Extending the Productive Life of Mature Assets
CONTENTS

1 Remediation Techniques for Mature Assets
   Remaining reserves are tempting target for new remediation techniques.

8 Refracturing Has its Benefits
   Precision refracturing can regain conductivity and access new reserves.

16 Fluids and Solids Production
   A range of options can help keep water and sand out of the wellbore.

24 Cement Solutions
   Fit-for-purpose cement solutions can handle weak and depleted zones.

30 Stimulation and Recompletion
   Pinpoint stimulation and an integrated recompletions approach help produce remaining reserves.

38 Current Price vs. Future Cost
   Advancing technology to drive remediation effort is a key component to the process.

42 Integrating Stimulation Tools
   Expertise gets the most from mature reservoirs.

PROFILES

4 CARBO Ceramics
6 Champion Technologies
12 Economy Polymers and Chemicals
14 Saint-Gobain Proppants
20 Magnablend Inc.
22 Nalco Co.
26 Quality Tubing, A Division of National Oilwell Varco
28 Rhodia
34 Santrol, a subsidiary of Fairmont Chemicals
36 Hexion Specialty Chemicals Inc.
   Oilfield Technology Group
40 Univar USA, Inc. Oilfield Services Group
As the decline of producing oil and gas reservoirs accelerates and big fields get harder to find, the effort intensifies to recover more of what has already been found. Discovered, unproduced reserves present a huge target of opportunity; even a modest increase in average recovery will add significant supply.

Recovery and production from these fields can be boosted by infill drilling, acid and fracture stimulation, and by reducing water and solids influx. Remediation can slow the decline of a producing asset and enhance its value.

Completing today’s wells with an eye to extending their life can make future remediation efforts more effective.

An expanding range of remediation techniques aimed at creating cleaner, more productive wellbores promises to accelerate the revitalization of mature fields, extending their life and adding economic value for operators and increasing energy supply.

These tools offer solutions to the key challenges facing operators of aging and under-performing reservoirs, including:
- large volumes of produced water;
- influx of proppant and formation fines;
- drilling through weak or depleted zones; and/or
- a need to access stacked pays and bypassed reserves.

Meeting these challenges is often made more difficult because reserves are marginal, and an operator’s engineering and technology resources may be limited. An integrated approach built on the latest stimulation and reservoir management capabilities can help tailor solutions to these special conditions.

**Eye of the beholder**

‘Mature’ is a relative term.

“A field does not have to be 50 years old to be mature,” said Mark D. Whitley, senior vice president, Permian Business Unit and Engineering Technology, Range Resources Corp.

Many of Range Resources’ fields are “very mature — long in the tooth, even,” Whitley said.

Some were discovered in the 1920s and 1930s; many have produced large volumes of oil, but much remains to be produced.

Some of the company’s low-pressure, low-volume gas wells in western Pennsylvania have produced from the Clinton/Medina sands for 40 years.

“And they will produce for another 40 years,” Whitley said. “Mature has much to do with where you are in the overall field depletion.”

A mature gas field, for example, may not be very far along the depletion curve because it is “tight” or was developed on the wrong spacing. The opportunity in that case may be in infill drilling. The same could be true of an oil field that has not been water-flooded or properly developed in terms of spacing, Whitley said.

“The definition of mature is much like that of beauty — it’s in the eye of the beholder,” he said.

Range Resources’ Furman-Mascot field in Andrews County, Texas, was discovered in the 1930s. A pilot...
waterflood begun several years ago has been expanded to full-field injection, and infill drilling has now been done on 20-acre and 10-acre spacing, and a pilot 5-acre drilling program is in progress, Whitley said.

“The field is now producing at its highest rate ever,” he said.

In New Mexico, on the other side of the Permian Basin, fields that “watered out” years ago can now be produced because today’s pumps can move large volumes of fluid.

For many aging reservoirs, infill drilling and larger pumps are not the best solution. Instead, remediation requires special technologies to clean and re-energize existing completions and producing intervals, and limit the entry of water and solids into the wellbore.

**Big opportunity**

Together, mature fields account for an estimated 70% of the world’s production, according to a Halliburton report.

It is difficult to estimate how much average recovery can be increased with today’s and tomorrow’s remediation technology. Wells, reservoirs and operating environments vary widely.

Average recovery from oil reservoirs is about one-third of the oil in place, but primary recovery from tight gas sands can be two-thirds of gas in place. To re-enter a tight gas reservoir and recover significantly more gas is tough.

The United States is the world’s most mature petroleum province. According to the U.S. Department of Energy’s National Energy Technology Laboratory (NETL), of the roughly 3.5 million wells that have been drilled to date, about a quarter are still producing – many at the economic margin.

“Stripper” wells, defined by the agency as those that produce at less than 10 b/d of oil or less than 60 Mcf/d of gas, constitute about 80% of 500,000 U.S. oil wells and account for about 19% of U.S. oil production.

From 1994 to 2003, about 143,000 marginal U.S. oil wells were plugged and abandoned, leaving 110 million bbl of oil in the ground, according to the NETL. When marginal wells are prematurely abandoned, as much as two-thirds of the oil remains in the reservoir.

A common misconception is that oil left behind
remains readily available for production when markets improve. In most instances, that is not the case, according to NETL.

About 246,000 U.S. stripper gas wells produce 1.4 Tcf of natural gas per year, roughly 10% of all onshore production in the lower 48 states. Proper disposal of increasing volumes of produced water adds a significant cost burden to these wells, the NETL said.

Many wells decline to stripper status prematurely and unnaturally, according to the organization. Avoiding or repairing wellbore damage through remediation can enhance the value of these mature assets and add to energy supply.

### Economic reality

For individual companies, the importance of mature oil and gas assets ranges from core business to low priority.

Remediation of mature assets is increasingly important to a growing number of companies, many of whom make much of their living by acquiring fields others left behind because the fields did not meet the previous owner’s financial criteria. Re-evaluating these reservoirs with sophisticated diagnostic tools, then applying new remediation technology, can unlock these assets and recover additional reserves.

Even with advanced technology and today’s higher oil and gas prices, market realities are always a challenge. Tight gas, for example, is a now a commodity-price-driven play. Development can be expensive, and large swings in product price can be devastating to programs. While the limited availability of equipment requires planning well in advance, price fluctuations between plan and execution can have a big impact on margins.

For Range Resources, which operates only on land in the United States, mature fields in Texas, New Mexico, Oklahoma and the Appalachian Basin comprise its core business. At the end of 2006, the company’s reserves were 1.9 Tcfe, mostly from mature assets.

In its San Andres fields in west Texas, where recovery efficiency is typically in the range of 10%, “by drilling on tighter spacing and injecting water, we hope to double that,” Whitley said.

### Knowledge, integration and HSE

Hydraulic fracturing to create new fractures or extend existing fractures can yield quick production increases.

Refracturing is commonly done once production from an interval has declined to an unacceptable level. Because aging wells often produce from multiple intervals, some very thin, the ability to place these stimulation treatments with pinpoint accuracy is a key to more effective remediation and increased ultimate recovery.

Predicting water influx problems, selecting candidate wells for water control treatments or stimulation and justifying expenditures are critical steps in developing improved reservoir management strategies.

The process must begin with an understanding of fluid flow behavior in the reservoir under production and injection conditions. Information about the target zones – and the ability to interpret it accurately and apply the latest technology to execute the resulting plan – is arguably the most valuable remediation tool.

When modern logs are not available, obtaining new data with which to estimate recovery is a top priority. New wells can provide up-to-date logs; in some cases, a new 2-D seismic survey – perhaps even 3-D – is warranted.

“It is very important to have log data that tells you what the reservoir’s characteristics are today, and to the extent possible, how much the reservoir has changed,” Whitley said.

Another company notes that combining geology and engineering is a key to success in tight gas development. To be effective in optimizing production, engineers must understand the rock and how it responds to liquids, gas fracs or horizontal drilling forces.

In addition to technical and economic challenges, mature fields can pose more difficult health, safety and environmental (HSE) issues than younger fields. Hydrogen sulfide and carbon dioxide concentration levels typically increase during water flood operations, for example.

As production operations become more complex and more technological options are available, integration of services, tools and disciplines becomes increasingly important.

Halliburton suggests a comprehensive mature field development plan that achieves the following:

- maintains a holistic perspective on surface facilities and subsurface issues;
- optimizes the value of the assets, new or existing;
- creates the most favorable long-term production plan at the most reasonable cost;
- ensures the most likely scenarios encountered as the field is depleted can be managed; and
- facilitates the achievement of economic objectives after the field re-engineering plan is executed.
Designing Fractures to Optimize the Productive Life of Oil and Gas Assets

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

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 largest manufacturer of ceramic proppant, complements the work of well-treatment service providers such as Halliburton — as well as operating company customers — in several ways. Not only does CARBO supply the volumes of ceramic proppant necessary for fracturing operations anywhere in the world, but it also provides technical expertise 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 four manufacturing plants in the U.S., one in China and our most recent addition in Kopeysk, Russia," said Terry Palisch, senior staff petroleum engineer, in Irving. "By year-end 2007, we will be capable of producing over 1.3 billion lb per year of tightly-sieved ceramic proppant, which provides conductivity superior 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, North Africa, Asia and Australia. Our distribution and storage network is unequalled in the industry."

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 results after the job is completed. Not only does such detailed, post-job analysis help assure the customer of superior well productivity, but field results are fed into CARBO’s fracturing technology database, which the engineers use to identify the most effective proppant applications for 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 to the petroleum industry," 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 has found most traditional conductivity models do not reflect the many complex downhole conditions to which the proppant is exposed. These include non-Darcy and multiphase flow effects; density and width implications; long-term proppant degradation; gel damage; fines migration; and cyclic stresses.

"These effects can decrease the conductivity of the proppant pack by over 95%," said Palisch, who along with BP America engineers, co-authored SPE Paper No. 106301 to get this information out to the industry.

CARBO’s engineering staff realized only a few models account for any appreciable number of these effects, he said, and even when they are considered, even fewer have actual field data on which to justify correlations.

Eight years ago, CARBO Ceramics embarked on a field trial campaign with several operators in which they identified fields where they could — under as controlled conditions as possible — make a head-to-head comparison between CARBO’s ceramic proppants and lower effective conductivity products.
“Through these documented field trials, we have shown the benefits of our high-quality ceramic proppants over sand, resin-coated sand and broad sieved proppants in a variety of applications, even including tight gas reservoirs and mature fields,” Palisch said. “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.”

CARBO also completed a thorough literature review and identified more than 100 cases worldwide – encompassing the full spectrum of reservoir conditions – that demonstrate a direct correlation between heightened conductivity and increased production. (See www.carbo-ceramics.com and SPE Paper No. 77675.)

CARBO’s most recently published field trial was conducted in a slickwater frac application in the mature Cotton Valley-Taylor intervals of east Texas (SPE Paper No. 110451). The improved production exhibited by wells receiving CARBOECONOPROP® relative to conventional sand and resin-coated sand (RCS) was dramatic.

“Traditional wisdom suggested that ceramics could not be placed in these slickwater fracs, and most operators in the area did not believe that increasing the conductivity would be beneficial, much less economic. Yet, when these same Cotton Valley – Taylor completions were treated with CARBOECONOPROP, they provided enough production to pay out the incremental cost of the proppant in less than a month,” Palisch said.

The operator also projects that wells receiving CARBOECONOPROP will yield 30% higher recoveries, thereby extending the life, improving the economics of this mature asset. CARBO has recently initiated similar field trials in east and west Texas, the Rockies and Oklahoma to continue proving to the industry conductivity does matter even in tight and unconventional gas applications.

‘Required conductivity’ a better goal
CARBO’s sales and engineering staff believes the industry paradigm of using stress as the primary criterion for selecting proppant is outdated. The focus might better be placed on “required conductivity.” Merely selecting a proppant based on well depth or reported crush statistics rarely matches the proppant conductivity requirements to the well deliverability. Optimal proppant selection can be made more accurately 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 better conductivity than conventional sands and RCS.

Sales and petroleum engineers are not the only staff involved in ensuring CARBO Ceramics’ products deliver superior fracture conductivity to the customer. The company maintains state-of-the-art laboratories at all six manufacturing facilities. Research specialists at those labs are dedicated to assuring the quality of all products produced and distributed from the facilities.

Additionally, the company’s dedicated team of research and development scientists and specialists are working diligently to develop new products. One particular example is the recent development of CARBOHYDROPROP® 40/80. CARBO scientists modified their existing lightweight ceramic line to create a ceramic proppant tailored specifically for slickwater fractures.

“CARBOHYDROPROP 40/80 represents the best combination of strength, conductivity, transport and economic value available in the market,” says David Gallagher, CARBO Ceramics vice president. “This is the latest addition to the line of high quality, value driven products CARBO brings to the hydraulic fracturing marketplace to help our clients get the most out of their wells and thereby maximize the productivity of their assets.”

CARBOECONOPROP and CARBOHYDROPROP are registered trademarks of CARBO Ceramics Inc.
One Champion, Infinite Solutions

In the past half-century, Champion Technologies has grown from a small regional oilfield service company in the Permian Basin of west Texas to become one of the world’s largest and most successful specialty chemical companies serving the oil and gas industry.

Privately owned Champion Technologies has thrived because throughout its existence, the company has focused on understanding the specific needs of each of its customers. Their custom-designed chemical solutions applied as part of comprehensive production strategies have been demonstrated to enhance well productivity and optimize recovery economics.

Champion Technologies has worked tirelessly to advance the science of oilfield chemistry and create a global knowledge-based company with an industry-leading staff of chemical experts uniquely capable of delivering an infinite variety of chemical solutions meticulously tuned to fit local conditions, wherever in the world their customers are working.

Confronting technical challenges
As the oil and gas resource base has matured, exploration, drilling and production have been forced to become more precise, requiring more knowledge-based activities to deal with the increased complexity of remaining prospects. All over the world, producers are using new, more powerful tools to locate, penetrate and produce from oil and gas accumulations that previously were inaccessible because of such factors as reservoir depth, deep water or remote locations.

Such challenges are not allowed to be barriers to oil and gas development in the 21st century.

- Oil and gas wells today are deeper on average than in the past, and many have design parameters – multiple production zones or long directional laterals – that are more difficult and more costly to drill and require special production systems.
- More oil and gas reservoirs are exhibiting geologic characteristics that make them more difficult to produce, for example, higher temperatures, greater pressures or limited permeability.
- More reservoirs contain toxic or corrosive gaseous, fluid or solid contaminants, which can hamper production or endanger wellsite workers or the environment if not properly managed.
- Producers also are developing unconventional resources such as heavy oil, coalbed methane and shale gas.

- More wells are placed on secondary and tertiary recovery after their primary production rate has declined.
- More stringent environmental requirements in many places around the world restrict the use and disposal of oilfield chemicals that are toxic to local flora and fauna.

These factors heighten the risks producers must assume at the wellsite. They also significantly increase the difficulty of developing chemical products capable of achieving or surpassing producers’ performance objectives, while at the same time protecting the environment and maintaining a safe work place.

Champion Technologies Special Products Division has confronted the profound challenges reshaping the upstream oil and gas industry alongside its customers, one well at a time.

Advancing oilfield chemistry
The Special Products Division provides chemical products and technologies specifically targeted to oilfield service companies. While working intimately as trusted advisors with customers’ research and development groups, the division helps create cost-efficient solutions to drilling and stimulation problems that create value for customers.

