Well productivity can be adversely affected by formation damage in the near wellbore or by low natural permeability of the reservoir rock. Damage may be caused by drilling operations or the effects of long-term production. Carbonate minerals dissolve readily in acids, and acidizing has for years been a method of stimulating production in carbonate reservoirs. Mathew Samuel and Mahmut Sengul explain some of the situations that benefit from carbonate well stimulation, and how techniques such as matrix acidizing and acid fracturing are evolving to ensure optimum production and injection.
The carbonate reservoirs of the Middle East and Asia contain about 69% of the world’s oil and gas reserves. To sustain global oil and gas demands, the effective stimulation of carbonate reservoirs, therefore, is very important in this region. Moreover, the complexities of carbonates that are due to their heterogeneous structure, including natural barriers and fractures, present some of the greatest challenges to reservoir stimulation.

For many years, reservoir teams have sought ways to avoid early abandonment of oil and gas wells as a result of formation damage and low natural permeability in carbonate reservoirs. Such abandonments have caused incalculable loss of revenue resulting from the hydrocarbons left behind. Recovery can often be improved using stimulation techniques for removing or bypassing the formation damage in the near-wellbore area, or by partly increasing the formation’s natural permeability, or, in many cases, both. Formation damage—plugging or partial plugging of perforations, or plugging of the rock matrix by debris from the well and from well operations—restricts the flow of hydrocarbons into the wellbore.

Identifying the causes of formation damage and preventing it from happening have been the subjects of much research. Well operations still, however, continue to cause some degree of damage to the formation in the near-wellbore region.

Thousands of well stimulation jobs are performed in the region every month, using treatments that range from pumping hydrochloric acid into the formation to dissolve and/or fracture the rock, to very advanced technologies that use viscoelastic surfactant-based (VES) fluids to help acid placement and control leakoff.

**Carbonate stimulation**

The main objective in carbonate stimulation is to create a conductive flow path and bypass the damage. The dissolution of the rock matrix leads to the formation of highly conductive flow channels, known as wormholes (see boxed article Working with wormholes, page 46). Bypassing formation damage, therefore, improves connectivity between the well and the reservoir rock. This increases the well’s productivity or injectivity index by reducing skin.

Using acid to dissolve the carbonate minerals may also help to remove the damage that blocks perforations and pores in the near-wellbore area.

Hydrochloric acid is commonly used for fracturing and matrix acidizing in carbonate reservoirs. This acid is highly reactive with carbonates, relatively inexpensive and available globally. It can be easily inhibited to minimize damage to tubulars, or reduce surface tension, allowing subsequent control of penetration, wetting properties and friction pressure. Most of the reaction products of hydrochloric acid and carbonate are water soluble and are easily removed. Although hydrochloric acid is considered to be the best oilfield acid for most applications, the system can be very costly, particularly in high-temperature environments that require additives to control reaction rates.

Prolonged contact of hydrochloric acid with steel pipe at high temperatures can cause severe corrosion. In high-temperature wells, effective inhibition can be difficult and costly. Consequently, with their slower reaction rates, organic acids can be more effective. They also have lower corrosion potential and are easier to inhibit at high temperatures than hydrochloric acid.

Hydrochloric acid reacts so quickly with limestone that by the time placement is complete, the acid is already spent, regardless of the downhole temperature and pressure. Chemical retardants, such as emulsifiers and gelling agents, may be added to extend the reaction time. The damage and various impurities in limestone that are not dissolved by the acid can plug the formation if they are allowed to settle after a matrix treatment. This means that the spent acid must be removed almost immediately.

The use of SXE* SuperX acid-in-oil emulsion offers significant advantages over both hydrochloric and organic acids. The SXE system is a 70:30 hydrochloric acid:diesel blend, stabilized with an emulsifier. Retardation of SXE systems can be 15 to 40 times greater than that of conventional hydrochloric acid systems, depending on temperature, acid concentration, flow regime and rock type. The dissolving power of SXE systems is comparable to that achieved with regular hydrochloric acid, but creates deeper wormholes, and has much lower corrosion rates.

Organic acids such as acetic, formic or citric are less commonly used in carbonate stimulation because of their high cost and relatively poor performance in dissolving carbonate material at low temperatures. Table 1 shows a comparison of the solubility of calcium carbonate in different acids.

Other possible treatment fluids include combinations of hydrochloric acid with one or more organic acids. These are sometimes used for acidizing high-temperature carbonate formations. They combine the fracture-face etching power of hydrochloric acid with the deeper formation penetration of organic acids. They can be further emulsified to get the additional benefits of SXE systems. However, these systems are expensive and require careful evaluation before use.

