Options for High-Temperature Well Stimulation

As wells become deeper and hotter, there is a growing need for high-temperature matrix acidizing techniques. Newly developed procedures allow acidizing of both carbonates and sandstones at elevated temperatures. These advances vary from new chemical agents to simplified fluid-placement techniques.
Using acids to improve well performance by removing or bypassing damage has been a common practice for a long time—nearly as long as the existence of the oil industry itself. In 1895, the Ohio Oil Company used hydrochloric acid (HCl) to treat wells in a limestone formation. Production from these wells increased by several fold—and unfortunately so did casing corrosion. As a result, acidizing to stimulate production disappeared for about 30 years.

Acidizing in limestone reservoirs experienced a rebirth in 1931 with the discovery that arsenic inhibited the corrosive action of HCl on wellbore tubulars. But acid treatments for sandstones required a different approach. HCl does not react easily with minerals that reduce sandstone permeability, but hydrofluoric acid (HF) does. Early attempts using HF in sandstones failed because of plugging from secondary reactions. This problem was overcome in 1940 with a combined HF-HCl treatment. The HF in the acid combination dissolves mineral deposits in sandstones that hinder production, while the HCl controls precipitates. These acidizing techniques have evolved over subsequent years, but the goal has not changed—create or restore production pathways close to the wellbore in a new or existing well.

Well acidizing, more commonly referred to as matrix acidizing, is one of two intervention methods used to restore flow in an oil or gas formation. The other route—hydraulic or acid fracturing—creates fractures to allow relatively distant accumulations of oil and gas to flow to the wellbore. Acidizing works on the formation near the wellbore to bypass damage or to dissolve it. The choice of fracturing or acidizing to stimulate production depends on a multiplicity of factors that include formation geology, production history and intervention goals.

Well-intervention techniques such as matrix acidizing play an important role in helping operators produce all they can from their fields. Pressure on acidizing experts to develop new treating formulations and techniques is coming from several directions. One important need is extension of acidizing to high-temperature environments. Use of conventional mineral acids such as HCl and HF at higher temperatures—above 93°C [200°F]—leads to reaction rates that are too rapid. These fast rates cause the acid to be consumed too early, reducing its effectiveness, and may cause other problems.

Furthermore, as regulations tighten, there is a greater need within the industry for fluids with reduced environmental and safety risks. Conventional mineral acids such as HCl and HF are difficult to handle safely, corrosive to wellbore tubulars and completion equipment, and must be neutralized when returned to the surface. Additionally, as the bottomhole temperature increases, corrosion-inhibitor costs rise rapidly because of the high concentrations required—particularly with some exotic tubulars currently used in well completions. Finally, conventional sandstone acidizing techniques typically involve many fluid treatment steps, increasing the potential for error.

This article will focus on matrix acidizing and discuss how this technology has been extended to higher-temperature environments through development of new fluids and techniques. Case studies from Africa, the USA, the Middle East and Asia demonstrate how these techniques are being successfully employed around the world.

### Different Formations—Different Acidizing Chemistry

The first consideration in matrix acidizing any particular well—high-temperature or not—is formation lithology. Carbonate reservoirs are mostly acid soluble, and acid treatment creates highly branched conductive pathways called wormholes that can bypass damage. Conversely, in sandstone reservoirs, only a small fraction of the rock is acid soluble. The goal of acid treatment in sandstones is to dissolve various minerals in the pores to restore or enhance permeability. The chemistry and physics for treating both types of reservoir have been extensively studied and are well-understood.

Carbonate reservoirs—principally limestone and dolomite—react easily with HCl in moderate-temperature environments to form wormholes (above). The reaction rate is limited primarily by the diffusion of HCl to the formation surface. Wormholes in carbonate reservoirs increase production not by removing damage, but by dissolving the rock and creating paths through it.

The formation of wormholes in carbonates is explained by the manner in which acidizing affects the rock. Larger pores receive more acid, which increases both their length and volume. Eventually, this extends into a macroscopic channel, or wormhole, that tends to receive more acid than the surrounding pores while it propagates through the rock. The shape and development of wormholes depend on acid type as well as its strength, pump rate and temperature—plus the lithology of the carbonate. Under the right conditions, wormholes can grow extensively, forming macroscopic channels called wormholes (red). These channels are the result of the reaction of HCl with the calcium and magnesium carbonates in the cores to form water-soluble chloride salts.

