity of ClearFRAC fluids is broken by two mechanisms: contact with hydrocarbons or dilution by formation water (previous page, bottom). Because one or both of these conditions occur in fractured wells, no additional breaker chemicals are required; however, there are some common additives which can contribute to the break mechanism. Produced oil, condensate or dry gas affects the electrical environment in the fluid, disrupting the micelles. The micelles change shape from rods to spheres, and fluid viscosity is lost because the micelles can no longer become entangled. In the case of formation water, dilution of ClearFRAC fluid reduces the surfactant concentration, and the rod-shaped micelles no longer entangle with one another.

The field application of these fluids has been successful. Present applications include wells in which fracture conductivity or fracture length is important, mobilization of complex mixing equipment is difficult, or situations where cleanup is an overriding concern.

Operationally, the preparation of ClearFRAC fluids is simple (left). Because no polymer hydration is required, the surfactant concentrate can be metered continuously into the brine for easy mixing. No crosslinkers, breakers or other chemical additives are necessary. The mixing of the fracturing fluid is simplified by elimination of variances due to polymer hydration and breaker effects and the need for extensive metering and pumping systems. Moreover, there is less waste due to elimination of tank bottoms, the unpumpable residual fluid remaining in the bottom of the containers used in batch-mixed jobs.

---

6. A micelle is a molecular aggregate.
8. Stewart et al., reference 3.
**Fluid-Loss Control**

Unlike polymer-base fracturing fluids, ClearFRAC fluid does not form a filter cake as a result of leakoff into the formation. Consequently, the fluid-loss rate is essentially constant with time (left). Also, unlike polymer-base fluids where a lower viscosity aqueous phase enters the formation matrix, leaving most of the solids behind, whole ClearFRAC fluid with full viscosity enters the matrix. At formation permeabilities less than about 5 mD, it is difficult for an elastic, viscous fluid such as ClearFRAC fluid to enter the pore throats.

As a result, the leakoff rate of ClearFRAC fluid, with no fluid-loss additives, is less than that of a 20-lbm/1000 gal crosslinked-borate fluid. In high-permeability formations, ClearFRAC fluid is compatible with fluid-loss additives, and significant improvements in fracturing fluid efficiency are observed.

**Proppant Transport**

The conventional guideline for proppant transport is that the viscosity of a fracturing fluid should be at least 100 cp at a shear rate of 100 sec\(^{-1}\) or 50 cp at a shear rate of 170 sec\(^{-1}\) (below left). This guideline was derived from experience with conventional polymer-base fracturing fluids whose rheological behavior generally follows the power-law rheological model. This rule-of-thumb may not apply to ClearFRAC fluid.Viscoelastic surfactant fluids behave more like Newtonian fluids, with a flatter apparent-viscosity profile across the shear-rate spectrum. This response is different from that of most aqueous-base polymer systems. The viscoelastic surfactant fluid is shear thinning, but its rheology is completely reversible and has no permanent degradation of viscosity when exposed to high-shear conditions. Viscoelastic surfactant fluids provide ample viscosity for proppant transport in the fracture.

At a given surfactant concentration, the viscosity of a ClearFRAC fluid will decrease with temperature (next page, top). This temperature-related thinning can be reduced by increasing the surfactant concentration or adjusting the salt concentration. Unlike conventional polymer systems, however, the viscosity does not degrade with time at a given temperature. Until the fluid is contaminated with hydrocarbons or diluted with formation water, the viscosity will remain stable.
The behavior of surfactant-base fluids differs substantially from that of guar-base fluids, and laboratory observation and field experience have suggested that viscoelastic surfactant fluids with viscosities below the conventional guideline are efficient and are capable of placing proppant as per design. These observations led to a series of proppant-transport tests at STIM-LAB, an independent laboratory in Duncan, Oklahoma, USA. ClearFRAC fluids were tested at various flow rates, proppant concentrations and temperatures to correlate fluid properties with proppant transport capability (see “Laboratory Testing,” page 27).