Optimizing acid reaction rates is a key factor in obtaining the desired effects on the formation at downhole conditions. Sufficient acidization must be achieved without overtreatment, which could cause the collapse of pore structures, and may reduce well productivity (Figure 5.1). Acid strength, temperature, pressure (Figure 5.2), pumping rate, leak-off control and rock composition are among the factors that

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**Acid**          | **Dissociation constant, $K_a$, at 77°F** | **Relative solubility of carbonate (lb/1000gal of acid)**
--- | --- | ---
Hydrochloric | 10 | 3500
Formic     | $1.77 \times 10^{-4}$ | 700
Acetic     | $1.75 \times 10^{-5}$ | 400

**Table 5.1:** Relative solubility of calcium carbonate in various acids
influence reaction rates. Additives, especially fluid-loss additives, viscosifiers and surfactants, help to ensure the requisite performance during and after spending time.

The type of acid selected for a stimulation treatment depends on many factors, including the severity of the damage, the type of rock, its natural permeability and on downhole conditions. A number of options are available for acid-stimulation techniques, including

- wellbore cleanup
- matrix acidizing
- acid fracturing.

**Wellbore cleanup**

Damage, or potential damage to perforations, tubing and the area immediate to the wellbore caused by formation fines, mud or cement filtrate, scale and debris from well operations may be removed by exposing the well to acid over a period of time (soaking), followed by some form of agitation.

Acid can be circulated across the openhole or perforated interval using coiled tubing, allowing a short soaking period. The coiled tubing string is worked up and down through the interval, and the spent acid is returned through the annulus. A second method is to apply pressure against the perforations, followed by rapid release of pressure by opening the bleedoff valve at the pumping unit—a method known as back surging. This technique is primarily effective when the reservoir pressure is greater than the fluid hydrostatic pressure. A further approach involves spotting acid across the perforations and swabbing back, either through tubing or casing.

**Matrix acidizing**

Matrix acid treatments are pumped at pressures lower than the formation parting, or fracturing, pressure to ensure removal or bypass of the damage in the pore spaces and to leave zone barriers intact. These treatments are applied primarily to remove skin damage and to improve formation permeability by dissolving acid-soluble solids. The factors that identify a well as a candidate for

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**Figure 5.1:** The data are indicative of tests performed under controlled laboratory conditions on a 10-in. carbonate core. Overtreatment of the core with uninhibited acids can lower the permeability of the core. Attention must be given to factors such as temperature and overburden pressure when calculating throughput. If this is excessive, the resulting pore collapse can decrease permeability

**Figure 5.2:** Using high volumes of hydrochloric acid without retardation or without the use of diverter can cause collapse of the pore structure. This results in significant reduction of permeability. These effects increase with temperature and pressure. The use of an emulsified acid system eliminates these problems and allows the development of extended wormholes
Matrix treatment include a high skin factor, high natural permeability and a shallow depth of damage (generally confined to a zone less than 3 ft from the wellbore). Matrix stimulation of severely damaged limestone or dolomite reservoirs can increase well productivity. However, if there was no skin damage, a matrix treatment in limestone or dolomite would stimulate natural production by no more than one and a half times. If the natural, undamaged permeability is low (less than 10 md for oil wells), then fracture stimulation is more appropriate.

Most carbonate reservoirs are matrix acidized with hydrochloric acid, although it is not suitable for high-porosity (more than 35%) or chalk reservoirs. Careful treatment design and execution are required to minimize entry of the acid into the highly permeable sections of the formation, as this could create a high-conductivity channel breaking into unwanted gas- or water-producing zones.

The first steps in a matrix-acidizing program are to examine the history of the well and the formation, and to quantify formation damage using well and/or production testing. Core-level examination is important for determining the mineral composition, permeability, and acid solubility. Using this information, a suitable recipe for the remedial acid treatment can be determined. Once the formulation has been identified, the treatment fluid needs to be checked for compatibility with reservoir fluids.

To avoid secondary damage during treatments caused by emulsions and undesirable precipitates produced by reactions in the wellbore or rock matrix, additives such as surfactants, scale inhibitors and iron control agents are necessary. Mutual solvents that prevent adsorption of dissolved material onto the rock surfaces or prevent precipitate entering the pore spaces may also be needed.

In addition, iron compounds produced by the reaction may also result in formation damage when they precipitate as the acid spends. This can be minimized using iron control additives—chelating or reducing agents—or avoided by using formulations that are less corrosive. Significant corrosion may occur if there is contact between acid and steel pipe. The use of suitable corrosion inhibitors can prevent acid damage to tubulars. Use of an SXE system reduces the contact between the acid and well tubulars. This minimizes the tendency for corrosion and hence less inhibition is required.

**Putting acid in its place**

Accurate acid placement is a major concern in matrix acidizing of carbonates, as the acid tends to flow preferentially where the permeability is highest, further increasing permeability and leaving the low-permeability regions of rock untreated. Industry experience shows that around 35% of matrix treatments around the globe do not meet expectations because of improper job design. In some cases, huge increases in water production are observed after a stimulation job because acid may have preferentially stimulated the high-permeability sections associated with water. Once a highly permeable water zone has been stimulated, the chance of acid getting into the pay zones is reduced and the result is the production of more water. Proper use of diversion techniques can avoid such disasters.

