Positive Reactions in Carbonate Reservoir Stimulation

Carbonate reservoir stimulation has improved significantly with the application of innovative viscoelastic surfactant chemistry to acidizing. This simple, novel, nondamaging acid system has been used in both matrix and acid-fracturing stimulation treatments, and has led to substantial injection and production increases—in some cases adding millions of dollars of production per month—in many oil and gas fields worldwide.

Carbonate reservoirs contain about 60% of the world's oil reserves and hold huge gas reserves.\(^1\) Yet experts believe that over 60% of the oil trapped in carbonate rocks is not recovered because of factors relating to reservoir heterogeneity, produced fluid type, drive mechanisms and reservoir management. The quantity of trapped oil becomes even greater in carbonate reservoirs producing heavy oil—API gravities below 22°—where untapped reserves exceed 70%.\(^2\) A considerable percentage of these resources currently are not accessible because of economic and technological barriers.

Limestone and dolomite reservoirs present tremendous completion, stimulation and production challenges because they commonly contain thick completion intervals with extreme permeability ranges. Often, they are vertically and laterally heterogeneous, with natural permeability barriers, natural fractures and a vast array of porosity types, from intercrystalline to massive vugular and cavernous porosity. In these reservoirs, engineers and geologists know that the rock that is penetrated by the drill bit and evaluated through coring and logging may not fully represent the reservoir at a larger scale.

Completion and stimulation engineers must consider these complexities during the design stage and when selecting appropriate technologies to optimize production and hydrocarbon recovery. Carbonate reservoirs are stimulated using acid—predominantly hydrochloric acid (HCl)—to create conductive pathways from the reservoir to the wellbore, and to bypass the wellbore region that has been damaged during drilling and cementing. Acid-fracturing

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\(^3\) Skin is the dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates that some damage or influences are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.
techniques are also used in areas where the natural permeability of carbonate reservoirs is insufficient to promote effective matrix acid stimulations. The goal in carbonate reservoir stimulation is to effectively treat all latent productive zones, reducing formation skin and improving productivity or injectivity.

Matrix stimulation is even more complex when there are multiple intervals having significantly different permeabilities. High-permeability zones preferentially take the acid and leave zones with lower permeability untreated. These untreated intervals mean less production and lost reserves. This nonuniform stimulation can also lead to high drawdown, causing early and undesirable gas and water production. For these reasons, acid-diverting techniques, both mechanical and chemical, have been developed and recommended to ensure uniform stimulation of carbonate reservoirs.

However, many placement and performance problems complicate the acidizing process. This article examines the development and use of a new self-diverting acid system based on non-damaging viscoelastic surfactant (VES) technology. Also included is a general discussion of matrix acidizing, acid fracturing and a description of challenges encountered when stimulating carbonate reservoirs. Case studies from around the world demonstrate the overwhelming success of this new technology.

Acidizing Is Not Basic
Acid stimulation in carbonate rocks involves a reaction of hydrochloric acid with the minerals calcite and dolomite [CaCO3 and CaMg(CO3)2 respectively], producing calcium chloride [CaCl2], carbon dioxide [CO2] and water [H2O] in the case of calcite, and a mixture of magnesium chloride [MgCl2] and calcium chloride in the case of dolomite. As live acid is introduced, more CaCO3 dissolves, creating small conductive channels, called wormholes, which eventually form a complex, high-permeability network.
The Damköehler number depends on a variety of factors, including the specific rock characteristics, acid-system properties, injection rate and temperature.

Typical matrix treatments often require low injection rates, and therefore pure hydrochloric acid cannot be used because rapid acid spending—or consumption—severely limits the acid penetration distance. This causes face dissolution and fails to create a wormhole network long enough to effectively bypass the damaged zone around the wellbore. For this reason, acid systems often include additives that delay, or retard, the acid’s reaction with CaCO₃, thus extending the reaction time.

Chemical retardation techniques typically include emulsification and formation of gels. Depending on the acid concentration and the pumping environment, an acid-diesel blend, SXE SuperX emulsion for example, can be highly effective because it slows reaction times by a factor of 15 to 40 compared with conventional HCl acid systems. The dissolving power—a function of acid strength—of the HCl-base SXE system, coupled with slower carbonate reaction time—retardation—creates deeper wormholes and makes the emulsion less corrosive to steel casing and tubing. The corrosion threat to steel tubulars, especially at higher temperatures, can be reduced further by adding inhibitors to acid systems. Retardation of the reaction and corrosion minimization can also be achieved by using organic acids, but because of their cost and lower dissolving capability, their use is limited.

Many treatment-design factors must be considered to optimize reaction rate and cleanup, including acid strength, temperature, pressure, leakoff rate and the rock composition. Controlling the acid-reaction rate in the target formation is critical to the success of acid-stimulation treatments in carbonate reservoirs. The acid system must bypass the damaged zone to open up reservoir communication to the wellbore but must also minimize damage to tubulars and clean up sufficiently after the acid has spent. Additives play a key role by limiting fluid loss, minimizing the generation of emulsions and precipitates, regulating viscosity, decreasing corrosiveness and improving cleanup.

Even a well-designed matrix-acid fluid system does not guarantee a successful stimulation. The stimulation fluid must be properly placed in the selected intervals. Acid systems are generally pumped downhole through the casing or tubing—a technique called bullheading—or delivered through coiled tubing. In bullheading operations, undesirable preferential placement of acid into high-permeability zones leaves intervals with lower permeability untreated. In some cases, high-permeability water-producing zones take a disproportionate amount of acid, increasing undesirable water production and associated water-disposal costs.