Effective proppant transport was demonstrated in a large-scale fracture simulator at fluid viscosities as low as 30 cp at 100 sec⁻¹. This result was due to the fluid’s elasticity and high viscosity at low-shear rates. The proppant transport tests proved that viscoelastic surfactant fluids provide adequate proppant transport throughout the 75 to 175°F [24 to 79°C] fluid temperature range. Even when small amounts of proppant settling occurred, the perforation area was kept clear at all times, and more than 90% of the proppant remained in suspension throughout the fluid volume. It is important to mention that when a nonviscosified brine/sand slurry is pumped through the slot, the sand immediately drops and plugs the perforation.

The tests demonstrated that the conventional viscosity versus proppant transport guideline derived for polymer-base fluids may not apply to ClearFRAC fluids. At ambient temperature, a 42-cp fluid provided excellent proppant transport (no apparent sand settling), yet at 175°F, a 100-cp fluid allowed some sand to settle. A better guideline might be to use the minimum concentrations that were empirically estimated during this experimental program.

Fluid viscosity, as calculated by the power-law model, does not adequately predict the proppant transport capability of ClearFRAC fluids. Further work is needed to determine rheological parameters that better describe the proppant transport behavior of ClearFRAC fluids.
Foam Stability and Rheology

To help reduce fluid cost, improve fluid efficiency and accelerate cleanup, ClearFRAC fluids have been mixed with nitrogen to produce foamed fracturing fluids. Experiments to quantify the stability and rheological behavior of these systems at elevated temperatures and pressures were performed at Schlumberger Cambridge Research (SCR), Cambridge, England, and at STIM-LAB.

Initial experimental work at ambient temperature and pressure showed that stable foams with a half-life—the time at which half of the liquid phase has separated—exceeding 12 hr could be obtained with ClearFRAC fluids containing only the surfactant itself as the foaming agent.

To determine the suitability of ClearFRAC foams for use in the field, it was necessary to conduct experiments to quantify their stability and rheological behavior at elevated temperature and pressure. The initial tests were conducted with the SCR test apparatus, which uses a heated syringe pump to feed the liquid phase into a foam generator. A nitrogen bottle with a digital flow controller feeds the gas into the foam generator. The foam passes by a sight glass, allowing observation of foam texture and bubble size distribution. A collection vessel with a glass wall is then filled. The cell is heated by a water bath to control temperature. The foam generator and collection cell can be pressured up to 1200 psi (8273 kPa) (right).

Four base fluids were tested, all prepared from 3% ammonium chloride brine and varying concentrations of ClearFRAC surfactant. The foams were generated at about 1100 psi (7583 kPa) and ambient temperature, then pumped into the preheated collection vessel. The foams were evaluated at three test temperatures: 110°F (43°C), 150°F (66°C) and 190°F (88°C). Each experiment was videotaped to show the texture of the foam, foam during filling of the collection vessel and the condition of the foam after aging in the collection vessel. The half-lives of foam prepared from ClearFRAC fluids range from greater than 12 hr at fluid temperatures less than 150°F to 40 min at 190°F.

At STIM-LAB, the rheological behavior of ClearFRAC foams was tested with base fluids containing 0.2 to 3.0% ClearFRAC surfactant. At a fluid temperature of 75°F, the rheological behavior of ClearFRAC foams was evaluated at various concentrations and foam qualities (next page). In most cases, the maximum viscosity was achieved at a foam quality of approximately 80%. The finest and most uniform texture was observed at a 70% foam quality. There is little apparent morphological difference between the foams prepared from different brine compositions.