In carbonates, because of their rapid reaction with acid, matrix acid may create dominant wormholes through which the acid flows with ease, leaving most of the pay zone unstimulated. This cannot be avoided if the acid is simply bullheaded into the well and allowed to find its own route naturally. Some form of diversion or temporary plugging is necessary to attain effective placement of the stimulation fluids. This can be achieved by chemical or mechanical diversion.

Computer modelling can determine the best method of placement for a particular stimulation treatment. StimCADE® well simulation software helps to optimize matrix stimulation treatments in both production and injection wells. StimCADE software (Figure 5.3) models all aspects of the acidizing process, including the fluid flow for each zone, reaction kinetics, temperature changes such as cool down, and diversion.

![Figure 5.3: StimCADE well simulation software allows stimulation treatments in production and injection well completions to be optimized. The acidizing process, including fluid flow for each zone, reaction kinetics, cool down and diversion can be modeled](image-url)
Mechanical diversion

Mechanical diversion is achieved by pumping the necessary amount of acid in front of the intervals to be treated. Coiled tubing has been increasingly used to achieve diversion in the last two decades. Where the use of coiled tubing is impracticable, other methods of diversion may be considered. The most common method of mechanical diversion uses ball sealers (Figure 5.4). Before injecting the stimulation fluid, balls (made of nylon, hard rubber, biodegradable materials such as collagen, or combinations of these materials) in the treatment fluid are used to plug and shut off the perforations that are taking most of the treatment fluid. Mechanical diversion can also be achieved by using a straddle packer arrangement (Figure 5.5) to isolate the required interval.

Stimulation in multilayer reservoirs with zones having wide injectivity contrasts and heterogeneity is resulting in a combination of mechanical and chemical diversion methods becoming more popular.

Chemical diversion

Temporary plugging of selected zones can also be achieved using a chemical diverter. It is usual practice to pump in the diverter and the acid in alternating stages. The number of stages depends on the height of the zone being treated. This is typically one acid–diverter combination for every 15 to 25 ft of zone height. More recent methods involving VES technology eliminate the need for a multistage process.

Chemical diversion can also be accomplished by careful use of bridging agents such as rock salt or benzoic acid flakes. Rock salt is water soluble and keeps its mechanical integrity in the oil phase, while benzoic acid is oil soluble. Both chemicals are used to create temporary plugging against high-permeability fractures, channels, vugs and fissures while the acid is diverted to low-permeability zones. Rock salt is valuable for plugging high-permeability oil-bearing zones. When the treatment is complete, the spent acid dissolves the salt, restoring permeability. Benzoic acid retains its integrity in the acid but when production is resumed, it is dissolved in the hydrocarbon.

Foam is also effective in diverting acid from a high-permeability zone to the zone of interest (normally an oil–gas zone). Foam is generally produced by injecting nitrogen into fluid containing a surfactant. Foamed fluids break down and become ineffective quite quickly (usually in less than an hour), so they are often mixed with polymer gelling agents to increase stability and improve rheology. Foam is even less stable at high temperatures and also in the presence of hydrocarbons. However, techniques have recently been developed for postponing breakdown, including using a preflush of surfactant. The surfactant is injected with each subsequent stage in the acid treatment process. Diversion techniques, such as FoamMAT® diversion services are very effective, but are more commonly used in sandstone formations.

Other advanced diversion techniques include the use of the polymer-based SDA® Self-Diverting Acid. This is an in-situ gelled acid system that changes viscosity during the acidization process. Fresh SDA fluid has a low viscosity before reacting with the formation. As the
acid spends, the polymer crosslinks at about pH 2, and the viscosity increases dramatically, forcing fresh acid into untreated lower-permeability intervals (Figure 5.6). Between pH 2 and 4, the SDA gel forms a temporary barrier in wormholes created by a previous acid stage or in acidized natural fractures, halting channel growth and reducing the loss of incoming fresh fluid to the wormhole or fracture. At around pH 4, the gelled acid breaks and the viscosity reduces. Like particulate diverters or foams, SDA systems are also pumped in several stages, alternating with stages of regular or retarded hydrochloric acid. Good results are reported in long, open intervals where benzoic acid flakes or precrosslinked gelled acid have not provided effective fluid diversion. Figure 5.7 shows the schematic of a typical SDA treatment and the pressure response.

In-situ acid-viscosity development can also be achieved with VDA* Viscoelastic Diverting Acid technology that uses a nonpolymeric surfactant system for gellation. This gelled acid system can attain viscosity increases between two and over 100 times as it leaks off into the formation. This diverts the subsequent lower-viscosity, acid/fluid stages into the lower-permeability zones.

Acid fracturing

Acid fracturing (Figure 5.8) describes the creation of highly conductive fractures by pumping acid at pressures exceeding the minimum stress in the rock, in the same way as propped hydraulic fracturing. This method is usually preferred where the native permeability of the formation is very low.