to substantial lengths, resulting in efficient use of acid to bypass damage. In conditions that are less favorable, the acid creates short channels that do little to increase production. For any formation being treated, there is an optimal set of treatment parameters that creates wormholes with the most efficient use of acid (above).1

In contrast to carbonate formations, the quartz and other minerals that make up most sandstone reservoirs are largely acid insoluble. Acid treatment for sandstone—HF usually combined with HCl—seeks to dissolve the damaging particulates that block the pores and reduce permeability (below).4 Acidizing in sandstone targets damage in the first 0.9 to 1.5 m [3 to 5 ft] radially from the wellbore—the area that experiences the largest pressure drop during production and is critical for flow. This area is typically damaged from migrating fines, swelling clays and scale deposition. Sandstone acidizing reactions occur in areas where acid meets minerals that can be dissolved. The primary dissolution reactions of the clays and feldspar with a typical HF-HCl mix form aluminosilicate products. Sandstone acidizing chemistry is complex, and the initial reaction products can react further and possibly cause precipitation. These secondary reactions are slow compared with the primary dissolution reactions and rarely present problems with mineral acids except at higher temperatures (next page, top).

Extension of matrix acidizing to temperatures above 93°C presents the operator with both possibilities and concerns. The possibilities are obvious—acidizing at higher temperatures allows stimulation of hot wells using familiar field procedures. However, at higher temperatures, use of HCl causes a host of problems. In carbonates, the rapid HCl reaction rate at elevated temperature may lead to face attack instead of wormhole creation and may create acid-induced sludge with high-viscosity crudes. High-temperature problems in sandstones are different. Clay dissolution may be too rapid, decreasing penetration by the acid, and secondary reactions may cause precipitation. Finally, rapid reaction rates can deconsolidate the sandstone matrix, creating mobile sand.

Of particular concern in high-temperature sandstone and carbonate reservoirs is accelerated corrosion of tubulars and other wellbore equipment. Although increased injection of inhibitors may adequately control corrosion rates, the greater inhibitor loading at higher temperatures may itself cause formation damage.5

The challenges of extending matrix acidizing to higher temperatures have led to development of new treating fluids and techniques. Treating fluids include acid-internal emulsions to retard reaction rates in carbonate reservoirs and mild, slightly acidic chemical agents for treating both carbonates and sandstones. New techniques include a simplified sandstone-treating system that uses laboratory data and predictive software—in combination with new chemical treating agents—to arrive at a simplified procedure. These new treatments and techniques can be easily understood by examining some of the laboratory data that were instrumental in their development.

\[ ^\text{\^} \text{Carbonate dissolution patterns. Wormhole structure is related to the efficiency of the acidizing operation and can be viewed by plotting the number of pore volumes to core breakthrough (PVBT) versus the flow rate. Porosity patterns obtained from a software model calibrated with experimental data illustrate how dissolution proceeds with increasing flow rate. The least efficient acidizing operation is face dissolution—the entire matrix must dissolve in order to advance the reaction front. Slightly more efficient at higher flow rates is the creation of large, conical channels. The most efficient operation occurs at the curve minimum, with creation of highly dispersed wormhole channels. At even higher flow rates, the curve turns upward and large channels, called ramified wormholes, form. Increasing to higher flow rates leads again to uniform face dissolution.} \]

\[ ^\text{\^} \text{Sandstone matrix. The framework of sandstone reservoirs is typically made up of grains of quartz cemented by overgrowth of carbonates (A), quartz (B) and feldspar (C). Porosity reduction occurs from pore-filling clays such as kaolinite (D) and pore-lining clays such as illite (E).} \]
Laboratory Testing
Testing new treatments and techniques in the laboratory offers many advantages including simplicity, cost and avoidance of possible problems in the field. Good laboratory data will confirm treatment models and indicate the right path for successful field operations. Proper laboratory testing for acidizing techniques can optimize treatment volumes and pinpoint potential problem areas as well as confirm theoretical underpinnings. A strong case in point is the use of emulsified acids in matrix acidizing of carbonate formations at higher temperatures.

One way to address the problem of fast reaction rates at high temperatures is to use acid-oil emulsions to retard the reaction rate. These emulsions have been applied in both acid fracturing and matrix acidizing of carbonates. In acid fracturing, the emulsions help enhance and enlarge conductive pathways far from the borehole. Acid fracturing typically employs chemical and mechanical diversion techniques to ensure that the treatment flows to its intended location. By contrast, acid-oil emulsions for matrix acidizing are designed to work close to the borehole and have lower treatment volumes than those for acid fracturing techniques.