The results of these experiments showed that ClearFRAC surfactant is an excellent foaming agent in its own right, and no additional surfactants are necessary to produce stable foamed fracturing fluids from 50 to 90% quality up to a temperature of at least 175°F. In addition, in the 70 to 80% quality range, viscosities far greater than those of the base fluids can be attained. This effect reduces the surfactant concentration required to prepare useful ClearFRAC fluids. These findings have been borne out by a successful series of more than 100 experimental foamed fracturing treatments in...
Laboratory Testing

In proppant transport tests conducted at STIM-LAB in Duncan, Oklahoma, the laboratory equipment consisted of two 50-gal (0.2-m³) mixing tanks and a heated section of tubing. The fluid was agitated with mixing blades and then pumped through the 1-in. (0.89-in. ID) tubing, which was heated by gas burners. Shear was simulated by pumping the fluid through the tubing. Once the fluid left the tubing, it traveled through a series of four sizes of pipe ranging from 1/2 in. to 1 in. Pressure drops were measured over each section of pipe and a rheogram of shear stress versus shear rate was generated to calculate the flow behavior index, n, and consistency coefficient, K, values. Changes consisted of two 50-gal [0.2-m³] mixing tanks and in Duncan, Oklahoma, the laboratory equipment.

In proppant transport tests conducted at STIM-LAB, pressure drops were measured over each section of pipe and a rheogram of shear stress versus shear rate was generated to calculate the flow behavior index, n, and consistency coefficient, K, values. Changes in pressure were measured in duplicate on all pipes and slots to allow a backup measurement in the event of transducer line plugging by proppant. Flow rate and pressure data were recorded continuously throughout the test runs, and the data were processed to plot shear stress versus shear rate.

The capability of a fluid to transport proppant was assessed visually when the fluid system was pumped through a slot 1 ft [0.3 m] high by 8 ft [2.4 m] long with a 5/16-in. [0.8-cm] gap width. One panel of the slot was transparent to allow visual inspection. The diameter of the perforation in the center of the slot entrance was 5/16 in. Dynamic transport of proppant in the slot was recorded on videotape. A grid system was placed on the slot to observe proppant-settling velocities as the slurry traveled across the 8-ft length. The fluid was stopped at the end of a run to record the static settling time. The pumping rate of fluid through the slot was varied from 1 to 3 gal/min [4 to 11 L/min]. The shear rate at the slot varied from 20 to 60 sec⁻¹, and the shear rate at the perforation varied from 1300 to 3900 sec⁻¹.

The proppant used in all tests was 20/40 Ottawa sand, and tests were performed at 4 and 8 ppa. The goal of the tests was to determine the minimum concentration of surfactant necessary to provide adequate proppant transport. The tests were run at ambient temperature, 150°F and 175°F. The first test fluid consisted of 0.5% ClearFRAC surfactant in 3% ammonium chloride at 75°F [24°C] with a viscosity of 22 cp at 100 sec⁻¹. Before the proppant was added, the fluid was allowed to circulate through the system. At 3 gal/min [11 L/min], significant turbulence was observed around the perforation opening. The fluid exhibited a chunky texture upon exiting the perforation, showing a quick recovery after experiencing the high-shear environment.

When red dye was added to the fluid to observe flow behavior, it was immediately apparent that the fluid in the center of the slot was moving more quickly than at the edges. Such laminar flow behavior may explain why lower friction pressures are observed in the fluid compared to polymer-base systems when ClearFRAC surfactant is used.

When sand was added at 4 ppa, the perforation area was kept clear at all times; however, some minor amounts of sand settled at the bottom of the slot. Nevertheless, the settled proppant continued to be dragged along the bottom of the slot to the exit perforation. An in-line densitometer showed that greater than 90% of the proppant was in circulation. Since the area around the perforation opening never plugged, this can be considered as adequate proppant transport. This finding is supported by field results.

The test was repeated with a doubling of the ClearFRAC concentration to 1%; the fluid viscosity increased to 42 cp at 100 sec⁻¹. When dye was shot into the fluid prior to the addition of proppant, laminar flow behavior was again apparent; however, the fluid displayed a much tighter structure. After exiting the perforation, the fluid instantly recoiled to form a gelatin-like mass. When sand was added at 4 ppa, there was no evidence of settling. The fluid appeared to grab the sand grains at the perforation exit and carry them across the slot. The same effect was seen at higher concentrations. Pumping was stopped, and sand settling was not evident after 30 min. Further tests were conducted with varying concentrations of ClearFRAC surfactant and at varying temperatures.