Mechanical-diversion techniques, such as use of ball sealers or coiled tubing with straddle packers, are widely used, but may not always be feasible or recommended (above right).

Mechanical methods are not very effective in the stimulation of long horizontal and extended-reach wells. Conventional chemical-diversion methods include nitrogen foam, bridging agents like benzoic acid flakes and crosslinked polymer gels. These methods temporarily plug high-permeability carbonate zones to effectively divert the treatment fluids to zones of lower permeability. Chemical-diversion methods vary in effectiveness. Sometimes temporary plugs become permanent, and the reservoir that was meant to be stimulated becomes damaged, diminishing well productivity.

A common chemical-diversion technique uses polymer-base gels. These acid systems use reversible pH triggered crosslinker additives to alter the viscosity of the fluid at critical times during an acid treatment. For example, SDA Self-Diverting Acid is a polymer system mixed with HCl. It initially has a low viscosity to allow easy pumping, but once this fluid enters a carbonate formation and when the acid spends, the polymer crosslinks when the pH reaches 2, increasing its viscosity. The increase in gel viscosity restricts further flow of new acid through...
the wormholes, thereby diverting fresh acid to zones with lower permeabilities, and eventually to other zones. As the acid continues to dissolve the rock, pH increases. Once the pH rises to about 3.5, the gelled acid breaks, reducing the viscosity and enabling fluids to flow back and clean up.

Polymer-base acid systems have several drawbacks. Independent studies by Stim-Lab, FRAC TECH Services, L.L.C., Saudi Aramco and other companies have shown that conventional polymer-base acid systems obstruct wormholes and could damage the formation. Cleanup of fractured wells was also systematically studied using flowback analysis and showed cleanup at less than 45%. Because of a narrow pH window, this crosslinking and breaking phenomenon can be difficult to control, especially in treatments with several stages of different fluids. Moreover, the stability of polymer systems degrades as the temperature increases. This instability hinders proper diversion or, at worst, permanently damages the formation to the point of preventing flow. Complicating matters even more, in sour environments where hydrogen sulfide \([H_2S]\) is present, formation damage and scaling problems can occur when metal crosslinker additives react to precipitate sulfides.

A Unique Fluid Emerges
The potential damaging effects of polymer-base stimulation fluids prompted researchers at the Schlumberger Product Center at Tulsa, Oklahoma, USA, to explore the use of viscoelastic surfactants (VES) in hydraulic-fracturing fluids, leading to the introduction of ClearFRAC polymer-free fracturing fluids in 1997. Subsequent R&D led to the development of VES molecules tolerant to higher temperatures. In 2001, the ClearFRAC HT fluid was introduced to extend the practical operating temperature to 275°F \([135°C]\).

More recently, Schlumberger applied VES chemistry to produce a polymer-free acid called the VDA Viscoelastic Diverting Acid system. The viscoelastic-surfactant molecule used in the VDA system is made up of a hydrophilic head composed of positive quaternary ammonium groups, and a negative carboxylate group with a long hydrophobic tail that is a hydrocarbon chain. While being pumped down the tubing or casing, the VDA fluid system—a blend of HCl, viscoelastic surfactant and common additives required for acid treatment—maintains a low viscosity. The amount of acid in the mixture determines the system’s initial viscosity (above right).

### VDA fluid viscosity response.

The mixed HCl concentration largely determines the viscosity of the VDA fluid as it is pumped downhole (top). The VDA fluid viscosity decreases when mixed with high concentrations of acid and is often designed with 20 to 28% HCl, but lower concentrations can also be used. The reaction of HCl with the carbonate formation increases pH and provides CaCl₂ brine as a reaction product. The brine reacts with the viscoelastic surfactant and viscosifies it (bottom). This in-situ viscosity response effectively diverts new acid to other wormholes and to other zones.

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As the acid is consumed through the reaction with calcite or dolomite, the surfactant gels. Two factors trigger the gelation process. When the acid spends, the increased pH allows the surfactant molecules to come together and form long structures called micelles, in which the hydrophilic heads point outward and the hydrophobic tails point inward. Dissolution of CaCO₃ in HCl results in the formation of CaCl₂ brine, which further stabilizes the worm-like micelles. The micelles continue to grow longer and become entangled above a critical concentration of the surfactant, forming a mesh structure and producing a highly viscous, elastic gel. The increased viscosity of the gel further reduces flow into existing wormholes and fissures within the treated zones, thereby providing effective in-situ acid diversion to unstimulated, low-permeability and damaged zones. The viscosity of the spent VDA fluid is related to several factors, including temperature, and to the initial percentages of both acid and surfactant.

After a treatment, the surfactant gel breaks down on contact with produced oil, condensate and mutual solvent preflush flowback, or when diluted with produced formation brine during flowback. During breakdown, the elongated micellar structures are reduced to spherical micelles, and the fluid system attains a low viscosity because the spherical micelles do not entangle. A preflush or postflush solution of mutual solvent enhances the breakdown of the gelled surfactant and promotes quick cleanup.
The new acid system can be used to stimulate wells that have a bottomhole static temperature up to 300°F [149°C].