Acid fracturing of carbonates not only creates long wormholes, but also etches irregular channels on the fracture face. The irregularity of the etched channels ensures that there is still communication with the wellbore when pressure is released and the fractures close after the treatment. This eliminates the need for proppant in acid fracturing. The effective length of the fracture is determined by the length that has been sufficiently etched and is accessible for flow.

The main factor that adversely affects acid fracture growth and wormholing is fluid loss. Acid leakoff is not uniform, resulting in the enlargement of some wormholes and natural fractures. This greatly increases the area from which fluid loss occurs, making fluid-loss control difficult and preventing acid reaching untreated parts of the fracture. One way to control this, is to pump viscous fluid slugs (pads) intermittently throughout the acid treatment. The initial pad is used to initiate the fracture and to deposit a filter cake in it that forms a temporary barrier.

Figure 5.6: The SDA system crosslinks as the pH reaches around 2 when the acid is spent. The viscosity developed returns to its initial low value at around pH 4 when the breaker is activated. The gelled acid forms a temporary barrier in wormholes or in acidized natural fractures, preventing further loss of incoming, fresh acid. This helps divert the incoming acid to low-permeability zones.

Figure 5.7: SDA systems are applicable only for carbonates. This snapshot of a typical SDA treatment shows where the fluid has migrated and reacted with the high-permeability carbonate formation, resulting in an increase of pH that triggers the in-situ gellation. This allows the following acid stages into the other producing zones.
to prevent acid leakoff. With time, acid dissolves and erodes the filter cake, resulting in increasing leakoff. In order to minimize leakoff further, polymer fluid stages are pumped to reestablish control of fluid loss.

Fluid-loss control can also be achieved using two-phase fluids in the form of foams or emulsions, and crosslinked leakoff control acids such as LCA® leakoff control acids. Recently, VES-based gelled acids such as ClearFRAC® AC systems have been found to be very effective in leakoff control in acid-fracturing applications. The most popular fluid for acid fracturing of high-temperature carbonate formations is an SXE system. This is for the same reasons that these systems are suited to high-temperature matrix acidization.

Getting it right

Matrix acidizing, because it is a low-cost treatment compared with acid fracturing, may not benefit from the same level of execution and evaluation. Laboratory testing is needed for proper assessment of the damage, reactions with the formation fluids and the effectiveness of the treatment to ensure the desired results.

Diagnosing formation damage around the borehole can only be done successfully by analyzing a complete pressure profile from deep in the reservoir up to the wellhead. NODAL® production system analysis helps to achieve this using production history, well-test data and flowing pressures to predict a well’s steady-state production pressures. Comparing a NODAL analysis with actual measured pressures helps to pinpoint and quantify the skin.

Job design and real-time job control are key elements in a successful stimulation operation. They require a geological model based on known reservoir characteristics, such as permeability, porosity, lithology, pressure and production data, obtained from logging, core data from the current well and offset wells, and from other sources such as outcrops. Local operating companies and integrated service companies can also share data and experiences from their intimate knowledge of the fields and reservoirs under consideration to achieve optimum design. As the number of stimulated wells in a field increases, the geological model and the stimulation designs can be refined to continuously optimize the stimulation model.

In acid fracturing, job design, monitoring and evaluation are more complex and are best understood by 3D representations. FracCADE® fracturing design and evaluation software achieves this by giving a physical description of acid diffusion paths and the two-dimensional pressure gradients, combined with fracture length and height evolution algorithms, complete fluid leakoff information and the effects of multiple fluid injections, including temperature changes.

It is possible to modify the treatment during the job using real-time monitoring. Modern communication systems enable experts worldwide to contribute in real time while a job is in progress. The MatTIME® matrix treatment evaluation software within StimCADE allows monitoring of skin evolution during treatment. Once skin evolution decreases, the next stage is pumped. The effectiveness of the chemical diverter can also be determined using this software. FracCADE® software uses a net pressure plot to determine if fracture extension is occurring, and to determine fluid efficiency so real-time decisions can be made, allowing changes to pumping schedules during treatment (Figure 5.9).

Figure 5.8: Acid fracturing is applicable only in carbonates. This diagram showed the sequence of events in an acid fracturing treatment. A viscous pad followed by acid stages is pumped into the well above the natural fracture pressure of the rock to create a fracture (1). The acid continues to penetrate the open fracture and create etched patterns on the inside surfaces. These patterns are more prevalent near the opening of the fracture (2). The acid also penetrates the rock further, forming a network of wormholes (3). When the pressure is released, the fracture closes, leaving the etched paths and wormholes open as an outlet for spent acid and later for produced gas or oil.
Post-treatment analysis is key

A comprehensive post-treatment analysis is essential to validate the acidizing model, understand the results of treatment and improve future designs. A good match between actual and predicted bottomhole pressures indicates that the reservoir was described properly and that the entire process modelled accurately. Similarly, the predicted pressure response during stage diversion can be compared to the observed pressure changes to verify diverter effectiveness. In fracturing, the net pressure plot obtained from FracCADE software during fracturing can be used to quantify fracture extension, height growth and fluid leakoff.