1. In a power-law fluid, viscosity is a function of shear rate: \( \mu = K \cdot g^{n-1} \).
2. The abbreviation ppa indicates pounds of proppant added to 1 gal of fluid.

Canada and Kansas, USA. Use of nitrogen or carbon dioxide to prepare energized—less than 52% foam quality—or true foamed ClearFrac fluids with foam quality greater than 52% has been established.

To date, nearly all of the foamed ClearFrac jobs have used ammonium chloride as the brine salt, partly due to the low foam viscosities at low temperatures observed in the laboratory experiments.

In Canada, ammonium nitrate is now used as the brine component in many wells. Most of the spent fracturing fluid is disposed of by landfarming, so brines with chlorides must be carefully monitored to remain within environmental limits. Because ammonium nitrate is a fertilizer, landfarming these brines is advantageous to the environment.

Foam rheology. Mixed in a 3% ammonium chloride brine at 75°F, ClearFRAC foam reached maximum viscosity at 80% foam quality.

Autumn 1997
Fracturing Fluid Flowback

To maximize well productivity, it is essential to maximize fracture cleanup. Polymer residues that stay in the fracture contribute significantly to a lowered proppant-pack permeability, leading to a loss in treatment effectiveness. Even a small amount of porosity loss can cause major loss in retained permeability. Parameters such as types and concentrations of gelling agent, crosslinker, breaker, reservoir temperature, flowback rate and shutdown time can affect the degree of permeability damage. To understand the relationship between these parameters to fracture cleanup, quantification of the polymer in the flowback fluid is crucial. A basic assumption is that a cleaner fracture will produce reservoir fluids at a higher rate. But how is fracture cleanup related to production? A reasonable analysis is that a given mass of returned polymer produces a given volume of pore space available for flow in the proppant pack. Therefore, under equivalent reservoir conditions, a direct relationship should exist between returned polymer and production. The conventional method of quantifying cleanup from a hydraulic fracture has been to report loadwater recovery. This amount may be affected by produced formation water, and hence may be inaccurate. Instead, a colorimetric method that involves a phenol-sulfuric acid reaction is used to accurately test the returned fluids for guar or HEC.

Analysis of the fracturing fluid returned to the surface after hydraulic fracturing indicates that only 35 to 45% of the guar-base polymer that is pumped during the treatment flows back out of the well during the 1- to 10-day flowback period (below). The remaining polymer stays in the fracture and decreases well productivity. Thus, there is a need for a fracturing fluid that can be brought back to the surface more efficiently. One method of assessing damage involves core-flow tests. Leakoff tests were conducted on 12-in. (30-cm) Berea sandstone cores at a differential pressure of 1000 psi (6890 kPa). Two core permeabilities were tested: 230 mD and 1000 mD. The cores were flooded with 40-lbm/1000 gal borate-crosslinked guar, an 80-lbm/1000 gal HEC polymer and 4% ClearFRAC solution, respectively (next page, top). After the leakoff test, the cores were left in a fluid-loss cell, and brine was injected in the opposite direction. Steady flow rates were reached to determine the retained permeabilities. In the core flooded with ClearFRAC fluid, flow immediately as the brine diluted and broke the fluid. The guar- and HEC-flooded cores had significantly lower permeabilities, even after 24 hr of cleanup. These core-flood tests clearly indicate that polymer residues can decrease the core permeability.

When wells treated with ClearFRAC fluid are initially flowed back, the tail of the slurry may still have significant viscosity if it has not yet contacted hydrocarbons or formation water. To help clean up the fracturing fluid during the initial flowback, especially in underpressured reservoirs, small amounts of some polar organic compounds can be added to the tail slurry to accelerate breakdown. Used in conjunction with proper flowback techniques, this procedure can minimize or eliminate early sand production.