Prior to its first use, the effectiveness of the VDA system in treating carbonate rocks was documented in simultaneous multicore flow tests. Schlumberger and Stim-Lab compared several acid systems for their diversion and retained-permeability characteristics, including straight hydrochloric acid as a baseline, a polymer-base acid, a foamed acid and the VDA fluid system. The tests showed that the straight acid penetrated only the most permeable core, while the VDA system increased permeability in all cores because it successfully diverted acid to the lower-permeability cores. Computed tomographic (CT) cross-sectional imaging employed at each inch along the length of the cores demonstrated the changes in pore structure due to acidizing above.

**Multicore testing.** Several acid systems were tested for diversion effectiveness at 150°F [67°C]. Each test involved the simultaneous treatment of three cores of different initial permeabilities, while measuring the pressure drop across the parallel assembly of cores. After a core-flow test, a computed tomographic (CT) cross-sectional image of the core was obtained at each inch along the length of the cores to assess the changes in pore structure caused by acidizing. Pressure-profile behavior, as a function of pore volume, was plotted for each test to show fluid viscosity changes that lead to diversion. Straight 15% hydrochloric acid, used as a baseline, showed enhanced permeability in only the most permeable Number 1 core (left). The flat pressure profile indicates that no diversion took place. The VDA fluid system with 15% acid was tested across cores with low initial permeability contrast (middle) and across cores with high initial permeability contrast (right). Permeability was enhanced in all cores, and the increasing pressure profile confirmed that effective diversion was taking place. Once the acid penetrates one of the cores, the pressure drop goes to zero. The increase in pressure drop is an indication of diversion, while a reduced pressure drop indicates stimulation.
Compared with the viscosity of polymer-base acid, the VDA fluid viscosity remained high as the acid was consumed, while the polymer gels broke down when the pH reached 3.5 to 4.0. Examination of the injection core faces showed that the cores injected with the VDA fluid remained clean and showed no trace of residue. In contrast, cores treated with the polymer-base acid system clearly had damaging residue on the injection face and also inside the wormholes.

From an operational standpoint, the new VDA fluid can be pumped as a one-stage fluid or combined with other stimulation fluids in stages, depending on the application. By comparison, polymer-base fluids require several stages of acid and diverter to achieve the desired stimulation and diversion. This can be a significant disadvantage since the more polymer that is pumped into the formation, the greater the formation damage. Moreover, laboratory tests have shown better cleanup of spent VDA fluid as evidenced by lower flow-initiation pressures when subsequently injecting mutual solvent into test cores. The excellent performance of this VDA system is particularly beneficial in low-pressure oil reservoirs.

The importance of laboratory testing of stimulation fluids cannot be overstated. In Schlumberger, this work is done in local laboratories around the world, supported by three Client Support Laboratories (CSLs) located in Houston, Texas, USA; Aberdeen, Scotland; and Kuala Lumpur, Malaysia.

**Diversion in Kuwait**

The new VDA system was first used in the northern Kuwait Sabriya field, which is operated by the Kuwait Oil Company (KOC) (below). The six lithological units within the multilayered Mauddud carbonate reservoir range in permeability from 3 to 600 mD. Perforated intervals range between 100 and 200 ft [30 and 60 m] in total length. Reservoir pressure averages 2500 psi [17.2 MPa] and typical well temperatures reach 170 to 180°F [77 to 82°C]. During matrix stimulation, high-permeability zones tend to take acid and become further stimulated, leaving damaged and low-permeability zones untreated. This increases the drawdown within a limited distance from the wellbore and could cause production problems. For this reason, uniform stimulation of the entire zone with chemical-diversion fluids is critical for production optimization.

In the past, acidizing long, heterogeneous carbonate intervals within the Mauddud formation required either foam or chemical diverters, most commonly crosslinked polymer systems. Acid concentrations of 15% were used for tubular pickling and formation breakdown, whereas acid concentrations of only 3 to 5% were used with polymer-base diverter stages. The polymer diverter fluids were crosslinked either at surface or in situ, and usually one stage was pumped for each of four to five sets of perforations. For each Mauddud interval, acid-treatment volumes varied according to the formation characteristics. Zones with lower permeability and porosity were treated with up to 200 gal/ft [2.5 m³/m] of perforations, while zones with higher permeability and porosity were treated with 75 gal/ft [0.9 m³/m]. Openhole completions were commonly stimulated with 10 to 20 gal/ft [0.1 to 0.2 m³/m]. After treatment, the wells were displaced with diesel and, if required, the fluids were lifted with nitrogen pumped down coiled tubing.

Early in the field test of the VDA system, reservoir experts from KOC and Schlumberger identified several potential wells that would benefit from the new VDA technology. These included newly drilled wells, underperforming older wells, horizontal wells with openhole completion intervals, wells with shallow and depleted reservoirs, and high-pressure, high-temperature (HPHT) wells.

Newly drilled wells in the Sabriya field required acidizing because drilling damage and low reservoir pressure limit their ability to flow naturally. Many new wells employ dual completions, with the Mauddud intervals completed on the short string. These completions discourage the use of coiled tubing for acidizing because there is a risk of getting stuck. Without the coiled tubing option, bullheading the treatments from surface is required. Proper chemical diversion has been deemed critical for the uniform stimulation of the Mauddud carbonates.
On new wells requiring bullheaded treatments from surface, 15 wt% acid concentrations are used for both tubing pickling and as an HCl preflush containing a mutual solvent. The VDA treatments typically contain 15% acid, although concentrations up to 28% HCl have been used. The entire completion interval is treated with 50 gal/ft [0.6 m³/m]. After the VDA treatment, a 15% HCl overflush containing a mutual solvent is bullheaded and then overdisplaced with diesel. In early wells, a one-to-one ratio of HCl to the VDA treatment volumes was pumped. However, subsequent wells have shown better performance with higher percentages of VDA fluid.