The analysis of the concentrations of polymers, surfactants, inhibitors and key cations and anions in fluids flowed back to surface after treatment will contribute significantly to the success of future stimulation treatments. In the process of treatment optimization, output from the post-treatment analysis of the current and preceding jobs produces valuable input for the next job. This approach to optimization has been successfully demonstrated in the PowerSTIM* well optimization process, currently in use in Saudi Arabia and elsewhere (Middle East & Asia Reservoir Review, Number 3, 2002, pages 16–21).

The way ahead

The use of nonpolymeric and nondamaging VES systems (such as the ClearFRAC system) has proved very successful in hydraulic fracturing applications. This unique technology is now extended to applications in wellbore cleaning (MudSOLV* filter-cake removal), matrix stimulation (VDA systems), diversion (OilSEEKER* acid diverter), lost circulation (ClearPILL systems) and in acid fracturing (ClearFRAC AC systems). These technologies will be presented in detail in future issues of Middle East & Asia Reservoir Review.

Extensive research has been carried out on the use of chelating agents (chelants) in carbonate stimulation. Laboratory studies indicate that these fluids are highly retarded and can form extended wormholes. They are particularly useful in high-temperature applications because of their less-corrosive nature and slow dissolution of carbonates in

**What is formation damage?**

Formation damage occurs in the formation adjacent to the wellbore. It is characterized by a reduction in permeability for a given damage radius and causes an additional pressure drop that decreases the production rate. Since it is difficult to determine the radius and the permeability of the damaged zone, it is usually represented by a term called skin. The effect of formation damage on production is taken into account in Darcy’s equations by the addition of a skin factor. This is a dimensionless number that is positive when the formation is damaged or some other factor has increased the pressure drop in the well during production, and negative where the pressure drop is reduced, for example, because of induced fractures or other stimulation processes.

High skin can also occur for many reasons other than formation damage. These include partial completion, mechanical restrictions, three-phase production and high-pressure drawdown. Acid stimulation is only used to remove skin that is associated with formation damage.

Well operations can damage the formation from the moment the drill bit first penetrates a permeable formation, and this will continue until the end of its productive life. Damage reduces the formation’s natural permeability. The extent of this reduction depends on the amount of damage and the depth to which it occurs. Invasion of the near wellbore by mud solids and mud filtrate can cause pore-throat plugging, either during drilling, or, for example, when it is pushed ahead of cement (Figure 5.10). Unfiltered fluids transported during well killing, clay swelling, debris from completions, sand-consolidating material and fines migration during production can also plug the formation. The action of the drill bit itself can physically alter the pore structure in the near wellbore, and adverse fluid-to-fluid
chemical reactions can lead to emulsion–water blockages and inorganic scaling. Table 5.2 summarizes the extent of formation damage attributable to various well operations.

Many horizontal wells do not produce any more than vertical wells under the same conditions. This may be due to formation damage having greater impact in horizontal wells than in vertical wells. Drilling long, horizontal boreholes leaves the reservoir exposed to potentially damaging drilling mud for a much longer time than short, vertical intervals. Long openhole sections or lengthy perforation intervals mean greater opportunities for formation damage. It is much more difficult and costly to remove formation damage from a horizontal wellbore. For this reason, consideration of potential formation damage and its prevention are key factors in the completion design.

Table 5.2: The severity of formation damage attributed to some of the most common well operations

<table>
<thead>
<tr>
<th>Damage severity</th>
<th>Drilling and cementing</th>
<th>Well completion</th>
<th>Workover</th>
<th>Stimulation</th>
<th>Drill stem tests</th>
<th>Primary production</th>
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<td>Injected particulate plugging</td>
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<td>Sanding</td>
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Figure 5.10: Formation damage can occur for several reasons. During drilling, hydrostatic or circulating pressure forces mud filtrate or mud solids into pore throats in the near-wellbore rock (1 to 4). Invasion and pore throat plugging can also occur when, for example, mud is pushed ahead of cement. Unfiltered fluids transported during well killing, clay swelling and debris from completions can also plug the formation.
Working with wormholes

As acid dissolve carbonate minerals, the area open to flow increases, causing linking, or collision of the pores. This creates highly conductive channels in the rock that are referred to as wormholes (Figure 5.11).

As fresh acid is introduced, the channels interconnect, eventually forming a wormhole network. In acid fracturing, a high injection rate is used to generate enough pressure to fracture the rock. The acid then irregularly etches the fracture face so that a high-conductivity channel remains open after the pressure is released. How acid etches fracture faces and how wormholes develop are shown in Figure 5.8.

Live acid penetration is limited by the reaction rate of the acid. High temperatures cause the hydrochloric acid to spend so quickly that it is used up before it moves out of the area near the wellbore. Controlling reaction rate and fluid loss are the keys to successful acid fracturing treatments. Reaction rate can be reduced by using acid-in-oil emulsions, which delay the interaction between acid droplets and the carbonate. Fluid loss is generally controlled by increasing acid viscosity (surface or in-situ gellation) and optimizing the pumping rate.