Shallow Gas Foam Fractures

In September 1996, PanCanadian Petroleum Ltd. conducted a field test of the ClearFRAC system in 10 wells in a shallow gas field in the Princess East field in Brooks, Alberta, Canada. Like many stimulated wells, these wells were in poor-quality reservoir areas. Five wells were fractured with this fluid, and five were fractured with a low-gur system as a control. Each well had four formations treated. These low-pressure gas wells were fractured with foamed ClearFRAC fluid; the nitrogen in the foam provided the energy to assist the wells back to production and improve cleanup. The wells treated with ClearFRAC fluid flowed back a greater volume of fracturing fluid—based on fluid volumes and colorimetric analysis—than did the control wells. This improved initial
cleanup and flowback of the fracturing fluid are believed to have contributed to higher production rates.

An initial comparison of well production during the first few months following the fracture stimulations was impossible because fluid from all zones in each well and from all the wells were commingled into a common pipeline and not monitored individually. From June through August 1997, PanCanadian conducted flow-prover tests on these wells to quantify the long-term differences in production attributable to the different fracturing fluids.

Before the wells were tested, each was cleaned out with coiled tubing to remove any water and sand fill. The formations in this part of the Princess East gas field are of poor quality; hence, overall production per well is low. In addition, the wells tend to load with water over time if water is present, as was the case here. The gas rates for each group of five wells were plotted during the test period (below right).

The results were encouraging. A year later, the wells treated with ClearFRAC fluid still averaged about 9 to 10% more production. The curves converged slightly after one month as certain wells had water loading and slugging. It is possible that the quality of the reservoirs in the specific wells may account for the incremental production; however, statistical averaging of the 20 zones in each group of wells in the same area indicates this cause is unlikely. Assuming an average rate difference of 500 scm/d [17 Mscf/D] for the five wells over time—not integrated for specific decline curves but taken from the cumulative difference during the first 51 days of the test shown in the figure—ClearFRAC wells produced a cumulative volume of 150,000 m³ [5300 Mscf] more than the control wells. The incremental revenue may be small from these low-producing wells, but the favorable trend has caused PanCanadian to analyze the potential long-term production improvement in other wells in Brooks and Drumheller, Alberta, with 500 to 600 wells slated for ClearFRAC treatments next year.

### Acid Fractures

Several cases involving acid fractures illustrate the importance of using a nondamaging fracturing fluid. Imperial Oil Resources Limited’s Norman Wells field is an oil field now under waterflood in the Northwest Territories, Canada. The field has 325 wells—166 producers and 159 injectors arranged in a five-spot pattern on six man-made and three natural islands in the Mackenzie River. The field’s economic life is expected to run through the year 2010. At present, some areas of the field are marginally profitable, and a solution is needed to improve recovery rate.

The formation is the Kee Scarp, a micritic limestone with natural fractures, vertical and horizontal, induced by the tectonics of the mountain ranges on both sides of the river. Because the overburden stress is the least principal stress, any induced fracture will be horizontal, not vertical. Thus, to increase production, each low-rate layer in each well has to be treated. The frequency of natural fractures varies throughout the field. The formation has up to 18 distinguishable layers in four separate reef or shoal sequences, with an average reservoir height of 80 m [262 ft]. The respective layer heights...
The isolation problem was solved, and an initial fracturing program was proposed with alternating stages of a low-pH guar gel, for fluid leakoff control, with 25 m³ [660 gal] of 15% hydrochloric acid. This gel system was selected because of its compatibility with acid at low temperature and its ease of preparation, with minimal manpower and equipment. A crosslinked guar was deemed better for leakoff control than gelled acid because the bottomhole temperature in these wells was below or at the minimum recommended for these fluids. One of the main concerns in using a guar-base fluid was suspected loss of whole polymer into secondary fissures and fractures and the inability to recover this fluid. Unrecovered polymer could remain in these pathways, thereby limiting production.

ClearFRAC fluid became available at the beginning of the stimulation program in the field. The fracturing fluid system was changed because the viscoelastic surfactant fluid is easy to mix, fracturing fluid viscosity can be altered simply by changing surfactant concentration, crosslinking times are not an issue, and no breakers or extra chemicals are needed. A viscoelastic surfactant fluid was most desirable because it would not plug the secondary fissures and fractures.

