CONDUCTIVITY

ENDURANCE

Keeping it flowing and going

The secret to long-term production

A Supplement to E&P and Oil and Gas Investor
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Hydraulic fracturing treatments of oil and gas wells are designed to create highly conductive propped fractures that yield sustained production increases and control fines migration. New Conductivity Endurance technologies are improving long-term asset performance onshore and offshore.

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New Technologies Improve Long-Term Production
When designing hydraulic fracturing projects, operators are planning for uninterrupted reservoir fluid flow, while wanting to achieve a high level of conductivity for the present and long term. New technologies can help achieve conductivity endurance through the following parameters:
- Increasing the proppant pack conductivity;
- Reducing effects of production cycling;
- Maintaining proppant pack permeability;
- Immobilizing fines to prevent intrusion and plugging; and
- Reducing proppant flowback.

The value of increased production from proper application of these new technologies can be significant.
Hydraulic fracturing treatments of oil and gas wells are designed to create highly conductive propped fractures that yield sustained production increases and control fines migration. New Conductivity Endurance technologies are improving long-term asset performance onshore and offshore.

Virtually every oil and gas well drilled today at some point in its life will require some type of stimulation. The goal is to increase the flow of hydrocarbons to the wellbore. Since hydrocarbons are contained in the pore spaces in the formation rock, exposing more of the formation to the wellbore often can increase production of viable reserves, which normally is done by fracturing the producing formation or placing a reactive fluid (acid) in contact with the producing formation. In financial terms, the goals of stimulation are to help improve the net present value (NPV) of the asset, improve the production rate and help increase recoverable reserves. This handbook will focus on new technologies related to hydraulic fracturing and the importance of maximizing fracture conductivity to enhance production.

The Need for Improved Technology

“Energy prices are going to face continued pressure — reflecting fundamental changes in demand, supply and geopolitics. We are, in fact, witnessing a change in the basic energy equation. To understand why, we have to understand the dynamics of supply and demand today. Global energy demand will expand about 40% over the next two decades, driven largely by population growth and rapid industrialization in the developing world,” said David J. O’Reilly, chairman and chief executive officer of ChevronTexaco.

To illustrate this point, one only has to look toward China, whose population grows by about 8 million people annually. As Chinese incomes rise, so does car ownership. Car registrations in China are expected to jump from 20 million to 50 million between 2002 and 2007. Chinese crude oil imports increased by 30% in 2003, and the country’s energy needs will more than double by 2020.

In the United States, oil demand is expected to continue rising annually by nearly 2%. Cleaner burning natural gas is projected to increase by about 25% during the next 15 years. With increased demand, ever-increasing pressures are placed on finding new supplies, which means increased imports. More than 60% of the crude oil and 15% of the natural gas the United States uses today is imported.

**Crude oil**—For 2003, U.S. imports of crude oil and petroleum products averaged 12.25 million b/d, an estimated increase of 724,000 b/d or 6% from 2002. This represented more than 61% of domestic petroleum demand. Fifteen years ago, by comparison, imports comprised just more than 40% of U.S. needs and constituted a U.S. $39 billion trade value price tag (imports only) compared to the current U.S. $132.5 billion burden. The Organization of Petroleum Exporting Countries (OPEC) imports made up 42% of all U.S. crude imports in 2003, up 2% from 2002 but down almost 8% (in percentage terms) from 1993 levels.

In 2003, estimated U.S. crude oil production (excluding natural gas liquids) averaged 5.74 million b/d, compared to 5.75 million b/d in 2002, representing a 1.43 million b/d (almost 25%) decrease since 1992. U.S. crude production has fallen for 12 straight years.

**Natural gas**—Annual natural gas imports for 2003 amounted to 3.9 Tcf, almost double U.S. natural gas imports in 1992 (2.1 Tcf). Imports of natural gas have been rising fairly steadily since 1986 — up almost 424% (25%/year annualized) — while U.S. dry production is up only 19% (or 1.12% annualized) during the same time period.

Natural gas is a critical source of energy and raw material, permeating virtually all sectors of the U.S. economy. Today, natural gas provides nearly one-quarter of U.S. energy requirements and is an environmentally superior fuel, contributing significantly to reduced levels of air pollutants. It provides about 19% of electric power generation and is a clean fuel for heating and cooking in more than 60 million U.S. households. Industries in the United States get more than 40% of all primary energy from natural gas. Figure 1 illustrates the contribution of natural gas to U.S. energy needs, and Figure 2 shows gas use by sector.

According to a recent National Petroleum Council study, the gas bubble is gone. Today, no additional production capacity exists at the wellhead (Figure 3). The requirements to fill storage during the traditionally slow periods are now great enough to require wells to be produced continuously at high rates. Plus, the average decline rates (Figure 4) for newer gas wells are steeper than in the past because of two key issues: the reservoir quality has been declining, and economics require wells be produced at maximum rates to generate the necessary revenue.

During the 1990s, environmental standards

3. Ibid.
5. Ibid.
and economic growth were the forces driving the demand for natural gas in North America. Historically in the United States, drilling activity has responded quickly to market signals and, together with increasing supplies from Canada, has yielded sufficient production to meet demand. Figure 5 shows U.S. and Canadian production from 1985 to 2002. It now appears that natural gas productive capacity from accessible basins in the United States and Western Canada has reached a plateau. Recent experience shows steeper decline rates in existing production and a lower average production response to higher prices from new wells in these areas. This trend is expected to continue. As a result, markets for natural gas have tightened to a degree not seen in recent experience and prices have increased well above historic levels. These higher prices have been accompanied by significant price volatility (Figure 6).

A need exists for higher production rates, both short- and long-term. Oil and gas operators, in close cooperation with industry service suppliers, are providing promising new solutions. One such initiative involves a family of fracturing products and techniques that Halliburton has designated as “Conductivity Endurance” technologies.

Hydraulic fracturing in low permeability, hard rock formations and fracpacking in high-permeability, soft rock formations have long been recognized as effective means to improve production. Higher production rates can be most easily achieved through the use of more effective hydraulic fracturing focused on maximizing the effective fracture length and maintaining conductivity. Recent research has demonstrated and field results have proved that Conductivity Endurance fracturing can enhance the outcome of stimulation treatments and achieve sustained production increases through a combination of factors:
- proper treatment design;
- low-damaging fluid systems;
- accurate proppant selection; and
- coated propping and packing materials.

Fracturing Concepts, Geometry and Rock Mechanics

By design, fracturing stimulates production. The extreme advantage of fracturing wells to increase productivity is now largely accepted, but there still is substantial room for growth worldwide through proper application of the process and use of new conductivity endurance technologies. It is estimated that hydraulic fracturing may add several hundred

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thousand barrels per day from existing wells in a number of countries, and worldwide the gains in added production could be millions of barrels per day.

A detailed discussion of rock mechanics and creation of a hydraulic fracture are beyond the scope of this text. However, certain general principles are assumed to be understood and believed valid for most reservoirs:

- fractures are nearly always vertical (except in very shallow wells and tectonically active areas);
- fractures are oriented perpendicular to the direction of minimum principle stress (in most formations, this is the direction toward the maximum horizontal stress);
- fracture initiation pressure is normally higher than fracture extension pressure; and
- fracture height and length continue to increase as long as the fluid pressure inside the fracture is larger than the least in-situ principal stress or until a barrier is reached, or a tip screen out (TSO) or sand out obtained.

Hydraulic fracturing is most commonly done in strong or hard rock formations that have permeabilities less than 1 md or 2 md, where a contrast between the proppant and formation permeabilities of 10,000 or more is desirable. Fracture lengths of 500+ ft (152.4+ m) and propped fracture widths of 0.2 in. or less are common. This is enough for good initial production results in low permeability formations.

There are many unknowns and disagreements on the best means of fracturing strong, low permeability rocks where fracturing has been applied for several decades. For instance, the Society of Petroleum Engineers (SPE) Monograph Vol. 12, Recent Advances in Hydraulic Fracturing, published in 1989, states “fracture height is a variable that can be only grossly estimated with today’s technology.”

Today, fracture design technology has improved in design software, and acquiring and managing the data needed for a design.

Even though the sophisticated computer programs used to design, model and evaluate fracture treatments have helped the process, the programs often are based on certain assumptions and questionable input data that affect the results of fracture geometry. Length and height of a fracture are used to calculate its width. A fracture is usually assumed to be elliptical, rectangular or “penny shaped,” and both wings are equal length, height and width.

In low permeability or hard rock formations (1 md to 2 md), viscous fracturing fluids generate long fractures because of low fluid leakoff while less viscous fluids, such as water, leak off quickly and create shorter fractures (Figure 7). In micro Darcy reservoirs, however, the opposite may be true. If fluid leakoff is minimal, thin fluids can create much longer fractures with very narrow widths. Viscous fluids, on the other hand, create wider fractures and less length. Reservoir permeability and pressure are two important parameters that need to be considered in both these situations. In either case, hydraulic fracturing increases effective completion radius by establishing linear flow into propped fractures and dominant bilinear flow to a wellbore (Figure 8).

In high permeability or soft rock formations, TSO fracturing treatments are designed to create short, wide propped fractures that provide some reservoir stimulation and mitigate sand production by reducing near-wellbore pressure drop and flow velocity. In low strength (soft/unconsolidated sand) formations, proppant concentration after fracture closure must exceed 2 lb/ sq ft (10 kg/ sq m) to overcome proppant embedment in fracture walls (Figure 9).

A logical question might be: “How much confidence can be given to computer programs for designing, modeling and evaluating fractures?” This question can be answered based upon knowledge of rock mechanics, linear elastic fracture mechanics, and laboratory and field based studies published by SPE. The fracture geometry (height, length and width) is
normal leakoff (left) indicating a normal frac design is appropriate. The plot on the right shows pressure dependent leakoff indicating the fracture treatment should be redesigned to control leakoff.

If all or most of the above properties are known, successful fracture treatments are expected.

Designing an optimal fracturing treatment requires data. Most of the information is readily available or can be obtained at reasonable expense. For example, previous fracture treatments in the same zone can yield valuable information for future treatments. Collecting, storing and applying all available data will provide answers for the best possible treatment. The completion engineer must determine specific data related to each of the following:

- reservoir information;
- fracture width;
- fracture length;
- fracture height;
- fracture initiation and propagation points; and
- frac fluids and proppants.

Reservoir information—The geology of the play has a major effect on fracture design. Faults, unconformities, natural fractures and other geological features will impact the treatment. In designing the optimum frac treatment, the completion engineer needs to gather the following information related to the target reservoir.

Permeability, porosity and bottomhole pressure—Perhaps the most important information needed is the reservoir permeability. A high permeability well might be designed with a TSO treatment to give greater frac width, whereas a low permeability well would need a longer frac length for increased reservoir exposure. Permeability can be obtained from pressure build-up (PBU) tests, nodal analysis matches (production decline analysis) and core measurements. Reservoir porosity can be obtained from log measurements and/or core sample analysis. Current and original reservoir pressure can be obtained from direct measurement after perforating or measured from PBU analysis.

Temperature, saturation and geology—Bottomhole temperature and information about the production fluids (oil, gas and water) and their saturations can be obtained from log and/or core data. The geology of the play will yield the drainage area, pressure transients and information about other potential tectonic parameters.

Reservoir fluid properties—The reservoir-wetting phase (oil or water wet) can be determined from core analysis or inferred from production in the same reservoir. The gas gravity and percentage of impurities such as carbon dioxide, nitrogen and hydrogen sulfide can be obtained from a reservoir sample sent to a fluid lab for analysis. Oil gravity, viscosity and solution-gas content can be determined from lab measurement of formation fluid samples. The production yield can be measured or estimated from other known reservoirs in the area. This information is essential to ensure the proper use of compatible frac fluid systems.

Rock properties—A lithology log, usually a gamma ray or SP, is critical to identifying the formation layering, such as sand, silt, or shale, among others. Young’s modulus and Poisson’s Ratio of the rock can be determined from laboratory measurements of core samples. Modulus also can be obtained from a calibrated dipole sonic log. Sieve analysis of core samples from the producing interval will yield data about possible fines movement, especially in soft formations. Rock “hardness” (or “applied toughness”) controls pressure required for fracture propagation. This is a complex variable that must be measured from a pretreatment field test or minifrac.

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. After developing preliminary stimulation designs, engineers perform a

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pretreatment evaluation, or minifract, to quantify five critical parameters: fracture-propagation pressure; fracture-closure pressure; fracture geometry; fluid efficiency; and leakoff mechanism.9

This procedure consists of two tests – stress and calibration – 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 treatment analysis and proppant selection.

The type of test performed depends on the rock type or hardness and the data needed. A step-rate injection test is used to determine the minimum injection rate necessary to extend a fracture and is usually conducted with the actual frac fluid. Step-rate tests are only of practical value in high permeability reservoirs where injection below frac rate is physically possible. A flow-back test only provides an estimate of closure pressure.

For low permeability reservoirs, a flow back test is a convenient method to estimate closure pressure; however, these tests provide no information about leakoff or efficiency. Flow back tests are usually done when leakoff is too slow to observe closure in a reasonable amount of time. A diagnostic fracture injection test (DFIT) is conducted with low viscosity, non-damaging fluids to determine closure pressure, leakoff mechanism, some inference of fracture geometry and reservoir permeability as well as pore pressure (Figure 10).

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 or fluid 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 efficiency.

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

During the initial design of a fracturing treatment, completion engineers determine the 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.

**Fracture initiation and propagation**—Fracture initiation and propagation in soft and hard rock are affected by these properties:
- in-situ stresses;
- stratification;
- rock strength and properties, such as elastic modulus, Poisson’s ratio, toughness and ductility;
- fluid, pressure and permeability profile in the fracture; and
- pore pressures.