Champion has developed a technology organization that draws upon its vast experience to create new oilfield chemicals, treatment strategies and service capabilities specifically designed for the new, more rigorous operating conditions of the 21st century.

The company has established a global technology organization with technology centers in Houston, Texas; Calgary, Canada;
Aberdeen, Scotland; and Delden, The Netherlands. The laboratories are outfitted with the best available modeling and analytical tools, creating its own testing equipment and instrumentation when conventional petroleum industry research tools fell short of replicating field conditions.

Champion is unique as an oilfield specialty chemical company because it actively works to discover new molecules that can be adapted to solve longstanding and emerging oilfield problems. Thanks to its steadfast willingness to invest in the future, Champion Technologies Special Products Division is at the forefront of the most chemically challenging stimulation, cementing and drilling fluid projects around the world.

Learning to succeed
If knowledge is the foundation of successful companies and individuals, the process of learning provides the key to sustaining success.

Champion Technologies has grown to become one of the world’s most successful upstream oil and gas chemical companies because its employees are never satisfied with what is known about chemistry and the way chemicals behave as they interact with the environment.

Because Champion always has been linked intimately with its customers, the company’s knowledge of oilfield chemistry has expanded as the upstream oil and gas industry has matured and producers have been forced to solve an unrelenting series of new, more complex technical problems. To help its customers succeed, Champion developed an exacting learning process in which it subjected empirical information about chemical performance at the wells to exhaustive scientific inquiry. This learning process is embedded in Champion’s corporate culture.

Today, Champion researchers and wellsite technicians continually review basic chemical attributes to improve its fundamental understanding of chemicals. The company studies findings from academia, joint industry projects, the lab and the wellsites, comparing outcomes, reorganizing ideas, reinterpreting results and describing new chemical relationships. We test and retest initial ideas to detect subtle nuances and build up evidence that supports or refutes the validity of inferences. The company synthesizes the knowledge it creates in new ways, to produce new chemical solutions for long-standing technical obstacles, as well as unique, emerging oil and gas production problems.

This structured learning process has enabled Champion to develop multiple new industry-leading drilling and stimulation products, many of which are already deployed helping customers profitably produce oil and gas around the world.

A pledge for the future
Champion’s philosophy of providing its customers with personalized service and its independence as a private company underscore the company’s commitment for a continuing endeavor to develop and deploy the most effective, safest and environment-
Extending the Productive Life of Mature Assets | 2007

REFRACTURING HAS ITS BENEFITS

Precision refracturing can regain conductivity and access new reserves.

After completion, production from hydraulically fractured oil and gas wells begins to decline because of natural depletion, lost conductivity, water influx or a variety of other factors. Refracturing with today’s precision techniques can often result in a significant increase in productivity, especially when production comes from a single large interval. “Just about everything we have must be fracture stimulated to produce, whether it is tight gas in the northeast U.S. or oil in west Texas,” said Mark D. Whitley, Range Resources Corp. senior vice president, Permian Business Unit and Engineering Technology. “Restimulation also is a key part of the remediation of these older fields. Restimulation may require a technique different from the original frac, but ‘different’ may not necessarily be extremely high tech.”

Why refracture?

In wells producing from multiple intervals, conventional restimulation approaches are often less than successful. The opportunity to boost production in these reservoirs lies in a focus on the properties and potential of individual layers rather than on the commingled well performance.

Halliburton’s new multiple interval stimulation technologies, new refracture candidate diagnostics and an improved understanding of fracture orientation after partial reservoir depletion bring new opportunities for increased recovery from declining reservoirs.

Refracturing goals may include fracture reorientation, fracture remediation or gaining access to bypassed layers. In the Barnett shale in the Fort Worth Basin and the Codell formation in the DJ Basin, for example, restimulation after partial depletion has reoriented fractures or created complex fracture patterns.

Fracture remediation also may be necessary when a premature screenout results in a short effective fracture half-length, a damaged fracture face or a plugged proppant pack.

Fracture conductivity damage can result from formation fines migration, proppant crushing or proppant-pack diagenesis. Damage can also be done by an inappropriate fluid system.

A remedial chemical stimulation treatment may fix proppant-pack damage, particularly if the damage is the result of fines plugging the near-wellbore conductivity. But if fracture conductivity is severely damaged, a refracture treatment may be the most effective solution (Figure 1).

Multilayer well completions can contain layers intentionally bypassed to pursue higher productivity zones, or bypassed inadvertently because the original stimulation was ineffective. A recent Halliburton study of production logs, radioactive tracers and microseismic fracture imaging suggests stimulation is not effective in 5% to 30% of the layers targeted for fracturing.

Making the right choice

Halliburton’s refracture candidate-selection method typically involves:

• a thorough review of well records to identify problems with the initial fracturing treatment and find layers intentionally bypassed during the original completion;
• field-wide screening using statistical methods, neural network analysis or production data analysis; and
• application of candidate diagnostics that include production logs or pressure-transient testing to evaluate the benefits and predict the results of refracturing.

Halliburton has developed a refracture-candidate diagnostic test that requires completing a fracture-injection/falloff sequence. The injection fluid is nitrogen or a liquid, which can be lease crude, water or a remedial chemical treatment fluid.

Each targeted layer is isolated with a straddle-packer and the fracture-injection/falloff sequence initiated. Pressure falloff data are analyzed to identify an existing fracture and determine whether the fracture is damaged. With sufficient data, the analysis also can provide estimates of fracture half-length, fracture conductivity, bottomhole pressure and reservoir permeability.

Pressure depletion can be an important factor in refracturing when choosing a treatment fluid and defining contingencies in the event of an early screenout. When performing a pinpoint fracture treatment or isolating a zone in a well that has already been stimulated, it is often difficult to contain the fracture after it leaves the wellbore because the original treatment created a pathway to nearby intervals.

Especially where there is little separation between stacked pays, it is important to know whether the separation was breached by the previous stimulation treatment, and if so, to what extent. In cases where the original fracture treatment connected multiple perforated intervals, it may be necessary to collectively treat these intervals in a refracturing treatment.

As reservoir pressure declines, capillary pressure is also an issue in tight gas formations where pore throats are small. Formation pressure may not be great enough to push out the frac fluid and the well can become “fluid blocked” just by pumping into the zone.

New microemulsion surfactant technology and/or energized treatment fluids can be applied in remedial work to facilitate flowback of the frac fluid.

Fixing earlier mistakes

Refracturing can remedy mistakes made during the original stimulation that now inhibit production, including poor perforating techniques, loss of near-wellbore conductivity and insufficient proppant concentration.

When insufficient proppant concentrations are combined with low-strength proppant, heavy gel concentra-

Figure 2. Diagenesis effect is shown on this 20/40-mesh ceramic proppant after 126 hours at 250°F in 2% potassium chloride between Ohio sandstone at 10,000 psi closure stress.
A significant choke effect can result from the loss of near-wellbore conductivity, which can be caused by formation fines migration, gel residue or proppant-pack diagenesis. New technology such as conductivity endurance products that prevent fines from migrating or minimize the effects of diagenesis have proved effective in sustaining increased long-term production (Figure 2).

The products can be applied during hydraulic fracturing or as a remedial treatment to flush and lock the fines in place away from the wellbore.

**How it’s done**

Refracturing wells producing from multiple layers requires pinpoint stimulation capability, typically achieved using straddle-packer, sand plug or frac liner isolation. Each method can use jointed pipe or coiled tubing.

Straddle-packer isolation is fast and effective when the annulus is capable of holding a column of fluid and the refracture injection rates are low. If the annulus will not hold a column of fluid because of low reservoir pressure, placing a frac liner across the intervals can isolate all exposed perforations. This will reduce the inner diameter of the production casing, but without tubing in the hole, higher injection rates than with the straddle-packer method are still possible.

Halliburton developed RamStraddle™ fracturing service for deep preperforated vertical wells with multiple intervals. Starting at the lowest interval, each target zone is first straddled with the EZ-Straddle™ packer assembly, which eliminates the depth and pressure limitations of cup-type systems. The ability to circulate between packers without moving them allows for easier retrieval in a sand screen out.

Halliburton’s Swellpacker™ system also can achieve complete isolation of producing zones. Based on the swelling properties of rubber in hydrocarbons, it swells as much as 200%, sealing the annulus around the pipe to isolate producing zones.

When deployed, the rubber retains its flexibility, allowing the Swellpacker to adapt to shifts in the formation and fit irregular borehole geometry to provide seal integrity.

Used in cased and open holes, the system eliminates the expense of cementing and perforating in an open hole. It can be used for SmartWell® completions, multi-lateral completions and expandable tubular completions.

Halliburton’s Delta Stm™ completion service is designed for selective multizone fracturing or acidizing through the production string. This versatile sleeve can be operated by a mechanical or hydraulic shifting tool run on coiled or jointed tubing, or by using a ball-drop system.

Opening the sleeve permits zonal stimulation through the selected sleeve and diverts the flow through the ports. After stimulation, clean up is assisted by flowing all lower zones simultaneously.

The tool will function as a standard production device, allowing full wellbore access. It can be used in an uncedent openhole completion using the Swellpacker isolation system or the Wizard® III packer.

**Some field results**

A south Texas well had been producing from a sandstone formation for six months after the initial completion. Production from the initial frac was 10 MMcf/d, but had declined to 0.5 MMcf/d. Since the reservoir pressure in the sand decreased by 3,000psi during the first six months of production, a refrac was designed that would stay contained in the slightly depleted sand, yielding a longer frac length and exposing more drainage area.

The refrac treatment increased production to 5 MMcf/d.

In Arkansas, excessive fracture sand production from a 2003 treatment was damaging the electric submersible pump, resulting in costly workovers and a loss of production. A remedial treatment used Halliburton’s PropStop™ service, a process that utilizes the combination of resin consolidation technology, coiled tubing and Pulsonix® TF pulsing tool technology.

Result: Successful control of proppant flow back and increased gas production had a value for the operator of $220,000 to $400,000 annually.
What is reliability worth?

Overcoming flow-convergence issues with maximum near-wellbore conductivity.

**Industry Challenge**
- Improve sustained production
- Consistently create fractures in cased and cemented horizontal wellbores
- Optimize frac design
- Overcome flow-convergence issues, especially in near-wellbore region

**Halliburton Solution**
CobraMax® H fracturing service (with Hydra-Jet™ service through coiled tubing for perforating) uses a proppant pack as the final stage of each fracture treatment. Major benefits include:
- Performing multiple-interval treatments individually
- Eliminating the need for packers or separate trips in the hole
- Providing diversion for successive treatments up the hole

**Operator Benefit**
Halliburton’s CobraMax H service achieved maximum conductivity in the near-wellbore region. With this service, risk was lowered and completion costs per BOE reduced (up to 50% lower when compared with conventionally fractured horizontal wells).

To learn more about how Halliburton puts reliability in action, visit www.halliburton.com/reliability or e-mail us at stimulation@halliburton.com.

*Unleash the energy.*

HALLIBURTON
Company Improves Guar Polymer Performance

Hydraulic fracturing and refracturing are popular stimulation techniques for revitalizing and extending production from mature fields.

Advances in carrier fluids, particularly guar-based polymers, are improving fracturing results by increasing regained permeability, the ratio of post-treatment permeability to pre-treatment permeability.

Not long ago, 50% regain permeability was considered acceptable, meaning formation productivity after fracturing was only half what it was previously. For Economy Polymers and Chemicals, a Houston-based company that manufactures high molecular weight, guar-based polymers, 50% was not good enough. Several years ago, the company initiated research and development (R&D) projects to improve polymer performance. That R&D has paid off as the company recently announced polymer advances delivering regain permeabilities as high as 95%, significantly boosting economic return on fracturing.

“The industry used to focus on efficiently carrying the proppant into the ground,” said Economy Vice President Walter White, “but now we’ve found ways to do that and improve fracturing results at the same time.”

A significant cause of low post-fracture permeability regain is polymer residue in the formation and on the face of the formation in the form of a polymer filtercake. One straightforward solution to reducing polymer left behind is reducing the amount of polymer going in. Economy Polymers has spent years working toward that end by improving the performance of guar-based polymers to reduce polymer loading, the concentration of polymer required to achieve the viscosity needed for proppant support. The new generation of guar-based polymers is based on a new variety of guar White calls “super efficient”, because of the speed with which the guar polymer chain unfolds to build viscosity when hydrated.

“Seven years ago, the standard guar product had slow hydration rates, with tests results ranging from 22 cps to 24 cps in 3 minutes and 34 cps to 36 cps in 60 minutes,” White said. “Today, we produce guar-based polymers with 3-minute viscosities of 42 cps and 60-minute viscosities of 50 cps, a significant performance improvement.”

Economy’s newest polymers boast improved purity, which, by eliminating almost all residue and insolubles, contributes to higher regain permeability. White said the company is growing hybridized guar plants in India that yield cleaner seeds, which is resulting in a purer guar gum at the start of the process. Combined with new, more efficient cross-linking and breaker packages, the new super-efficient polymers have made it possible to reduce polymer loading from 40 or 50 lb/1,000 gal to 15 lb/1,000 gal while still maintaining viscosity needed to carry proppant into the fractures. In some applications, polymer loading is as low as 8 to 12 lb/1,000 gal. That means fewer polymers to remove post-fracturing, from the proppant pack, the formation and the formation face.

Cyamopsis tetragonolobus, the guar plant, also called cluster bean. This annual plant is native to India and is well adapted to semi-arid regions in the north and northwest. The tissue (endosperm) surrounding the beans’ seed embryo is the source of guar gum galactomannan.

One of Economy’s guar-processing facilities in Jodhpur, India, in the heart of the guar-growing region.
In addition, Halliburton capitalized on the fast hydrating quality of the new polymers and developed and extended the dry-polymer blending concept to a fully functional on-the-fly blending system. On-the-fly mixing is environmentally beneficial, because it does away with slurries and the oils and solvents used to make them.

“We believe eliminating oil-based slurries altogether – particularly those using diesel oil – provides significant health and environmental benefits and improve fracturing economics,” White said.

New plant in Siberia, Dubai planned
At the end of last year, Economy established a new manufacturing facility near Tyumen in Russia’s Siberia region to support Halliburton’s operations in that region. Another new plant will soon open in Dubai, giving Economy five manufacturing facilities, including those in Houston, Calgary and Jodhpur, India. The company also operates facilities in Fresno, Calif., and Rock Springs, Wyo., which are blending (slurrying) plants only.

Economy’s natural guar and guar-derived polymers are an integral component of several special treatment fluids used by Halliburton in its Conductivity Endurance™ group of well completion services. Among Economy Polymer products used by Halliburton and other service companies are Ecopol 2000, composed of unmodified guars; and Ecopol 18 and Ecopol 400, both double derivatives of guar. All are fast hydrating, easily dispersible and will respond to conventional cross-linking products under basic as well as acidic conditions. The company also manufactures a number of other polymers for use in well treatment fluids.

Continuing quest for better polymers
Founded as a chemical supply company in 1951, Economy entered the polymer business in 1982. Since then, it has introduced a number of products to the petroleum industry, including the high-purity, faster hydrating polymers for well treatment fluids described above. 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. Indian growers separate and hand-process the beans for shipment to the company’s Jodhpur plant. Once there, each bean’s endosperm, the source of the guar gum material, is isolated for treatment and grinding to powder form; the remainder – consisting of solid protein – is sold as livestock feed.