The nature of the wormhole network depends on factors that include fluid properties, rock material, injection rate and temperature.

Figure 5.11: Wormholes formed by the dissolution of carbonate into highly conductive flow channels.

comparison to acids. As the oil industry explores deeper and hotter reservoirs, the use of chelants for matrix stimulation and acid fracturing will become more widespread.

The era of real-time reservoir management offers new opportunities for stimulation. Automated candidate selection, computer-aided operations at the wellsite and remote witnessing and evaluation of the stimulation treatment will bring new opportunities for the engineers to increase the productivity and injectivity of carbonate reservoirs. Middle East and Asia region has successfully tested the InterACT* system that allows real-time well monitoring and control by data transmission from the field using the Internet. It allows users to see a job from anywhere, from any computer. Future developments will include live video transmissions from the field to ease communications.
Stimulating times in Indonesia

The results from an acid stimulation job conducted for the China National Offshore Oil Co. at the RX field in Indonesia underlines the value of acid-diversion methods. The job aimed to boost total oil production, extend the working life of the pump, maintain a low water cut and remove any scale deposits that had formed during production. The removal of scale would help to enhance pump performance and ensure continued operation.

Well RX-8 has a maximum hole angle of 63° and six perforation zones in a 90-m interval where the hole angle is 56°. The well was treated with eight stages of 20% hydrochloric acid for stimulation. Each hydrochloric acid stage was followed by two stages. First, an SDA stage for diversion and, second, a small mutual-solvent stage before the next hydrochloric acid stage. In the final stage, the treatment fluid was displaced by ammonium chloride solution.

Careful planning, and proper design and execution ensured that all of the objectives were met. The job was pumped at 4.0 bbl/min and the pressure chart indicated that the desired stimulation and diversion were achieved (Figure 5.12). Production increased from 60 BFPD to 170 BFPD—an increase of around 200%. The post-treatment oil rate showed an increase of 300% (Table 5.3). Production data indicated that the hydrochloric acid and SDA combination provided effective diversion and stimulation of the entire interval (Table 5.3).

Table 5.3: Following stimulation, the oil rate was increased by 300% and tubing pressure rose from 210 to 870 psi.
A slow reaction is important in Saudi Arabia

Attempts were made to restore production to an oil-producing well (Well A) in a carbonate reservoir in Saudi Arabia. Initially, the well was acidized using 15% hydrochloric acid. Because of the rapid reaction rate, the acid spent quickly and only caused dissolution of the rock face or surface washout, instead of the required wormholes. The well remained unproductive after the hydrochloric acid matrix treatment. A thorough laboratory study was then conducted to evaluate the use of the emulsified acid SXE system as a means of retarding the reaction of the acid with carbonates in this well, which had several tight zones. The diesel in the system would act as a diffusion barrier between the acid and the rock, slowing down the reaction and allowing the acid to penetrate deeper into the formation by forming multiple, penetrating wormholes.

Getting to the core of the problem

The laboratory study aimed to determine the rheological properties of the SXE system, measure the thermal stability of the emulsified acids at reservoir temperature, analyse the propagation of emulsified acid into the tight carbonate reservoir cores, and design a stimulation treatment to improve oil production from the low-permeability producing zones. Core-flood tests were conducted with an SXE volume ratio of 70:30 acid:diesel (15% hydrochloric acid). Rheology, thermal stability, compatibility and reactivity with reservoir rocks tests were also carried out on the SXE system (Figure 5.13).

The apparent viscosity of the SXE system decreased as the shear rate increased, indicating that it was a non-Newtonian fluid. The fluid had several-fold viscosity at ambient and bottomhole temperatures when compared to regular hydrochloric acid. Thermal stability tests indicated that the SXE system was stable for several hours under the high-temperature downhole conditions in the well, and would not separate out before reaching the formation.

Compatibility tests showed that, while the system was compatible with crude oil and the acid additives, it broke down on contact with the mutual solvents or demulsifiers. These additives, therefore, were not used with the SXE system.

Reactivity tests, in which the weight loss in samples of reservoir rock was measured for the SXE system and for 15% hydrochloric acid at 24°C, indicated that the reaction rate of the emulsified acid was slower than the 15% hydrochloric acid by a factor of 45. The retardation also depended on the temperature, the rate at which the fluid was pumped and the type of fluid flow.

Measuring the calcium ion concentrations in the core effluent during core flood experiments on the carbonate cores at 96°C confirmed that propagation of the SXE system was slower than the propagation of regular hydrochloric acid, and that the SXE fluid penetrated deeper into the rock. Core permeability was increased nine-fold by the SXE system, which created deep wormholes, but only two-fold by 15% acid (face dissolution only). The results also showed that increasing the flow rate of the emulsified acid led to faster propagation of the SXE system in the core. The number of wormholes and the wormhole diameters on the inlet and outlet faces of the core also increased with the increasing injection rate.