In Well 5, a new completion, the Mauddud reservoir was completed on the short string, so a bullheaded VDA treatment was planned to treat five different sets of perforations over a 133-ft [41-m] interval. Severe permeability contrasts between zones and the strong possibility of formation damage due to an earlier loss of 800 bbl [127 m³] of polymer-base drilling fluid necessitated exceptional chemical diversion during stimulation. To monitor the impact of stimulation, the operator decided to run prestimulation and poststimulation PLT Production Logging Tool surveys. Before the VDA stimulation, the PLT log showed that not all the perforations were contributing to production. The well was also producing below the bubble point of 1800 psi [12.4 MPa] because of high drawdown pressure, causing gas to come out of solution. The flowing wellhead pressure (FWHP) was only 195 psi [1.3 MPa].

After a successful VDA treatment, oil production increased from 510 to 1760 BOPD [81 to 280 m³/d] at an increased FWHP of 750 psi [5.2 MPa], and the PLT log showed all perforations were contributing to production. The drawdown pressure, causing gas to come out of solution.


15. The pickling procedure uses an inhibited acid to remove scale, rust and similar deposits from the internal surfaces of equipment such as treating lines, pumping equipment or the tubing string through which an acid or chemical treatment is to be pumped. The pickling process removes materials that may react with the main treatment fluid to create undesirable secondary reactions or precipitates damaging to the near-wellbore reservoir.

comparison of well tests, before and after the treatment, further demonstrated the success of the VDA system (right). The prestimulation well-test analysis showed high drawdown pressure and a skin factor of +170, while the post-stimulation well test showed a significantly reduced pressure drop and a greatly improved skin factor of –3. Higher downhole pressures minimized drawdown and eliminated the undesired gas production.

Successful treatments in the initial wells prompted KOC to stimulate Wells 11, 12 and 13 on the flanks of the Sabriya field structure. These wells, which produce heavier oil—17 to 20°API gravity—had not produced for 6 to 10 months. Coiled tubing was used when acidizing these three older wells that would not produce even after initial, and sometimes multiple, conventional acid treatments and nitrogen-lift techniques. These wells contain single-string completions, so coiled tubing operations pose less of a risk. A disadvantage of pumping conventional acids and diverters through coiled tubing was the inherent reduction in pumping rate caused by high friction losses because of the smaller tubing diameters and high fluid viscosities. However, as it is pumped down coiled tubing, the VDA system has drag-reducing characteristics that significantly reduce the friction, allowing higher pumping rates. After the VDA treatments, all three wells began flowing naturally, adding a cumulative production gain of 3280 BOPD [521 m³/d].

Shallow and depleted reservoir zones in the Eocene carbonate rocks have been stimulated with VDA fluid alone, with 5% mutual solvent added in the postflush, with excellent results. With reservoir pressure down to 400 psi [2.8 MPa], these wells are produced through sucker-rod pumps. Well 7 was identified as a stimulation candidate well because it had an upper zone with extremely high permeability and multiple lower zones of lower permeability that had not been stimulated in the past because of a lack of acid diversion. A 50-gal/ft treatment of 15% VDA fluid was successfully bullheaded through a dual packer (next page). When the VDA system is pumped as a single fluid, it enters the high-permeability zones, stimulates them and then diverts the treatment to lower permeability zones. This behavior can be observed repeatedly on the treatment plot as more zones are stimulated. Production from Well 7 increased dramatically, from 300 BOPD [48 m³/d] with a water cut of 11% before the VDA treatment to 1300 BOPD [207 m³/d] with a water cut of 15% two months after VDA stimulation.

Another beneficial application of VDA technology for KOC is in HPHT wells where bottomhole temperatures reach 295°F [146°C] and reservoir pressure is 10,000 psi [69 MPa]. Two HPHT wells, Well 14 and Well 17, have been stimulated with the VDA system. Here, the reservoir is extremely tight, so KOC and Schlumberger have found it beneficial to spot HCl using coiled tubing. Next, a staged treatment consisting of a 28% breakdown acid, a 20% VDA fluid and then 28% HCl is bullheaded from surface. One stage of each has yielded exceptional results; Well 14 production increased from 2760 to 9029 BOPD [439 to 1445 m³/d], and Well 17 production increased from 3140 to 5242 BOPD [499 to 833 m³/d] with a substantial increase in FWHP—from 2914 to 3930 psi [20.1 to 27.1 MPa].

The VDA system also proved successful in a Kuwait Oil Company horizontal well. Well 13 contained a 2000-ft [610-m] horizontal open-hole-completion interval in the Mauddud
reservoir and was flowing 1037 BOPD [165 m³/d] naturally at a FWHP of 320 psi [2.2 MPa]. NODAL production system analysis before stimulation indicated a +10 skin factor, suggesting that the well had been damaged during drilling. KOC and Schlumberger decided that several acidizing stages might be needed to effectively treat the long openhole interval. The acidizing team pumped a combination of 10 gal/ft VDA fluid, and 10 gal/ft of 15% regular, emulsified acid, or HCl containing additives to combat high mud and silt percentages. Ultimately, only two stages were required to reach the desired productivity. A production test conducted after the VDA stimulation showed a substantial production increase to 3800 BOPD [604 m³/d] at a FWHP of 275 psi [1.9 MPa].