After processing, the gum is soluble in water, becoming gelatinous after time. It hardens when dried, allowing it to be powdered and combined with various additives to manufacture specific oilfield polymers shipped in bulk form or in sacks. White 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 improving polymer performance, but Economy is searching for even better results. Ongoing agronomy programs are an important part of that search, White said.

“We’ve come a long way, but we think there is still room for improvement,” he said.

Commitment to quality
As part of its commitment to bring new polymer technology to its markets, Economy controls the process of producing raw guar materials and intermediates, starting with the seed-splitting operations and processing train in Jodhpur. The company’s state-of-the-art facilities are or will be ISO 9001 2000 certified. This end-to-end control enables Economy to deliver products that perform consistently worldwide, a significant benefit for a global company like Halliburton.

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.

A test proppant pack after the guar-polymer-based carrier fluid has been flowed back, leaving little residue and resulting in regain permeability of 95%, higher than was achievable only a few years ago.
Higher Strength Yields Higher Fracture Conductivity

Proppant-specific performance characteristics are crucial to ultimate long-term fracture conductivity.

Ceramic proppants manufactured by Saint-Gobain Proppants (formerly Norton Proppants) have been a leading industry product of choice for more than 30 years. The company’s intermediate strength Versaprop® line has proved to be ideal for use in Halliburton’s array of Conductivity Endurance fracturing procedures. To extend the resulting advantages of the Versaprop sieve distribution, Ultraprop® Sintered Bauxite was developed to provide the enhanced performance of the Versaprop sieve distribution under the harshest of well conditions.

A component of conductivity endurance is the degree that a proppant maintains conductivity during time. Among other things affecting a proppant’s conductivity endurance, such as embedment, fines migration, physical damage and diagenesis, the response to cyclic stress loading must be considered. Plots in Figure 1 show material strength and conductivity comparisons at 8,000 psi closure stress after one, three and five stress cycles, comparing Versaprop and a lightweight, kaolin clay-based ceramic.

Production remediation in maturing fields can include a number of options such as stimulation, re-stimulation, and wellbore and/or surface equipment intervention. Re-fracturing is an effective tool for maintaining and improving production in older wells, but the choice of which wells to re-fracture is critical. When evaluating re-fracturing candidates, one of the important things to consider is the proppant used in the initial stimulation. At elevated closure stresses (above about 5,000 psi), look for candidates with sand, glass beads or lightweight ceramics used in the initial stimulation. Re-fracturing with Versaprop or Ultraprop Sintered Bauxite could be very effective in restoring and improving production, because of superior material strength.

Saint-Gobain Proppants developed Versaprop to meet the widest range of applications at a competitive price. Its enhanced particle size distribution and strength provide increased conductivity at all closure stresses when compared with lightweight ceramic proppants. Ultraprop Sintered Bauxite expands this concept to the deepest wells while comparing economically with intermediate density products.

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 new well 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 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 helping prolong the flow of much-needed oil and gas from existing wells, as well as increasing production from new ones.

To better serve the worldwide market, Saint-Gobain Proppants has expanded 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 China’s domestic supply. This new arm of Saint-Gobain Proppants also will supply ceramic proppant product to the growing Russian, Middle Eastern, African and Southeast Asian markets.

Figure 1. Conductivity at 8,000 psi closure stress and 1, 3 and 5 stress cycles
The Guanghan manufacturing site has benefited from increased capital investment by Saint-Gobain Proppants, which is providing the existing plant with leading-edge technology to meet the company objective of increasing production threefold with further expansion under way.

**Higher strength means less fines in service**

Jack Larry, general manager of Saint-Gobain Proppants, demonstrates that the median particle diameter (MPD) of a ceramic proppant is the primary determining factor in the level of conductivity the proppant will provide.

When Saint-Gobain Proppants developed Versaprop, the company commissioned a series of independent crush tests to compare the size, strength and MPD attributes of Versaprop with those of lighter weight proppants such as the ones used most frequently in conventional fracturing (Figure 2). Identical samples for each proppant were produced at the Fort Smith plant using the current manufactured sieve analysis for each. The dry samples were then stressed through multiple cycles in a crush cell at a concentration of 4 lb/sq ft. This procedure has been repeated while developing Ultraprop Sintered Bauxite, using intermediate strength ceramic as the base comparison.

“Stress cycling can be a significant problem for proppant packs,” Larry said. “Each time stress is changed on the proppant pack through any change in flowing conditions, additional damage occurs, reducing conductivity.

“Though long-term conductivity tests in a laboratory can’t reproduce actual downhole conditions, crush tests can mimic stress cycling at a particular closure stress and then measure the effect of that stress through sieve distribution changes. What’s more, crush tests take far less time to conduct and therefore can be performed more economically for a great number of conditions and in a timely manner.”

During testing, sieve distribution results revealed that while both proppant types generated some fines after stress cycling, the lighter weight proppant produced significantly more fines, particularly at higher closure stresses. The test results indicated intermediate strength proppants such as Versaprop retained a greater percentage of their original MPD than lightweight materials. These results, Larry said, point to higher fracture conductivity at a competitive price, thus increasing the conductivity ratio per dollar of cost.

Recently, Saint-Gobain Proppants has begun multiple-cycle conductivity testing, verifying results seen in cyclic stress crush tests. Versaprop is nearly identical to 20/40 mesh proppants as far as MPD is concerned; allowing it to be used in place of commonly used lighter weight 20/40 materials.

In addition to Versaprop, Saint-Gobain Proppants markets Ultraprop Sintered Bauxite, which has the same enhanced particle size distribution as Versaprop in a high-strength sintered bauxite composition. Saint-Gobain Proppants also offers 12/18, 16/30, 20/40 and 30/50 products in the Interprop intermediate strength composition and 16/30, 20/40 and 30/50 products in the high-strength sintered bauxite material. All the company’s proppants are manufactured for storage in bulk form at its various North American distribution points as well as several points in China and are available via 24-hour truck dispatch to designated land 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 more than 50 countries around the world and employs more than 200,000 individuals. The company’s HPM business unit produces ceramics, abrasives, crystals, grains and powders, and reinforcement products for numerous industry sectors.

---

**Company Profile | SAINT-GOBAIN PROPPANTS**

Saint-Gobain Proppants
5300 Gerber Road
Fort Smith, AR 72904
Tel: 479-782-2001
Fax: 479-782-9984
Web address: www.proppants.saint-gobain.com
Production of unwanted fluids and solids—mainly water, sand and proppant—is a common obstacle in optimizing recovery from mature producing assets. Dealing with produced water is especially expensive, both in direct handling and treatment cost and in lost production.

The U.S. Department of Energy’s Argonne National Laboratory estimates 15- to 20 billion bbl of produced water is generated in the United States and more than 50 billion bbl is generated annually in other countries. By comparison, world oil production in 2006 was about 31 billion bbl.

Argonne, which operates the Produced Water Management Information System, an online resource, estimates the worldwide water-to-oil ratio at 2:1 to 3:1. In the United States, the ratio is estimated to be 7:1, and many older U.S. wells have ratios greater than 50:1.

Halliburton data indicate a conservative estimate of the cost of handling produced water is in the range of $0.10 to $0.50/bbl.

Produced water can come from flow behind the casing, leaking casing, coning and watered-out layers at any time during the well’s life. It may include water originally held in the reservoir and water injected during production. Its chemical and physical properties vary with geography, geology and type of hydrocarbon being produced.

To further complicate the matter, produced water properties and volume can vary widely during the life of a well or reservoir.

Although an operator’s goal usually is to leave water in the reservoir, it sometimes makes sense to control the cost of handling, rather than minimize what is brought to the surface. Range Resources Corp., for example, focuses on controlling handling costs in some of its mature fields because water-handling systems are already in place and producing the water also increases oil production.

Declining production rates in fractured wells also often result from proppant flow back and the production of formation fines. Excessive water production may cause, or increase, sand production.

But sand control and formation consolidation technologies, and water management processes can minimize the influx of unwanted materials into the wellbore and help optimize production and recovery.

Water conformance solutions include retrievable or inflatable plugs or packers, zonal isolation squeeze cementing or injection of a chemical agent such as a synthetic gel. Successful results are continually being delivered via chemical sealants using in situ polymerized systems, cross-linked polymeric solutions and silicate-based gels. These include Halliburton’s PermaSeal®, H₂Zero® and Injectrol® services.
Understand the reservoir is always the first step in remediation. Halliburton has developed tools to help analyze a mature reservoir, determine the best water management solution and review its performance as operating conditions change.

The QuikLook® conformance simulator accurately predicts the outcome of water management treatments. Any number of wells with various flow constraints can be handled simultaneously. Its local grid refinement works horizontally and vertically to model near-well effects, including conformance fluid injection or coning and field scale simulations.

QuikLook also models fluid placement by incorporating the thermal effect in the reservoir and wellbore (Figure 1).

Modifying the permeability to water
The unique polymer chemistry of Halliburton’s WaterWeb® service helps impede water production, leaving water in the reservoir while facilitating the flow of hydrocarbons to the wellbore. The resulting reduced water column improves natural lift for oil and gas, increasing reservoir drainage.

WaterWeb service is designed to treat wells capable of sustained production if water/oil ratios can be reduced. It can reduce water production in wells where the hydrocarbon zones cannot be protected from treating fluid, or in wells with high-permeability streaks.

The service is appropriate for layered sandstones that do not have crossflow in the reservoir. It can be used in wells with bottomhole temperatures to 325°F (163°C) and in zones with absolute permeability ranging from 1 mD to 6,000 mD.

Treatment fluid consists of a polymer, a buffering agent and mix water. The polymer adsorbs onto the rock surface, dramatically reducing permeability to water compared with permeability to hydrocarbons (Figure 2). The treatment fluid is unaffected by multivalent cations, oxygen or acids; the treatment does not require rig time or a catalyst and does not set or gel up. No zonal isolation and no shut-in time are required.

In Bolivia, a gas well was shut in because of high water production. After two years, the well accumulated 1,200psi at surface. The operator then decided to attempt to reduce the water cut and regain gas production. Halliburton designed a WaterWeb service treatment for 8-ft (2.4-m) radial penetration. After the WaterWeb service, the well produced 399 b/d of water with 0.8 MMcf/d gas. A second WaterWeb service treatment was implemented to achieve 11ft (3.4m) of penetration. After the second treatment in November 2006, the water production dropped to 232 b/d of water.

Today, the well continues to produce gas and condensate at economic levels.

No isolation, no drill out
Halliburton’s new slurry squeeze system, BackStopSM service, can shut off water without the need for zonal isolation or drill out. Candidates for the treatment include wells in which isolation of the offending water/gas zone is not feasible, where re-perforation is an option and where bottomhole temperatures are between 100°F and 350°F (38°C and 177°C).

Unlike standard cement squeezes, the filtrate is the key to the success of BackStop. The slurry, combining Halliburton’s H2Zero agent and fluid loss control additives, is bullheaded into all open perforations; the entire wellbore in the selected interval can be filled with the slurry and squeezed. The fluid loss particles create a diverting filter cake that aids in uniform and shallow placement of the polymer.

Penetration into the formation is typically less than 3 in., allowing for re-perforation.

Following placement, pressure is slowly applied by pumping a volume of displacement fluid – water or brine – equal to 1 in. to 3 in. of penetration over the interval. Slurry left in the hole can be easily jetted out with coiled tubing.
Extending the Productive Life of Mature Assets

In a Middle East dual completion, the water cut in the lower zone had reached 96% in a 610-ft (186-m) interval. Two middle perforated sections produced most of the water, and water flowed between these two sections when the well was closed in. Isolating the watered-out section in the top of the lower zone mechanically was not possible, nor was a workover to install a cemented completion.

After a BackStop treatment, a survey indicated the squeezed zone was not contributing to water production. The zone was re-perforated and production resumed, virtually water free.

Treat the injector to stop water breakthrough

Waterflooding and water-alternating-gas (WAG) flooding are often used to improve the production from mature fields. CrystalSeal™ service is designed to help stop injected fluids in flood projects from flowing into fractured or highly vugular zones and eventually communicating directly with the producing wells. The patented process treats the injection wells rather than the producing wells, providing a farther-reaching effect with no risk of damage to the producers. The process uses CrystalSeal agent – a water-swellable synthetic polymer capable of absorbing 30 to 400 times its weight in water – to achieve multiple benefits and help increase production from mature fields.

The service helps improve the sweep efficiency of injection systems and is effective in a matter of hours. In addition, it does not require specialized mixing equipment. The agent is resistant to carbon dioxide (CO₂) contamination, acid contamination and/or hydrogen sulfide environments. It is able to withstand influx of water and help prevent dilution of cement or other remediation products. In addition, CrystalSeal agent is environmentally acceptable, contains no heavy metal crosslinker, is considered nontoxic and can be removed with oxidizers or bleaching compounds.

A major operator in west Texas was injecting into an openhole, lateral, CO₂ WAG injection well. Most of the fluids were entering into an interval near the toe of lateral, making 90% of the lateral ineffective. A CrystalSeal service treatment was implemented followed by acidizing to improve injectivity into the previously unused lateral section. Before treatment, about 80% of the injected CO₂ was being lost into thief zones. Withdrawal rates from surrounding producing wells improved by almost 50%. The treatment paid out in about 30 days.

PropStop service treats proppant pack with a low-viscosity curable resin that provides cohesion between proppant grains without damaging permeability or the conductivity of the proppant pack.

Consolidation without damaging conductivity

Halliburton’s PropStop service is designed to control proppant flow back and fines production, and help maintain high fracture conductivity for long-term productivity (Figure 3).

PropStop service treats proppant pack with a low-viscosity curable resin that provides cohesion between proppant grains without damaging permeability or the conductivity of the proppant pack. The coiled-tubing deployed, single-trip, rigless intervention service requires no isolation packers, reducing treatment time, cost and risk.

In the process, a preflush removes particles from the wellbore and conditions the proppant pack. After PropStop agent is injected, an over flush forces the agent far-
ther into the proppant pack and the area surrounding the perforation tunnels. The process results in about a 10-ft (3-m) penetration into the proppant pack. The treatment is applied using pulsing action provided by Halliburton’s Pulsonix TF or DeepWaveSM service.

If water production is also an issue, PropStop can be preceded by a WaterWeb service treatment. This process is referred to as ProStop WC service.

In the U.S. Mid-continent, a well was producing proppant into the electric submersible pump, separator and choke. Water production was 300 b/d; initial gas production was 1 MMcf/d, but dropped to zero in less than a month. Twelve days after a PropStop treatment of the 14-ft (4-m) interval, no sand was found in the choke, separator, dumps and water meter. Two months after treatment, water rate was about 175 b/d.

Keep sand where it belongs without screens
Through-tubingsand control techniques are a cost-effective option for recovering bypassed reserves and boosting production. Halliburton’s SandTrapSM service uses advanced resin technology to consolidate the near-wellbore area to help prevent sand production. The consolidated area maintains almost 100% of initial permeability.

SandTrap service can be applied to new or existing completions and can be placed down production tubing with jointed pipe and service packer, or with coiled tubing. The four-stage treatment includes a brine pre-flush; a solvent pre-flush; the formation consolidation system; and a brine post-flush overdisplacement.

This new system’s solvent/resin mixture is deposited as a thin film on the formation and clay surfaces. The solvent package provides a low-viscosity treating fluid and a means to get the resin in contact with the formation. The resin is internally catalyzed so no post-flush treatments are required to initiate curing.