Acid-oil emulsions for matrix acidizing of carbonate formations consist of an internal HCl phase and an external oil phase. Hydrogen ion transport from the acid droplets to the rock surface takes place by Brownian diffusion—which dramatically slows the acid reaction rate. Laboratory data show that when HCl droplets are suspended in diesel oil, the reaction rate can be retarded by more than an order of magnitude (right). In addition to the slow reaction rate

7. Brownian diffusion or motion is the random movement of particles suspended in a liquid or gas.
with the carbonate rock, acid-in-oil emulsions have other advantages. Their relatively high viscosity improves distribution in heterogeneous reservoirs, and since the acid does not have direct contact with well tubulars, corrosion is reduced. Although emulsified acid systems have been commonly used for matrix acidizing of carbonates below 93°C, laboratory data indicate that they can be extended to higher temperatures if properly formulated.

The Schlumberger acid-oil emulsion formulation—called the SXE-HT system—was developed for high-temperature acidizing in carbonate reservoirs. It consists of an acid phase, containing a corrosion inhibitor, and a diesel-oil phase with an emulsifier. These two mixtures are combined at high shear rates to form an oil-external acid emulsion. Laboratory data on the physical properties of this formulation show low corrosion and pitting for a variety of metals, high viscosity retention even up to 177°C [350°F] and good emulsion stability. For example, a typical SXE-HT emulsion is stable for at least two hours at 149°C [300°F], and this stability time can be prolonged by increasing the emulsifier concentration. Tests on limestone cores with the SXE-HT fluid at 135°C [275°F] confirm its ability to create wormholes at typical injection rates.

Use of a properly formulated acid-oil emulsion is one solution for well stimulation at high temperature. Another approach is to consider a completely different type of reservoir acidizing fluid. Data confirm that a different class of chemicals—chelants—allow well stimulation at conditions that preclude the use of mineral acids. The slower reaction rates exhibited by the HACA chelants at high temperatures have important implications. In carbonates, slower rates allow efficient wormhole creation, while in sandstones there is less possibility of damage to sensitive formations. Low corrosion is another important characteristic of HACA chelants. For example, at high temperature, hydroxyethylideneethylene diamine triacetic acid (HEDTA) exhibits corrosion rates up to an order of magnitude lower than those of conventional mineral acids (below left). Significant health and environmental benefits include lower toxicity, reduced need for return fluid neutralization and lower concentrations of corrosion products in these fluids. Of all these advantages of HACA chelants, however, the most important may be slower reaction rates at elevated temperatures. Coreflood testing in carbonates at elevated temperatures demonstrates the advantage of using a chelant rather than HCl to create an efficient wormhole network (next page).11

Another gauge of chelant effectiveness in carbonates versus that of HCl is the amount of acid required to penetrate a formation—as measured by pore volumes to core breakthrough (PVBT). In one simulation that was scaled up from laboratory data, PVBT values for HCl and HEDTA were predicted for acidizing a carbonate formation at a depth of 2,185 m [7,170 ft], a bottomhole temperature of 177°C, and with damage that extended 0.3 m [1 ft] from the wellbore. At a pump rate of 0.95 m³/min [6 bbl/min], the simulation predicted that the PVBT for HCl was nearly 100 times that for HEDTA—indicating low acidizing efficiency for HCl at high temperature.

As in carbonates, use of HACA chelants in sandstones offers a way to avoid the rapid reaction rates that lead to precipitation. Laboratory tests on West African sandstone with an HACA chelant confirm that proposition.
The Nemba reservoir is one of a group of production zones lying offshore Cabinda, Angola. This layered reservoir consists of varying thicknesses of sandstone, limestone and shales. Although some high-permeability streaks exist due to fissures and fractures, permeability elsewhere is low and temperature is high—149°C. The Nemba formation contains high levels of native calcium carbonate, making the formation particularly difficult to acidize at elevated temperatures without causing deconsolidation. Prior treatment and workovers in the Nemba formation had caused significant damage related to carbonate scale. Nemba sandstone samples represent good candidates for evaluating the use of chelants in high-temperature acidizing.

Ten core samples were taken from the Nemba field over a narrow depth interval at about 3,534 m [11,595 ft] and subjected to a variety of experiments with an HEDTA chelant. These experiments measured composition, examined metals evolution during reaction and determined permeability. The composition of the Nemba core samples ranged from 5% to 44% calcium carbonate with significant amounts of feldspar and chlorites. Two different procedures were performed in the laboratory to determine the results of HEDTA treatment—slurry reactor and coreflood permeability tests.