The first treatment was on a well in the southeast end of the field where the wells intersect the lower, tighter layers of the Kee Scarp. The ClearFRAC fluid was mixed in a 4% potassium chloride brine. The treatment called for alternating pads of ClearFRAC fluid and acid, followed by an overdisplacement with brine. A DataFRAC analysis indicated the pad volumes of ClearFRAC fluid could be reduced by 60% from the original design because of a low leakoff rate. It is not known whether the low leakoff rate was a local formation phenomenon or a property of the viscoelastic surfactant fluid, because the original leakoff rates were determined from matrix treatments using gel-base fluids in other parts of the reservoir.

In total, seven fracturing treatments with staged ClearFRAC fluid and acid were done on three wells. The production results so far are encouraging (left). In all three wells, oil flowed to surface within 30% of the recovered injected volume with no signs of emulsion or other fluid incompatibility problems. If a polymer fluid had been used, with little fluid returned, there would be the potential for a large amount of unrecovered polymer to plug the secondary fractures and fissures and impede production.

### Frac Packing

Hydraulic fracturing has long been considered a stimulation treatment for low-permeability formations in hard-rock areas. In these treatments, the goal is to create a long, thin fracture with a large surface area. Fracture half-lengths, or wings, can reach 500 to 1000 ft [150 to 300 m] and have widths in tenths of an inch or less.

In contrast, frac packs typically have short wing lengths of 10 to 50 ft [3 to 15 m] and fracture widths of 1 to 2 in. [3 to 5 cm]. A frac pack, or STIM PAC treatment, is a fracture created using high-viscosity fluid, pumped above fracture pressure, to place sand outside the annulus between the casing and downhole screen and a short distance into the formation. The aim is to create a high-conductivity sand pack extending a sufficient distance from the wellbore, beyond any wellbore damage, to create a conduit for the flow of reservoir fluids at lower pressure differentials.14

In late 1991, Dowell and BP Exploration performed the first true frac pack in the Gulf of Mexico.15 Since then, the incidence of frac packing has skyrocketed, with some 600 frac-pack treatments conducted last year out of roughly 1200 sand-control completions in the Gulf. The trend is continuing as more operators are considering frac packs in areas that were once gravel packed.

Frac packs are ideal completion techniques to bypass formation damage. Many mechanisms can cause wellbore damage—crushing due to stress, fluid and solids invasion during drilling, perforating damage, fines migration or precipitation of paraffin or scale. Some of this damage is stress induced and, therefore, may not be uniform.
Stress and radial flow. Damage from drilling fluids, drilling-induced stress, perforating damage and fines migration all contribute to nonuniform damage in the near-wellbore region. The damaged area shown above is an area of increased stress. Higher stress on an unconsolidated formation will reduce permeability. Fluid no longer flows equally in all directions, increasing fluid velocities and fines migration, which further damage the near-wellbore region.

Radial flow toward the wellbore causes higher velocities and pressure drops adjacent to the well (above). These high rates and pressure drops can cause formation minerals to become mobile and bridge near the wellbore, in the perforation tunnels, or in the annular gravel-pack region. This damage, along with declining reservoir pressure, causes production from gravel-packed wells to decline over time. As wells age, operators often open the wells up, increasing drawdown to maintain production; however, such actions also increase fines migration and damage.

A frac pack addresses these problems by creating a conduit perpendicular to the minimum principal stress, extending beyond any near-wellbore damage. The flow area into the wellbore increases, reducing pressure drop and fluid velocities in the formation, thereby eliminating the causes of fines migration. Formation fluids establish a somewhat bilinear flow at lower velocities (right). The key property of the fracture is that it must be highly conductive.