Low-viscosity fluids allow more effective placement into reservoirs with variable permeability, and the service has good consolidation performance in sands with clay mineral content. For wells with failed gravel packs, SandTrap service can be used to consolidate the existing gravel pack and reservoir sand.

In one application, after SandTrap treatment in a 2-ft (0.6-m) pay interval in a Gulf of Mexico gas well re-completion, the well flowed sand free at 1.3 MMcf/d with a flowing tubing pressure of 2,000psi and a shut-in tubing pressure of 2,200psi.

Cleaner wellbores
LO-GardSM service, based on Halliburton’s proprietary relative permeability modifier technology, helps control fluid loss in gravel pack completions and also is effective in horizontal gravel pack applications where fluid loss through the filter cake could cause problems with gravel placement.

“In addition to gravel pack fluid-loss control, the service can be used in almost any situation where lost circulation occurs, including coiled tubing cleanouts, work-over operations and tubing-conveyed perforating,” Halliburton’s Harvey Fitzpatrick said in an article in the company’s Knowledge Central newsletter. The technology should be mixed only in systems with a neutral or lower pH.

Fitzpatrick said LO-Gard is especially suitable for openhole applications because it offers several features, including:

- a solids-free, low-viscosity, lost-circulation control system;
- decreased formation permeability to aqueous fluids, limiting leak off into high permeability streaks; leaky, thinned or eroded drill-in fluid wall cake; breched or fractured wall cake; and natural or hydraulic fracture networks;
- no significant permeability loss to oil or gas – retention with 100-mD core material is typically greater than 95%; and
- applicability over a range of temperatures and permeability, and effective in sandstone and carbonate.

Among field results is an attempt to kill a 300°F (149°C) well with 10-lb/gal brine that was unsuccessful because the formation was taking fluid at 18 bbl/hour. Pumping 80 bbl of the LO-Gard agent eliminated fluid loss and the project was successfully completed.

In another situation, a horizontal openhole Texas completion was producing 300 Mcf/d of gas from a lateral at 6,756 ft (2,059 m) with a bottomhole pressure of about 200psi. During a coiled tubing and nitrogen cleanout operation, the operator could not maintain circulation (fluid was at 5,900 ft – 1,800m). After a 10-bbl treatment pill of LO-Gard™ agent, the well was jetted dry following a 15-bbl additional treatment pill. Production increased to 1.6 MMcf/d following treatment.
Partnership Expands Capabilities and Facility Sites

Since 1980, Magnablend has been dedicated to blending and packaging a range of specialty oilfield products for Halliburton.

Privately owned Magnablend, headquartered in Waxahachie, Texas, had always responded quickly and confidently to its key customer’s requests, and Tuned Spacer was no exception.

Tuned Spacer is an important component of Halliburton’s Tuned Cementing Solutions™ cementing systems, which was first introduced in 1998, but has undergone steady evolution. Tuned Spacer III, introduced this year, is more cost-effective and offers more reliable performance than previous versions, and is produced domestically by Magnablend at its powder-blending facility in Waxahachie.

Magnablend has a production line dedicated to Tuned Spacer products. Three new silos were installed to receive raw material as well as a high-speed automated bagging line and stretch-wrapping system. Each of the three silos holds up to 200,000 lb of raw material, while the facility is capable of storing 1 million lb of bulk powder. One particular Tuned Spacer component requires grinding.

“Through a collaborative effort among Halliburton, Magnablend and our raw material supplier, we sourced a grinding partner with just the right capabilities for this project,” said Scott Pendery, vice president and chief operating officer of Magnablend. “Magnablend’s level of commitment goes beyond providing a blending and packaging service. We view ourselves as a partner who helps facilitate the success of our customers’ ideas.”

All of the Tuned Spacer components and finished product are handled via dedicated pneumatic conveyance, which helps maintain the high product purity required. Product quality is double and triple checked following quality control procedures developed by Halliburton and implemented by Magnablend. Tuned Spacer III is manufactured in a 480-cu-ft (14-cu-m) double-action ribbon blender with a maximum batch capacity of 20,000 lb.

The dedicated Tuned Spacer production line is one of nine double-action ribbon blender lines at the 162,000-sq-ft (15,050-sq-m) powder-blending plant, which has 58,000 sq ft (5,388 sq m) of manufacturing space and 104,000 sq ft (9,661 sq m) of warehousing. The ribbon blenders range in size from a 40-cu-ft (1-cu-m) pilot-batch blender to 480-cu-ft production blenders. The number and variety of blenders is one reason Magnablend can quickly move a new product from concept through laboratory bench-scale production to pilot-plant production and into full commercial production. The plant has significant packaging and repackaging capabilities, too: 1-lb to 100-lb polyethylene bags, 10-lb to 100-lb multi-wall paper bags, 15-lb to 30-lb jugs, valve bags, open-top bags, super sacks and bulk trucks.

Liquid products
Magnablend also manufactures liquid products used in Halliburton’s PropStop™ service and SandTrap™ service. The PropStop service uses a low-viscosity curable resin to control proppant flowback and fines production and helps maintain high long-term fracture conductivity. The SandTrap service also uses advanced resin technology for sand control. Until recently, both products have been produced in Magnablend’s 76,000-sq-ft (7,061-sq-m) liquid-blending facility, a few miles north of the powder-blending facility. At this location, 52,000 sq ft (483 sq m) is dedicated to production and packaging, with the remaining 24,000 sq ft (2,230 sq m) given over to warehousing. The plant can handle virtually any size blending and packaging project, with more than 30 mixing vessels, from 150-gal to 15,000-gal capacity. To accommodate a variety of reactive chemicals, vessels include stainless steel, fiberglass and high-density polyethylene. Jacketed vessels can handle exothermic or endothermic reactions. There is also specialized equipment for
high-viscosity blends, suspensions or dispersions and ammoniated products. Packaging capabilities range from 1-gal jugs through pails, drums, tote tanks, tank trucks and rail cars.

New ‘central facility’
The two Halliburton resin products have been moved to dedicated production lines at Magnablend’s new “central plant,” so named because its location on Texas Highway 287 is almost exactly halfway between the powder-blending plant and the original liquid-blending plant. This new 98,500-sq-ft (9,151-sq-m) state-of-the-art facility is designed to handle dedicated, large-volume projects. It has a 12-car rail spur, which allows the company to take on large projects that require big shipping capabilities, and it also has ready access to Interstate 35. The building houses powder and liquid capabilities, including two 300-cu-ft (81⁄2-cu-m), dual-action, jacketed ribbon blenders for dry products, one stainless steel, the other carbon steel. For liquid products, there are 10 mixing vessels from 1,500-gal to 6,500-gal capacity. Packaging options are similar to those at the original liquid blending facility.

There is plenty of room for expansion at this location to accommodate large-scale growth, Pendery said.

Serving the Rockies and western Canada
In October 2006, Magnablend opened a new liquid blending and repackaging plant to serve the Rockies area.

The Mills, Wyo., plant is similar to the company’s central plant in that it will accommodate liquid and powder products. It has tall eave heights to handle large mixing equipment and a rail spur for receiving and shipping large volumes. At present, the plant handles only liquid products, but it has adequate space to add dry blending and packaging in the future.

“Although we opened this plant primarily to serve Halliburton, we hope to serve other customers both here in the Rockies region and in western Alberta, Canada, which is well within economical shipping reach,” Pendery said.

Continued growth as customer base expands
Halliburton and Magnablend have grown together for the past 27 years. While the company’s oilfield business has evolved through its relationship with Halliburton, Magnablend is now serving other oilfield customers as well as those in other industries, including fertilizers, water treating, industrial cleaning and specialty cements for construction.

During the past 18 months, Magnablend has reinvested heavily in its business, adding the central and Wyoming plants, as well as a lot of capabilities, including specialty packaging systems dedicated to specific customer needs. All of the company’s blending vessels are on digital load cells, for the most accurate production blending possible. The company has also expanded its laboratory facilities to offer all required quality control testing, as well as product development support and bench-scale production.

“In our partnership with Halliburton over the past 27 years, we’ve proven that we can meet just-in-time requirements while maintaining the highest quality requirements,” Pendery said. “We’ve also demonstrated our willingness and ability to grow and customize our operations to take care of the ever changing needs of our customers.”
Weak formations pose drilling and completion challenges that can increase well cost and shorten productive life.

During completion, a key to managing weak formations is a fit-for-purpose cementing solution. Fluid-loss additives play a major role in successful cementing operations; by controlling fluid leak-off from the slurry into the formation, the additives help maintain the desired rheology, viscosity, thickening time and compressive-strength development of the cement slurry.

Recently, Halliburton created a new-generation fluid-loss additive for cementing that offers better fluid-loss control performance, especially in high-salt-content slurries, more desirable slurry rheological properties and a wider temperature range than additives currently used. In addition, the new product is more versatile and will serve as a global fluid-loss additive in Halliburton’s service areas around the world, simplifying inventories and operations.

For help in turning the new additive formulation into a market reality, Halliburton turned to a long-time partner in new product development, Adomite Well Service Chemicals, part of Nalco’s Energy Services Division. Based at Nalco Energy Services Division headquarters in Sugar Land, Texas, near Houston, Nalco’s research chemists and applications engineers work closely with Halliburton and other service companies to develop and supply chemicals and additives for a range of well treatment applications, including drilling, cementing, completion, acidizing and fracturing.

Dr. Ralph Cheung, research associate at the Nalco’s Adomite group, said the new fluid-loss additive, like many Halliburton proprietary chemicals, was originally conceived at Halliburton’s Duncan, Okla., research and development laboratory.

“In this case, we started with Halliburton concepts and developed them into new product candidates. Further iterations, with ongoing evaluation by Duncan research, refined the candidates down to the winning formulation. When we had optimized the formulation, we first produced pilot-level quantities at the Nalco complex in Clearing, Ill., to validate the process and then initiated required regulatory registrations for this new chemistry,” he said. “Our respective research groups often cooperate to jointly develop new products from the ground up, as in this present case, and in some cases, Nalco’s research chemists independently create a new product that we offer exclusively to Halliburton, if we know it has the potential to solve a key problem or improve upon current technology.”

“Halliburton is continuously striving to improve its services,” said Gary Aman, general manager of Nalco’s Adomite group. “Once an improvement has been developed, there is a push to implement it as quickly as possible.”

That’s where Nalco’s substantial manufacturing and distribution capability comes into play.

“This new additive will be introduced in North America in the first quarter of 2008, and by the middle of the year, the product will be available throughout the world,” Aman said.

The key to the rapid expansion of product availability is Nalco’s global manufacturing and distribution presence. The company has international manufacturing centers which are ISO certified supporting Adomite global business in Garyville, La.; Sao Paulo, Brazil; Northwich,
England; Cisterna, Italy; Konnagar, India; and Nanjing, China; with further distribution centers in Aberdeen, Scotland; Abu Dhabi, United Arab Emirates; Nisku, Alberta, Canada; and Singapore. Altogether, the company operates 49 plants, with more than 10,000 professional, skilled, managerial and administrative personnel.

Partners in sustainable development
Halliburton and Nalco are committed to the principles and practices of sustainable development. Nalco’s business activities support these commitments by maximizing its contribution to environmental protection, supporting and promoting economic prosperity, and building strong stakeholder communities. All these activities combined contribute to true sustainable development, where actions we take today safeguard the world of tomorrow.

Specifically for Nalco, this means the programs it brings to market must be focused on providing the greatest environmental, economic and social benefits. Many of the processes that contribute to sustainable development are not new, and Nalco continues to build its ongoing commitments to improve upon its environmental performance. Since 2002, Nalco’s manufacturing output has grown by 16.9%; however, the volume of waste created has declined by 29.4%, and total energy consumption has fallen by 3.2% during the same period.

A long history
Nalco has long been 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 partner, and process enhancement company. The company serves customers globally in numerous industries, ranging from aerospace and aviation to cosmetics, to mining and minerals, to pharmaceuticals and petroleum. Nalco’s contributions to oil and gas service companies help it drill, complete and stimulate wells for optimum production.

One of Nalco’s global manufacturing plants in England.
Depleted sands and weak formations pose drilling and completion challenges that, if not overcome, can significantly increase the cost of the well and shorten its productive life. Lost circulation and hole-washout are common problems in weak zones.

“Standard cement weighing about 16 lb/gal is too heavy for these formations because the bottomhole circulating pressure during cementing may exceed the rock strength, open fractures in the rock, and allow cement to be lost to the formation,” Halliburton’s David Kulakofsky said in an article in the company’s newsletter Knowledge Central.

If a portion of the cement is lost to the formation, top of cement (TOC) may be significantly lower than designed, requiring remedial cementing operations. To avoid losing cement to the formation, the cement slurry density should be less than that of the fracture pressure of the depleted zone, which can be done by adding water (water-extended cement), nitrogen (foam cement) or lightweight microspheres (LMS cement).

Water extended and LMS cement systems
In less difficult drilling conditions, simply adding extra water and the water-extending additives necessary to tie up the extra water can reduce the slurry density enough to safely circulate and achieve the desired TOC.

The primary advantage of a water-extended slurry is low cost. Typically, only a small amount of water-extending material is required to tie up large amounts of water. These systems, in addition to being lightweight, increase the slurry yield per sack. As more water is added, less cement (and associated additive) needs to be purchased.

“However, as water is added above the standard 4 gal/sack to 6 gal/sack, the cement becomes more dilute, strength declines and permeability increases,” Kulakofsky said. As the density approaches 10 ½ gal/lb to 11 lb/gal, the dilution effect when water alone is added becomes so great, and compressive strength development so slow, that the cement may no longer be useful as an annular sealant.

For wells that require slurry densities substantially less than 11 lb/gal or higher cement performance at densities greater than 11 lb/gal, LMS and stable foam designs provide better performance.

In LMS cement systems, relatively inert material with low specific gravity is added to the cement slurry. Typically, these are hollow glass or ceramic micro spheres with a specific gravity of less than 0.7. Less frequently, they are solid, plastic micro spheres with a specific gravity similar to water. “Properly designed LMS systems have advantages over other lightweight cement slurries,” Kulakofsky said. LMS systems can:

- offer competent cement slurries with densities as low as 7.3 lb/gal;
- provide the fastest strength development of any system at a given density, reducing waiting-on-cement time;
- have the lowest permeability at a given density; and
- utilize conventional mixing and pumping equipment.

In exploration wells, where last minute changes in mud weight are common, the LMS system provides flexibility to change the density at the last minute, provided the proper lab tests were completed prior to the job. Lightweight microsphere slurries are often the first choice of operators, but slurry mixing and blend segregation are issues.

“However, liquid micro spheres have been tested under two different injection strategies and both eliminate this density control/mix-water ratio issue, as well as blending and transfer issues,” Kulakofsky said.

Foamed cement
One premium density reduction method involves introducing a gaseous phase, normally nitrogen, to create foamed cement. Foamed cement can be effective in delivering zonal isolation during and after the wellbore construction process.

Foamed cements have two key advantages. The cement slurry is more compressible than conventional cement in a liquid state, making it an excellent annular gas migration or shallow water flow prevention option.

“Another benefit gained from foaming the cement slurry is more efficient displacement,” Kulakofsky said. Foamed cement slurries typically exhibit high levels of wall-shear stress, which can aid in mud-removal.