Depth of Producing Zones in Well A

<table>
<thead>
<tr>
<th>Zone</th>
<th>Depth (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>X564–X575</td>
</tr>
<tr>
<td>Zone 2</td>
<td>A X575–X626</td>
</tr>
<tr>
<td></td>
<td>B X626–X704</td>
</tr>
<tr>
<td>Zone 3</td>
<td>A X704–X770</td>
</tr>
<tr>
<td></td>
<td>B X770–X833</td>
</tr>
<tr>
<td>Zone 4</td>
<td>X833–X880</td>
</tr>
</tbody>
</table>

Table 5.4: Well A has four producing zones
Putting it into practice

Well A was drilled in a carbonate reservoir as an openhole oil producer in 1973. The formation is divided into four main zones (Table 5.4). Zone 2 is the main productive zone, while zones 3 and 4 are tight carbonate zones. The second workover operation was completed in February 1995 to isolate a high-permeability interval at the top of zone 2B, which increased water production. Following the workover, a total of 15 m was perforated in zones 2B, 3A and 3B. The perforated intervals were acidized with 3000 gal of 15% hydrochloric acid using coiled tubing. This did not sustain flow to the gas–oil separation plant. In July 1995, a further 4.5 m of perforations were made in zone 2A and acidized with hydrochloric acid, but this did not increase well productivity.

Following various diagnostic studies, it was decided to stimulate zones 2A, 3A and 3B using an emulsified acid to improve permeability of the formation (Table 5.5).

Nitrogen lift was used to clean up the well while flowing into the flare pit. Two hours after the backflow, the well flowed at a wellhead pressure of 360 psi without nitrogen lift. Acid return samples were collected during flowback for about 4 hr and analyzed for key ions.

Return to production

Emulsified acid treatment for Well A was successful in increasing the productivity significantly in the stimulated intervals, especially in zone 3, which generally has a low permeability. Flowmeter tests confirmed that the production rate more than doubled from 14 to 29% in zones 3A and 3B.

There was a significant reduction in iron concentration in the acid returns (Figure 5.14). The source of iron is acid reacting with coiled tubing, mixing tanks and corrosion products. In Well A, the total iron concentration in the backflow reached 237 mg/l after 1.8 hr, falling to 1 mg/l after 4.0 hr.

By comparison, the iron concentration in Well B (another oil producer), which was acidized with regular 15% hydrochloric acid, reached 6000 mg/l. In an emulsified acid system, the diesel minimizes the contact between the tubing and casing surfaces and the acid, as it is the dispersed phase and has less interaction with these surfaces. The SXE system significantly reduced corrosion and the potential for sludge formation.

Table 5.5: Stimulation was carried out with SXE acid-in-diesel emulsion system and SDA fluid for diversion

<table>
<thead>
<tr>
<th>Stage</th>
<th>Volume (bbl)</th>
<th>Fluid</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>15 % HCl</td>
<td>To improve injectivity while acidizing the intervals below the gel</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>High-pH spacer</td>
<td>To separate acid and gel plug</td>
</tr>
<tr>
<td>3</td>
<td>1.5</td>
<td>PROTECTZONE* fluid</td>
<td>To isolate the interval X627 to X710 ft</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>High-pH spacer</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Diesel</td>
<td></td>
<td>The volume was adjusted to have a hydrostatic head inside the coiled tubing equal to reservoir pressure to avoid the plug movement during the gel-setting period</td>
</tr>
<tr>
<td>6</td>
<td>15.5</td>
<td>15 % HCl</td>
<td>A preflush for the interval below the gel plug</td>
</tr>
<tr>
<td>7</td>
<td>3</td>
<td>Diesel</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>69</td>
<td>SXE fluid</td>
<td>To acidize zones 2A and 3 (A and B)</td>
</tr>
<tr>
<td>9</td>
<td>12</td>
<td>SDA fluid</td>
<td>To minimize the downward movement of the plug while acidizing the interval above the gel</td>
</tr>
<tr>
<td>10</td>
<td>8</td>
<td>15 % HCl</td>
<td>As a preflush for the interval above the gel plug</td>
</tr>
<tr>
<td>11</td>
<td>2</td>
<td>Diesel</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>36</td>
<td>SXE fluid</td>
<td>To acidize the interval above the gel plug</td>
</tr>
</tbody>
</table>

Figure 5.14: The amount of total iron recovered in the flowback fluid. When using an SXE system, acid is the dispersed phase. It has less interaction with reactive surfaces and shows significant reduction of iron concentration in the acid returns, even at higher temperatures
Active Partnership

Dr Abdulaziz Al Kaabi is director of the Center for Petroleum and Minerals in the Research Institute of King Fahd University of Petroleum & Minerals (KFUPM), Saudi Arabia. Established in 1963, the KFUPM campus occupies an impressive 6-km² site in Dhahran. The university has six colleges, with 700 faculty members and 8000 students. Schlumberger is building its new carbonate research center on the campus. In this article, Al Kaabi describes his great hopes for active partnership between industry and academia.