The permeability profile and rock strength of most weak, high permeability formations vary more than in high strength, low permeability formations. For instance, the permeabilities of weak sandstone commonly vary from near zero in shale and clay strata to higher than one Darcy; whereas, the permeabilities of strong sandstone commonly range from near zero to only 5 md or 10 md. Similarly, weak sandstone formations that are candidates for fracpack treatments often have strata or pockets of strong sandstone, shales or carbonates. Strengths may range from nearly zero to many thousands of pounds per square inch unconstrained compressive strength.

Fracture orientation in weak formations is the same as in stronger formations. The static stress fields that force them to always be perpendicular to the minimum principal stress dictate the direction of all fractures, which means that the fracture is usually in the same direction as, and parallel to, the maximum horizontal stress.

**Focusing on Fracture Conductivity**

The importance of fracture conductivity and its effects on well productivity are widely understood in the petroleum industry. Laboratory testing procedures are well documented, and sophisticated modeling software and databases are available to help engineers optimize fracture treatment designs in terms of fracture geometry, and proppant concentration and type. In spite of the availability of advanced design tools and reams of conductivity test data, post-treatment performance in many wells seems to suggest the effective fracture length may be shorter than expected. The shorter fracture lengths may be the result of fluid cleanup issues or loss of fracture conductivity because of fluid residue such as filter cake. Effective fracture length can be affected by broken fluid properties and the conductivity in the fracture.14,15,20

**Increased fracture conductivity**—The impact of increased fracture conductivity in lower permeability reservoirs may be argued; however, improved fracture cleanup and longer effective fractures should be a direct result of the increased fracture conductivity. In the simplest form, the effective fracture length can be estimated using the following equation:

\[
Cr = wK_e / (\pi X_{eff} K)
\]

Where: \(Cr\) = Conductivity ratio (dimensionless)

\(wK_e\) = Fracture conductivity (md ft)

\(K\) = Reservoir permeability (md)

\(X_{eff}\) = Effective fracture length (ft)

Solving the above equation for the effective length and setting the value of the conductivity ratio to 10 can approximate the effective length. This process defines the infinite conductivity fracture length, which provides a reasonable estimate of effective fracture length when fracture cleanup is taken into account. In this case, the effective fracture length is defined as the length of the created fracture that actually cleans up and contributes to production (Figure 11).
Based upon the previous information, one would expect to see improved early flush production as a direct result of higher fracture conductivity, and improved long-term productivity and a slower production-decline curve resulting from improved reservoir access caused by increased effective fracture length. This expectation differs from conventional fracture design theory that suggests the drainage radius is constant and increasing effective fracture length would result in higher production rates and more rapid pressure declines. In other words, the effective drainage radius, for example, in a low-permeability gas reservoir may not be limited by physical boundaries, but is actually a function of the effective fracture length.

Increasing the effective fracture length actually improves reservoir exposure, resulting in a higher effective-drainage radius. This mechanism achieves the combination of higher production rates and flatter production profiles that are often seen when longer effective fractures are obtained.

Many operators believe that given sufficient time, fracture cleanup will occur and greater effective fracture lengths will be obtained. In practice, results have been more rapid production declines than predicted, with consequent lower ultimate recoveries. Many concepts have been put forth to address some of these issues, including the effects of non-Darcy flow in gas wells, multi-phase flow conditions and yield strength of broken fracturing fluids.

Recent testing performed through a large industry consortium was begun to evaluate fracture conductivity performance more rigorously under high gas flow-rate conditions. This testing has helped provide valuable insight into non-Darcy flow effects, but also has shown some additional potential sources for fracture conductivity loss under high-stress and high-gas flow-rate conditions. Specifically, the mechanical failure of the high-strength core material used in the conductivity testing equipment and the subsequent penetration of formation material into the proppant pack caused significant damage to the proppant pack. This damage became even more pronounced under high flow-rate conditions.

Results of the rigorous conductivity testing indicate there is significant benefit gained through the use of surface-modification agents (SMA) (Halliburton’s proprietary SandWedge® agents) and liquid resin systems (LRS) (Halliburton’s proprietary Expedite® service) added to the surface of the proppant (a process involving on-the-fly, direct coating of proppant just before it is blended with the carrier fluid). Previous work suggested these techniques could sharply reduce the potential damage associated with formation material entering the proppant pack. In the most current study, a test series was conducted to evaluate the effects of using liquid coatings on proppant under extreme conductivity testing conditions. Field results were analyzed to help support the data obtained from coating of SMA or LRS on proppant.

Data from this study strongly suggest multiple factors impact the conductivity performance of the proppant pack:

- for uncoated proppant, a negative impact on fracture conductivity appears to be related to the high point loading of the proppant at the interface. The magnitude of this loading appears to be highly dependent upon the mechanical properties of the formation material. This aspect is currently being evaluated much more closely;
- applying the SandWedge (SMA) coating or the Expedite (LRS) material to proppant results in a proppant pack of higher porosity, providing increased conductivity and pack permeability over a wide range of stresses (Figure 12) until the proppant strength is exceeded and the proppant begins to crush. This high-porosity pack may result in a slight weakening of the proppant pack as opposed to a more tightly packed system;
- SMA and LRS materials on the proppant minimize the loss of conductivity associated with the formation mechanical properties by stabilizing the formation surface at the interface;
- under high stresses, the primary damage mechanism to uncoated proppant appears to be intrusion of formation material into the proppant pack. This invasion occurs after the forma-

Figure 12. Conductivity vs. closure stress for 20/40 bauxite, 20/40 bauxite plus 2% SMA, and 20/40 bauxite plus LRC at 250°F and 2,000psi, 4,000psi, 6,000psi, 10,000psi and 12,000psi.

Figure 13. Untreated proppant pack (left) shows significant intrusion of formation material resulting in clogged pore throats and reduced flow area. Proppant pack (right) treated with SandWedge enhancer shows virtually no intrusion of formation material and open pore throats.

tion has undergone a significant degree of failure at the interface (Figure 13); and
• under high-stress conditions, the primary damage mechanism for the SMA and LRS coated proppants appears to be proppant crushing in the center of the pack. The stabilized formation interface apparently reduces the formation intrusion so stresses are transmitted more directly to the individual proppant grains and contact points (see page 22, “Stick to Tacky: It Pays”).

Conductivity and the Fluids Factor 24,25,26,27,28

The relationship between fracture conductivity damage and rheological properties required to accomplish fracture stimulation seems to be inversely related. Many incremental technology advances aimed at providing “cleaner” carrier or fracturing fluids have been implemented, but with each improvement, a sacrifice in fluid rheology and fluid loss control also has occurred to a point where traditional fluids are so weak that fracturing treatments often end prematurely.

Innovative application of chemistry has permitted the development of a new fracturing fluid system as robust as the high concentration guar fluids of the early 1980s but with fracture conductivity properties expected of the polymer-free fluids.

Inherent problems of traditional polymer-based and surfactant-based fluid systems—

Because of their low cost and highly controllable fluid rheology, water-based polymers, guar and derivatized guar have been the mainstay fracturing fluids for many years. Unfortunately, these materials can damage fracture conductivity leading to poorer-than-expected production after fracture stimulation. Steps taken to help reduce conductivity damage caused by these fluids include:

• application of special purification chemical processes;
• improving polymer breakers;
• formulating fluids with less polymer; and
• improved fluid recovery during well flowback after treatment.

Each of these steps has incrementally improved conductivity; however, one-half or more of the native conductivity can be lost to fracturing fluid damage because of using guar-based polymers.

Another approach to reducing conductivity damage is the recent application of surfactant-based, polymer-free viscoelastic fracturing fluids. This technology has demonstrated the value of non-conductivity damaging fluids by generating high well productivity with small fracture stimulation treatments. The downside is that these non-damaging fluids have limited application because of high fluid loss and consequent inability to generate extended fractures at a reasonable cost. What this implies is that an optimum fluid system must be able to transport proppant, extend fracture length and contain no more polymer than absolutely necessary to perform these functions. Then, the fluid must break cleanly and flow back from the fracture. New polymer technology is enabling such fluids.

Until recently, throughout the industry, most fracturing fluid systems are designed and priced with the primary focus on polymer concentration (lb/Mgal). This standard was established years ago because the polymer concentration was the primary means of modifying fluid performance and the resulting value to the operator.

Now, with advanced chemical knowledge and new technologies, polymer concentration is not always the primary component that drives fluid performance and value. Consequently, Halliburton is taking the lead in introducing a performance-based approach to fracturing fluid systems: the “vis” system. This approach enables the optimization of fluid performance rather than being limited by the quantities of various fluid components.

Vis-based fluid systems—Under this new system, fluid performance and price are benchmarked on the base gel viscosity, which corresponds to required downhole performance rather than the polymer concentration.

Historically, a measured quantity of liquid gel concentrate was blended into the base fluid and the base fluid viscosity checked to determine whether the correct fluid blend was being prepared. The vis-based fluids are prepared in the same way. Under this new approach, however, fluid performance based on reservoir conditions, regardless of polymer loading, is now the reference point. The result: no more polymer than is needed is introduced into the fracture resulting in improved cleanup and enhanced conductivity.

Halliburton’s extended complement of vis-based, performance-focused fracturing fluids (Table 1) represents a step-change improvement in fracturing fluid technology. These fluid systems offer the most desirable qualities of both polymer-based and surfactant-based systems.

All fluid systems are integrated into advanced stimulation software to enable tailored treatment designs. Temperature prediction and analysis models are programmed into proprietary 3-D model or pseudo 3-D model

This results in increased damage to fracture conductivity, which reduces flow rates. Earlier findings now confirmed by an independent research facility, coupled with recently completed studies of long-term production results have demonstrated that along with reservoir depletion, two additional factors accelerate production decline following propped stimulation treatments – invasion of crushed formation grains into the proppant pack and loss of fracture width because of proppant embedment and flowback.

The findings and studies also conclude that designing treatments and choosing propping material based on enhanced reservoir understanding along with applying the appropriate coating to the propping agents used in the stimulation treatments can mitigate these negative effects. To this end, Halliburton has introduced proprietary Conductivity Endurance Technologies based on a family of new proppant enhancers and complementary fracturing fluid products.

While no one can affect reservoir quality, these new technologies address getting more conductivity from the proppant placed, allowing for increased flow – at first production and throughout the well’s productive lifetime. Additionally, during periods of restricted or limited proppant availability, Halliburton’s new proppant coating systems, SandWedge™ enhancer and Expedite™ agent (Table 2), can achieve the conductivity needed but use up to 30% less proppant. These agents are changing the manner in which the industry approaches fracture stimulation in high perm (soft rock) and low perm (hard rock) reservoirs.

The SandWedge™ conductivity enhancement system attacks two significant problems that result in fracture conductivity loss: formation fine intrusion into the proppant pack and proppant pack damage resulting from production stress cycling. The unique characteristics of the SandWedge™ agent reduce or eliminate intrusion of formation material into the proppant pack and stabilize the proppant pack, which increases its resistance to stress cycling damage that can occur when wells are shut-in for service.

The system works by chemically modifying the surface of the proppant grains to enhance fracture conductivity resulting from treatments using water-based fluids. The coating process allows the system to be used on any available proppant, and it is compatible with all Halliburton water-based fracturing fluids. Also, since this coating is performed in real time at the well site, only the material pumped into the well is coated.

In addition, the SandWedge™ OS enhancer is specially designed to allow overboard discharge in the Gulf of Mexico. It conforms to all overboard oil and grease limits set by the U.S. Minerals Management Service and can be used in coaled methane wells and other environmentally sensitive land areas.

In reservoirs of 60°F to 550°F (16°C to 288°C) where controlling proppant flowback is a primary concern, Expedite service can improve proppant flowback control, enhance conductivity and reduce time to production, thereby helping to improve the NPV of fracturing treatments. Expedite service provides the highest compressive strength available, which is critical to effectively controlling proppant flowback and allowing operators to optimally produce their wells.

Widely used (precoated) resin-coated proppants often cannot provide the necessary compressive strength because high closure stress is required to provide good grain-to-grain contact prior to resin curing. This requirement can lead to proppant flowback, since in many formations the fracture may not close sufficiently during the first 24 hours after treatments. However, even with no closure stress, proppant coated using Expedite service can provide high strength, consolidated proppant packs. These packs can reduce proppant flowback under the most severe conditions and sustain exceptionally high production rates.

Higher production rates can be most easily achieved through the use of more effective hydraulic fracturing focused on maximizing the effective fracture length and maintaining conductivity. Conductivity Endurance fracturing can enhance the outcome of stimulation treatments and achieve sustained production increases through a combination of:

- proper treatment design;
- low-damaging fluid systems;
- accurate proppant selection; and
- coated propping and packing materials.

As in the past, advances in hydraulic fracturing technology will continue to play a major role in increasing production of vital hydrocarbon reserves.