Ideal foam porosity provides a balance of increased elasticity, increased compressibility, good strength and the ability to maintain low permeability.
In practice, downhole densities are typically reduced to between 70% and 90% of the base fluid density. Typical downhole foam slurry density ranges upward from 10 lb/gal.

Foam cement jobs typically require more people and equipment on location, and the cementing operation is more complex, compared with conventional cementing operations.

**Fit for purpose**

With its Tuned Cementing Solutions™ cementing systems, Halliburton has created a set of innovative fit-for-purpose solutions with the flexibility required to allow each system to be tuned specifically for a given set of wellbore conditions. ElastiSeal™ cements are formed cement systems, designed to create a more elastic wellbore sheath. At ultra-light densities, that can provide long-term reliability.

ElastiCem cement has increased elasticity in the set cement, making it more able to absorb the stresses present downhole and maintain its seal. This light and resilient cement provides increased compressibility, bridging and elasticity gained through the introduction of small, stable and well-dispersed nitrogen bubbles.

In loss-prone wells, ElastiSeal cement can help bring the top of cement to the planned depth while forming an effective annular seal that will be resilient in the presence of significant physical and thermal changes during the life of a well. Such environments may include:

- low-pressure/high-temperature;
- geothermal wells;
- gas-storage wells;
- depleted reservoirs;
- coalbed methane wells; and
- fractured, carbonate reservoirs.

ElastiSeal cements can be mixed over a density range from 5 lb/gal to high-density designs exceeding 19 lb/gal. The cements can be designed for operating temperatures from 50°F (10°C) to 600°F (316°C), so that these systems can withstand conditions imposed by deepwater, high-pressure/high-temperature and other demanding applications.

**Field results**

The right cement properly placed provides zonal isolation that reduces water influx, helps keep stimulation treatments in zone where they can produce better results and minimizes production lost to thief zones. The result can be increased production (see charts).

In one example of the economic value of an improved annular seal, two wells did not produce water for 230 days after completion with ElastiSeal cement while their offset wells produced 19,000 bbl of water that had to be separated and disposed.

During the first 240 days of production, one well produced more than 700,000 bbl oil, more than the average of its two offsets. Another well produced 258,000 bbl more oil in the first 210 days than its offset.

At $50/bbl, the combined increase in production from these two wells cemented with ultra-light ElastiSeal cement is 958,000 bbl for a revenue increase of almost $48 million.

In six wells cemented with ultra-light ElastiSeal cement in Mexico’s Cantarell field, cement was circulated up into the liner lap for the first time since drilling began in 1979.

ElastiSeal cement at a higher (8 lb/gal) downhole density was used in more than 40 additional onshore Mexico wells. In the land-based and offshore wells, stimulation was performed on these wells, and the resilient ElastiSeal cement sheath eliminated water production.

After the offshore work had 250 producing days, and the first land-based ElastiSeal cement jobs was three years old, the wells were still intact and in production.
Much of the remediation work Halliburton is performing in mature fields throughout the world is accomplished using coiled tubing. These services include fracturing, sand control, acidizing and well cleanouts, with trade names like CobraJet Frac® service, SurgiFrac® service, CobraMax® fracturing service, DeepWave® stimulation service and Hydro-Blast® Pro service.

"Coiled tubing has come a long way since it was first introduced," said John Martin, senior vice president of NOV Quality Tubing. "In the beginning, inconsistent material and tube properties were formidable issues. Even though coiled tubing offered cost and operational advantages over using conventional tubing, there were some risks associated with it, which limited its use."

Then NOV Quality Tubing built the first plant dedicated to manufacturing coiled tubing in quantity, with rigorous production controls. Since then, Martin said, there has been steady improvement in coiled tubing reliability, which is reflected in the strong growth of coiled tubing use throughout the oilfield.

"The number of coiled tubing units has more than tripled over the past 10 years, and coiled tubing services are now offered by all the major service companies and a host of smaller operations," he said.

Those companies are providing an ever-wider array of coiled tubing well intervention, remediation and stimulation services, and coiled tubing is increasingly being used for drilling.

Martin pointed to several key factors that have contributed to the rapid development of coiled tubing capabilities during the past decade.

"First, of course, is quality. Improved metallurgical properties and advanced manufacturing techniques deliver a consistent, reliable tube product. Second, there have been significant advances in predictive modeling of coiled tubing service life, encompassing cycle fatigue resulting from changing radii and pressures within the coiled tubing. Third, there is the advent of best practices for running and maintaining the tubing, supported by the ability to accurately model actual job dynamics," Martin said. "These factors have significantly boosted coiled tubing reliability and service life. Coiled tubing is now used to service wells at 30,000ft [9.150m] and beyond, which was unheard of 10 years ago, and we are now seeing operators confidently employing coiled tubing on multi-million-dollar assets."

Martin also credited service companies, especially Halliburton, for making major investments in state-of-the-art coiled tubing units, specialized bottomhole equipment, personnel training and service infrastructure.

Importance of the perfected bias weld
One of the key advances in manufacturing techniques is the automated bias weld, which NOV Quality Tubing introduced in 1989. Continuous tube lengths thousands-of-feet long are made by welding steel strips together, end-to-end, before the strip is formed into a tube. With the patented bias-weld process, the strips are connected with a biased connection (45° angle) that becomes an integral part of the strip. When the strip is rolled into a tube, the joint forms a spiral-shaped connection stronger than a butt weld, which are only used for new tubing when transportation constraints require extremely long strings to be shipped on separate reels. All bias welds are examined using digital radiography.

Manufacturing overview
NOV Quality Tubing manufactures coiled tubing to industry standards and customer specifications at its Channelview, Texas, plant, where tube mills (lines) form and weld steel strips into continuous tubing strings as long as 30,000ft, depending on wall thickness and tubing diameter. First the steel strip passes through rollers that form it into a “U” shape. A second set of rollers prepares the strip for the longitudinal weld, which is made using the high-frequency induction method to heat the edges of the strip to fusion temperature. Insulated rollers squeeze the edges together to form the welded seam. After weld flash is removed, the welded seam is

---

Coiled Tubing Behind Halliburton’s Coiled Tubing Remediation Services

The coiled tubing Halliburton uses for its services is manufactured by NOV Quality Tubing, a National Oilwell Varco company, which first introduced commercial coiled tubing to the oilfield in 1976.
reheated to recrystallize the heat-affected zone so it matches the grain structure of the base metal. Then the tube is cooled before it enters the sizing section of the mill, where rolls form it to the final dimensions. After NDT inspection, the tube is stress-relieved by heating and slow cooling. Each string is hydrostatically tested and its internal diameter is verified with a gauge ball. Finally the tube is wound onto a shipping reel, purged and blanketed with nitrogen and prepared for shipping.

More materials, more sizes
NOV Quality Tubing’s customers enjoy a choice of carbon steel product offerings, ranging from 70,000psi to 110,000psi yield strength, plus a 90,000-psi yield strength, corrosion-resistant product. They can design coiled tubing strings for specific applications based on well depth and configuration, type of fluid in the well, pressure and more. The most popular diameters are 1¼ in., 1½ in., 1¾ in., 2 in., 2.375 in., and 2.875 in., but there are calls for 3¼ in. or 3½ in. coiled tubing. During the past 3 to 5 years, the company has seen a trend toward the larger diameters, which are used when there is a need for larger volumes and flow rates, as in drilling or fracturing.

Lowering coiled tubing string weights
For longer coiled tubing strings, larger diameter tubing and higher-yield material, weight increases dramatically. The only way to solve the problem is to taper the wall thickness of the strings from top to bottom to reduce string weight. Tapered strings made by welding together strips of different thicknesses have been used, but many strips were required, and stress concentrations at the welds compromised strength. NOV Quality Tubing, in cooperation with its steel supplier, developed a patented process for producing steel strips with gradually diminishing thickness over the length, except at each end where there is a short section of the same thickness as that of the section to which it is joined. That allows the bias-welded junc-

ture to be between equal thicknesses, reducing stress concentrations caused by non-uniform load transfer and eliminating wall “steps” to produce a smoother tube wall. True-Taper® strings have increased the theoretical cycle life of the tubing over that of the conventional tapered strings.

Taking care of customers’ tubing
NOV Quality Tubing operates three major service centers. The centers are in Aberdeen, Scotland; Red Deer, Alberta, Canada; and Abu Dhabi, which opened during the summer of 2007. The service centers perform critical maintenance and repair functions on coiled tubing being used in the field. Coiled tubing strings are thoroughly inspected. Damaged or corroded sections can be removed and the tubing rejoined with certified tube-to-tube welds. Coiled tubing strings are cleaned, and corrosion protection is applied. Strings are also respooled to and from shipping and work reels. These vital services help service companies get the maximum life out of their coiled tubing strings.

NOV Quality Tubing service centers also provide storage for the tubing strings between service campaigns. Often the service centers provide consignment strings of tubing that can be utilized in emergency situations.

NOV Quality Tubing also has portable “mini service centers,” which can be dispatched to any location where local support is needed on a temporary basis. These mobile units comprise welding and inspection equipment equivalent to that used in the major centers.

Keeping up with market growth
As recently as 18 months ago, the demand and limited manufacturing capacity caused delays in delivering new coiled tubing orders. NOV Quality Tubing was not standing still; plans were under way to increase output. During the past year and a half, the company has added more than 50% to its production capacity, significantly reducing lead time for new orders. An additional building planned for early next year at the Channelview site will house expanded tube finishing and servicing operations.

“We believe coiled tubing is a proven and cost-effective service technology. With the support of NOV, we are well prepared to respond to the growing demand for our products,” Martin said.
Oilfield Production Focus Raises Chemicals Demand

International spread, decades of experience and research and development expertise add know-how to optimization of assets.

Soaring prices for oil created booming demand for service-company chemical products that make wells produce better and fields last longer, and Rhodia oilfield and water group is a prime mover in that production improvement chain.

The company distributes its products and provides support mainly to oil and gas service companies, including Halliburton. Chances are high, however, that nearly every producing company in the business has depended on a Rhodia-made product at one time or another.

Products
Among its products are guar-based viscosifiers and gels that improve fracture treatments and offer better placement of proppant. It also makes guar-based polymers and synthetic polymers for specialized jobs. There is no one-size-fits-all solution in this segment of the industry.

The company also has invented a new environmentally friendly biocide called Tolcide® PSSOA to control ferrous sulfide in pipes and clear tubing to let oil reach the surface. That product family earned the U.S. Environmental Protection Agency’s U.S. Presidential Green Chemistry Award during the Clinton Administration.

Most current research focuses on environmentally friendly chemicals, which include scale inhibitors such as the company’s Aquarite®.

The Rhodia oilfield and water group’s association with Halliburton grew during the years and has continued with the development of specific applications of guar. Rhodia is the largest manufacturer of guar through its 50-year-plus association with Hi-Chem. The guar bean “splits” can be processed to powder in India or shipped to other countries for final processing.

That capability has expanded to include standard and derivative guar products specifically aimed at improved performance in fractures.

Custom work
In a typical situation, Halliburton, or another service company, might come to Rhodia with a need for a specialized compound fit-for-purpose for a specific area.

Rhodia and Halliburton research scientists regularly communicate with others and discuss projects of mutual interest, which usually start with existing products that work in similar situations with modifications added to take care of specific conditions.

This research and development (R&D) has grown in importance for a variety of reasons, said Mo Beyad, vice president of Performance Solutions for Rhodia Novacare, for guar and all products.

In some cases, laboratory tests will tell scientists whether a product is successful at its appointed task. In other cases, such as fracturing fluids, the true test is in the wellbore, which is usually a job for the service companies, either working with producers or oilfield test centers in producing areas around the world.

“In production, you used to drill a hole, push in pipe and the oil came out,” Beyad said. “Now, producers realize there’s a lot to optimizing production with chemicals playing a more significant role. Each site is geologically different. Each has different oil chemistry, pressures and temperatures. Rock quality and makeup are different.”

Producers depend on the service companies to come up with the solutions that allow them to produce economically.

In Russia, for example, as the economy declined with low oil prices, no one paid attention to improving production. Now, as prices recovered and Russia once again set out to become an oilfield powerhouse, producers are using service-company tools and solutions. A lot of that improvement has come from remediation, the removal of scale and application of corrosion inhibitors to revive existing wells. Those solutions had to fit Russia reservoirs.

Conditions in the deserts of the Middle East are different from conditions in Siberia.

A product that works well in the Middle East doesn’t necessarily work well in Siberia. In Russia, compounds had to be formulated for storage in cold climates. In the Middle East, heat was a more pressing problem. In both areas, the compounds had to

Rhodia’s Vernon, Texas, facility is one of about 75 production sites around the world. The company has a worldwide employee base of some 16,000 people.
remain stable through the full temperature range of working conditions on the surface and in the well.

Growth
National oil companies with huge production numbers and reserves also are paying more attention to the products and techniques service companies can provide to maximize the lives of their reservoirs.

In the Middle East, Beyad said, oil company executives know their reservoirs have limited reserves. They see the high oil price and recognize the benefit of high income for their nations. They also see the cost of drilling a new well is higher than that of stimulating production from an existing well.

With that in mind, the company also is looking at the whole area of polymers for enhanced oil recovery. Typically, Beyad said, that part of the industry boomed when prices were high and collapsed when prices folded. Now, however, prices have remained above $50/bbl for a long period of time. The company isn’t yet ready to talk about its plans in that area.

While Rhodia continues to innovate in the development of new polymers and surfactants to optimize well productivity, the company is also organizing its operations to make that chemistry available in all regions. This direction allows more efficient technology transfer to improve logistic and service levels. Evidence of its commitment in operational excellence in all regional operations, Rhodia Novecare has recently completed the global multi-site ISO 9001 certification.

The push to optimize production makes the Middle East, with all of its reserves, an emerging market for oilfield service companies and Rhodia’s operations. Russia is another emerging market for the company.

With the emergence of China and India as major petroleum users and efforts by Eastern countries to try to fill that demand, the need for production-enhancing chemicals is moving east, Beyad said, and Rhodia is moving with that demand.

Global reach and R&D network
Rhodia Inc., the parent company based in Paris, has a long-standing R&D center at Aubervilliers outside of Paris and a new “Laboratory of the Future” near Bordeaux, providing state-of-the-art throughput and screening technologies. It has a technology center in Shanghai that will eventually house 120 scientists and a technical services laboratory in Singapore. It has a large service center in Sao Paulo to handle South American operations. Its North American research center is in Bristol, Pa., near the company’s North American headquarters office in Cranbury, N.J.

In addition, Rhodia Group has some 75 production sites around the world and a worldwide employee base of some 16,000 people. The Rhodia Novecare division, which includes the oilfield and water group, home and personal care products, and industrial ingredients, accounts for about $1 billion of the full company’s revenues of about $5 billion.

Alliances
A key part of the company’s operating strategy is its alliances with significant partners. For example, its partnership with the Institut Français du Pétrole extends the company’s research capability. It also has R&D partnership arrangements with several renowned universities around the world.

Those relationships are key because the company must do more than just respond to specific requests from its service company partners. It must also work with service company partners, other R&D operations and universities to stay a step ahead of the needs. Those partnerships are windows to the future needs of the oil and gas industry and, in the case of the parent company, all of the industries it serves.

The company’s strategy works, Beyad said. The overall rate of growth for all companies in Rhodia oilfield and water group’s business lines is between 5% and 7% worldwide, with higher rates in the emerging markets and slower growth in developed areas. Rhodia’s growth exceeds that overall rate.