Perhaps the most critical factor to ensure future production in a frac pack is keeping the proppant pack clean. With polymer fracturing fluids, polymer residue can be significant on the small fracture face in a frac-pack completion. At the end of a treatment, as the formation begins to close, a polymer fluid will have no place to go but into the formation. The fluid leaks off into the formation, and the polymer residue can become highly concentrated as a filter cake. Part of this problem can be mitigated by using greater concentrations of breakers or encapsulated breakers, which are crushed by the closing formation and release the breaker in the appropriate location. These mechanisms work well, but are still imperfect. Some estimates put the efficiency of these breakers at less than 50%. The breaker itself could leak off into the formation, bypassing dehydrated polymer.

HEC has often been used as a frac-pack fluid because of its small particle size. The disadvantage, however, is that too much polymer is needed to create the viscoelasticity to fracture high-permeability zones; a viscous polymer membrane may form and require high volumes of breakers. Borate-crosslinked low-guar systems are used in many frac packs worldwide, especially where temperatures exceed 200°F. The use of crosslinked fluids cut frac-pack costs and expanded use of the technique. The fluids, however, can still produce a positive skin factor in the completion.

Viscoelastic surfactant fluids are particle free and behave like linear fluids, making them ideal for frac-pack operations. Viscoelastic fluids typically have lower fluid efficiency than normal fracturing fluids, but, in this application, that is a desirable feature. Viscoelastic surfactant fluids have a nearly constant leakoff response to pressure. In addition to being solids free and nondamaging, viscoelastic surfactant fluids have advantages over crosslinked polymers in the way they propagate fractures.

As the viscoelastic surfactant fluid is pumped, much of it leaks off into the formation. The viscosity of the remaining fluid produces drag forces on the rock, initiating the fracture. With a fluid that does not build a filter cake, the rate required to create a fracture can be calculated from Darcy’s law. The main factors that control this fracturing rate are the kh product, injected fluid viscosity, fracturing pressure and reservoir pressure.

Of these, only the injected fluid viscosity can be controlled, thereby eliminating the causes of fines migration. The kh product is the permeability times the height of the fracture.
be controlled, unless a fluid-loss agent is used—thereby reducing the kh product by decreasing the permeability. The fluid leakoff limits the length of fracture that can be created, but it affects the job cost if large volumes of fluid leak off. The fracture is created by a volume of fracturing fluid that does not contain proppant. Once the proppant-laden slurry reaches the tip of the fracture, it bridges off and the fracture can no longer increase in length. Proppant at the top and bottom similarly prevent height growth. This situation is called a tip screenout. Further pumping causes the fracture to balloon or widen. In soft rock, the fracture width can increase four to six times with this technique.

An interesting application of ClearFRAC fluids is in the treatment of selective completions. In the spring of 1996, Phillips Petroleum Company performed two frac packs in a well in the High Island area in the Gulf of Mexico. The lower gas sand was completed with a crosslinked-guar fluid system, and the selective zone above was completed with ClearFRAC fluid because the frac pack was to be left behind pipe until the lower zone was depleted. Phillips did not plan to flow back the fracture immediately for cleanup; hence, a polymer fluid system might undergo severe dehydration and damage the formation over time. The ClearFRAC fluid remains in place and breaks over time as it contacts the formation gas. When the selective zone is produced at some point in the future, it should flow back as if it had just been fractured.

**Fracturing for Water Control**

Frac packing with ClearFRAC fluid has another advantage—the capability to fracture near but not into water zones. The leakoff rate of the viscoelastic surfactant fluid helps prevent the fracture from growing up or down, possibly contacting nearby water zones. In certain applications, a typical guar-fluid frac pack might break down the formation being treated, allowing the fracture to propagate downward directly into an underlying water zone, accelerating water production. The predictable leakoff characteristics of viscoelastic surfactant fluids make them the fluids of choice in these operations. Once a tip screenout is achieved, the frac will widen rather than increase vertically into the water zone.

Coastal Oil & Gas Corp., like many operators in the Gulf of Mexico, has changed its completion practices from gravel packing to frac packing. Frac packing is the completion of choice for high-permeability wells that may have potential sand-control problems, drilling-induced formation damage, fines migration problems, perforation damage, or other borehole damage. A typical frac pack accesses the formation beyond these damaged zones. Coastal’s frac-pack completions have held up over time, requiring less remedial work than offset gravel-pack completions.