### Table 1. Performance-based frac fluid systems.

<table>
<thead>
<tr>
<th>Performance-Based Fracturing Fluid Systems</th>
<th>Bottomhole Static Temperature Rating (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SilverStim™ LT</td>
<td>80 – 180</td>
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<tr>
<td>SilverStim™</td>
<td>175 – 300</td>
</tr>
<tr>
<td>SeaQuest™</td>
<td>300</td>
</tr>
<tr>
<td>Sirocco™</td>
<td>400</td>
</tr>
<tr>
<td>Delta Frac™ 140-R</td>
<td>140</td>
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<tr>
<td>Delta Frac™ 200-R</td>
<td>200</td>
</tr>
<tr>
<td>Delta R Foam Frac™</td>
<td>140</td>
</tr>
<tr>
<td>Hybor™</td>
<td>100 – 320</td>
</tr>
<tr>
<td>Water Frac™ G-R</td>
<td>70 – 200</td>
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</tbody>
</table>

### Table 2. Conductivity Endurance agents for proppant coating.

<table>
<thead>
<tr>
<th>Conductivity Endurance Proppant Coating Systems</th>
<th>Primary Application</th>
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</thead>
<tbody>
<tr>
<td>SandWedge™ NT</td>
<td>Conductivity enhancement in BHTs 80°F to 350°F</td>
</tr>
<tr>
<td>SandWedge™ OS</td>
<td>Same as SandWedge NT except OS meets overboard discharge requirements for GOM. Also applicable for environmentally sensitive land applications such as CBM.</td>
</tr>
<tr>
<td>SandWedge™ XS</td>
<td>Same as NT but provides a small amount of proppant flowback control.</td>
</tr>
<tr>
<td>Arctic SandWedge™</td>
<td>Applicable to -20°F surface temperature</td>
</tr>
<tr>
<td>Expedite™</td>
<td>Proppant flowback control and conductivity enhancement – 60°F to 550°F. 400°F to 550°F range is mainly for geothermal wells.</td>
</tr>
</tbody>
</table>

software. This service helps achieve an optimum viscosity profile so proppant can be placed properly to maximize the initial production rate and sustain long-term production.

**New Conductivity Endurance Products/Services**

The quality of available reservoirs is decreasing and the nature in which wells are produced today is more aggressive than in years past.

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The stimulation industry is reconsidering the true nature of fracture conductivity technology – and how it can improve and maintain that technology.

Implied vs. Applied Fracture Conductivity

With the invention and implementation of the modern computer, hydraulic fracturing designs have taken a quantum leap forward over the hand designs and field knowledge used for fracturing treatments in the past. Today, all service companies and many operators are equipped with hydraulic fracture modeling and reservoir simulation software that allows engineers to customize all aspects of the treatment from fracturing fluids to flowback and production rates. In this same age of modernization, unfortunately fewer improvements in fracture conductivity technology have taken place, leaving the industry with little enhanced understanding.

In 2003, about 6.1 billion lb of proppant – ceramic, resin-coated and raw sand – were injected into formations worldwide. The proppant is the only thing that should be left in the formation after the treatment and is the most important feature in achieving and maintaining a profitable completion. With this in mind, the stimulation industry is rethinking what fracture conductivity really is and what it can do to improve and maintain it.

Flow capacity

When designing fracturing treatments, engineers select a proppant type based upon several key criteria such as closure stress, fracture conductivity requirements, whether they require flowback control and cost. These numbers typically are available within the fracturing software programs or on proppant suppliers’ Web sites. It is apparent to most engineers that as closure stress goes up, stronger materials are required; and as formation permeability increases, greater conductivity is required. This often is not as readily apparent as the need for flowback control, or it often is not realized until too late.

Closure stress (applied by the formation) is a fairly simple calculation based upon several well-known equations and is one valuable point in determining the criteria to be placed on the proppant for the chosen treatment. As closure pressures increase, the ability of the proppant to maintain fracture conductivity is reduced. This number (fracture conductivity) is important to the operator because it describes the flow capacity that will be left in the formation after the treatment to improve production rates.

In a nutshell, fracture conductivity is the product of proppant permeability and fracture width. It is the ability of the fracture to conduct fluid to the wellbore that increases production rates as well as profitability. Fracture conductivity of most proppants is measured in third-party laboratories and reported by proppant manufacturers in graphical and tabular form. An engineer who designs a fracturing treatment must realize that even though the numbers are generated by side-by-side standard laboratory testing procedures, the “implied” fracture conductivity numbers reported are not what is really “applied” to the formation.

Implied vs. applied fracture conductivity

In all wells, reservoir characteristics and parameters vary significantly throughout the production cycle. For example, closure stress on the proppant is at a minimum at the beginning of production and increases to a maximum when reservoir pressure is depleted. Multi-phased fluid flow usually does not begin to occur in most wells until significant drawdown pressure is applied or reservoir depletion begins to occur. Over the well’s production cycle, repeatedly opening and shutting-in the well subjects the proppant to an incredible amount of cyclic stress. These pressures can cause pack rearrangement, near-wellbore fracture width loss and can also increase embedment and fines generation (Figures 1 and 2). For these reasons, engineers must understand and analyze additional factors that affect the overall applied fracture conductivity prior to selecting the necessary proppant.

As reservoir changes begin to occur, one item that should be maximized is fracture conductivity. The basic premise for improving the ability to drain the reservoir efficiently is to provide a conduit for the hydrocarbons to reach the wellbore. Any change in the capacity of this conduit can impede or reduce these results. Therefore, when selecting the correct proppant, engineers should take care to understand how issues like quality assurance, storage and handling, slurry pump time, fines...
migration and flowback control of the prop­
pant can impact applied fracture conductivity.

Quality assurance—To generate sufficient
quantities of proppant to meet today’s global
demand, proppant suppliers are required to
mass-produce large volumes in short periods
of time. The production runs require compi­
lcated procedures that, though standard and
documented, still raise opportunities for error.
It then becomes necessary to create a quality
assurance process to ensure the proppant
designed for the customer is the one delivered
to the wellsite. It is important to know how
each manufacturer accomplishes and tracks
quality assurance/quality control to ensure a
quality product.

Storage and handling—Most operators and
service companies neglect or take this for
granted when using proppants. Improper stor­
age or handling of proppants can generate
“dust” within the proppant load. This dust is
then transported into the fracture along with
the proppant and reduces the ever-important
fracture conductivity. Resin-coated proppants,
even the curable (bondable) products, can be
significantly affected by temperature and han­
dling. Some of the curable resin-coated prod­
ucts can lose bond strength by partially curing
in the bulk bags or storage containers. This
loss of strength results from prolonged expo­
sure to excessive temperature while being
stored and/or shipped in bags. Excessive use
of pneumatic transfer also can degrade any
proppant because of the transfer of fines
generated during the process.

Slurry pump times—Along with the effects
of storage and handling, a portion of the
bonding capability of the curable resin coating
on proppants can be lost while being injected
into higher temperature formations. As pump
times are extended and formation tempera­
tures increase, part of or sometimes the entire
curable portion of the resin can be reacted.
This reduces bond strength or the conversion
of a curable product into a precured one.
The loss of bond strength often can be the
difference between fracture conductivity
and proppant flowback.

Proppant flowback control—The ability of
the proppant pack to maintain fracture con­
ductivity throughout the well’s productive life­
cycle is directly related to the ability of the
proppant to “stay” in place during production.
Proppant flowback can dramatically affect the
overall efficiency of the propped fracture to
drain the reservoir. In some instances, it can
cause a choke point, reducing efficiency.
Proppant flowback also can damage tubulars
and surface equipment, resulting in costly
downtime and replacement.

Applied fracture conductivity
During the past 20 years, the Oilfield
Technology Group of Borden Chemical Inc.
has led the fracturing proppant industry with
technology that not only can be easily applied
to the well, but also stands up to pre- and post­treatment testing. The company is committed
to providing the customer with products that
meet or exceed required specifications. In its
effort to maximize product performance,
Borden has established a number of internal
specifications that exceed those the industry
has put in place. To illustrate this commitment,
the company has introduced two new develop­
ments to the industry that not only will
increase stimulation rate of interest, but also
will confirm what Borden says and what it
provides are the same things.

XRT Stimulation Technology is a new
platform of products, applications and sup­
porting research focused on significantly
improving applied fracture conductivity.
WebQC is Borden’s online, real-time prop­
 pant management and quality control assur­
ance Web site. From it, Borden provides oper­
ators and service company personnel with
information on individual orders specific to
that customer; or, customers can review the
overall performance of their orders to docu­
ment trends. This Web site also will allow cus­
tomers to see when their order was shipped,
who is transporting it and the quality control
test results. By placing this information on the
Web site, Borden is ensuring the product
shipped is within specifications and meets
quality control assurances.

By launching these two developments,
Borden is delivering fracture conductivity that
can be applied to the stimulation industry.
Saint-Gobain Proppants concentrates on strength and innovation to deliver higher conductivity and value to the hydraulic fracturing industry.

Innovative Particle Size Distribution and Higher Strength Yield Higher Fracture Conductivity

Strength. Endurance comes from strength. Athletes know that to achieve endurance they need strong muscles. To run a marathon, an athlete needs strong muscles that won’t break down over the length of the race. Strength is the key. Even the smartest of the Three Little Pigs knew that bricks are better for building a house than straw or sticks. So whether you need protection from the Big Bad Wolf or need a proppant that will hold up under pressure, choose a material that is strong.

Strength is at the heart of every Saint-Gobain Proppants product. For 28 years, Saint-Gobain Proppants (formerly Norton Proppants) has been making quality ceramic proppants for the oil and gas industry. Versaprop® and Ultraprop™, the company’s primary products, represent our commitment to quality, use of the strongest ceramic materials and innovative approach to sieve distribution design. These products provide the highest value available to the industry in ceramic proppants.

Versaprop, introduced in the fall of 2002, has combined intermediate density ceramic proppant material and an innovative sieve distribution to become the value leader in the ceramic proppant market. The combination of strength and sieve distribution gives Versaprop 25% more conductivity than comparably priced ceramics, which means more conductivity delivered to the fracture per unit cost and therefore increased value. The result: Versaprop is the fastest growing proppant product in the industry.

Ultraprop features the same innovative sieve distribution design as Versaprop and the highest strength ceramic material, sintered bauxite. This combination makes Ultraprop the value leader in high-strength ceramic proppants.

Name change reflects worldwide scope

Fort Smith, Ark.-based Norton Proppants was the first manufacturer of ceramic proppants. However, its experience with highly processed, naturally occurring base materials dates back more than a century, to the F.B. Norton Pottery Shop in Worcester, Mass., which grew from humble beginnings to become a diversified, multinational industrial abrasives manufacturer.

Norton Proppants was established in 1973, when sintered bauxite pellets became a key component of hydraulic fracturing technology. The company grew as the oil and gas industry recognized the value of higher-strength ceramic materials in fracturing applications. As part of its continuing evolution, the company recently took on the name of its corporate parent, Saint-Gobain, a world leader in ceramics, glass and plastics, whose High-Performance Materials (HPM) business unit acquired Norton in 1989.

The name change, which took effect Oct. 1, 2004, reflects more than just the parent company’s resources and specialization in ceramic materials development. It also embodies the increased focus by Saint-Gobain Proppants on additional world markets at a time when formation stimulation and re-stimulation are enhancing the flow of much-needed oil and gas production around the world.

To better serve the worldwide market, Saint-Gobain Proppants is in the process of expanding production capacity at its Fort Smith plant by 30%.

In addition, Saint-Gobain HPM recently purchased the proppants business of the Chinese firm Chengdu-Hengda Refractory and Proppant Co. Ltd. This business, with headquarters in Guanghan, Sichuan Province in central China, services hydraulic fracturing operations involved in the development of the province’s widespread natural gas reserves.
which provide more than half of China's current domestic supply. This new arm of Saint-Gobain Proppants also will supply ceramic proppant to the growing Russian and Southeast Asian markets.

The Guanghan manufacturing site will benefit from increased capital investment by Saint-Gobain Proppants, which will provide the existing plant with leading-edge technology to meet the company objective of increasing proppant production capacity three-fold by 2005.

**Higher strength means conductivity endurance**

Jack Larry, director of worldwide sales and marketing for Saint-Gobain Proppants, stated that the median particle diameter (MPD) is the primary determining factor in the level of conductivity a proppant will provide. However, the completions engineer should be aware of how a proppant’s MPD changes as stress increases. Typically, we only look at the proppant sieve distribution under surface conditions - before any stress is placed on the proppant.

While Saint-Gobain Proppants was developing Versaprop, the company worked to understand why a proppant with a wider sieve distribution could have higher conductivity than proppants with a tighter distribution. To investigate this proppant physical behavior, a series of crush tests were performed by an independent laboratory to determine how the sieve distribution changed with stress. A summary of this work is found in SPE Paper No. 90562, presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition in Houston in the fall of 2004. The work indicates that a proppant with a tighter sieve distribution under surface conditions can actually have a wider distribution once stress is introduced if a weaker material is used. Also, the ability of a proppant product to retain its MPD as stress increases correlates to its ability to retain more of its conductivity with increasing stress.

Versaprop and Ultraprop are able to retain their unstressed MPD much better than lightweight ceramic counterparts. “This is why they can deliver superior conductivity and value,” Larry said. Conductivity comes from size, conductivity endurance comes from strength and value comes from combining the two at competitive prices.

“Stress cycling can be a significant problem for proppant packs,” Larry stated. “Each time stress is relieved through increasing bottom-hole pressure and then increased again through a return to production, it can cause additional crushing and a resulting loss in conductivity.” Long-term conductivity tests have difficulty mimicking this behavior. However, it can easily be duplicated using crush tests. The results from these cyclic crush tests continue to support the need for strength in the proppant material, showing that proppants that are already crushing have this extenuated, while those demonstrating strength are not affected to the same degree.

While Versaprop and Ultraprop are the backbone of the Saint-Gobain Proppants product line, the company continues to manufacture the same quality Interprop® and Sintered Bauxite products it always has. Interprop can be purchased in 12/18, 16/30, 20/40 and 30/50 American Petroleum Institute (API) mesh sizes. Sintered Bauxite is currently offered in 16/30, 20/40 and 30/50 API mesh sizes. All the company’s products are manufactured for storage in bulk form at its eight North American distribution points and a ninth in the United Kingdom. They are available via 24-hour truck dispatch to designated land locations or offshore loading terminals.