Thanks to its expertise in environmentally sustainable chemistry, Rhodia is placing more emphasis on “green” products as customers and world opinion demands more environmentally friendly products.

In its brand-new Laboratory of the Future, near Bordeaux, France, Rhodia makes extensive use of new technologies such as microfluidics and robotics to speed up the innovation process.
One definition of a mature asset is a producing field in which a well-planned development drilling program cannot offset natural field decline. But that definition can pose the question: is something being missed?

The key to the answer can lie in evaluating the stacked tight gas pays individually. Integrating geology and engineering enhances the value of that analysis. During a well or reservoir’s productive life, multiple payzones typically decline at different rates and reservoir properties change. The performance of the zones can vary at any time.

Accurate, effective fracture stimulation of multiple pays is possible in less time and at lower cost using an expanding array of fracturing technology that allows pinpoint treatment of selected zones in wells with multiple lenticular pays and precise placement of fractures in horizontal wellbores.

Stimulation is arguably the most useful tool for enhancing the value of mature producing assets. The best stimulation processes are flexible, capable of delivering the best treatment to a precise interval and cost effective.

Pinpoint fracturing can access small pays not effectively stimulated by an original, larger frac. These small, tight channels can contain respectable amounts of bypassed hydrocarbons.

Fully exploiting pinpoint treatment technology requires an understanding of individual sand lenses that, in the past, might have been considered part of a large sand system. This large system might, in reality, be made up of five to six separate sands, all with different reservoir characteristics.

**A family of technologies**

Pinpoint stimulation processes can accurately perforate and fracture a precise interval and tailor the treatment to fit the characteristics of each zone. Halliburton’s family of pinpoint stimulation processes can reduce treatment time, streamline logistics, require a smaller work force and minimize environmental impact.

A range of coiled tubing stimulation services that offer advantages over conventional methods cover the spectrum of applications, providing effective and efficient treatment of preperforated vertical wells with multiple intervals, nonperforated cased and cemented vertical wells, cased and cemented horizontal wells, and horizontal open hole intervals.

All can save time and cost compared with other options, increasing safety and reducing environmental impact.

**Effective stimulation of deep zones**

For unperforated, cemented casing completions in vertical wells, the patented CobraMax® V fracturing process...
is performed with a coiled-tubing-deployed Hydra-Jet™ bottomhole assembly (BHA). There are no packers or mechanical devices to set. The BHA is moved to the first target and perforating is accomplished by hydrajetting via the coiled tubing. The annulus is closed in to enable breaking down the perforations, and the fracture treatment is pumped through the annulus.

During the fracturing treatment, the coiled tubing is moved above the treatment interval and acts as a dead string for fracture diagnostics. A final proppant stage of non-cross-linked (linear) fluid with high proppant concentration is pumped to induce a near-wellbore proppant pack that further improves near-wellbore conductivity and acts as a diversion for treatments further uphole.

When all intervals have been treated, the well is cleaned out with the coiled tubing unit and can be jetted or flowed to recover treatment fluid. Up to 22 individual intervals have been fracture stimulated in a single completion.

CobraMax V service was successfully deployed in Chevron’s Lost Hills asset with significant reduction in overall cost/barrel of oil equivalent (based on 180-day cumulative production) over conventional “perf-and-plug” limited-entry fracturing method (37.6% higher cumulative production reported). This work has been documented in SPE Paper No. 101840.

The CobraMax service process is available for vertical and horizontal wells (CobraMax H service) and can be implemented with coiled tubing and jointed pipe. The jointed pipe version uses a hydraulic workover unit and is called RamMaxSM service.

**High rates, volumes, depths using packers**

The CobraJet Frac® fracturing process also uses a coiled tubing deployed BHA. This process is similar to CobraMax service in that the Hydra-JetSM service perforating is accomplished by pumping through the coiled tubing, and the fracture treatment is pumped though the annulus. In this process, however, diversion from previously stimulated intervals down hole is accomplished using a compression set packer.

CobraJet Frac service offers the same dead-string advantages as CobraMax service. One advantage of CobraJet Frac service is the time savings between treatments. The packer isolation method is often quicker than the process of setting proppant plugs in the wellbore and often does not require a cleanout at the end of the completion.

In the SurgiFrac service process, sand-laden fluid pumped through a jetting tool impinges on the foundation creating a cavity. As the cavity is formed, pressure on the bottom of it increases, eventually initiating a fracture. Annular fluid is pulled into the fracture, helping extend it.
In North Louisiana, CobraJet Frac service was used to stimulate a sandstone formation in four stages because it could treat the individual small sand stringers more effectively than a conventional blanket frac. All four stages were treated in one day, and gas production averaged 1,895 Mcf/d with only 21 b/d of water. The productive zones were near water zones, and other wells in the area often produced hundreds of barrels of water per day after a conventional frac treatment.

Proven approach to relatively shallow zones
A common approach to stimulating an aging reservoir has been to fracture wells with multiple layers in stages down casing, using wireline retrievable plugs to isolate lower zones.

CobraFrac service offers a better way to exploit gas-bearing sands in new wells and refrac old wells containing bypassed pay zones. With a single trip, it can stimulate multiple zones by straddling each individual productive stringer. Completion costs are lowered and single-day stimulation reduces time to sales.

The service has been used successfully in more than 30,000 fracture treatments in more than 5,000 wells at depths to 7,700 ft (2,349 m).

The CobraFrac service BHA includes a specially-designed straddle packer and an equalizing valve that allows movement of the tools without flowing the well. A reciprocating J allows multiple sets on a single trip. A top cup packer acts like a check valve to allow reverse circulation, and a safety shear sub permits release of the tools. Compression-type tools make it possible to isolate the wellbore if necessary.

In southern Alberta, CobraFrac service was used to recover trapped gas in under-pressured low-temperature sandstone reservoirs in shallow wells on tight spacing on environmentally-sensitive pasture land. The selective straddle packer system helped the treatment team set a record by treating 19 zones in two wells with a single crew in a 12-hour day. A total of 520,000 lb of 20/40 sand at concentrations of up to 16 lb/gal was placed. Wells responded with increased production at higher flowing pressures.

For deeper wells, the CobraFrac process can be performed using HWO. This process is called RamStraddleSM service.

Unequaled control for horizontal openhole fracturing
Halliburton’s SurgiFrac® service offers a quick, effective method to help boost production from openhole horizontal completions. In the process, sand-laden fluid pumped through a Hydra-Jet service tool creates a cavity in the formation. Increasing pressure on the bottom of the cavity eventually initiates a fracture and annular fluid is pulled into the fracture, helping extend it.

SurgiFrac service’s unequaled control of fracture initiation and propagation can help operators achieve several goals:

- increase production in openhole horizontal wells with high or low permeability formations using coiled tubing or jointed pipe to create precisely-positioned fractures in bypassed and underperforming zones;
- optimize reservoir drainage by precisely locating fractures customized to meet well conditions;
- add new production more quickly by creating multiple fractures in hours with no sealing required between zones; and
- reduce fracturing treatment costs by using less equipment and lower viscosity fluids.

The service has been used for multiple propped fractures and multiple acid fractures in open hole, and deviated cased holes and slotted liners. Experience includes coiled tubing acid frac to bypass damage and multiple fractures in a cased horizontal wellbore.

For example, SurgiFrac service deployed with 2 3/8-in.
coiled tubing successfully placed eight fractures in a 5-hour period in a 3,821-ft (1,165-m) well with 5 1/2-in. casing and a 4 3/4-in., 1,600-ft (488-m) open hole horizontal section, boosting production by 800%.

Unequaled control for horizontal cased hole fracturing
The Delta Stim™ completion system provides operators new options for completing horizontal wellbores to enable highly accurate placement of fractures. The service incorporates the newly developed Delta Stim stimulation and production sleeve that allows operators to selectively access a variety of pay zones in a single wellbore.

The VersaFlex® liner hanger system enables reliable, trouble-free installation of the Delta Stim completion assembly. Based on reservoir conditions, isolation can be achieved with the Swellpacker™ Lite isolation system for an openhole completion, or the sleeves can be cemented in place using Halliburton’s patent-pending SoluCent™ acid-soluble cement.

Multiple options are available for shifting the Delta Stim sleeves – a ball-drop system or a mechanical/hydraulic shifting tool run on coiled tubing or jointed pipe.

Integrated service, cross-trained team
Revitalizing mature reservoirs offshore poses multiple challenges, while the engineering and rig resources of many operators often are limited.

Halliburton’s Complete Solution℠ service aims to reduce the impact of this dilemma with a cost-effective approach to increasing recovery and accessing bypassed reserves offshore. Applying advanced technologies to lower-margin projects can further reduce project cost and time on location. In addition, operator opportunities can be generated at a faster pace.

The Complete Solution service integrates Halliburton’s well intervention (coiled tubing, hydraulic workover and slickline) and project management expertise with its portfolio of services to deliver cost-effective, through-tubing, rig-less solutions. Halliburton provides the engineering, job design and implementation. The process also enables operator opportunities to be generated at a faster pace. Complete Solution service teams can deliver three key packages.

To plug and abandon zones, it offers cement plugs, retainers, vented bridge plugs, and rig-less conventional completions with crane and tubing/casing jacks.

Electric line options include perforation of new zones, and deployment of vent screens and conventional screens.

Pumping services can include batch-mixed gravel packs, small high-rate water pack treatments, screenless sand control service, small acid jobs and water control service.

Complete Solution can draw on a range of Halliburton technologies, including:

- VentPac AF℠ service, which offers advantages over conventional vent screen completions. Some VentPac AF service completions are producing more than 30 MMcf/d, compared with 6 MMcf/d to 8 MMcf/d possible with conventional vent screens, while maintaining mechanical integrity of the completion;
- Antifluidization® technology to enhance proppant pack conductivity, and help control fines migration and pack plugging;
- WaterWeb® service, which uses unique polymer chemistry to help create oil-water separation in the reservoir;
- SandTrap® service, a four-step process that uses resin to provide sand control with operational simplicity; and
- AquaLinear® gravel pack fluid service, based on a viscosified fluid system used for gelling a range of water-based brines, completion and treating fluids. Its high viscosity under low shear conditions suspends sand much like a cross-linked gel and can control fluid losses during work over and completion with reduced formation damage.

Real results
In one well, the Complete Solution service approach reduced work during time and cost from an average of 12 days and $750,000 to three days and $122,000 as a result of detailed project management and use of the SandTrap service to eliminate a standard gravel pack screen and nine days of additional lift boat time.

In another situation for shallow gas completions above a depleted interval, the Complete Solution service used a single-trip, coiled-tubing-deployed, rigless vent screen completion with a high-rate water pack. During a five-day period, the choke size was increased and a peak production rate was gauged at 30 b/d of oil, 30 MMcf/d of gas and no water, with a flowing tubing pressure of 1,964 psig.

It was the third-highest peak gas production rate in the field, and the treatment paid out in about 12 days.
Halliburton and other oilfield service companies are using a new kind of ball sealers when fracturing zones.

Like conventional rubber-coated nylon (RCN) ball sealers, BioBalls, five-eighths-in. or seven-eighths-in.-diameter spheres, are pumped down to seal newly created perforations, temporarily diverting stimulation pressure to other zones. However, where RCN balls have to be circulated out of the well when the well flows and trapped in a ball catcher at the surface, BioBalls simply disappear without a trace.

BioBalls are the first in a new wave of environmentally friendly oilfield products from Santrol, whose parent company, Fairmount Minerals, initiated a “sustainable development” program two years ago, committing its companies to creating and commercializing earth-friendly, user-friendly products for the oilfield. In response, Santrol, which for years has manufactured resin coatings for proppants, turned to its expertise in plastic resins and focused on applications for soluble and degradable polymers.

“The basic idea,” said Syed Akbar, Santrol’s technical applications manager, “is that leaving less material downhole is always better, and having less material to dispose of at the surface is good, too. So, our approach is to replace as many downhole components and products as we can using polymers that dissolve or degrade after they’ve done their job.”

BioBalls were first introduced seven years ago and have evolved through several generations, each with improved performance characteristics. The most recent generation was introduced a little more than a year ago. BioBalls are now being used throughout the world, Akbar said, with demand especially strong in North America.

“We expect demand to continue growing as the market gets more comfortable with the concept,” he said.

Soluble and degradable polymers have been around for a long time, but they lacked the strength and other mechanical properties needed for downhole functions. Santrol has worked with and modified a variety of polymers, creating a new family of plastics that not only have sufficient strength, but also can be customized for specific applications, according to temperature, pressure and lifespan requirements. BioBalls, for example, are available in medium-range (MR) and high-range (HR) versions. Both versions are structurally stable up to 3,000 psi, but MR BioBalls are temperature rated at 180°F (82°C), while HR BioBalls work up to 300°F (149°C). In addition, the lifespan of the balls in-situ can be from 45 minutes to 10 hours, depending on customers’ operational plans.

A similar Santrol product Halliburton and other service companies use is zone-isolation balls. These are larger spheres, typically 1¼ in. to 2 in. in diameter, that are pumped downhole to seal the inner diameter of the workstring and isolate a horizontal zone for fracturing operations at up to 6,000 psi. Like the BioBalls, these also degrade and disappear when no longer needed, eliminating the need for shear-out ball seats and leaving nothing harmful in the workstring or hole. Soluble balls can also be used as “trip balls” to operate downhole tools.

Soluble proppants?

One patented application Santrol is preparing for the market is soluble proppant materials. Although the industry typically thinks of proppants as high-strength, long-life materials, tests have shown proppant pack conductivity can be improved by creating superconductivity pathways through the pack. To create these pathways, soluble proppant particles are mixed with the conventional proppant (preferably resin-coated particles with strong grain-to-grain bridges and low grain mobility) at a calculated concentration and dispersed into the fracture. When the well flows, the hydrocarbon-soluble proppant particles dissolve, leaving interconnected pore spaces with essentially infinite permeability. Laboratory tests have demonstrated this technology will perform successfully at closure stresses up to 4,000 psi. Santrol is conducting research and development on placement techniques for soluble proppants.

Downhole chemical-delivery containers

Precision-release containers for delivering acids or other chemicals downhole are another practical application for soluble plastics. Called chemical-delivery containers (CDCs), the tube-shaped vessels are handled like common oilfield soapsticks. By not releasing their contents for a specified length of time or until they are in a pre-defined temperature or pH environment, CDCs prevent premature product release, reducing the amount of treating chemical needed. In acidizing for example, CDCs provide precise placement at the formation, without spending acid during pump-down and
without the need for coiled tubing. So far, Santrol has commercialized CDCs from 6 in. to 12 in. in length.

**Like steel, like water**
Degradable plastics can also substitute for metals in applications requiring high short-term strength, before the component dematerializes to allow subsequent operations. An example is threaded plugs for pre-perforated production liners. The plugs allow the completion string to be run without allowing well fluids to enter the bore. When the plugs are no longer needed to seal the liner, they disappear via hydrolysis or thermal degradation, depending on the polymer formulation.

**A new genre of fluid-loss additives**
Santrol has also applied soluble-polymer technology to fluid-loss problems. Here the company offers some important product features that give operators more control over downhole performance and better results compared with conventional fluid-loss additives. Like other additives, Santrol coats the formation face to prevent further loss of well fluids. Unlike those additives, however, solubility of the Santrol additive can be precisely controlled for temperature and time for specific applications. At the appropriate time, the seal on the formation face dissolves, leaving the formation essentially unaffected and resulting in permeabilities as high as 98%.