KOC has treated more than 75 wells with this innovative fluid. The VDA system's unique rheological behavior allows for higher pumping rates for operations using coiled tubing, while offering the superior diversion capability required for bullheading operations in more complex completion scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios. It uses less equipment for mixing and fewer chemicals at the wellsite, and requires no crosslinkers that can lead to damaging precipitation scenarios.
Acid Fracturing in Saudi Arabia

In some Saudi Arabian water-injection wells, conventional matrix-acid treatments do not generate the required injection rates, so these wells need to be acid-fractured. An initial pad is pumped at pressures exceeding the fracture pressure of the formation; a hydraulic fracture is initiated and propagated by continued injection. In conventional hydraulic fracturing, proppant is used to hold the fracture open and to create a conductive pathway for flowback and production. However, in carbonate rocks, acid is used to create nonuniform etched patterns on the fracture surfaces. This gives the fracture sufficient conductivity after closure. In acid fracturing, the effective hydraulic-fracture length is that portion of the fracture that has been sufficiently etched (next page, top).

To combat fluid leakoff, conventional acid-fracturing treatments use multiple stages of polymer and acid. The objective of these systems is to limit leakoff by increasing fluid viscosity. The increased viscosity and emulsified acids reduce the rate at which the acid reacts with the carbonate formation, helping to reduce leakoff and improve fracture geometry. This technique has been successful. However, polymers form filter cake that, if left in the fracture, can hinder production, especially in tight formations.

Additionally, crosslinkers function within a narrow pH range and their behavior can be difficult to predict at high temperatures. They can also cause precipitates that damage the formation.

The reactivity of the acid to the rock, which helps create a permeable fracture, also promotes undesired fluid loss during pumping. This leakoff negatively impacts fracture growth and hinders the creation of wormholes along the length of the fracture. There are several ways to limit fluid loss during acid fracturing, including pumping intermittent viscous pads that deposit filter cake to reduce acid leakoff and using two-phase fluids, such as foams, emulsions and crosslinked gels. These techniques can be effective but can damage the permeability of both the formation and the fracture. The acid can also destabilize commonly used fluids that are high in pH and can hydrolyze the pad making it less effective. For this reason, several large-volume pads are pumped. When using foam, foam-stability problems can negatively impact acid-fracturing operations, especially in the presence of hydrocarbons at high temperatures.

In Saudi Arabia, the combination of ClearFRAC fluid, emulsified acid, VDA fluid and a mutual solvent has proved to be an effective treatment. This combination eliminates the

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average production from 11 offset wells that were stimulated without the VDA system (top). Water cut in the wells treated with the VDA fluid is much lower than in wells treated with other systems, primarily because the high viscosity in water zones is not broken, whereas gel formed in the hydrocarbon zones is broken and allows the acid to migrate further into the matrix. Therefore, these hydrocarbon-bearing zones are more effectively stimulated and produce higher volumes of oil or gas.

Recently, Saudi Aramco stimulated seven water-injection wells using foamed VES fluid as the diverter system, a combination of 20% HCl regular acid and 20% HCl diesel-emulsified acid, and a mutual solvent overflush. These injection wells are crucial for maintaining reservoir pressure. The injection zone is 200 ft [60 m] thick and contains widely varying permeability streaks. When stimulating this section without proper diversion, all of the acid goes into the most permeable zone and does not treat the damaged zone and zones with lower permeability. Treatments have been bullheaded from surface or delivered through coiled tubing, and have improved injectivity when compared with wells treated with a combination of emulsified acid and gelled polymer-base acid systems (above). Polymer-base systems also require crosslinker and breakers. Furthermore, the VES diversion fluid has eliminated the need to flow back for cleanup because it does not use any polymers.

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A telling comparison. Production from five VDA treatment wells was compared with the average production from 11 wells treated with conventional stimulation systems. The five VDA wells showed significant increases in oil production, with no produced water.

Injectivity index comparison of foamed VES fluid versus gelled polymer-base fluids. Throughout the long-term injection history, the injectivity index—injectivity after stimulation divided by injectivity before stimulation—of the VES fluid treatments remained higher than that of the polymer-base fluids. This finding is directly attributed to improved acid diversion during the treatment and to the nondamaging nature of the VDA fluid.
Acid creates conductive wormholes. During an acid-fracturing job, a viscous pad is first pumped to limit fluid loss and minimize the fracture closure, and then emulsified acid to etch the fracture. In the final stages, VDA fluid containing 5 to 6% surfactant, was pumped to limit fluid loss and maximize the total amount of polymer pumped into the fracture and formation.

In 2003, Saudi Aramco acid-fractured eight Khuff gas wells using a combination of crosslinked gel and new viscoelastic surfactant technology (above). The pad stage used a high-temperature borate gel to initiate and extend the hydraulic fracture, with emulsified acid to etch the fracture.