**Saint-Gobain: The big picture**

Saint-Gobain Proppants is part of Saint-Gobain, one of the world’s 100 largest industrial companies and a leader in the development and manufacture of ceramics and other engineered materials. Saint-Gobain operates in 46 countries around the world and employs more than 171,000 individuals. The company’s HPM business unit produces ceramics, abrasives, crystals, grains and powders along with reinforcement products for numerous industry sectors, including energy, automotive, aerospace, medical and optical, electronic, and semiconductor. Saint-Gobain HPM is a world leader in ceramics for thermal and mechanical applications and devotes significant resources to ongoing research and development into new materials and new applications of existing materials.
Building the Case for Conductivity Endurance

Since Conductivity Endurance technologies were first introduced, Halliburton has placed several thousand stimulation treatments in reservoirs to enhance fracture conductivity and increase production potentials. Initial data and field tests on performance characteristics of the SandWedge® conductivity enhancer and Expedite® service were encouraging. Now, with time and production records adding substantial information to the analysis, it is clear these new technologies help prevent intrusion of formation material and control proppant flowback for improved long-term production. The realized benefits from the proper application of Conductivity Endurance technologies have been demonstrated in case after case. Here are just a few examples.

Case History 1: Gulf of Mexico High Perm Formation Wells
Production rates from four wells were compared (Figure 1). The wells were offsets and had essentially identical completions except that the proppant in one of the wells was treated with SandWedge® OS enhancer.

Results: Compared to the average production from the other three wells, the SandWedge treated well produced more initially, maintained higher production, and produced 50% more cumulative.

Case History 2: New Mexico Coalbed Methane Wells
SandWedge® conductivity enhancer used with Delta Frac service helped a major operator add coalbed methane production worth an estimated U.S. $10 million/year from 10 coalbed wells in the San Juan Basin. Unlike other area operators who traditionally had drilled another blind sidetrack wellbore that had to be cased and cemented, the SandWedge enhancer with Delta Frac® service treatments called for hanging an uncemented liner inside the existing 7-in. casing and then perforating at four shots per foot. The wells that had been completed open hole were cavitated. The treatments were pumped at a rate of 65 bbl/min using a 20-lb/1,000-gal Delta Frac service fluid to place 5000 lb of 20/40 sand/ft of net coal. All proppant was coated with the SandWedge enhancer.

Results: Average production from the under-performing wells increased 2.4-fold to more than 14.8 Mmcf/d. Treatment costs were recovered in 3 months.

Case History 3: Gulf of Mexico Shelf Wells
Production rates from four Gulf of Mexico shelf wells were compared (Figure 2). The wells were offsets completed in almost the same way, with the exception that two of the wells benefited from Conductivity Endurance technology (SandWedge service).

Results: Notice the production from the SandWedge-treated wells showed little decline during the 12-month period and provided about three times the cumulative production of the wells completed conventionally.

Figure 1. Production comparison of four Gulf of Mexico high permeability wells.

Figure 2. Comparison demonstrating SandWedge production impact on two Gulf of Mexico wells.
Case History 4: New Mexico Coalbed Methane Production Increases Almost Four-Fold

Even though they had already been fractured, stimulated with slick water and put on artificial lift, three Fruitland Coal wells in northern New Mexico’s San Juan Basin were not producing up to their potential (averaging about 200 Mcf/d each). Halliburton worked closely with the operator to restimulate the wells using Delta Frac service and coating all the proppant with the SandWedge agent to enhance fracture conductivity and control fines migration. Since all three wells under consideration were virtually identical in depth, hole size and formation conditions, it was decided to use SandWedge on two of the wells to confirm the system’s performance. Between 95,000 gal and 100,000 gal of Delta Frac® fluid was used to pump more than 300,000 lb of proppant into each well through 5 1⁄2-in. casing.

**Results:** All three treatments successfully increased gas production. In the well using Delta Frac fluid by itself, the anticipated production increase was achieved. However, the two wells in which the SandWedge agent was used showed an almost four-fold production increase. The wells are still flowing several months after the job without artificial lift. The production increase and lift cost savings created an additional economic value of more than U.S. $60,000 a month.

Case History 5: South Texas Gas Wells

A South Texas operator needed to stimulate a series of wells and achieve production more quickly than with the normal procedures using RCP. Typical well conditions included bottomhole temperature greater than 325°F (162.6°C) with closure stresses up to about 12,000psi. Typical treatments were pumped at 35 bbl/min to place 300,000 lb of bauxite at 2 lb/gal to 8 lb/gal.

**Results:** Using the Expedite® service, temperature and pressure of these wells enabled cleanup to begin after only 2 hours with little or no proppant flowback. Production rate increased 30%. Time to achieve 40 MMscf/d production was reduced from the usual 200 hours with RCP to 65 hours for a 68% improvement. Cumulative proppant flowback was reduced by 60% compared to flowback with RCP material.

Case History 6: Eight South Texas Gas Wells

In the Monte Cristo field, production from eight similar wells was compared – four treated using Expedite service and four treated conventionally (Figure 3).

**Results:** After 10 months, the four wells treated using the Expedite service provided 2½ times the production of the conventionally treated wells.

Case History 7: San Juan Basin CBM Wells

Three coalbed methane wells in the San Juan Basin (Four Corners area) were refractured using SandWedge® enhancer (see table). The wells were studied in terms of the effect of SandWedge agent on advancing dewatering and overall production.

**Results:** All three wells responded significantly and provided fast payouts of the refracs.

<table>
<thead>
<tr>
<th>Case</th>
<th>CBM Refrac 1</th>
<th>CBM Refrac 2</th>
<th>CBM Refrac 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas produced 9 months after initial stimulation (Mcf)</td>
<td>463,747</td>
<td>88,406</td>
<td>72,452</td>
</tr>
<tr>
<td>Delta gas 9 months after refrac (Mcf)</td>
<td>179,071</td>
<td>408,818</td>
<td>268,294</td>
</tr>
<tr>
<td>Time to pay out of stimulation treatment</td>
<td>3 weeks</td>
<td>3 weeks</td>
<td>1.33 months</td>
</tr>
</tbody>
</table>

San Juan Basin wells refractured using SandWedge.

Case History 8: Michigan Refrac

In Michigan, Halliburton applied its SandWedge service in fracturing one of two wells with the same production and very similar characteristics on the log. Three additional wells were fractured with regular sand. One well experienced a production decrease from 275 Mcf to 220 Mcf. Another well screened out. Then on the third well, the comparison well, initial production increased from 40 Mcf to about 150 Mcf with water production also increasing. However, when the water production dropped off, production of gas also dropped to 80 Mcf.

**Results:** When the comparison well was fractured using SandWedge, production increased five times from 40 Mcf/d to 200 Mcf/d. Water production also increased, but when it later dropped off, gas production held at 200 Mcf/d. The well has since gone as high as 300 Mcf/d. The economic value to the operator is about U.S. $290,000 for the first year (at then current gas prices).
Filling the Bill for Custom-made Fracture Treatment Chemicals

Texas company helps develop, manufacture and blend several Expedite proppant flowback control products.

Quality manufacturing and precise blending of component chemicals are crucial to developing new compounds that, when used in advanced treatment fluids, help coax more production from oil and gas well completions.

This is as true for the small quantities of fluids to be analyzed at the laboratory bench level as it is for the somewhat larger recipes tested at the pilot stage, but even more important when it comes to producing the much greater batch volumes necessary for commercial applications in the field.

Magnablend Inc., with 25 years of experience in custom chemical manufacturing, blending and packaging, merits high standing in the oil and gas industry as a “go to” partner for providing chemical products prepared and blended to exacting customer specifications. These and other capabilities have earned Magnablend “preferred supplier” status with a number of major companies around the world.

The company has long been an alliance partner with Halliburton Energy Services (HES) as a key manufacturer of specialty liquid and powder compounds incorporated into many of its downhole applications. They play a critical role in the success of the HES line of Conductivity Endurance services, including its Expedite proppant flowback control system.

Grass roots participation pays off

Along with several other specialty chemicals suppliers, HES called upon Magnablend to consult very early in the grass-roots development of the dry and liquid chemical products used for the service applications that came to be grouped together as Conductivity Endurance technology.

Scott Pendery, vice president and chief operating officer, said Magnablend’s demonstrated ability to acquire raw materials quickly from domestic and international sources, along with the capability of bringing its extensive blending facilities to bare rapidly and dependably, added tremendous value during the technology’s formative stages.

“In the fall of 2001, Magnablend made small pilot batches of Conductivity Endurance chemicals for testing purposes,” Pendery said. “In January 2002, HES started ordering full-scale production quantities to supply a number of fracturing jobs that included the Expedite® service. They relied on Magnablend to manage chemical components sourcing to ensure that enough were on hand to meet the volumes required for Expedite applications, which were growing rapidly.”

Magnablend manufactures and blends component chemicals used for the medium- to high-temperature and low-temperature versions of the Expedite chemical products.

Since demand forecasts for any new product is difficult at best, Pendery said, Magnablend stayed in constant communication with the field to calculate and fill a high-end inventory of Expedite component chemicals at its 40,000 sq-ft liquid blending facility in Waxahachie, Texas, about 25 miles (40 km) south of Dallas.

“By April of 2002, HES booked several fracturing jobs requiring Expedite coating of millions of pounds of proppants,” he said. “They needed all the product we could supply and asked us to do our best to anticipate the near-term demand. So, we geared up to do just that.”

In addition to ordering and warehousing large supplies of expensive raw chemical feedstock, Magnablend also dedicated the manpower and equipment necessary for rapid-fire turnaround that, during 2002, required 24-hour-a-day/7-day-a-week (24/7) accessibility.

“It was a challenging time, and the idea of falling behind was totally unacceptable,” Pendery said. “But while fulfilling the Expedite chemical product orders on time and at a competitive price, we also focused intensity on high standards for safety, health and environmental concerns, which we maintain at all of our facilities.”

Modified ‘tote tanks’ benefit customers

To better handle distribution of the blended Expedite chemicals during “on-the-fly” mixing at well sites, Magnablend ordered 36 gal of the first 330-gal tote tanks in the well treatment industry to be equipped with 3-in. interior diameter (ID) ball-type discharge valves.

“Standard” tote tanks are equipped with 2-in. ID butterfly valves.

Additionally, Pendery said, the tanks were engineered with top-mounted valves for pressurizing to further assist discharging of the tanks’ liquid contents into well site mixing equipment.

Later, with input from one of its key suppliers, Magnablend assisted HES in making changes in chemical formulations to further thin component products, transforming the blend from a suspension of chemicals into a true solution, Pendery said. This not only
helped lower Expedite coating viscosity, he said, but also extended its shelf life, which had economic and job-specific benefits for the customer.

“As the Expedite product continues to mature, both Magnablend and HES are engaged in a joint process of continuous improvement,” Pendery said. “We cooperate with HES to make sure that every product iteration simplifies application in the field.”

As an example of one such solution, Pendery said that after a well treatment was finished, the inside surfaces of well site mixing and pumping equipment was filmed with the adherent compound produced by mixing Magnablend-supplied products with other chemicals to form the Expedite proppant coating. Depending upon time elapsed for moving the equipment back to HES facilities, this film gradually stiffened, posing a potentially lengthy cleanup time.

However, he said, Magnablend chemical specialists worked with their counterparts at the HES laboratory in Duncan, Okla., to develop a cleaning compound that can be used on location that diffuses such stickiness, leaving the equipment clean and ready for the next job.

Plants meet wide-ranging specs
Founded in 1979 and headquartered in Waxahachie, Texas, Magnablend has earned high recognition in the industry for consistently maintaining a competitive edge by dint of its thorough attention to detail in customer service, and through the quality workmanship and honesty of its management and employees.

The company operates two chemical product-blending facilities, one each for liquids and powders, with the ability to quickly shift to a 24/7-production schedule. The 40,000 sq-ft liquid blending facility is comprised of 21,000 sq ft dedicated to manufacturing and packaging, with the remainder committed to warehousing. An additional 12,000 sq ft of warehouse space is being added, with completion scheduled for spring 2005.

With more than 30 liquid-mixing vessels ranging in size from 250 gal to 15,000 gal, the plant can accommodate nearly any sized project. Mixing vessels are fabricated out of stainless or carbon steel, fiberglass and high-density polyethylene, allowing coverage of an array of chemical reactions. Built-in heating or cooling capability allows routine handling of exothermic and endothermic reactions. Specialized equipment exists for extremely viscous blends as well as suspensions or dispersions. After a product is manufactured and approved by Magnablend’s quality control laboratory, it can be packaged and labeled as specified by the customer.

Located nearby is the 162,000 sq ft powder blending facility, comprised of 50,000 sq ft for manufacturing and packaging, and 112,000 sq ft of warehouse space. Production equipment includes seven double-action ribbon blenders ranging in size from a 40-cf pilot batch unit to a large 480-cf model, as well as several large storage/blending silos.

“The small unit allows us to make batches in the 500-lb to 1,000-lb range, while the large blenders handle batches up to 20,000-lb,” Pendery said. “By incorporating our 60,000-lb capacity blending silos, we can produce full transport truckloads all under one lot number, a feature which some companies find extremely valuable.”

Such flexibility, he added, benefits customers, since Magnablend can assist with trial batches during testing and then move directly into mass production. Powder products can be packaged in containers ranging from 1-lb bags to 50,000-lb bulk transport trucks.

In addition to its oilfield customers, Magnablend serves companies in the agricultural, water-treatment, rubber and industrial cleaning compound industries, among others.
New well conductivity enhancement services benefit from cross-fertilization among widespread labs and production sites.

When Halliburton Energy Services (HES) decided to conduct additional research into improved polymers for cleaner well stimulation fluids, they went to long-time research and development (R&D) partner the Rhodia Group for assistance in creating new polymeric compounds and improving existing ones.

Rhodia, headquartered in Aubervilliers, France, is a far-reaching specialty chemicals company with strong technology positions in applications chemistry, specialty materials and services, and fine chemicals. It has a number of subsidiaries in Europe, the Far East and the Americas. Combined, the Rhodia companies have more than 23,000 worldwide employees, a large percentage of whom are chemists, as well as chemical engineers, and other engineering specialists and business development professionals.