The slurry reactor tests on the Nemba sandstone samples used an isothermal, stirred reactor to measure product composition as a function of time. Powdered sandstone samples containing 24% and 44% carbonate levels were treated in the reactor with HEDTA at 149°C. Samples of the reaction mix were withdrawn over time and analyzed by inductively coupled plasma emission spectrometry. For both carbonate levels, the concentrations of calcium, silicon, aluminum and magnesium rose smoothly over time with no decreases that would indicate precipitation.

In this experiment, concentrations of calcium and other components showed an initial rise followed by a decrease—indicating precipitation—a common cause of sandstone treatment failure. The slurry reactor data on HEDTA suggest that this chelant dissolves the pore-filling and blocking minerals at high temperature without causing precipitation. These positive results for HEDTA were followed by coreflood tests at two carbonate levels. Results from these tests show that...
chelant significantly increases permeability in the damaged cores (left).

In aggregate, the laboratory results on carbonate and sandstone samples provide an advance in overcoming problems associated with acidizing in high-temperature environments. In contemplating the scale-up of laboratory data to actual field operation, treating carbonates represents a more direct extension of the technology since secondary precipitation reactions are not present. Complex, multilayer sandstone formations present a more difficult problem since both complicated mineralogy and precipitation reactions must be considered. Job success in sandstones can be improved by using a geochemical simulator package called Virtual Lab software that optimizes stimulation parameters for a variety of fluids and bottomhole conditions (next page, left).

Field results from the application of these advances in high-temperature acidizing confirm their potential.

Acidizing High-Temperature Carbonate Wells

The carbonate reservoirs of the Smackover formation, located in the southeastern USA, have been prolific producers of oil and gas since their initial discoveries in 1937. The Smackover Formation, http://www.visionexploration.com/smackover.htm (accessed October 20, 2008).

18. The composition of the emulsion as % by volume was 30% of an HCl solution (20% by weight HCl in water) mixed with 70% diesel oil.
20. Cocoalkylamine is a cationic surfactant that includes high concentrations of several long-chain acids that include lauric, myristic, palmitic and caprylic varieties.
22. Like the cocoalkylamine, tallow amine acetate is a cationic mixture of acids. However, this emulsifier has longer carbon chains and contains some double bonds.

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Reaction simulations in sandstone. Virtual Lab software is a prediction system that determines optimal acidizing parameters for sandstone treatment. This semianalytical system is based on laboratory data taken from samples of the formation being considered for treatment. In the first step, slurry reactor tests are carried out using acid and crushed solids (top). Analysis of reaction kinetics and identification of precipitates in the second step, coreflood tests determine permeability and porosity at reservoir conditions (middle). In the final step, all the data are combined with radial-flow simulations to determine the best acidizing treatment (bottom).

Although acid-oil emulsions have been employed for many years, additional focus on the details of the technique has yielded significant improvements. A case in point is their use in treating a group of deep, high-temperature wells in the Middle East. These wells are located in eastern Saudi Arabia and produce nonassociated sour gas at a depth of about 3,500 m [11,500 ft]. The producing zone lies in the Khuff formation and is composed of dolomite layers intermingled with limestone. Bottomhole temperatures are in the range of 127° to 135°C [260° to 275°F].

Stimulation efforts have been conducted on a regular basis by the operator to enhance permeability and remove drilling mud damage. Both straight HCl and acid-in-diesel emulsions have been used for stimulation of gas wells in this formation with varying results. HCl is an effective stimulation agent but is highly corrosive at the higher temperatures encountered in these wells. An acid-oil emulsion was found to be effective in providing stimulation without corrosion, but field application showed the need for optimization of the emulsifier formulation. Work to improve the emulsifier was concentrated on two areas—reduced quantities and improved field operations.

Earlier field tests of acid-in-diesel emulsions to stimulate wells in the Khuff formation used 28% by weight HCl in a 30% by volume acid and 70% by volume diesel emulsion. The emulsifier was a cocoalkylamine at 0.08 to 0.11 m³ [0.48 to 0.71 bbl] per 3.78-m³ [23.8-bbl] emulsion loading. The field application showed that although the emulsion was effective at stimulating production, further improvements were needed. Emulsifier loadings were high, and the emulsion often broke at ambient conditions in the field, necessitating remixing and quality control in the field before use. Both of these cocoalkylamine emulsifier attributes meant longer operation times and higher cost.