**Dissolution and degradation**
There are two basic mechanisms by which solid components disappear downhole: dissolving and degrading. In the first, the material dissolves in a solvent (water or oil) without changing its own chemical nature. Degradation involves a significant change in chemical structure brought about by a change in environmental conditions, such as pH or temperature, or by the action of microorganisms, such as bacteria. This last mechanism is called biodegradation.

“Several factors govern solubility and degradability,” Akbar said. “In all our applications, we are looking at well-known materials in new ways, engineering their behavior to achieve practical results. In general terms, we are talking about some key molecular characteristics, including weight [molecule size], polarity, structure and crystallinity,” he said.

**Limitless opportunities**
“We think we are in the very early stages of a market with huge potential,” Akbar said. “The applications described here are the very first. As our technology continues to advance, we are certain to discover more and more ways to put this ‘disappearing act’ to work in drilling, production and remediation to save operators money, to get better results, and to be as planet-friendly and user-friendly as possible.”

Santrol, based in Fresno, Texas, south of Houston, pioneered proppant-coating with multiple layers of phenolic and other specialty resins for greater flowback resistance (proppant-pack stability) and higher conductivity. The company began offering resin-coated sand for proppants more than 27 years ago. Research and development for soluble and degradable plastics is performed at the Fresno facility. Santrol also has resin-coating plants in Roff, Okla., Troy Grove, Ill., Bridgman, Mich., Monterrey, Mexico, and Fredericia, Denmark. All the plants are ISO 9000 registered. The company also owns and operates its own aggregate mines in Wedron, Ill., and Maiden Rock, Wis., and has an extensive network of rail-linked distribution points strategically located in the United States, Canada and Mexico.

Fairmount Minerals is one of the largest producers of industrial sand in the United States, serving a range of industrial applications, including construction, glass, foundry, oil and gas, industrial coatings, abrasives and filtration. Headquartered in Chardon, Ohio, Fairmount has strategically located facilities throughout the country and operates a global distribution network.

Santrol
P.O. Box 639
2727 FM 521
Fresno, TX 77545
Tel: 281-431-0670
Fax: 281-431-0044
Web site: www.santrol.com
Extending the Productive Life of Mature Assets

Innovative approaches and advanced proppant technology are helping improve fracturing treatment results.

For decades, operators have relied on hydraulic fracturing to help make their assets more attractive to develop and produce. In fracturing, a proppant (carefully sized grains of sand or ceramic, coated or uncoated) is pumped down the well under high pressure in slurry form. The pressure fractures the rock and the proppant “props” the fracture open so hydrocarbon can flow easier after the well is put on production.

Proppant is often looked at as simply sand, but when the trucks have left the location, the fracturing fluid has flowed back, and the well is put on production; the only thing left is the proppant. Proppant is the part of the treatment that should stay behind for the life of the well and provide adequate payback for the well’s total investment.

While this sounds simple, the success of a treatment depends on how well the fracture technology answers many questions, some of which are: Did the formation fracture in the right place? Will the proppant pack allow oil or gas to flow economically? Will the proppant resist the forces trying to close the newly created fracture, or will it shatter into fine particles that hinder flow? Will the proppant stay in the fracture, or will it flow back out, damaging well equipment and causing costly downtime? And finally, will the proppant do its job during the life of the well, or will pressure cycling between shut-ins and production or increasing closure stress cause grain failure and/or flowback?

The Oilfield Technology Group (OTG) of Hexion™ has utilized its core strength of several decades of fracturing experience to develop pioneering technologies to address the concerns of its customers seeking answers about how to maximize their investments.

New way to measure fracture geometry

The “propped height” of a fracture is critical – whether it is confined to the producing zone (the desired result) or extends upward or downward into other zones. For years, one method to determine propped fracture height was to add radioactive tracers to the proppant slurry and use standard logging tools to measure the location of the radioactivity. But radioactive tracers pose a number of safety and environmental concerns, and stringent regulations sometimes limit their transport.

Hexion’s breakthrough technology – PropTrac™ H – is a safe alternative that not only provides more accurate post-treatment data, but can also provide data during the life of the well (Figure 1). In this technology, a non-radioactive “tag” is incorporated into the resin coating of the proppant. This non-hazardous, environmentally safe, coated proppant can be transported and applied without restrictions as with all resin-coated proppants. Once the proppant is in the well, a standard logging tool is used with a fast neutron source. The neutron source activates the tag, and the tool detects and reports the short-lived radiation.

PropTrac provides a picture of the fracture height in the near wellbore area since the tag is in the coating of the proppant itself and not the fluid. This enables Hexion’s customers to perform well diagnostics to determine what intervals actually have proppant based on the fracture designs. Since the tag only responds when stimulated by the neutron source, the logging process can be completed free of the timing constraints associated with the half-life of radioactive tracers. It can also be repeated as often as desired to monitor fractures during the life of the well rather than a one-time usage. The material can be utilized as “normal” resin-coated proppant for “insurance” purposes. If the well does not respond as desired, even months or years later, it can be logged to determine what zones were actually fractured with PropTrac material.

Extreme proppant performance properties

The harsh conditions in high-pressure, high-temperature (HPHT) wells place enormous stress on proppants. Most operators have moved from sand proppants to more durable ceramics, but even ceramics can shatter into abrasive particles that reduce hydrocarbon flow and flowback to damage surface equipment.

Customers in south Texas approached Hexion to develop a resin system that could answer the flowback challenge of cyclic stress from their HPHT wells. The previous systems did not allow for the affect of lengthy production operations, curing of the resin as it was being pumped in the well and the high temperature summer storage conditions in field storage bins in south Texas.

Hexion’s answer to this challenge was its patented XRT CeraMax™ product line — XRT for Extreme Resin Technology that, in

Figure 1. PropTrac provides a more accurate view of propped fracture height utilizing a unique non-hazardous, environmentally acceptable technology developed by Hexion.
addition to addressing the above concerns, also provides the highest fracture flow capacity in the industry.

The XRT Ceramax resin completes its curing under the high temperatures and pressures within the propped fracture. Unlike conventional resin-coated proppants, XRT can be shipped, stored and pumped at elevated temperatures without losing its ability to bond in the fracture.

XRT Ceramax excels at surviving multiple cycles of shut-ins and production that would crush conventional proppants. If, however unlikely, the XRT pack does break under extreme conditions, the bond can “heal” itself and regain its ability to limit proppant flowback. This translates into proppant flowback control and excellent fracture flow performance during the life of the well – exactly what operators need.

Because of the length of time it takes to pump many larger treatments today, the amount of curable resin remaining on conventional proppants is diminished. XRT products have the unique and patented benefit of withstanding the elevated temperature affects occurring during long pump times. This benefit is also a primary reason XRT is sought out for fracturing in long horizontal stimulation treatments.

**XRT Ceramax case history**

A south Texas operator experienced severe proppant flowback and disappointing production results in its HPHT wells after pumping conventional resin-coated proppants. The situation forced the operator to keep flowback equipment on site to reduce damage to surface production equipment, and it also led to costly wellbore cleanouts with coiled tubing. Switching to XRT Ceramax eliminated proppant flowback and increased production.

**Answering customer needs**

Waterfrac treatments are widely applied, especially in low-permeability reservoirs. A waterfrac uses a thin fluid (sometimes called slickwater) and proppant to fracture wells where temperatures and pressures are not extreme. The success of these treatments requires the proppant to be transported deep into the fracture and maintain the fracture flow capacity during the lifetime of the well.

The most predominant problem that occurs because of improper waterfrac proppant selection is proppant crushing. Proppant crushing occurs when the fracture closure stress exceeds the strength of the proppant placed in the fracture. This leads to fines generation, resulting in lower fracture flow capacity and diminished well production rates.

Hexion’s Prime Plus™ is an advanced, field-proven partially cured resin-coated proppant in the 40/70 mesh size that is most appropriate for wells with closure stresses between 6,000psi and 10,000psi and bottomhole temperatures below 450°F (232°C). Designed for the waterfrac basins of North America, Prime Plus resin is applied to the highest quality sands to provide the best properties of any waterfrac proppant in the industry (Figure 2).

Prime Plus reduces proppant crushing and fines migration in several distinct ways. The resin coating provides additional strength to individual grains, generates uniform stress distribution throughout the pack and mitigates fines migration by encapsulating loose fines within the resin coating.

Get the Results You Expect™

At Hexion, we recognize fracturing is a key component of long-term well productivity. A superior frac treatment depends on having the right technology and expertise to deploy products the right way. Hexion offers the broadest range of thermoset resin technologies, plus unmatched technical support – our job is not to just manufacturer resins, it’s to help operators get the results they expect.
CURRENT PRICE VS. FUTURE COST

Advancing technology to drive remediation effort is a key component to the process.

It is never too early to plan for the inevitable decline in well and reservoir productivity. Many of today’s remediation efforts would be more effective if the eventual need for re-energizing the reservoir or returning to bypassed zones had been given more consideration in the original development plan.

New technologies are aimed at completing today’s wells in a way that will extend well life and flatten the decline curve, moving the need for remediation farther into the future and making it possible to do a better job when remediation is necessary.

Technology is important; so are economic realities. Higher oil and gas prices will make more reserves that are already located more valuable, but costs will rise, too. In developing mature producing assets, current product price vs. future cost will be a fundamental challenge, according to one operator.

Inflow control devices
A key challenge in mature asset remediation is managing flow into the wellbore. Often, the older a well or field gets, the greater the challenge to minimize water production and facilitate the flow of hydrocarbons. Differences in influx from the reservoir can result in early water/gas breakthrough, leaving valuable reserves in the ground.

Better flow management, even in the early life of a well and reservoir, can delay the need for remediation and boost production and recovery.

Halliburton’s EquiFlow™ inflow control devices (ICD) are designed to improve completion performance and efficiency by balancing inflow throughout the length of a completion. It can reduce inflow from high-productivity zones while stimulating low-productivity zones.

The tool helps reduce water and gas production associated with heel-toe effects; the breakthrough of water and gas; permeability differences; and wells producing high viscosity oil.

An EquiFlow ICD installed as a part of the completion string is typically placed at the end of a sand screen in unconsolidated sand reservoirs (Figure 1). Prior to installation, simulation software optimizes the configuration of the device.

Figure 1. The EquiFlow inflow control device is designed to improve completion performance and efficiency by balancing inflow throughout the length of a completion.

Figure 2. The EquiFlow Oil Selector valve helps control inflow based on changes in the reservoir fluid, significantly reducing unwanted water or gas while helping increase oil production.

Advancing technology to drive remediation effort is a key component to the process.
**Novel idea reduces water cut**

Most multi-zone wells would benefit from inflow control, which can limit maintenance cost, accelerate production and maximize recoverable reserves.

Halliburton’s novel approach to reducing water cut is to engineer part of the completion string to react to the presence of water in the surrounding formation fluid. Using the simple principle of buoyancy, balls able to float in water but not in oil can rise to seal off production nozzles at times of high water cut without the need for electrical or mechanical parts.

Water breakthrough occurs on the low side of horizontal completions. Flotation balls rise and seal off nozzles as the water cut increases until inflow through the active chamber is shut-off. The gas management configuration works in much the same way, though gas breakthrough occurs from the high side. As gas cut increases, the flotation balls sink in gas to seal off the inflow nozzles.

The EquiFlow Oil Selector™ valve allows production control without cables, additional installation time or a reduction in pipe diameter (Figure 2).

The valve helps control inflow based on changes in the reservoir fluid, significantly reducing unwanted water or gas while helping increase oil production.

The valve is easy to install and effective when combined with zonal isolation systems such as Halliburton’s Constrictor™ annular barrier tools or Swellpacker™ isolation systems.

Installed as a unit in the end of each screen joint to limit inflow of gas and water at that particular point, the EquiFlow Oil Selector valve can be configured for a specific reservoir, yet it is simple, robust and easily combined with sand screens.

The valve consists of a flow chamber on the end of a sand-control screen joint, where the inflow to the valve is from the annulus between screen and base pipe. The outflow passes through a number of nozzles penetrating the base pipe. The valve has two chambers – bypass and active. For water breakthrough, the active chamber contains balls with the same density as the formation water. For gas breakthrough, the balls have a lighter density than the oil.

A separator ring limits passage of balls to the bypass part of the chamber.

**Maintaining zonal isolation**

Complete zonal isolation is a must in mature field development, where complex pressure regimes combined with small pockets of oil and high potential of water or gas encroachment can severely affect a well’s producing potential.

An effective zonal isolation solution to the requirements of water and gas shutoff, multizone stimulation, cement integrity and openhole intelligent completions is Halliburton’s Swell Technology™ systems. These systems are unique in terms of simplicity. There is no need for specialist on location, no setting tools, no pressure up, no rotation or overpull required to set or activate swell technology. It is as simple as running the tools in the hole and letting them swell.

The Swellpacker OBM isolation system reduces risk and maintains a maximum performance envelope while running completions in oil-based muds. Swellsim™ software simulates Swell Technology product response and performance in the operator’s well conditions. These technologies have now enhanced more wells than expandables and surface-controlled completions together.

**Maintaining cement integrity**

Drilling new wells or sidetracking existing wells in mature fields can create significant challenges to getting the cement properly placed. The Cement Assurance tool maintains the cement integrity by filling up void spaces in the cement such as mud channels or the micro annuli formed by debonding of cement from the pipe (Figure 3). The Swell Technology systems are able to self heal and can react to changes in the wellbore during time. The Cement Assurance tool can remain passive in the cement sheath for years and activate as a leak in the cement occurs as a result of years of pressure and temperature changes, to once again form a perfect seal.

**Figure 3. The Cement Assurance tool helps maintain the cement integrity by filling up void spaces in the cement such as mud channels or the micro annuli formed by debonding of cement from the pipe.**
Ensuring Right Chemicals, Right Time, Challenging

Making sure Halliburton has the right amount of the right chemicals on hand for jobs they do in North America is a big task. Univar USA’s Oilfield Services Group, which has been taking care of most of the oilfield services giant’s chemical needs for more than a decade, supplies Halliburton with a big part of those chemicals.

Univar USA warehouses, repackages and delivers 300 chemical products – more than 150 million lb annually – to 73 Halliburton field locations throughout the United States, Canada and Mexico, said Fred Chandler, general manager for the Oilfield Services Group. The chemicals come from suppliers worldwide and include proprietary Halliburton products and commodity chemicals.

“At any given moment, we have $12 million in chemicals stocked at our own locations or on consignment at Halliburton facilities, and on an average day, our facilities together deliver more than 500,000 lb of chemicals to Halliburton service locations,” Chandler said.

Univar USA’s main oilfield services operation is in Mesquite, Texas, near Dallas, where the company has a 65,000-sq-ft (6,039-sq-m) facility plus a 3-acre tank farm with 45 bulk tanks holding more than a quarter of a million gal. The company also utilizes seven Univar packaging operations, in Houston, Borger and Odessa, Texas; Oklahoma City, Okla.; and Casper and Rock Springs, Wyo. All of the packaging operations have bulk liquid storage capability. At Mesquite and other facilities, liquid chemicals are received in bulk and repackaged as needed into a variety of tote tanks, drums and pails for shipment to the field. From the eight packaging operations, the company’s network extends to 18 stocking points at key locations in Texas, New Mexico, California, Louisiana, Oklahoma, Wyoming, Alberta, Canada and Matamoros, Mexico. Dry products as well are warehoused and delivered from these 18 locations.