Rhodia Inc., the U.S. subsidiary, is among companies that assist HES with R&D into and manufacturing of chemical building blocks for their special formation treatment fluids. Much of this work is conducted under formal R&D partnerships.

Rhodia Inc., headquartered in Cranbury, NJ, operates an Oilfield Services group based in Houston that has generated more than 30 years of experience in supplying a range of products used in drilling, cementing, stimulation and production. That group supports oilfield service customers and partners with a product offering made up of surfactants, natural hydrocolloids and synthetic polymers used in the oilfield setting as emulsifiers, dispersing and wetting agents, viscosifiers and gellants, corrosion and scale inhibitors, biocides, and foaming and antifoaming agents. For the HES Conductivity Endurance services, the group conducts R&D to develop products from guar gum, xanthan gum, and other natural and synthetic polymers.

Rhodia’s oilfield service operations are not limited to the U.S. market. Under the parent company’s successful global business model, all of its resources, including five R&D centers worldwide – Aubervilliers and Lyon, France; Paulinia, Brazil; Shanghai, People’s Republic of China; and Cranbury – can be brought to bear to help formulate oilfield service or other industry-specific chemical products, wherever they are needed. The company also operates 113 production sites around the world, with several based in the United States working closely with service company customers and partners to manufacture formation-level products for use anywhere on the globe.

‘Fast-break’ conductivity

Kansas Hernandez, regional business director for the Americas, said that for oilfield chemicals, Rhodia’s suite of viscosifier and gellant products made from guar-based polymers as well as from synthetic polymers, is helping customers and partners enhance fracture conductivity in oil and gas wells.

“In the case of HES’s Conductivity Endurance services, our chemists work directly with theirs to develop various treatment fluid technologies, including fracturing fluid products whose viscosity is best broken with a separate additive, or those that break when they come into contact with formation fluids,” Hernandez said.

The newly developed micro-polymers, he said, help enhance fracture conductivity in three ways: they help carry an optimum proppant load into the fracture, and when “de-linked” on contact with formation-produced fluids, offer extremely high cleanout efficiency. This is particularly important in combination with the HES proppant surface modification agents, which help significantly raise overall fracture conductivity. The third benefit from the micro-polymer system and the way it is linked and subsequently de-linked is the possibility it can be re-used.

A company-wide ability to ‘cross-breed’ capabilities allows Rhodia to bring its worldwide research and development capabilities to bare to help solve customer/partner challenges.
Most of the feed stocks for Rhodia's guar-based polymers receive initial processing in India, where guar beans are grown, harvested and “split” to separate the endosperm from which the natural polymer base materials are derived (though, if market forces dictate, Rhodia can obtain splits from guar beans grown and harvested domestically, with the splitting process undertaken at a U.S. production site). In India, this initial step is handled under a long-term (50 years) partnership between Rhodia and Indian company Hindustan Gum and Chemicals. The guar is then shipped directly to a Rhodia warehouse and production sites as splits or, after additional processing in India, as standard guar powder.

Hernandez said that among other market R&D activities, the company’s Cranbury laboratory handles oilfield applications, including fracturing fluid formulations, and subjects them to standard American Petroleum Institute testing before submitting them for testing and approval at the customers’ own laboratories. Orders for fracturing fluid component chemicals and other products are fulfilled largely at Rhodia’s production facility at Vernon, Texas, near Wichita Falls, Texas. There, at a state-of-the-art plant on a 40-acre site, splits from India or domestic sources are processed into standard guar products or derivatized guar such as HPG, CMHPG, cationic or other specialty derivatized guar products.

Other well treatment chemical products are formulated and tested at various Rhodia labs around the world under similar R&D partnership arrangements, Hernandez said. Many are manufactured at the Vernon plant, with some coming from other U.S. and overseas production sites.

**The art of cross-fertilization**

David Kremmer, oilfield service account manager, said Rhodia Inc.’s research and product innovation strategies are important aspects of its well treatment chemicals business. Service company customer/partners expect more from suppliers than just the products, he said, and they depend upon suppliers to deliver complete solutions that address their unique, product-specific requirements.

Kremmer said Rhodia uses internal “cross-fertilization” capabilities to draw upon a vast reservoir of technical and field expertise in organic and inorganic chemistry to identify customers’ needs. After R&D completion, the company’s project engineers, who are chemists or chemical specialists, help determine which chemical products work best to fill those needs.

“Our global research centers are available to help deliver the user benefits our customers and partners expect,” said Kremmer, who added that any of the production sites also could be brought in to participate with individual project teams. “By stimulating interaction among the talented people employed by these company assets through this unique cross-functional business process, we can develop comprehensive, end-to-end solutions.”

While internal capabilities are an integral part of the company’s culture, Rhodia strives to identify skills and technology sources outside the company, as well, said Bruno Langlois, market innovation director for the parent company’s industrial and oilfield specialties group based in France.

This has resulted in numerous R&D partnerships with customers, he said. It also includes basic and applied research partnerships established with a number of major university and scientific research laboratories around the world. In the United States, these include Harvard University, Massachusetts Institute of Technology (MIT) and the University of California at Santa Barbara. Overseas research partners include the French National Scientific Research Center, Belgium’s University of Louvain and Brazil’s national university.

Overall, such cross-productiveness results in benefits where they count the most, Langlois said.

“By listening more closely to our customers and R&D partners, Rhodia is committed to designing the right end-products while minimizing the time required to manufacture them. That shortens the time it takes for the customer to move those products into the marketplace.”

**A worldwide market base**

In addition to oilfield specialties markets, the Rhodia Group also serves and partners with major players in the petrochemical and refining, automotive, electronics, fibers, pharmaceuticals, agrochemicals, consumer care, tire, paints and coatings, markets, among others.

More than half the company’s product development projects are undertaken in partnerships with customers.

In 2003, the company, whose shares are traded on major world stock exchanges, posted consolidated net sales of U.S. $6.8 billion (5.5 billion Euros). In the same year, the company allocated almost 4% of net sales to R&D activity, with 6% of that invested through external partnerships.▲
A surface modification agent (SMA) was introduced into the global stimulation market in 1997. The agent was designed to enhance and sustain fracture conductivity by making the proppant surface tacky. Several conductivity-enhancing mechanisms were suggested. Two important mechanisms resulting from increased surface tackiness are: increased proppant pack porosity resulting in increased pack permeability; and increased proppant pack stability that prevents encroachment of formation fines into the pack and migration of fines within the proppant pack. The myth that excess conductivity can be placed in a fracture or frac pack to allow fines production has been disproved. Stim-Lab testing has verified that locking fines in place will maintain greater proppant conductivity than allowing them to be produced. In terms of extended conductivity maintenance, the fines control aspect has proved the most valuable property developed from the product.

At the well site, the proppant is coated with SMA (a thermally stable, polymeric material) during the well treatment. It becomes tacky, resulting in long-term changes in the properties of the proppant pack. Because of its tackiness, SMA-coated proppant resists settling, resulting in increased pack porosity and permeability. It also resists movement caused by fluid flow. In addition, the SMA does not harden and the flexible, tacky coating makes the proppant resistant to stress changes resulting from variable production conditions.

Since first introduced, thousands of stimulation treatments have been placed in reservoirs with the surface modification agent (Halliburton’s proprietary SandWedge®) to generate conductivity enhancement. Most early detractors considered benefits from conductivity enhancement to improve the initial potential of the well and little else. What is now believed is that more hydraulically fractured reservoirs produce fines than previously thought. Soft rock reservoirs (Young’s Modulus less than 1 million) and coalbed methane reservoirs are notorious for producing fines. Conversely, few would expect reservoir rock with properties similar to the Vicksburg Sand of South Texas or the Tarrawarra of the Cooper Basin in Australia are capable of producing fines. However, several cases have evolved where some benefit from using an SMA is observed in these reservoirs.

Conductivity maintenance, then, is the long-term benefit of using an SMA material to abate fracture or proppant conductivity decline. The maintenance process is more than simply establishing a higher conductivity starting level, as in cases that use very low residue or otherwise non-damaging frac fluids. The process also is more than establishing fracture conductivity by including proppant flowback control or proppant pack stability. Conductivity maintenance is the process of addressing these issues, in addition to providing long-term fines control and proppant pack flexibility. Lack of fines control can have the most devastating effect on proppant pack conductivity.

Damage within the Proppant Pack

The invasion of fines into a proppant pack can affect pack permeability, resulting in underperformance and premature decline in well productivity, such as effectively “chocking” the productive capacity of the well. Formations produced from wells completed with hydraulic fracturing, frac-packing and gravel packing are susceptible to pack invasion of fines and subsequent permeability or conductivity losses. With each of these completion techniques, target productivity depends on proppant-pack permeability and conductivity. Again, conventional thinking leads one to believe that increasing the proppant size or concentration will provide adequate conductivity and allow the fines to be produced. This, however, is not the case. Some fines may be produced, but those left behind will bridge and ultimately reduce the conductivity of the proppant pack in both soft and hard rock stimulations.

Fines invasion has been limited historically to classic size exclusion processes (criteria reported by Saucier) in which the proppant-pack size distribution is sized to the median particle size of the formation. This approach is limited because one proppant size is selected for formations that are almost always heterogeneous. The tendency, therefore, is to undersize the proppant pack to exclude the smallest median formation framework grain size likely to be encountered. As a result, production may be conductivity limited assuming no further fines encroachment and damage to the pack. Even in adequately designed packs

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in which formation framework grains are excluded, many formations have a “fine” tail, or contain significant formation “matrix” or authigenic minerals within the pore network that can become mobile and infiltrate into the proppant pack. This condition, which usually is diagnosed after completion, requires post completion treatments such as acidizing for remediation.

However, alternative solutions and a fundamentally different approach using proppant surface-modification technology to prevent proppant-pack damage has emerged through study of the mechanisms of fines invasion, particle plugging and interface stabilization. SMA is now a proven technology that has changed previous solution paradigms (Figure 1).

It is important to note that proppant conductivity is a smaller-scale component of fracture conductivity. Standard industry conductivity testing usually is performed in the smaller-scale context of proppant conductivity. This scale-dependent concept is illustrated in Figure 2.

Proppant and fracture conductivity can be impaired or damaged from the several overlapping mechanisms. In each phase, the physics of particle retention and the net effect on permeability are different. The most significant finding in analysis of particle-deposition mechanisms and resulting permeability reduction involves deposition kinetics and the location of particle retention. The flow regime and the mechanism determining permeability damage depend on these variables. An important conclusion from extensive analysis is that interpack conductivity or permeability reduction depends on the specific particle-deposition mechanism (Figure 3).

**Surface deposition of particles**—In this phase, particles deposit on the grain/pore surface. The kinetics of this process depend on physical and chemical factors such as pore-scale hydrodynamics, electrostatic charge differences between particles and pore surfaces, pore-surface texture and particle composition. Whether surface deposition is restricted to monolayer or multilayer deposition depends on the tendency for particles to aggregate. It has been theoretically and experimentally demonstrated that this phase alone results in minimal damage. Colloidal and clay-sized particles normally would fit into this deposition mechanism in the absence of larger macro particles.

**Pore-throat bridging and accumulation**—Pore-throat bridging occurs when a particle flowing through a pore throat forms a bridge. The particle may attach to two particles already deposited onto a pore-throat surface (three-particle bridging) or to a previously deposited particle and pore-throat surface (two-particle bridging). Pore-throat bridging also can occur when particles are larger than the pore-throat size (single-particle bridging). Once formed, the pore bridge forms the structure for subsequent upstream accumulation of particles, thereby dramatically decreasing the fluid-flow rate through these pores. The most dramatic rate of permeability decrease is observed during this phase (Figure 4).

**Internal cake formation**—Once the formation of bridged pore throats reaches a critical value, the pores no longer are connected over some critical damage depth. In this phase, all the incoming particles accumulate not only in the immediate pore throat, but also within all pore bodies that still are available to flow, forming an internal filter cake. Weaver et al. introduces this impairment mechanism through

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8. Ibid.
13. Ibid.
micro visualization techniques. The depth of the internal damage and the permeability of this region control the system permeability or conductivity. The onset of internal cake formation is characterized by rapid reduction of downstream particle concentration. The amount of permeability damage depends on the concentration and distribution of smaller particles, including colloidal and clay size, in the flowstream. Expansion of this work has led to additional insights about particle-size distributions, shape and bridging mechanisms.

**External cake formation**—At the point where internal cake formation is achieved, particles accumulate upstream and may form filter cakes at the interface. In a fracture/gravel-pack application, this mechanism is not a primary phenomenon, since the internal filter-cake growth would dominate and continue along the length of the propped fracture.

**Infiltration-sedimentation**—In geologic media and sand filtration systems such as a propped fracture, mass flow of particle slurries into a porous medium results in particle accumulation in hydrodynamic low-flow regions. This accumulation can occur in the absence of internal filter-cake formation. This process can be largely gravity-driven, whereby the dynamic-flow vector force is less than the sedimentation force, resulting in the interpose accumulation of infiltrated particles. This process was first described in the context of fracture/gravel packing.

**Source of Fines, Transport and Conductivity Impairment**

Unconsolidated or poorly consolidated (“soft rock”) formations, and those completed with fracture/gravel packing methods are most susceptible, although not exclusively, to destabilization of the formation/fines interface and encroachment of fines into the proppant pack. Even in “hard rock” formations, the proppant pack can be susceptible to fines migration from proppant crushing because of formation and production cycle stress. Fines also are created during the fracturing process, and can migrate through the proppant pack and greatly reduce proppant conductivity. Formation types usually considered most susceptible to interface destabilization include unconsolidated clastics such as laminated sand/shale sequences, turbidites and volcanics such as tuffs or bentonite shales. Among the many well-known examples and analogs, the most notable are offshore formations producing from the Gulf of Mexico. Nonclastic formations susceptible to this phenomenon include carbonate chalks, organic coal and shale. Following is a brief summary of the various sources of fines destabilization and encroachment.