Coastal has been completing wells with frac packs at a rate of one or two per month during 1997 and has had six wells stimulated with ClearFRAC fluid. The reasons for using ClearFRAC fluid instead of a guar fluid include the capability of fracturing without hitting water zones, a shortened cleanup time and a cleaner fracture.
In a High Island area well located offshore Louisiana, Coastal encountered a 36-ft [11-m] gas zone overlying a 50-ft [15-m] water zone. Many operators would have perforated the upper section of the gas zone, performed a gravel-pack completion and flowed the well at reduced drawdown to stave off water coning. The well was perforated underbalanced with tubing-conveyed perforating guns, 13 ft [4 m] above the gas-water contact. The screen and packer assembly were then picked up and run in the well. The packer was set, and the pipe was pickled. A DataFRAC analysis was performed to determine the optimum pumping schedule design based on closure pressure and leakoff coefficients. Pumping time for the treatment was about half an hour (top).

The pumping operation was successful (above). Based on bottomhole pressure data and computer simulation results, the final frac pack was estimated to have a 30-ft [9-m] half-length and 1.5-in. [4-cm] width. The well was flowed back at moderate rates that were increased hourly until reaching anticipated production rates about 12 hr later. The well flowed back normal amounts of sand and load water and appeared to clean up properly as the gas contacted and broke down the ClearFRAC fluid. The well was then shut in as the rig was skidded to the next slot, and production resumed several days later. Initial production rates averaged 11 MMscf/D [300,000 scm/d] of gas and 300 BOPD [48 m3/d] with only trace amounts of water.

The frac pack successfully avoided the water zone. A comparison of the production to offset wells is difficult and potentially inaccurate due to the extremely faulted nature of the producing reservoir, however. On this well, the frac-pack treatment was slightly more costly than for a guar fluid. The total cost to drill and complete the well was more than $3 million. Coastal felt the cost difference for the fluid was minor, given the ability of the ClearFRAC fluid to ensure a clean frac pack above the water zone.

Looking Ahead

ClearFRAC fluid was commercialized on May 12, 1997. As of November 1997, more than 400 ClearFRAC jobs had been pumped in the USA and Canada. At present, use of ClearFRAC fluid is highest in Canada, followed by the Gulf of Mexico and then the eastern USA.

The two largest hurdles for ClearFRAC fluid to overcome are its upper temperature limitation and cost relative to guar fluids. The upper temperature limit for ClearFRAC fluids is 200°F, but research is under way to increase the temperature range.

The higher chemical cost of ClearFRAC surfactant increases the total cost of a fracture treatment by some 5 to 20% on small treatments, such as frac packs and jobs with less than a few hundred thousand pounds of proppant placed. Reducing the cost of the surfactant will increase the population of wells where the application of ClearFRAC technology is economically feasible. To address this cost issue, research is also in progress to increase the efficiency of the current surfactant and to develop less expensive second-generation surfactants. —KR

In a High Island area well located offshore Louisiana, Coastal encountered a 36-ft [11-m] gas zone overlying a 50-ft [15-m] water zone (previous page). Many operators would have perforated the upper section of the gas zone, performed a gravel-pack completion and flowed the well at reduced drawdown to stave off water coning.

The well was perforated underbalanced with tubing-conveyed perforating guns, 13 ft [4 m] above the gas-water contact. The screen and packer assembly were then picked up and run in the well. The packer was set, and the pipe was pickled. A DataFRAC analysis was performed to determine the optimum pumping schedule design based on closure pressure and leakoff coefficients. Pumping time for the treatment was about half an hour (top).

The pumping operation was successful (above). Based on bottomhole pressure data and computer simulation results, the final frac pack was estimated to have a 30-ft [9-m] half-length and 1.5-in. [4-cm] width. The well was flowed back at moderate rates