The operator, therefore, embarked on a program to develop and test an improved emulsion for use in stimulating the deep, high-temperature gas wells in this formation. Results from laboratory testing of more than 10 different emulsifiers showed that beef-tallow amine acetate would be more effective than the cocoalkylamine formulation. This new emulsifier could be used at 25% of the previous loading to make stable emulsions with no remixing at both ambient field conditions and high temperatures. In a four-well pilot campaign, the new tallow amine emulsifier was successfully employed. Mixing times in the field were reduced by 25% and poststimulation production rates exceeded expectations.

Acid-in-oil emulsions are not the only option for hot carbonate well stimulation; chelants can also be used successfully, as illustrated by a well in a Middle Eastern carbonate reservoir. After completion, the well was not flowing, and drilling mud filtrate damage in the formation was suspected. Despite the need to stimulate the well to start production flow, the operator had concerns about the high bottomhole temperature—110°C [230°F]—and the formation lithology at a measured depth of 2,620 m [8,600 ft]. At this
depth, the limestone-dominated formation has dolomite streaks containing significant amounts of entrapped gas. Surface facilities were limited in the amount of gas that could be handled to a gas/oil ratio (GOR) of 440 m³/m³ [2,500 ft³/bbl]. Any stimulation to initiate flow in the well had to avoid gas production and keep the GOR below this limit by minimizing stimulation of the dolomite streaks.

A chelant from the HACA family was the obvious choice for the stimulation job. Chelants in the HACA group exhibit enhanced reaction rates with limestone and more limited reaction with dolomites—an important factor for the success of this treatment due to the entrapped gas. A treatment plan for this well was developed using the Schlumberger StimCADE software for acid placement. This plan called for using coiled tubing to place an HACA chelant into a narrow zone of the limestone matrix at 2,620 m. The software predicted a 1.5-m radial penetration by the HACA chelant.

Stimulation treatment was carried out without incident. A preflush of a solvent mixed with water preceded the chelant to aid flowback by making the formation water-wet. Treatment pressure averaged 8.3 MPa [1,200 psi], and the chelating injection rate was 0.056 m³/min [0.35 bbl/min]. After treatment was complete, the operator displaced the well with diesel and pulled the coiled tubing. Positive results from the treatment with the chelant were immediately apparent. Oil production increased from the initial nonflowing state to 96 m³/d [600 bbl/d]. This oil production increase was accompanied by a GOR increase of only 264 to 299 m³/m³ [1,500 to 1,700 ft³/bbl]—well within the operator’s limits.

Results from these cases confirm that chelants are useful for stimulation of hot carbonate reservoirs. This capability is also present for sandstones.

Acidizing High-Temperature Sandstone Wells

A West African well drilled in 1984 typifies the choices an operator must make when confronting the need for acidizing a high-temperature sandstone formation. This well, completed at a depth of 2,360 m [7,743 ft] in a deltaic sandstone formation with 15% carbonates, had a bottomhole temperature of 128°C [263°F]. During a nearly 20-year period, oil production had declined from 490 m³/d [2,500 bbl/d] to 224 m³/d [1,408 bbl/d] with a corresponding increase in water output. The water, first noted in 1991, had increased to 30% by 2003. The effect of the water on completion equipment had been observed during a prior
well intervention to replace gas lift system components. The scale deposits on the gas lift mandrels were so severe that a 71-mm [2.8-in.] gauge cutter could not pass below 875 m [2,870 ft].

Faced with concerns about corrosion and possible damage to the formation using conventional acidizing, the operator chose to treat the scale problem with an HACA chelant. The treatment goal was to use a mild fluid that would remove carbonate scale and not damage the sandstone formation. The well was treated with the HACA chelant using coiled tubing with a rotating jet to spray and soak the areas containing the gas lift components. Following treatment, the fluids used in the operation were displaced with water and the gas lift system was restarted. A gauge cutter was run through the entire length of the wellbore and encountered no obstructions. After treatment, oil production increased to 402 m³/d [2,528 bbl/d], indicating removal of scale and possible stimulation of the sandstone.

As illustrated by the treatment in this West African well, using chelants in sandstones with conventional fluid placement plans is often quite effective. Schlumberger has extended the utility of these new chemicals in sandstones with its OneSTEP technology. This technology uses a unique chelant fluid and simplified placement techniques to stimulate production with less risk of damage and precipitates. This fluid substantially reduces the number of required stages during acidizing. Petronas Carigali recently employed this technology to stimulate one of its offshore wells in Southeast Asia.