**Unattached or weakly bonded fines**—Some formations contain unattached or weakly bonded fines. The slightest change in fluid salinity or interfacial tension can cause these fines to migrate with the producing fluid. These fines typically are small enough to move through a proppant pack without causing severe plugging, if not too many fines are moving at once.

**Formation stress and fluid velocity changes**—Stress changes resulting from variations in production rates and pressures often can cause formations to yield. In addition, the onset of water production and the resulting changes in the capillary pressure/relative permeability can weaken the formation matrix. Consequently, the formation integrity at the proppant pack interface can fail, resulting in fines migration and/or invasion into the proppant pack (Figure 5).

**Proppant crushing**—Fines are generated when proppant is crushed during the transporting, mixing and pumping operations required for well completion. Weak proppant or that which is not uniformly distributed, also can be crushed by excessive fracture closure stresses and production cycle. Fines resulting from proppant crushing vary widely in size distribution, but all can damage pack permeability (Figure 6).

### Historical Control Methods

Historical methods employed to prevent or treat damage caused by formation fines include chemical and mechanical techniques.

**Chemical treatment**—These methods are designed to produce a chemical reaction with the formation sand for the purpose of inhibiting its mobility. They normally include the use of chemical flocculation, or the use of organic cationic polymers, inorganic polymers and oil-wetting surfactants. Although chemical treatments sometimes are referred to as “permanent,” they are subject to deterioration with time and also result in reduced formation permeability. They focus on flocculation or agglomeration of clay fines for formation treatment, or involve changing the surface-wetting properties to reduce the tendency of aqueous fluids to migrate. Limited study or...
application has been performed with these systems in the context of fracture/gravel-pack completions. All of these existing technologies rely on treatment and contact with the particles, which may become mobile.

Another solution involves applying temporary clay stabilizers. These stabilizers minimize the tendency to disperse or deflocculate naturally occurring fines within the formation matrix. Such chemical systems may include mono and divalent salts or low-molecular-weight quaternary amines. This solution is considered temporary, since the subsequent changes in water salinity can cause chemical dispersion or swelling of the susceptible clays.  

**Mechanical exclusion methods**—These include the use of mechanical "screens" or sand-exclusion devices. However, the screen has no effect on fracture conductivity. The frac-packing technique, for example, provides stimulation and sand control. In poorly consolidated formations completed by frac packing, sand and fines exclusion and sufficient conductivity depend on careful proppant sizing. Smaller proppant sizes can provide sand and fines control without providing adequate conductivity.

**Controlling Fines with SMA Technology**

In fracturing or frac-pack operations, proppant coated with SMA becomes tacky, resulting in long-term changes in the properties of the proppant pack. Because of its tackiness, SMA-coated proppant resists proppant grain movement caused by fluid flow. The coated proppant also resists packing and settling, resulting in increased pack porosity and permeability. In addition, because the flexible, tacky coating SMA provides does not harden, it resists stress changes resulting from variable production conditions. Extensive laboratory data and thousands of field applications have led to the following conclusions:20,21,22

- conductivity maintenance can extend into an economic benefit by increasing ultimate recovery and reducing monthly operating expenses;
- SMA-treated proppant resists particulate invasion and maintains permeability over a range of flow rates;
- surface treatment of proppant to render the surfaces “tacky” has the following effects: the treatment adsorbs fines entering a proppant pack; and it reduces or eliminates fines entry into a proppant pack by stabilizing the proppant/formation interface;
- pore bridging and accumulation, internal cake formation and infiltration sedimentation are dominant mechanisms that cause the greatest damage to proppant packs;
- particle adsorption onto proppant surfaces produces minimal damage to permeability because of the location and distribution of the entrapped fines; and
- the proppant’s resistance to particulate invasion results in a new sizing criteria for frac-pack treatments, which enables larger proppant sizes to be used for maximum well productivity.

SMA-treated proppant has been found to prevent proppant-pack damage caused by infiltration of formation fines into a proppant pack:

- proppants coated with SMA that remains tacky while in the formation exhibit a great degree of control over the conductivity endurance of the proppant pack. This control has a longer effect than previously thought because of SMA’s capability to control other conductivity damaging factors;
- the economic benefit from using an SMA can outweigh the cost where fines contribute to diminishing conductivity;
- in cases where fines are the major factor contributing to conductivity loss, refracturing zones with SMA-laden proppant is value-proven; and
- SMA coating is resistant to water and hydrocarbon-based well fluids.

In summary, SandWedge (SMA) enhancer can be applied to proppant as a liquid additive. It dramatically increases the surface friction of individual proppant grains. Because SandWedge material coats the proppant before it becomes coated with frac fluid gel, more gel remains in the intergranular volume, helping improve the stereo-chemical capability of breakers used during cleanup. SandWedge material also helps improve proppant conductivity by enabling proppant grains to achieve better vertical distribution and alignment within the fracture. This, in turn, increases proppant porosity, which equates to increased proppant pack permeability.  

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20. Ibid.
Forging cooperative relationships with service providers creates teamwork to supply much-needed formation-level chemicals.

Nalco is a company name long recognized as a world leader in water treatment and industrial process products and services. The company has a 75-year history as a specialty chemicals manufacturer, technology innovator, research and development (R&D) partner, and process enhancement company with more than 10,000 employees. The company serves customers globally in numerous industries, among which range from aerospace and aviation to cosmetics, and from mining and minerals to pharmaceuticals.

One of Nalco’s most important markets is the petroleum industry, where its products and services extend across all phases of hydrocarbons development – from oil and gas extraction, production and transportation to refining and petrochemicals processing.

The company’s contributions to the extraction segment, including exploration and production, benefit producers and service providers who help them drill and complete wells with the common goal of yielding optimum production at the lowest possible field development cost. Nowhere is this more evident than in those contributions made by Nalco’s Adomite Group, which is heavily involved in formulating and blending chemicals with which to exclude co-production of brines and other costly water-based fluids, as well as undesirable sedimentary materials, from the well stream.

Based at the company’s Energy Services Division headquarters in Sugar Land, Texas, near Houston, the Adomite Well Service Chemicals group supports oilfield service providers by supplying special formulations to aid oil and natural gas well drilling at the formation level, where produced water and formation residues often create major barriers to efficient production. Adomite’s research chemists and field engineers are helping create new products for drilling, cementing, completion, fracturing and acidizing, among other downhole treatment services.

The company is working closely with oilwell service companies to provide special chemicals and additives for inhibiting corrosion of oilfield tubulars and pumping equipment downhole and at the surface. It also provides the means necessary to significantly reduce the effects of friction created by the flow of fluids under extreme downhole temperatures and pressures.

Partnering on well treatment solutions

One of Adomite’s key chemical development activities has been its long-term R&D partnership with Halliburton Energy Services (HES) in developing specialty chemicals for a number of well treatment applications. Among these is Adomite’s close cooperation in designing a large-scale manufacturing process at the Nalco Sugar Land plant to produce a number of water conformance chemicals used by HES in its Conductivity Endurance series of formation fracturing services.

Ronald B. Lessard, technical director for the Adomite group, said HES took the formulae for the proprietary water shut-off chemicals – developed originally at its Duncan, Okla., R&D laboratories – to Nalco Energy Services. Drawing on the confidentiality and trust established by the existing R&D partnership, HES asked Adomite to design and scale-up a process to manufacture the chemicals in batches of as much as 40,000 gal. The Duncan group teamed with Adomite’s chemists and technical consultants to produce pilot-level quantities at the Nalco complex in Sugar Land. They then designed and developed the necessary process train in time to supply HES with quantities sufficient to meet field requirements.

“It was a challenge for us to fulfill a fast-track product delivery schedule such as that one, because the chemistry is difficult,” Lessard said. “It was no short order. But we were successful, and the mutual confidence already
established between the two research groups did much to make it possible.”

**Wide-ranging focus on customers’ needs**

While R&D efforts made by Nalco Energy Services divisions, including Adomite, are focused on technical innovations created by their own Ph.D.-level research chemists to help solve customers’ current challenges as well as prevent potential new ones, they often call on such inter-company teamwork to help provide support for the customer’s own innovations, Lessard said.

“In this case, the actual chemistry was created by HES, but we also routinely supply HES, as well as other service companies, with products developed jointly by our respective research groups,” he said. “And, having forged this tight connection at the R&D level, our research chemists at times develop new material that we take exclusively to the companies with the knowledge that it has a potential role in specific types of service applications.”

In fact, he added, it is only with the HES R&D team’s approval that any Nalco Energy Services sales effort can be directed either to the Halliburton Co. corporate or HES field purchasing organization. This holds true for other service company customers, as well.

Meanwhile, as Nalco Energy Services divisions work to provide original and customer-formulated chemical products, its field sales engineers devote most of their time working with customers at their actual field service installations to help ensure Nalco products are being applied in the most result-effective, yet cost-efficient way.

“Most of our technical sales people are chemists by training, so they look at ways in which the assets can be managed to produce a maximum effect,” Lessard said. “But they also monitor product use with an eye on getting better results from more efficient application of the product.”

Getting better results also sometimes calls for development of subsequent product generations, he said.

“Once our research chemists have walked through a new chemical formulation with the customer and have returned to the plant to set up manufacturing processes and to follow through to actual production, they often consider new chemistry that might improve on the original formulation,” he said. “For instance, we are now working on a completely different chemistry with which we hope to extend the working temperature levels for a number of products now in field use. Since this work is being conducted under an R&D partnership, the potential benefits created by a new iteration would go directly to the partner. But in the end, both sides gain.”

**Divisions circle the globe**

The Energy Services Division of Nalco Co. is a global leader in providing on-site problem solving innovations through its extensive network of technical field specialists in more than 120 countries. The division’s upstream businesses concentrate on solutions to critical exploration and production issues, including corrosion control, oil/water separation, scale control, water treatment, paraffin/asphaltene control, gas/production handling, oil spill chemicals and flow assurance problems associated with gas hydrate formation.

The parent company’s worldwide staff of research and manufacturing professionals work at key centers around the world, including one at its Naperville corporate headquarters. Overseas research/manufacturing hubs include the Latin America Operations Center in Sao Paulo, Brazil; European Operations Center at Leiden, The Netherlands; and Pacific Rim Operations Center in Singapore. Combined, these centers constitute 49 plants with a total of 9,400 professional and skilled employees. Managerial, administrative and other staff constitute the remainder of the company’s total employment. ▲
Companies at the heart of hydraulic fracturing services share a common objective: to deliver nothing less than optimum fracture conductivity to each well so the customer benefits most where it counts – at the sales line meter.

Irving, Texas-based CARBO Ceramics, the world’s largest manufacturer of environmentally friendly ceramic proppant, complements the work of well-treatment service providers such as Halliburton Energy Services – as well as operating company customers – in several ways. Not only does the company supply the volumes of ceramic proppant necessary for fracturing operations anywhere in the world, but it also makes technical expertise available at no cost to help service companies and operators choose the most cost-effective proppant for every fracturing job.

“We meet the worldwide demand for our fully-tested, superior quality products from three manufacturing plants in the U.S. and a fourth in China,” said Terry Palisch, senior staff petroleum engineer in Irving. “We produce 735 million lb per year of tightly-sieved ceramic proppant, which provides superior conductivity to all competing proppants in the market. In all North American locations, this material is delivered to the wellsite in CARBO-dedicated trucks. Internationally, service companies supply our products from CARBO distribution centers located in South America, Europe, Middle East, Russia, Southeast Asia and Australia. Our distribution and storage network is unequalled in the industry.”

But manufacturing capacity, product quality assurance and efficient delivery are only part of the story. CARBO also boasts a team of petroleum engineers who have extensive field experience in hydraulic fracturing. These frac engineers are available to work closely with customers before a job to select the correct proppant for the specific formation involved and then assist with analyzing the actual results after the job is completed. Not only does such detailed post-job analysis help assure the customer a high degree of well productivity, but field results are fed into CARBO’s fracturing technology database, which the engineers use to demonstrate the most effective proppant applications through case histories, field studies, technical presentations and in future job consultations.

‘Real’ downhole effects often overlooked

“Our deep interest in conductivity technology stems from more than 25 years of manufacturing and supplying ceramic proppants,” Palisch said. “We have found that the industry often relies on models that do not realistically predict fracture conductivity under actual reservoir conditions. As a result, the industry too often employs frac sand in situations where ceramic proppant would yield far more profitable results.”

CARBO representatives have found most traditional conductivity models do not reflect the many complex issues and downhole conditions to which the proppant is exposed, including non-Darcy and multiphase flow effects; density and width implications; long-term proppant degradation; gel damage; fines

![Figure 1: Cumulative Conductivity Reductions](image1)

- **Conditions:** YM=5e5 psi, 50% gel damage, 250°F, 1 lb/ft², 6000 psi, 250 mcf/d, 1000 psi bhp, 20 ft pay, 10 bldp

![Figure 2: Normalized Production Benefit](image2)

**Reference:** SPE 90620
migration; and cyclic stresses. “These effects can decrease the conductivity of the proppant pack by over 95% (Figure 1),” Palisch said.

The engineering staff realized only a few models account for any appreciable number of these effects, he said, and if they are taken into consideration, even fewer have actual field data on which to justify correlations.

CARBO Ceramics embarked on a field trial campaign with several operators 5 years ago in which they identified fields they could – under as controlled conditions as possible – make a head-to-head comparison between the company’s ceramic proppants and lower effective conductivity sand, resin-coated sand or broadly-sieved ceramics.

“We also looked at other fields in which our products were being used and, even though they were not controlled trials, we could study production results to assess the impact of using top-quality ceramics. From that, we ‘reality checked’ the model predictions.