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In 2003, Saudi Aramco acid-fractured eight Khuff gas wells using a combination of crosslinked gel and new viscoelastic surfactant technology (above). The pad stage used a high-temperature borate gel to initiate and extend the hydraulic fracture, with emulsified acid to

21. Pad refers to the fluid used to initiate hydraulic fracturing that does not contain proppant.
sufficiently etch the fracture along its length. The viscous borate gel also cooled the formation, controlled leakoff and stabilized the bottomhole pressure. Acid pumped after the high pH borate gel destabilizes the filter cake and increases leakoff. To minimize this, acid was followed by gelled fluid that helped finger the next acid stage. Importantly, VDA fluid, containing 28% HCl and 5% to 6% surfactant, was pumped in the final stages when the leakoff became excessive. If a leakoff-control acid is not used, at high leakoff rates, the fracture will close and will not take any more fluid.

Since the operation was performed down tubing, significant steps to pickle the tubing were taken by pumping HCl across the tubing and connecting lines. This removes pipe dope, corroded iron, corrosion-inhibitor additives and scale from the tubing and connecting lines to ensure that only the intended fluids are pumped into the formation during acid fracturing.

Prior to designing and pumping the job, the emulsified acid and the VDA fluids were tested in Schlumberger and Saudi Aramco laboratories to determine their respective viscosity profiles under demanding temperature conditions. Laboratory testing determined that both the VDA fluid and emulsified acid could be used in the Khuff wells. Additionally, a systematic study on the influence of various additives on the rheology of live and spent VDA system has recently been published.27

In the eight Khuff candidate wells, the permeabilities in the completion intervals varied from 0.001 to 2.8 mD and the porosities ranged from 0.1 to 15%; typical perforated intervals were approximately 70 ft [21 m]; reservoir pressures were around 7500 psi [52 MPa]; and fracture gradients ranged from 0.976 to 1.06 psi/ft [22 to 24 kPa/m]. Before the acid-fracturing jobs, each well was flow-tested to determine a prefracture production rate and FWHP. This information was used later to assess the effectiveness of the stimulation treatments. All wells responded positively to the acid-fracturing treatments, surpassing Saudi Aramco expectations (above right). In addition, all of the stimulated wells cleaned up quickly, saving time and reducing the volume of flared gas before the wells could be put on line.

Normally, because of the high fluid loss when acid fracturing with conventional systems, the pumping rate needs to increase substantially to keep the fracture open. However, with the VDA fluid, the leakoff rate is reduced because the in-situ viscosification dramatically lowers pump rates and hence horsepower.

Gas production (top) and flowing wellhead pressures (FWHPs) (bottom) before and after VDA acid-fracturing treatments. In all cases, an increase in gas production rate and FWHP were observed using the new treatments.

Location of the Mataponche and Mecayucan fields, Veracruz basin, Mexico.
requirements. The success of these treatments in deep, sour HPHT environments demonstrates the extended operating range of this new fluid.

**Acid Fracturing in Mexico**

PEMEX has employed acid fracturing in the Veracruz basin, Mexico, since 1995 and attributes the last decade's increased gas production in the basin to these techniques. The Veracruz basin covers an area of 18,000 km² (6950 sq miles) and is located approximately 40 km (25 miles) southwest of Veracruz City (previous page, bottom). Here, attempts to divert treatments using ball sealers and to control leakoff using gelled oil-base pads were frequently unsuccessful. The introduction of self-diverting acid containing polymers improved diversion in 1997, but concerns regarding the damaging effects of polymers led to the use of VES technology in 1999.

Now, the combination of the ClearFRAC fluid and the new VDA system provides PEMEX with another technique to further enhance the production gains already realized from the acid-fracturing technique in this basin. Fracturing treatments use three fluids and the steps are repeated until the designed fracture parameters are achieved.

First, a viscous nonacid ClearFRAC pad initiates the hydraulic fracture and creates fracture length and width. Second, an alcohol-acid stage, containing 20% methanol or isopropanol and 80% acid at 15 wt% HCl concentration, etches a portion of the fracture and creates wormholes, which eventually lead to the loss of fluid. Third, a VDA fluid stage is pumped to fill the wormholes. The VDA fluid extends these established wormholes far more efficiently because the viscosity of the gelled acid and facilitates cleanup. Because the fracture surfaces are differentially etched, the fracture maintains its conductivity after the fracture closes.

Within the Veracruz basin, this fracturing design has been used by PEMEX in the Matapionche and Mecayucan fields to stimulate the Orizaba limestone formation. Candidate wells were selected after analysis of bottomhole pressure-buildup data to determine reservoir permeability, reservoir pressure and skin factor, and NODAL analysis to forecast the production after acid fracturing. Two wells in the Matapionche field were identified as promising candidates for the proposed acid-fracturing treatment using ClearFRAC fluid, alcohol-acid and VDA fluid.

The first well, the Matapionche Well 2181, was drilled in November 2002 and was subsequently perforated across three carbonate intervals between 9235 and 9416 ft [2815 and 2870 m] and then matrix stimulated. Porosity in the intervals ranged from 7 to 11% and the reservoir temperature averaged 180°F [82°C]. After the stimulation, the well produced 1.1 MMcf/D [31,504 m³/d] at a pressure of 420 psi [2.9 MPa] on a ½-in. choke. The well was not producing prior to the matrix stimulation. Buildup-test analysis determined an average permeability of 0.069 mD, a reservoir pressure of 3300 psi [22.8 MPa] and a skin factor of +1, indicating that the formation was slightly damaged (top left).