The Tiong field lies off the western coast of Malaysia in 77 m [253 ft] of water (previous page, top). Discovered in 1978, the field began producing oil and gas in 1982. Tiong is a sandstone formation with a high bottomhole temperature—109°C [228°F]. After experiencing declining production and noting a high skin value for the formation, Petronas evaluated several Tiong wells as candidates for acidizing treatment.25 Tests on core samples from the candidate wells indicated formation damage from kaolinite fines and calcite. Petronas selected a well for the acidizing tests and chose the OneSTEP system for its operational simplicity and use of chelants (below).26 This combination marries a low risk of secondary and tertiary reactions that might cause precipitation with fewer fluid stages and simplified logistics. Other benefits accrue from low corrosion rates and a good health, safety and environmental footprint.

Prior to carrying out the treatment, Schlumberger calibrated the Virtual Lab model using results from well testing before running simulations. The well tests determined formation dissolution kinetics, measured physical properties of the rock and compared treatment options in radial-flow tests. The final choice for the treatment fluid at Tiong was a chelant plus other additives. With this chelant fluid, the OneSTEP treatment was carried out at the Tiong well in April 2007. No operational problems were encountered and the test was successful—oil production increased by a factor of four and gas production by a similar amount (previous page, bottom).

For Petronas, stimulation of oil and gas production was not the only benefit of the OneSTEP technique. This simplified acidizing operation saves significant rig time, resulting in lower cost. In the Tiong treatment, the operational time saved was measurable—

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25. Skin is a 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 enhanced productivity, typically resulting from stimulation.
Acidizing deep, hot reservoirs. Acidizing with HCl and HF is typically effective at reservoir temperatures below 200°F, and use of chelants can extend this temperature range to about 400°F. Recent deepwater gas discoveries are good examples of hot reservoirs and can reach temperatures of 250 to 550°F (288°C). Chelants could be considered for acidizing fields between Ursa at 250°F and Egret at 350°F, but to acidize fields above 400°F, such as West Java, Deep Alex and Mobile Bay, new technology will be required.

New Fields—Severe Conditions

Great strides have been made in acidizing at high temperature in the past few years. Treatment with acid-oil emulsions and chelants allows operators to acidize formations at elevated temperatures with reduced corrosion rates and less risk of secondary damage. As promising as this picture seems for acidizing, more improvements in treating agents and procedures will be required to meet difficult conditions in the future.27

Current world demand for energy is expected to grow—it is estimated that 40% more energy will be required in 2020 than in 2007.28 As the search for new reserves continues, exploration is turning to deeper reservoirs; operations in the USA illustrate this trend. In 2007, wells deeper than 15,000 ft [4,572 m] accounted for about 7% of domestic production; this is forecasted to grow to 12% in 2010. The deep gas resource being produced by this type of well is large and could be as high as 29% of production in the future.

One defining characteristic of deeper basins is that they are hot. Deep gas wells in the Gulf of Mexico and Brazil have average bottomhole temperatures of 204°C [400°F], and even higher temperatures have been reported. To help operators focus on the implications of drilling and operating deep, hot wells, several classification systems have been developed.29 Many of these deep, hot wells will require matrix acidizing at some point in their life span, and current technology covers only part of the temperature range (above left). This trend toward increasingly higher temperatures will demand improvements in all aspects of acidizing, from corrosion rates to treatment-fluid stability.

In spite of the difficulty in acidizing at extreme conditions, some early successes have been reported. For example, a South American high-pressure, high-temperature sandstone well with significant damage was treated with a combination of acetic acid and HF, resulting in a doubling of oil production.30 Keys to success in this operation at high temperature included a mild acid—acetic—associated with HF, and inclusion of a phosphonic acid stabilizer to keep products in solution. Another example of innovative solutions to acidizing in high-temperature environments is the use of an in situ acid system.31 The treatment fluid in this system contains an acid precursor that delivers time-controlled release for long-interval wells.

In the final analysis, successful acidizing of high-pressure, high-temperature wells will place greater demands on both treatment fluids and procedures. Fluids will be required that have controlled reaction rates, low corrosion and acceptable health, safety and environmental footprints—chelants are a good example of a step in this direction. In addition to the development of new fluids, treatments like the OneSTEP technique that emphasize simplicity and minimize operational time will be at a premium. Taken together, future developments in both treating fluids and procedures that employ them will ensure that matrix acidizing keeps pace with difficult conditions as new fields are developed. —DA