“Remember, many fracture models will erroneously predict only trivial pressure losses within the fracture. Consequently, these models forecast minimal benefit to increasing conductivity by using premium proppants,” Palisch said.

The company also completed a thorough literature review and identified more than 100 cases from around the world – encompassing the spectrum of reservoir conditions – that demonstrate a direct correlation between heightened conductivity and increased production. Short summaries and full references for most of these cases are documented on www.carboceramics.com and in Society of Petroleum Engineers (SPE) Paper No. 77675.

The most recently published CARBO field trial was conducted in the Middle Lance intervals in the Pinedale Anticline of Wyoming (SPE Paper No. 90620). The improved production exhibited when comparing stages that received CARBOECONOPROP® vs. those that received a resin-coated sand (RCS) was “eye-popping” (Figure 2). “Traditional wisdom suggested that the middle Lance stages were of poor reservoir quality, and all operators in the field considered sand or RCS to provide adequate conductivity in this 12-microDarcy (0.012 md) formation. However, when these same middle Lance intervals were treated with CARBOECONOPROP, they provided among the highest productivity of any stages in the field,” Palisch said.

Representatives at CARBO have recently initiated similar trials in the Pinedale area and anticipate being able to further substantiate these results as well as compare productivity of their tightly-sieved ceramics with less uniform ceramics provided by other manufacturers.

‘Required conductivity’ a better goal

The company’s sales and engineering staff believes the old industry paradigm of using stress as the major criterion for selecting proppant is outdated. The focus might better be placed on “required conductivity.” Merely selecting a proppant based on well depth or even reported crush statistics rarely matches the proppant conductivity requirements to the well deliverability. Optimal proppant selection can more accurately be made with full economic analyses based upon the reservoir conditions and the operator’s specific economic criteria. The bottom line is that under realistic conditions, fractures propped with premium ceramic proppant exhibit far better conductivity than conventional sands and RCS (Figure 3).

Sales and petroleum engineers are not the only staff involved in making sure the company’s products deliver superior fracture conductivity to the customer. The company maintains state-of-the-art laboratories at all four manufacturing facilities. Research specialists there are dedicated to assuring the quality of all products produced and distributed from the facilities.

“In 2004 alone, CARBO will have performed more than 45,000 crush tests, 30,000 sieve analyses and 30,000 bulk density measurements,” Palisch said. “We will have performed over 600 short-term and 75 long-term conductivity and beta tests, with these numbers tripling upon completion of our new long-term conductivity lab at our plant in China.”

Additionally, the company’s dedicated team of research and development scientists and specialists are working diligently to evaluate new products and are engaged in a constant search for ways to make existing products better.

“We currently inventory seven tightly-sieved alternatives (40/70, 30/60, 30/50, 20/40, 16/30, 16/20 and 12/18) in four distinct product lines. In specialty applications, CARBO provides proppant in sizes ranging from 70/140 to 6/10,” Palisch said. “These all help CARBO reach its goal to deliver the most value to your wellsite.”

CARBOECONOPROP and CARBOLITE are registered trademarks of Carbo Ceramics Inc.
Curable resin-coated proppant was introduced to the industry during the 1980s as a means to prevent proppant flowback. For a hydraulic fracturing or frac-pack treatment to be effective, resin-coated proppants should consolidate under downhole conditions into a long-lasting, high-strength permeable pack.

Not All Resin-Coated Proppants Are Created Equal

Today, two general coating processes are used (Figure 1). The first is to precoat proppant with a resin (RCP) in a manufacturing plant and then partially cure it so the proppant can be conveniently stored and transported to the job site without consolidating. The second method involves “on-the-fly” coating of the proppant with an activated liquid resin system — LRS — (Halliburton’s proprietary Expedite® service) at the job site as it is used during a fracture treatment. This system was first introduced to the global stimulation market in late 1990s. As more wells are drilled into deeper reservoirs, severe conditions — including high temperatures, high production flow rates, and high-closure stresses in propped fractures — impose more constraints on the use of curable resin systems.

Nguyen et al. report on an extensive study related to a new liquid resin coating system that is particularly, but not exclusively, useful in controlling proppant flowback in high-temperature, high-flow rate wells. Additives included in the LRS eliminate fracturing fluid interference and permit consolidation properties to be achieved without any formation closure stress. Results of this work demonstrate the difficulty in designing fracturing treatments so the curing of resin does not occur too fast relative to fracture treatment time and the time for formation closure to achieve consolidation, but fast enough to prevent flowback upon fluid recovery operations. The useful window for resin-coated proppants has been expanded by the incorporation of simple chemical additives into the resin that react with fracturing fluids, rendering them non-interfering to the consolidation process. Additives included in the LRS emininate fracturing fluid interference and permit consolidation properties to be achieved without any formation closure stress.

The study provides new answers as to why RCP consolidations sometimes fail in the field. Operators can use the information presented to help them select the appropriate curable resin systems for their applications where consolidations are expected to withstand production conditions of high temperatures, high flow rates and high- or low-stress loading.

An earlier study has shown that a compressive strength of about 150psi is adequate to control proppant flowback in producing wells with moderate temperatures and production rates. However, for a consolidated proppant pack to be successful long term, one can infer that higher consolidation strength is required, coupled with flexibility to handle repeated stress changes that occur during normal production operations at the reservoir temperature. One of the targets of the Nguyen study was to provide a hydraulic fracture completion that can, in addition to being able to control proppant flowback at high temperatures, allow extremely aggressive flowback rates to remove the fracturing fluid in minimal time, so the production of hydrocarbons can begin as soon as the resin coating on the proppant is “cured” or set. There have been many techniques developed during the years to try to address these issues.

Failure mechanisms — The limitations and failure mechanisms of RCPs have been extensively studied and well documented. Vreeburg et al. have identified two types of proppant flowback that occur when RCPs are used; one is during the well-cleanup phase, and the other is after a long period of proppant-free production.
The early production-type scenario is thought to be caused by insufficient bonding strength of the RCP. The factors affecting the strength of the RCP pack include resin concentration, resin type, curing temperature, resin/fracturing fluid interaction (under shear and temperature) and erosion of the resin from the proppant grains.

The late flowback of proppant mechanism was believed to be caused by damage to the consolidated RCP resulting from the stress cycling that the proppant undergoes each time the well is shut in and put back on production.

During a fracturing treatment at normally used proppant concentrations, the proppant grains are, in general, not in contact (dispersed) while going downhole. In addition, the fluid and proppant temperature is increasing during this time. Once the proppant is placed in the fracture, it is believed that there is some proppant grain-to-grain contact that is required in order to form a consolidated pack. The loss of consolidation strength with curing under low closure stress has been identified as a potential failure mechanism. Some RCPs have been specially formulated to consolidate only under high closure stress. Although this feature facilitates tubing cleanout after a premature screenout, it can lead to reduced strength development of the RCP pack with delayed or uneven closure of the formation.

The confining stress acting on the proppant pack during the curing process is probably not uniform because of variations of the formation in-situ stress and the formation rock-mechanical properties. In addition, some formations may not completely close after treatments. Some hydraulic fractures do not completely close during the first 24 hours after hydraulic-fracture stimulation treatments, especially in the case of low permeability formations. In fact, it has been reported that many reservoir rocks do not sufficiently close to prevent proppant flowback and settling during the first 90 days after the fracturing operations.

RCPs may not be effective when wells with multiple or large perforated intervals are treated. Multiple fractures or parts of single fractures in high-stress zones can screen out during the proppant stages. Depending on the stage of the fracturing treatment, if RCPs are not run throughout, portions of the propped fractures may not contain any RCP and may contain only uncoated proppant that can be produced back. Uncoated proppant also can be produced from a well that has been perforated during a relatively short interval if the treatment was not properly designed, and the high proppant concentration RCP stages have been transported away from the near-wellbore area because of buoyancy forces.

Even when RCPs are placed as designed, failures can occur. Several factors that can affect RCP consolidation strengths and ultimate performances are:

- Loss of consolidation strength has been identified with increased fluid pH;
- Crosslinked carrier fluid incompatibility;
- Increased shearing;
- Low and very high closure stress; and
- Increased stress cycling.

These factors are now well recognized in the industry and usually are considered in job design and candidate selection. A factor not usually considered is the effect of the cure kinetics of the proppant’s resin coat on its ultimate consolidation.

Cure kinetics and closure stresses—An earlier study by Nguyen et al. has concluded that most, if not all, of the currently available RCPs lose their ability to form consolidations with adequate strengths after being exposed to extended pump times in water-based fracturing fluids and high temperatures. The cure kinetics of RCPs were found to have an impact on the resulting consolidation strength after curing. For an RCP to achieve maximum consolidation strength, the RCPs cure rate should be slow enough that there is minimal curing (or hardening) while the proppant is being pumped and until the formation has started closing.

By contrast, the systems that use a liquid resin applied to the proppant as it is being placed in the fracture have shown slower cure rates. These systems have demonstrated the ability to achieve consolidation strengths that are much higher than RCPs (Figures 2 and 3). The high strengths are achieved even when there are long periods of time before fracture closure occurs and in some cases even without closure stress applied to the proppant grains.

The later during the curing cycle the RCP is brought into grain-to-grain contact, the lower the ultimate consolidation strength that will be developed. Because the resin cure rate increases with temperature, the higher the temperature to which the proppant is exposed before grain-to-grain contact occurs, the lower the ultimate consolidation strength. In addition, fracturing fluid components can have a significant impact on the resin-curing rate (any test performed needs to be conducted in the actual fluid system planned for the fracture treatment). The combination of these effects of time before grain-to-grain contact, along with fluid effects and temperature, has a dramatic effect on the ultimate consolidation strength of the proppant pack.

It can be expected that the resin systems with slower cure rates and those that require minimal closure stress for consolidation would show less loss in consolidation strength in fracturing treatments with long pump times and slow formation closure rates.


Why LRS-coated proppant outperforms RCPs—Halliburton’s proprietary Expedite LRS-treated system shows superior performance because:

- capillary action causes flow of the liquid resin, concentrating it between proppant grains and resulting in greater concentration of resin at contact points (Figures 4 and 5);
- extrusion between proppant grains increases porosity and fracture conductivity; and
- LRS-treated proppant is tacky, which promotes grain-to-grain contact. In contrast, the RCPs, even when heated, are not as tacky and have little grain-to-grain contact without closure stress. LRS-treated proppant has a slower cure rate and is not removed from the proppant surface during stirring (simulated pumping) because the resin system has been specially formulated to preferentially coat proppants in gel. RCPs, on the other hand, have faster cure rates, and the resin from some of these proppants has been shown to be leached off into the fracturing fluids.

RCPs are partially cured to provide for storage and handling, and the portion of the resin that is cured does not contribute to the ultimate consolidation strength. Only a small fraction of the resin in RCP is curable, while all the resin in LRS is curable. Conversely, LRS efficiently contributes to the final consolidation strength even with less resin:

- LRS is formulated with additives that promote the removal of gelled fracturing fluid film that can sometimes impede grain-to-grain contact and consolidation; and
- LRS eliminates the problems of damage to coated proppants inherent in handling and storage.

Case History: Indonesia—A fracture optimization process was initiated in a low-temperature, low-pressure reservoir with an objective to increase production and control proppant flowback. Three design criteria were pinpointed:

- perforation scheme;
- hydraulic fracturing design with tip screenout (TSO); and
- proppant flowback control (if required).

After the optimum perforation scheme was completed, the hydraulic fracturing design was implemented to achieve TSO fracturing. A good TSO fracture treatment was expected to significantly reduce proppant flowback. A live annulus was available so the net pressure increase could be observed accurately in real time. It showed a steady net pressure increase, as reducing the pad from 14.5% to 4% quickly modified the design. This verified a good TSO was achieved. Nevertheless, proppant flowed back even with optimum perforation design and TSO fracturing. The LRS (Expedite service) was chosen to control proppant flowback.

Twenty-three wells were fractured in this campaign (Figure 6). Of the 11 wells in which the LRS was not applied, proppant flowback occurred in eight wells, necessitating workovers. Starting at the twelfth well, the fracturing treatments included the LRS additive as it was deemed to be the best suited system for low bottomhole temperatures and low closure stress. Results: When LRS was used, there was no decrease in production because the resin and frequency of workovers due to proppant flowback (sand fill) was reduced by 75%.

Conclusions—The Nguyen study and subsequent field applications demonstrate that:

- LRS permits aggressive well cleanup procedures to be used after fracture stimulation. This system significantly improves well production time to market;
- LRS minimizes chemical interferences with fracturing fluid and permits coating of proppant just prior to blending with the fracturing fluid;
- the slow curing rate of the LRS allows maximum consolidation strength to be obtained, but sufficient early strength to allow flowback to start with a short shut-in time;
- additives included in the liquid resin facilitate the removal of crosslinked fracturing fluid from the proppant grains;
- resin coating of the entire proppant stage eliminates the possibility for uncoated proppant being produced back; and
- LRS consolidates proppant grains to the formation face. This produces a larger “footprint,” which reduces fines creation and migration within the proppant pack during time.

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<th>Temperature ratings for various Expedite liquid-resin systems.</th>
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<td><strong>Liquid Resin System</strong></td>
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<td>Expedite 550</td>
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Figure 6. Comparison between fracturing treatments not using LRS (Expedite service) and treatments using LRS.
Among recent innovations that have extended the state-of-the-art in hydraulic fracturing has been reducing the concentrations of guar-derived polymers in well treatment fluids to help improve hydrocarbon conductivity from induced fractures.

At first it might appear to be a self-inflicted setback to its own future, but Houston-based Economy Polymers and Chemicals (Economy), a key supplier to the petroleum industry of naturally derived, high-molecular-weight polymers, is striving to reduce the concentration of their own products in such well treatment fluids. The company believes that combined with more efficient cross-linking technology, the use of higher quality, improved polymers will help reduce formation damage, and operators will have higher overall hydrocarbon production from their wells.