The buildup-test results were then used in a NODAL analysis and produced an inflow performance relationship (IPR) that matched the initial production results, verifying the reservoir parameters. Another IPR was constructed that incorporated the proposed acid-fracturing treatment, in the form of a lower skin factor. This analysis predicted that gas production would increase to 3.9 MMcf/D [85,920 m³/d] if a skin of −5 were achieved through stimulation (above left).

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29. Inflow performance relationships (IPR) are mathematical tools used in production engineering to assess well performance by plotting the well production rate against the flowing bottomhole pressure (FBHP).
Once the Matapionche Well 2181 was selected as a potential candidate, laboratory tests were performed to ensure the proper viscosity response of the VDA fluid at both room temperature and the expected bottomhole temperature of 180°F. Break tests evaluated the effectiveness and the amount of the mutual solvent proposed in the design. In this test, gelled VDA fluids at pH values of 5 and 6—highly viscous after the acid spends—were mixed with the mutual solvent. A significant decrease in viscosity resulted, indicating a quick and effective cleanup would occur in the reservoir.

The final treatment was designed using local expertise and input from the Schlumberger InTouchSupport.com online support and knowledge management system. Hydraulic-fracture behavior was simulated in FracCADE fracturing design and evaluation software to optimize the design and obtain fracture parameters. The FracCADE simulation predicted that the optimal job in this case would yield an etched fracture half-length of 61.0 ft [18.6 m], an average etched fracture width of 0.33 in. [8.4 mm] and an average fracture conductivity around 133,500 mD-ft.

The treatment—16,000 gal [60 m³] of ClearFRAC fluid, 16,000 gal of alcohol-acid and 12,500 gal [47 m³] of VDA fluid—was bullheaded through 3 ½-in. casing at a rate of 20 bbl/min [3.2 m³/min] (above). Throughout the job, nitrogen was pumped at a constant rate to enhance well cleanup. The acid stages were radioactively tagged and a postfracture gamma ray survey was run to evaluate the effectiveness of the stimulation.

Gas production after the acid-fracturing treatment exceeded PEMEX expectations; the Matapionche Well 2181 produced 5.2 MMcf/D [148,928 m³/d] at a FWHP of 1420 psi [9.8 MPa] on a ½-in. choke just after well flowback. After one week, the well stabilized to 3.3 MMcf/D [94,512 m³/d] at 700-psi [4.8-MPa] FWHP, matching the 300% increase seen in the NODAL forecast.

The postfracture gamma ray log showed that all three zones had been properly stimulated with acid (next page). Well cleanup has exceeded expectations; it is estimated that 70% of the treatment volume will be recovered. Another well in the Matapionche field, Well 1002, experienced similar results using the same methodology and the new acid-fracturing treatment.

In the Mecayucan field, PEMEX chose two adjacent candidate wells to acid fracture. On the Mecayucan Well 415, the company employed the same analysis, design and execution techniques used in the Matapionche field. This well contained five intervals of around 7% porosity, making this bullheaded stimulation down 3 ½-in. casing a challenging task. After successful bullheading of the fracturing treatment, which
included the VDA fluid for diversion, the well produced 2.5 MMcf/D [71,600 m³/d] of gas, matching the NODAL prediction. After the well stabilized, the well produced 2.0 MMcf/D [57,280 m³/d] of gas, a 100% increase in gas production from that recorded after the initial matrix treatment.

Nearby Well 411, a second candidate well for acid fracturing, contained four intervals to be stimulated, ranging in porosity from 3 to 7%. VDA fluid was not used in this well. After acid fracturing, this well significantly underperformed against the NODAL prediction, and the postfracture gamma ray log indicated that one zone was unstimulated and another zone was understimulated, clearly showing that proper diversion was not achieved.

The VDA system has proved highly effective for diversion in the Veracruz basin, even when treatments are bullheaded from surface to multiple zones of varying reservoir quality.

New Life for Egyptian Oil Fields
In the oil fields of eastern Egypt, much of the production comes from heterogeneous dolomitic reservoirs. Commonly, these formations are layered, naturally fractured and mineralogically complex, containing dolomite, calcite, glauconite and various clays. Reservoir permeabilities are variable and formation damage caused by drilling and stimulation fluids can be severe. In addition, reservoir temperatures are low—less than 130°F [54°C]—and produced oil is heavy.

Historically, these characteristics have complicated conventional stimulation efforts and limited their effectiveness because conventional acids are less reactive to low-temperature dolomite. The use of polymer diversion systems, which use breakers and metal crosslinkers, has led to reservoir damage and lower production volumes. Moreover, iron from tubing can induce polymers to crosslink prematurely, increasing friction pressure and thus requiring more horsepower during pumping. Consequently, operators in Egypt are investigating new stimulation methods for both new and old wells, and even wells that have been temporarily abandoned.

The Schlumberger CSL in Kuala Lumpur played a key role in the development of a customized treatment to address the specific
stimulation challenges in this region. First, the complicated reservoir mineralogy was defined through extensive petrographic studies (below). Next, multiple laboratory tests were performed to optimize the treatment fluid.

Given the low reservoir temperature, the high risk of formation damage and precipitate development, and the reservoir heterogeneity, an intensified VDA fluid was recommended to provide the most effective diversion and stimulation. Moreover, the high quantity of formation silt and clay suggested that the MSR Mud and Silt Remover system should be incorporated into the treatment schedule. The MSR system has been used successfully to disperse drilling-fluid damage and help in the suspension of formation silts so that they can be removed from the wellbore. The combined VDA-MSR treatment was thoroughly tested on formation samples and with different additives at simulated reservoir temperatures to ensure the optimum chemical dissolution rate and to minimize formation damage. Heavy-oil samples from the reservoir were also tested for potential emulsion problems.