"The Research Institute of KFUPM was created in 1978 to help solve industry's problems through our applied research. It has about 350 full-time researchers and support staff.

On average, more than 70 faculty members from various university departments participate in industry-funded research projects in the institute. If they are interested in certain projects, they can become institute members or project managers. Their graduate students can also come in and do part of their research on some aspects of our work. The Center for Petroleum and Minerals within the institute has about 40 multidisciplinary, full-time researchers and support staff.

The upstream oil and gas companies sponsor our contract research work. Saudi Aramco has been our major client for more than 24 years, accounting for more than 90 percent of our contract work. We are also cooperating with Japan National Oil Corporation in a joint, five-year project in fluid-flow visualization, and we have worked with regional clients such as Bahrain National Oil Corporation and Aramco Gulf Operations Company.

Schlumberger is now partnering with us, as well as receiving our consultancy and laboratory services, and it is about to become a member of our reservoir characterization consortium.

Focus on the practical

Within the center, we have four focus areas. The first is petroleum and gas engineering. This includes reservoir and production engineering, and petroleum-related rock mechanics. Reservoir simulation and fluid flow visualization are also part of this focus area. For example, we are engaged in a major program with a client to help develop a gas condensate reservoir.

We are also working on process development and testing new technology for another client to control sand production from sandstone reservoirs. This technology was invented here in the university and has a US patent. The client and KFUPM are already in the final stages of conducting a pilot test to evaluate it. If the field tests are successful, the technology will be applicable to sandstone reservoirs outside the Kingdom.
Rock mechanics is another important activity. We are drilling very deep, hot gas wells with huge, underground, in-situ stresses where rock behavior has been critical to successful drilling. Rock mechanics is also important in horizontal and highly deviated wells where we need to be aware of in-situ stresses.

Our second focus is on petroleum geology and geophysics, and includes work on many reservoir characterization projects involving our consortium on reservoir characterization. Schlumberger will soon join this consortium. Seismic processing and interpretation is an important activity that we hope to expand in the near future.

Petrophysics is part of this focus area. We measure many electrical parameters, and we take core samples, that are subjected to reservoir conditions of high pressure and temperature. We look at the electrical conductivity of the rock when it is saturated with reservoir fluids, and the information we gather can be used for estimating reserves. This information is part of an integrated study that includes geology and physics. It's another area in which our experienced geologists have been active.

Our third focus is on remote sensing. Our laboratory was the first to be established in the Kingdom. It provides images to help geologists and environmentalists with exploration and environmental monitoring.

Our fourth focus area is minerals. The Kingdom is putting more emphasis on mineral resources development, and we have a fairly new unit that is trying to set the direction for helping the minerals industry in the future.

In summary, we provide high-quality research and development (R&D) and consulting services to the oil, gas and minerals industries, focusing, at present, on industries within the Kingdom. We are hoping to eventually extend this cooperation internationally.

The right support, at the right time

Our vision is tied to what the industry wants to do. It is dynamic and it suffers from instability when it comes to setting long-term strategies. So most of our activities have to support what the industry really wants at a particular time.

I would like to be involved with the industry on medium- and long-range, strategic projects. Currently the focus is short term and the researchers change direction quite frequently. That's really becoming a characteristic of the oil and gas industry. So I hope that good planning with our local industry could help to move away from the short term and try to put emphasis on medium- and long-term R&D. I think we can do it.

This is especially important, as some of our oil fields are beginning to mature. New techniques can be used on our current fields for reevaluation of reservoirs. What we need to do in the medium and long term is to evaluate techniques for maximizing recovery, reducing the cost of development, and for recovering that extra oil and gas from the ground. We need to minimize the risk in our operations and be mindful of how can we lessen the impact on the environment.

Another vision is to form a real partnership with industry, so they can look on this center as a place that can add value to their operations. This can only be done through long-term commitment between the industry and an academic institution like ours.

Positive culture

I definitely see the proximity of the Schlumberger Dhahran Carbonate Research Center (SDRC) to the university as a step forward. Schlumberger is top of the list for R&D funding and expenditure. It invests about five percent of its sales revenue in R&D. I am hoping that the SDRC and the company's R&D culture will influence the students, the faculty and the partnership with the university in a unique way.

The university will benefit from the center by enabling talented faculty staff and students to interact with industry experts. This could be through research and industrial training. The institute will be able to participate in technology development and consulting projects with the SDRC, where our scientists work as a team with the Schlumberger scientists.

We are already seeing this happen. Dr Kamal Babour, for example, is advising a graduate student in the petroleum-engineering department on examining reservoir fluid tracking. This work is at the frontier of new technology.

This partnership shows industry how it can work closely with academia and create an environment that allows universities to contribute to the community. So, I am very happy to see this kind of cooperation. It will be a good example for others to follow.”