To lower polymer loading to as little as 25% of what it was in 1995, the company is involved in research in Houston and Jodhpur, India. They introduced the first fast-hydrating, high-viscosity products and are looking at more ways to continue improving the guar polymer. The company is looking into the origins of the gum by involving itself in several projects dealing with agronomy, which is the application of soil and plant sciences to land management and crop production. Economy is in a tightly focused search to develop even faster hydrating guar-based polymers than the ones they first introduced to the industry a few years ago. Their concept is simple: faster-hydrating, higher viscosity polymers reduce fracture fluid loading; therefore, they deliver more efficient chemical stability and viscosity, which suspends the fracture proppant better while it is sheared and heated in surface mixing and pumping equipment, well tubulars, perforations and the fractures themselves. But perhaps even more important, once introduced into the fractured zone, faster-hydrating polymers will help reduce flowback of so-called “additional residues” when the polymers themselves degrade and are removed with the frac fluid prior to placing the well on production. Better fracture conductivity means better formation flow.

The well operator benefits in several ways from the switch to more efficient, faster-hydrating, higher viscosity polymers. Less polymer lessens the cost per gallon of treatment fluid, fracture conductivity is improved, and less blockage to formation flow means higher ultimate hydrocarbon recovery.

Economy’s natural guar and guar-derived polymers — produced as an odorless powder, in processing plants in Houston and Jodhpur, or slurried with solvents at processing plants in Calgary, Canada; Fresno, Calif.; Rock Springs, Wyo.; and Houston — are used by oilfield service companies in a number of well treatment applications. They are, for example, an integral component of several of the special treatment fluids used by Halliburton Energy Services (HES) in its new Conductivity Endurance group of well completion services.

Among Economy Polymer products used by HES and other service companies are Ecopol 2000, composed of unmodified guar; and Ecopol 18 and Ecopol 400, both double derivatives of guar. All are fast hydrating, easily dispersible and will respond to conventional crosslinking products under basic as well as acidic conditions. The company also manufactures a number of other polymers for inclusion in well treatment fluids.

The quest for better polymers
Founded as a chemical supply company in 1951, Economy entered the polymer business in 1982. Since then, it has come to the petroleum industry marketplace
with a number of revolutionary products, including faster-hydrating polymers for well treatment fluids, introduced in 2002, which exhibit higher viscosities and lower polymer-loading characteristics.

Generally, the polymers are produced from the guar plant, or cluster bean (*Cyamopsis tetragonolobus*), an annual plant native to India and adapted to its semi-arid northern and northeastern regions. The plant's beans have been dried and used as livestock feed for thousands of years. Indian farmers grow the beans and then separate and hand-process them for shipment to the company's Jodhpur plant. Once there, each bean's endosperm, or nutritive tissue surrounding the seed embryo, is isolated to manufacture the guar gum base for polymerization, the remainder – comprised of solid protein – is sold as livestock feed. The gum, once processed, is soluble in water, becoming gelatinous after time. It hardens when dried, allowing it to be powdered and laced with various additives to manufacture specific oil-field polymers for shipping in bulk form or in sacks.

Walter White, Economy's vice president, said that while the company's guar-derived products also are used in the personal care and food industries, among others, it has become a staple for oil service applications that require a slurry additive for oil- and water-based well treatment fluids. The company's research chemists continue to work on reducing the amount of polymer required per thousand gallons of slurry, White said.

"Five years ago, the standard guar product had slow hydration rates, with tests results using a Fann*-35 viscometer ranging from 22 cps to 24 cps in 3 minutes and 34 cps to 36 cps in 60 minutes," White said. "Today, we provide guar-based polymers with 3-minute viscosities of 36 cps to 37 cps and 60-minute viscosities of 46 cps to 48 cps."

But Economy is searching for even better results. And that, he said, is where the agronomy comes in.

The company is growing hybridized guar plants in India that yield much cleaner seeds, he said, which is resulting in a purer guar gum. As a result, the company already is producing a powdered polymer that, instead of being slurried with various oils and shipped to the well site, can be mixed on the fly with water, proppant and other necessary chemicals – proppant surface-modification coatings, cross-linkers and fluid-loss agents – and then pumped directly into the formation as the well treatment fluid.

"Once a commercial-grade product is developed and tested in the field, we believe eliminating oil-based slurries altogether – particularly those using diesel oil – will provide significant health and environmental benefits, as well as trigger major cost structure changes," White said. The technology for this is available today.

**A commitment to quality**

As part of its commitment to bring new polymer technology to its markets, Economy controls the entire process of producing raw guar materials and intermediates, including the seed to split operations and processing train in India, as well as the processing-distribution plant in Houston. Both state-of-the-art plants are ISO 9001 2000 certified.

With such raw materials production control in hand, Economy's first obligation is to provide highest quality products and services to a global customer base at competitive prices. To accomplish this, the company is committed to its quality management system and quality policy, which demands continuous improvement while providing a safe environment for all full-time employees, associates, subcontractors and others involved in their operations.

Meanwhile, as the company works to innovate new technology, it communicates with customers to create new and better formulations, bring new products to the marketplace and provide technical help to customers whenever necessary.

In addition to the processing plants, the company owns seven blending and distributing facilities in North America, with more planned in a number of overseas petroleum industry provinces. ▲

* Mark of Fann Instrument Co.

Economy Polymers and Chemicals
P.O. Box 40245
Houston, TX 77245-0245
Tel: (800) 231-2066
Fax: (713) 723-1845
Web site: www.economypolymers.com
Multiple coats of uniquely formulated curable resin protect sand and ceramic propping materials from flowback and embedment, and greatly enhance conductivity and crush resistance.

As a negative result of hydraulic fracturing, even minor instances of proppant flowback compromise the conductivity and permeability of the proppant pack. The flowback, which occurs during initial cleanup or after the well is put back into full production, ultimately robs proppant from the fractures, eventually restraining production flow. But it also can lead to costly, protracted well service operations.

The ability to keep proppant flowback to an absolute minimum serves to stabilize fractures, even under cyclical stresses, thereby helping conduct hydrocarbons into the wellbore at or near the rate designated in the frac plan. With proppant flowback at a minimum, the customer justifies the expense of the fracturing treatment - i.e., he or she gets what is paid for - and benefits from results of higher long-term fracture conductivity, such as greater hydrocarbon recovery during the productive life of the well.

To prevent proppant flowback and other negative effects, operators often choose the full range of curable, resin-coated sand and ceramic proppants manufactured by Santrol, a subsidiary of Fairmount Industries. Santrol, based in Fresno, Texas, near Houston, pioneered coating proppants with multiple layers of high-quality phenolic and other specialty resins for greater flowback resistance and higher permeability throughout the range of closure stresses encountered in hydraulic fracturing. The company first began offering resin-coated gravel pack sands more than 25 years ago, and has since been at the forefront of proppant coating technology.

Curable proppants prevent flowback, reduce embedment and crushed fines, and increase long-term conductivity. Santrol uses patented multi-layer coating techniques to apply the resins to specially treated base sand or ceramic substrates. Differential crosslink density of each resin layer allows the product to attain added strength as well as the ability to attain grain-to-grain bonding, or "curability" in the formation. Free-flow additives, anti-dusting and anti-static agents enhance handling, water-wetting and flow characteristics.

**G2 proppant coating: layers of technology**

Among Santrol’s most recent advancements in proppant technology is the company’s G2 - second-generation - coating technology, which company representatives say is an advancement over existing encapsulated curable products, since it furthers the science of high-performance resins as well as the means with which to apply successive thin films of such novel resins as encapsulation layers over curable resin coats (Figure 1). The proppant grain or bead is first coated with a fully cured low-molecular-weight PF resin, followed by coating with a curable, low-molecular-weight “core” layer of resin, after which a fully cured thin-film encapsulation layer of epoxy resin is applied. Finally, the proppant is filmed over with a special coating containing free-flow additives and antistatic agents.

Jon Harper with Houston sales said that all of Santrol’s G2 proppant types provide excellent flowback resistance, embedment reduction and increased crush resistance, among other benefits. He added that they are curable and exhibit high compatibility with all fracturing fluids, including low-polymer and viscoelastic systems, and are stable in temperatures up to 600°F (315.2°C).

Developed by Santrol’s research chemists at the company’s Fresno plant, which, Harper said, happens to be dedicated to manufacturing ceramic-based coated products, the G2 technology has been incorporated into several new Santrol product lines:

- **OptiProp G2**—Santrol’s premier encapsulated multi-coat curable proppant. Most often using American Petroleum Institute high-spheroid silica sands, but also available on a variety of ceramic media (16/20 and 20/40), OptiProp provides superior performance for high closure-stress applications and exhibits high compatibility with fluid and breaker systems. The resin coating design allows for consolidation only under closure pressure in the formation, thereby virtually eliminating the possibility of bonding in the wellbore and allowing it to remain in the wellbore for extended periods without consolidating. It is designed for wells with bottomhole temperatures above 140°F (60°C) and closures in the 6,000-psi to 10,000-psi range.
- **MagnaProp G2**—Santrol’s economy ceramic proppant is designed for superior performance in moderate closure
stress applications and consolidates only after grain-to-grain contact under pressure has occurred. Because only formation closure pressure allows it to consolidate, MagnaProp is ideal for fracturing multi-zone, deviated and horizontal wells with bottomhole temperatures above 140°F in the 6,000-psi to 12,000-psi range.

- **DynaProp G2**—This is the company’s mid-range lightweight ceramic proppant. Exhibiting all the properties of Santrol’s patented G2 coating technology, DynaProp is designed as a stress-curable proppant and consolidates only after grain-to-grain contact under formation closure pressure. The resin protects the proppant base from quick stress loading and provides additional toughness resulting in higher crush resistance with bottomhole temperatures above 140°F in the 9,000-psi to 14,000-psi range.

- **HyperProp G2**—Santrol’s upper-range sintered bauxite-based proppant provides superior performance for mid- to high-closure stress applications and effectively lowers the density of bauxite when combined with the resin coating, allowing easier fracture placement and reducing costs on a volumetric basis. HyperProp may be used in hydraulically fractured wells with bottomhole temperatures above 140°F and closures in the 10,000-psi to 16,000-psi range.

“The downhole benefits of using Santrol’s G2 coating technology,” Harper said, “include increased thermal resistance to premature cure in hot fracturing fluids with reduced shut-in times; increased cyclic loading resistance to meet well production demands; and increased compatibility with all frac fluids.

“Also, G2 coatings do not adversely affect crosslinkers and breakers, and they are unaffected by high-pH frac fluids.”

**Big research, big reach**

In addition to the company’s range of curable coated proppants, Santrol also manufactures tempered proppants to produce low fines percentages on crushing while maintaining high conductivity. These products also are layered with multiple resins to enhance their toughness.

Another Santrol downhole product, BioBalls, is an aqueous soluble perforation ball sealer in its third iteration, Harper said. “They are composed of the organic compound collagen, which is the most fibrous protein found in living organisms,” he said. “Yet, unlike conventional rubber ball sealers, which are difficult to remove or drill out, BioBalls dissolve in any aqueous-based fluid, and the dissolution rate can be determined by adjustments in fluid pH and temperature.”

The newest BioBall product has high mechanical stability, superior high-pressure performance and improved seating efficiency, Harper said. They can withstand differential pressures in excess of 5,000psi and are routinely tested to 3,000psi for quality control.

“Customers can be confident that BioBalls deliver maximum perforation diversion,” he said.

Santrol’s parent company, Fairmount Minerals, is a diversified mining group, marketing resin-coated and raw sands to a variety of industries, principal among which is the oil and gas extraction market.

In addition to the one at its Fresno site, where a full team of research chemists works on perfecting new products and improving existing ones, Santrol has resin-coating plants in Roff, Okla.; Troy Grove, Ill.; Bridgman, Mich.; Monterrey, Mexico; and Fredericia, Denmark. The plants operate under ISO 9000 regulations. The company also controls and owns its own mines in Wedron, Ill.; and Maiden Rock, Wis.; and has an extensive network of rail-linked distribution sites spread strategically in the United States, Canada and Mexico. ▲

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**Santrol**

P.O. Box 639
2727 FM 521
Fresno, TX 77545
Tel: (281) 431-0670
Fax: (281) 431-0044
Web site: www.santrol.com
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Innovative Particle Size Distribution and Higher Strength Yield Higher Fracture Conductivity
Saint-Gobain Proppants concentrates on strength and innovation to deliver higher conductivity and value to the hydraulic fracturing industry.

Filling the Bill for Custom-made Fracture Treatment Chemicals
Texas company helps develop, manufacture and blend several Expedite proppant flowback control products.

Merging Worldwide Resources to Solve R&D Partners’ Needs
New well conductivity enhancement services benefit from cross-fertilization among widespread labs and production sites.

Research and Development Partnerships Help Drive Oilfield Success
Forging cooperative relationships with service providers creates teamwork to supply much-needed formation-level chemicals.

Designing Fractures for Realistic Downhole Demands
With a staff of field-proven petroleum engineers, a manufacturer works with customers to select the ideal proppant for each stimulation treatment.

Keeping an Eye on the Future for Polymers in Well Treatment Fluids
Houston company raises the bar for guar-based products and works toward adding powder only for ‘on-the-fly’ frac fluid preparation.

An Intelligent Alternative in Combating Proppant Back-production
Multiple coats of uniquely formulated curable resin protect sand and ceramic propping materials from flowback and embedment, and greatly enhance conductivity and crush resistance.
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It can triple your well's total production—by making your post-fracturing flow rates last much longer. It works by keeping formation fines from clogging the pores in your proppant pack. Minimizing the effects of stress cycling. Keeping the channels open. Keeping the hydrocarbons flowing. Proven effective in hard rock and soft.

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