The treatment design called for alternating stages of the MSR and intensified VDA fluids, with each fluid being batch-mixed before pumping. Operational challenges were overcome through the innovative use of available technologies. For example, a dual-injection technique was used to treat heavy-oil-producing intervals on dual completion. Other wells producing heavy oil were completed openhole and required a different method to administer the treatment. In these cases, the VDA-MSR treatments were delivered to the reservoir through 1½-in. coiled tubing. The VDA fluid is especially suited for pumping down small tubing since it maintains a low viscosity during pumping and does not viscosify until it reacts with the formation. As a result, the lower friction pressure made this technique feasible.

The VDA-MSR treatments have been performed on more than 100 wells with excellent results. Effective diversion was clearly demonstrated during pumping (next page). The new technique has been responsible for an increase in production ranging from 400 to 800%. The wells clean up faster and production-decline rates are notably slower than with conventional treatments. The operator experienced quick payback of the stimulation costs, ranging from one day to just over a month. Most of the treatments paid out in less than one week. The overwhelming success of this program is having a sizable impact on drilling and development plans in Egypt's eastern desert, and has made VDA technology an important element in the stimulation of new, old, and even abandoned wells.

The Right Chemistry

VDA treatment successes have been reported around the world. In September 2003, Transmeridian Exploration, Incorporated, Houston, Texas, USA, attributed significantly higher rates from their South Alibek 1 well in the Caspian Sea, offshore Kazakhstan, to improved stimulation and cleanup using the VDA system. This helped bolster the South Alibek field's estimated reserve potential of more than 300 million barrels [47.6 million m³]. In Bahrain, the VDA system was used to matrix stimulate dry gas reservoirs in two wells, leading to 82% and 65% increases in gas production rates over the initial rates. During 2003, impressive results have also been documented in Canada, Indonesia, United Arab Emirates, Pakistan, Venezuela, Russia, West Africa, Tunisia and the USA, including the highly depleted, low-pressure dry gas reservoirs in the Permian Basin, Austin Chalk and the Gulf of Mexico.

These successes have been the result of extensive research, uncompromising support from stimulation experts around the globe, Schlumberger CSLs and through the InTouch-Support.com system. Research on carbonate reservoirs continues at Schlumberger-Doll Research in Ridgefield, Connecticut, USA, and at Schlumberger Dhahran Carbonate Research in Al-Khobar, Saudi Arabia, because thorough

Photomicrograph of a rock sample. The photomicrograph shows the different types of rock fragments and bioclastic debris in a typical rock sample from a field in eastern Egypt. Knowledge of this complex mineralogy was crucial in the design of an optimal treatment at the Client Support Laboratory in Kuala Lumpur, Malaysia.
knowledge of the reservoir is the first step in effective stimulation. The knowledge gained from these research activities is exploited every day at the Schlumberger CSLs and other laboratories around the world. A vast field-support network is crucial for proper fluid selection, treatment design and quality control, and directly benefits the operating companies that use this technology. Real-time monitoring of stimulation jobs using InterACT real-time monitoring and data delivery from remote locations brings more expertise to the wellsite, facilitating rapid evaluation of both the stimulation treatment and the results.

Recent VDA treatments for Rosetta Exploration, Incorporated, in Canada demonstrate the important role of the CSL when well conditions are harsh and the stakes are high. A high-temperature 4600-m [15,000-ft] deep well in Canada had failed to produce to expectations after a 30,000-liter [7925-gal] energized-acid treatment. The well was producing at 2 MMcf/D [57,270 m³/d] at 2 MPa [290 psi] FWHP and then subsequently scaled off. Coiled tubing was required to clear the pyritic scale and to deliver a new treatment to the reservoir. Unfortunately, the well was known to contain 22% H₂S and 8% carbon dioxide [CO₂], making it a difficult environment for coiled tubing operations. At this depth, high temperatures and the combination of corrosive gases and acid meant the treatment would require careful selection of inhibitor additives to ensure a safe and successful treatment.

The CSL in Houston, Texas, working with the coiled tubing team in Red Deer, Alberta, Canada, determined the optimal combination and concentration of compatible additives. A 21,000-liter [5550-gal] VDA treatment, carefully designed by experts, provided sufficient diversion at the required low injection rates and successfully stimulated this problematic well. After the VDA treatment, the well produced 6.5 MMcf/D [186,160 m³/d] at 7 MPa [1015 psi] FWHP and has now stabilized at a production rate 50% above the previous rate.

The quest for better stimulation fluids continues. At Schlumberger Cambridge Research (SCR), new molecules are designed and tested to continue the momentum begun by previous breakthroughs. Scientists at SCR and the Sugar Land Product Center continue their drive to expand the capabilities of existing fluid systems and to develop new fluid systems that overcome current challenges.

The enormous success of the VDA system is due to the combination of innovative chemistry, far-reaching technical support, uncompromising quality control during the design and operation stages, and the willingness of operators to apply new technology. This development in carbonate stimulation is making a clear and positive impact on production and injection rates, from the smallest wormholes to the largest fields.

—MGG