Univar handles an average of 900 orders per month from Halliburton, Chandler said, with a little more than half shipping out of the main Mesquite facility and the rest being delivered from the company’s stocking locations. There is also a sizable export effort for proprietary Halliburton products at Mesquite.

“Each month, we package and label almost 2 million lb of Halliburton proprietary products for international shipping by Halliburton’s export contractor,” Chandler said.

The company maintains a fleet of 3,000 330-gal tote tanks to shuttle chemicals to the field (Univar USA also packages in steel and polyethylene drums and other common containers). Every day, at least 10 tractor/trailers leave the Mesquite plant alone, on the way to field stocking points.

Fast response

Response time is critical for Halliburton, Chandler said.

“Time is money in the oilfield, and holding up a stimulation or cementing job to wait for chemicals would be costly. So, we have to be able to react quickly, and we do. Our normal turnaround from receipt of an order is one or two days, and that includes even the biggest orders, which can involve 400,000 lb of chemicals, or 10 full truckloads, going to a single field location. Our multiple packaging plants and stocking points, combined with our 24-hours-a-day, 7-days-a-week operations at all locations, enable us to keep up with Halliburton’s job-scheduling requirements,” he said.

When Halliburton introduces a new oilfield chemical, Univar USA can have it in place throughout its North American network of stocking points in two weeks or less. Don Nixon, operations manager, is the Oilfield Services Group’s specialist in transportation and logistics. An experienced problem-solver, Nixon keeps everything moving. In addition, he locates and qualifies new commodity chemical suppliers when required to meet Halliburton’s changing needs.

“Halliburton is constantly improving their technology and services, and we are tasked with helping them phase out obsolete products and phase in new ones. It’s an ongoing process, and we’ve got it down to a science,” Nixon said.
Careful planning is another key to Univar USA’s fast response, and Joanne Tompkins, industry manager of the Oilfield Services Group, drives that area. Tompkins, who has been in the business for more than 30 years, oversees sales and pricing for all of the Halliburton business. To keep the operation running smoothly, Tompkins visits every Halliburton region at least once per year.

“Each Halliburton service location is unique in terms of products, packaging and scheduling,” she said. “By going out and talking to their people in the field, we can see their operations first hand and make sure we are delivering products in the most economical way. We can spot opportunities to improve our services, and we can identify and resolve even subtle issues that can make a positive difference for our customer. When it comes time to deliver, we don’t run into unexpected wrinkles, because we’ve already ironed them out.”

Chandler also pointed to another reason for his company’s excellent performance record: “We’re really good at chemicals packaging and distribution, because that’s our specialty. It’s all we do. There’s always a temptation to diversify into blending or other services, but we have decided to leave that to other Halliburton vendors. We just want to do what we do and do it better than anybody else.”

Going global for Halliburton
To date, Univar USA’s Halliburton support has been confined to North America and the limited amount of export packaging at the Mesquite hub, but the company has plans to serve its prime customer worldwide. The company is building a new export facility in Houston that should be operational late in the first quarter of 2008.

“Our plan is to take our North America model global in order to serve Halliburton wherever they are working,” Chandler said.

It probably won’t take long, because the company won’t have to build an international network from scratch. Earlier this year, Univar USA acquired CHEM CENTRAL, another major industrial chemicals distributor. CHEM CENTRAL had distribution centers in Univar USA’s current markets (U.S., Canada, Mexico) plus South America, Australia and the Caribbean, with joint ventures in China, Asia Pacific, India and the Middle East.

In addition, Univar USA’s parent company, Univar N.V., is an international chemicals distribution giant, with annual revenues of $8 billion.

“We believe we will be able to leverage Univar’s existing global network and our proven oilfield organization to rapidly expand our service coverage into major international oil and gas basins,” Chandler said.

A true partnership
Univar USA’s partnership with Halliburton goes back to the early 1990s, not long after Halliburton made a strategic decision to close its own warehouse in Duncan, Okla., and outsource chemical storage and distribution to others. Pioneer Chemical, a small, newly established chemical distributor, was given responsibility for a few of Halliburton’s chemical products. During the next several years, the number of products grew rapidly, and Pioneer was eventually acquired by Univar USA and became the Oilfield Services Group.

“We feel that we do a very good job for Halliburton, but it’s important to point out that Halliburton makes that possible,” Chandler said. “Their purchasing people are demanding, but they are also extremely professional and helpful. They make sure we have all the information we need so we can respond as needed. In addition, we have a mutually beneficial, long-term agreement that enables us to plan for and invest in the equipment, facilities and people we need to handle their business efficiently.”

To keep the partnership on track, the two companies have an annual meeting attended by more than 50 Univar USA personnel and people from Halliburton’s purchasing group.

“A primary purpose of these meetings is to make sure we understand Halliburton’s goals,” Chandler said. “Then we go over any problems or issues that came up over the previous year and discuss ways to improve the processes involved. It’s a process that serves both of us very well.”

Polyethylene drums and 330-gal tote tanks in front of bulk liquid tanks at Univar USA’s Mesquite, Texas, facility

Univar USA, Inc.
Oilfield Services Group
100 North Sam Houston Road
Mesquite, TX 75149
Tel: 972-329-8670
Toll free: 1-888-329-9376
Fax: 972-289-8464
Like people, technologies are more effective when they work together. The impact of an individual technology is leveraged when teamed with complementary tools to solve a multi-faceted problem.

Stimulating mature reservoirs is seldom simple. Well characteristics and reservoir properties vary widely, often over multiple intervals in the same wellbore.

Halliburton has a range of technologies to make well stimulation more effective and increase the value of a mature producing asset. Stimulation success depends in large part on systematic planning and the ability to determine what really happened in the reservoir as the job was placed. Fully exploiting the capabilities of today’s stimulation tools requires an understanding of their interdependence and how they will affect reservoir and field performance.

For re-energizing mature producing assets, three key Halliburton services work together to provide that comprehensive knowledge and guide job execution:

• SigmaSM service is a process that guides application of the best stimulation technology to improve production, recovery and profitability;

• StimWatch® service is a near-field stimulation monitoring capability that helps optimize treatment and job placement; and

• ExactFrac® service, a microseismic fracture mapping service, reveals the details of hydraulic fracture propagation from a far-field perspective as it happens.

As more technology options are available and new wellbore configurations pose more complex challenges, integrated workflows become the best way to optimize the performance of a reservoir stimulation job.

Halliburton executes this integrated strategy by first optimizing the fracture treatment through the Sigma process, then monitoring and managing the treatment using StimWatch service. The ExactFrac service provides performance data that can be used to update frac and reservoir models, design future treatments and select infill drilling locations.

**Sigma service: data, knowledge, perspective**

The list of high-impact technologies available to improve reservoir performance is long, covering the areas of drilling, logging, perforating, zonal isolation, completion, fracturing and more. It is the integration of these advances, however, that will help realize their full potential to reduce cost and improve recovery.

Understanding the interdependence of all the technologies that affect the success of field development strategies requires a focus on reservoirs and total solutions instead of on wells and discrete services.

That need drove the development of Halliburton’s Sigma process, designed to boost reservoir economic performance and improve profitability, the critical twin goals of mature asset remediation efforts. Sigma focuses Halliburton’s integrated structure, global experience and high-value-adding technology on achieving those objectives.

The process immediately proved effective. In early results, one operator gained a $2 million benefit in the first six months. Another operator realized a 20% increase in gas well production compared with offset producers.

Sigma service is a comprehensive analysis of the design, implementation and effectiveness of a well plan. The process also creates a calibrated log model that can be used to determine reservoir potential and is continuously updated.
Key features of the system that lead to improved reservoir understanding include:

• benchmarking;
• enhanced reservoir description;
• an integrated well design;
• superior quality assurance and quality control;
• on-site pressure analysis;
• comparison of actual and predicted results; and
• a data-based update of reservoir models.

Dedicated personnel and resources make up the Sigma service team, which has a strong commitment to leading-edge technology, including software and data management. Gathering a range of expertise ensures the process is based on a multi-well perspective. Available to the reservoir-focused, iterative process is a range of Halliburton products and technology, including MiniFrac™ analysis software, the StiMRIL™ process and others.

Use of the Sigma process can improve field performance in several ways, in addition to increasing cumulative production.

If a reservoir is performing below established benchmarked rates, Sigma service could help improve productivity. Operators of marginally commercial properties can use Sigma service to identify less expensive completions that would boost production rates. The detailed nature of the process makes it appropriate for reservoirs where completions were not satisfactorily performed.

A comprehensive Sigma analysis can also be used to thoroughly evaluate new technology or provide another perspective on treatment design and implementation. Operators of mature and marginal fields that may not have sufficient engineering resources for a full reservoir evaluation can rely on Sigma service for that evaluation.

The process

The Sigma service process begins by benchmarking the specific reservoir or area. Individual wells relevant to the study group are identified and their reservoir characteristics described using available data. Industry-accepted software models match the theoretical reservoir parameters to actual well production. Stimulation treatment parameters are defined where data are available to describe production performance.

Initial benchmarking has two primary purposes: to establish a historical perspective on expected production in the area, and begin characterizing the reservoir and rock properties.

Following benchmarking, each facet of the drilling and completion operation is reviewed for potential impact on

StimWatch stimulation monitoring service enables on-the-fly optimization of the treatment, post job follow-up and better future treatments.
Extending the Productive Life of Mature Assets | 2007

the treatment, including the casing plan, open-hole logging and formation evaluation procedures, the zonal isolation program, the completion assembly, the perforation program, and where possible, the stimulation program.

Access to the operator’s well files and production records is needed to review pressures, open-hole logs and treatment reports.

For proposed new wells, the process uses economic reservoir description technologies such as Halliburton’s Magnetic Resonance Imaging Logging (MRIL®) and Reservoir Description Tool (RDT™).

Following benchmarking, every aspect of the well completion is analyzed to determine its possible impact on the stimulation treatment. Any operation that might compromise the best stimulation procedure is excluded or replaced with a less-risky alternative.

Following a Sigma service-based treatment, operational performance and well performance are reviewed. The main reservoir, treatment and production parameters used for benchmarking are updated with data from the treated well. Reconciling conclusions formed during benchmarking with those based on the new data can improve subsequent treatment design.

The operator’s evaluation of the treatment also is incorporated into subsequent treatment designs. It focuses on the mechanical aspects of how the treatment was performed at the surface and how the treatment met the original design goals in the reservoir.

After each treatment, the status of the overall Sigma process is updated and presented to the operator.

StimWatch service: the value of real time
StimWatch stimulation monitoring service enhances real-time monitoring and guidance of stimulation treatments. It provides real-time information that allows on-the-fly optimization of the treatment, post job follow-up and better future treatments.

The service uses fiber optic distributed temperature monitoring system to provide continuous temperature profiles over the length of the well throughout the treatment. Those profiles provide a direct indication of how the treatment is spread along the wellbore.

Remediation of mature reservoirs is an especially appropriate use of StimWatch service. Wells in which multiple pay intervals are to be treated simultaneously and wells where multi-stage stimulation jobs require a diverter are good candidates for the monitoring service as is the treatment of large pay intervals.

The service can be used in bottomhole temperatures up to 572°F (300°C).

Advantages of StimWatch service include:
- visual indication of where stimulation fluids are entering the formation;
- maximum treatment efficiency, with the ability to halt the job and redesign or discontinue it if the treatment is going out-of-zone;
- information that aids in identifying problems during the job and enables real-time decisions to make changes to the procedure;
- ability to monitor the effectiveness of diversion processes;
- improved design of subsequent jobs;
- multiple bottomhole pressure monitoring systems; and
- wellbore temperature profiles provided every 1.6ft (0.5m) with profile update times as fast at 14 seconds.

ExactFrac mapping service shows a near-symmetrical bi-wing fracture with minimal out-of-zonal fracture height growth.
Field report

A California operator wanted to stimulate a well perforated in multiple sand and shale horizons. Halliburton recommended a multi-stage sandstone acid treatment with diverter. To understand the performance of the diverter and monitor treatment of all zones, a retrievable fiber optic system was included as part of the acid stimulation.

The StimWatch monitoring service allowed the operator to view the placement of the acid treatment in real time as well as make instantaneous changes in the stage size and pump rate. The service enabled seeing where fluid was exiting the formation. Thermal tracers were used to quantify fluid placement (% injection distribution) to confirm the intervals were sufficiently treated. The initial diverter on this job was not effective and was replaced with an alternative diverter to successfully stimulate the entire interval.

ExactFrac service: better understanding, decisions

ExactFrac real-time microseismic fracture-mapping service provides detailed information about hydraulic fracture propagation as it happens, bringing the big picture into focus and allowing real-time decision-making during well stimulation. Better understanding of the reservoir means improved treatments, more effective future drilling decisions and better long-term exploitation strategies.

ExactFrac service provides an accurate “live” view of stimulation operations; it also improves reservoir understanding that helps make better operating and treatment decisions in the future to optimize the reservoir’s life cycle performance.

The service uses field-proven tri-axial seismic sensors to deliver high-quality data fidelity for sharp, accurate images that give a true picture of reservoir characteristics.

Real-time 3-D fracture mapping confirms the success of multi-zone fracturing and provides insight into geophysical, geological and fluid flow dynamics for improved reservoir modeling. Accurate fracture characterization by the ExactFrac service helps ensure optimal hydraulic fracture placement and improves program design.

Better reservoir definition also makes it possible to optimize well spacing and well placement in the reservoir. Knowing drainage patterns, drilling or refracturing a well in an area of the reservoir that has already been drained can be avoided.

Real-time communication between the TechCommand® technical center and the ExactFrac service unit facilitates the most advanced, live fracture diagnostics possible. Watching fracture propagation live reveals the cause of many of the pressure responses.

Configured to monitor seismic activity from two wells, ExactFrac service can deliver greater resolution on the treated well. Combining the service with VSP vertical seismic profiling, check-shot, WaveSonic® crossed dipole tool and zonal isolation can streamline the operation.

Fracture azimuth, length and height are clearly defined by ExactFrac service, revealing details that confirm a successful frac job, allow frac model calibration and help refine the reservoir model.

Operating capabilities reach to 356°F (180°C) and 25,000 psi.

In addition to the real-time wellsite processing, the ExactFrac service deliverables include a detailed report and 2-D and 3-D visualizers of time-tagged microseismic event locations synchronized with stimulation treatment data. Combining ExactFrac service with StimWatch service for distributed temperature measurements in the near-wellbore region delivers solutions for near-field and far-field fracture propagation monitoring.

ExactFrac mapping service shows a bi-wing fracture with extensive vertical out-of-zonal growth because of probably fracture propagation along the fault plane.
THEY SAY CHALLENGE BUILDS CHARACTER.

WELL, IT ALSO HELPS CREATE BETTER TOOLS AND TECHNOLOGIES.

To operators around the world, Halliburton says “Thank You” for entrusting us with your major completion and production projects. And thanks for challenging us with the toughest obstacles you face — including deeper wells, deeper water, higher pressures, higher temperatures, more zones, narrower zones and environmental sustainability.

Wherever your project, know that Halliburton is committed to technical advancements that increase efficiency, recovery, safety and reliability. For more information, visit www.halliburton.com/reliability, or e-mail us at reliability@halliburton.com.