Virtual Testing: The Key to a Stimulating Process

Matrix acid stimulation in a sandstone reservoir involves complex chemical reactions that are strongly dependent on mineralogy. A new process includes a model for simulating acid reactions to help operators choose an optimal treatment for a formation.

Reacting to Damage

Acid treatments for sandstones differ significantly from those for carbonate rocks. Carbonate rocks dissolve rapidly in hydrochloric acid [HCl], and the reaction products are soluble in water. In carbonate rocks, a matrix acid job is usually designed to bypass near-well damage by dissolving minerals and creating channels, or wormholes, in the rock, providing a flow path past the near-well damage. Acid-fracturing techniques in carbonates create a hydraulic fracture that has a differentially etched surface, so that the fracture maintains its conductivity during production.¹

In contrast to acidizing reactions in carbonate rocks, the reaction chemistry for silicate rocks is quite complex. Sandstones comprise quartz grains, clays of various types, feldspars, chert, micas, and carbonate materials as cement or overgrowths on grains, along with other minerals (next page). HCl is not effective in dissolving most constituents of silicate rocks. Sandstone acid jobs typically use hydrofluoric acid [HF] in combination with HCl, formic or acetic acid.² HF dissolves silica and silicates, and HCl or organic acids are included to keep reaction products in solution.

Sandstone matrix acidizing primarily targets damage from migrating fines, swelling clay, carbonate or hydroxide scales, and plugging particles from drilling and completion operations. Understanding formation mineralogy and the
The nature of the damage is critical for designing a proper acid treatment. An improperly formulated acid treatment can precipitate reaction products in the formation, reducing rock permeability.

A primary objective of designing an acid treatment in sandstones is optimizing damage removal, while minimizing formation of damaging precipitates. The first 3 ft [0.9 m] into a formation from a wellbore experiences the greatest pressure drop during drawdown, and is critical for flow. This region, sometimes called the critical matrix, is the volume that matrix acidizing treatments target for cleanup.

If HF comes in contact with calcium carbonate \([\text{CaCO}_3]\) during a treatment, then it leads to calcium fluoride \([\text{CaF}_2]\) precipitation. For this reason, a matrix treatment usually includes a preflush stage with an acid such as HCl or an organic acid to dissolve most of the carbonate minerals. The main treatment that follows is often either a mud acid, a combination of HF and HCl, or a retarded formulation such as the ClayACID fines-control retarded acid, which is a combination of fluoboric acid \([\text{HBF}_4]\) and HCl. The \(\text{HBF}_4\) hydrolyzes slowly to form HF and also

1. A water block is a production impairment that may occur when the formation matrix in the near-well area becomes water-saturated, thereby decreasing the relative permeability to hydrocarbons. Water block may result from the invasion of water-base drilling or completion fluids or from fingering or coning of formation water.
4. The acid formulation used in any specific instance is dependent on formation mineralogy.
reacts with clays, leaving behind a glassy borosilicate coating that cements and stabilizes clay particles. Acid treatments are often followed by an overflush, either diluted HCl or ammonium chloride [NH4Cl], to remove the treatment-reaction products from the near-well volume. A treatment normally includes injection of a diverter followed by a repetition of these three stages.

A wide variety of acid formulations is available, and the best treatment for a given formation depends on the characteristics of that formation. The new Virtual Lab geochemical simulator provides a tool that helps guide the selection based on formation parameters and treatment chemicals. The simulator models reactions and indicates the amount and location of dissolution and precipitation of mineral species.

The primary reaction between aluminosilicates and HF from ClayACID and mud-acid treatments yields fluosilicic acid [H2SiF6], along with several aluminum-fluorine complexes. In the presence of sodium and potassium, and under certain conditions of temperature and acid concentration, precipitation of compounds such as sodium fluosilicate [Na2SiF6] and potassium fluosilicate [K2SiF6] can occur. In the presence of additional aluminosilicates, H2SiF6 can react to produce amorphous silica [H4SiO4] as a secondary reaction. Amorphous silica can also result from tertiary reactions of aluminum fluorides with aluminosilicates.

Amorphous silica and the other compounds listed above can block pores when they precipitate. A successful treatment design must minimize the precipitation of these compounds in the formation, particularly in the critical matrix.

Simulated Reactions

The reaction of HF with minerals in sandstones is slow, and the secondary and tertiary reactions that generate precipitates are even slower. The outcome of an acid treatment depends strongly on the amount and location of the precipitates. Therefore, predicting the results of a treatment requires knowledge not only of the equilibrium reaction products, but also of the reaction kinetics of the acid in the formation.

Reaction kinetics determine the rate at which the concentrations change as the system approaches equilibrium. The composition at equilibrium depends on the stability of the species at the given conditions and is calculated from thermodynamic data. Both kinetic and thermodynamic parameters must be known for all reactive fluids and minerals to predict the amount and the location of dissolved and precipitated minerals around the wellbore.

Past practice has been to obtain specific reaction information through core-plug tests. Ideally, a core should come from the well and formation that is to be acidized, but it often comes from a nearby well. Outcrop samples and samples formed of packed sand mixed with clay minerals have also been used, but matching a specific formation mineralogy and sedimentology may be difficult.

Although a core-flow test can provide vital information for designing an acid job, there are two inherent problems with such tests: the core plug is too short and the radial geometry around a wellbore is not honored (left).

Most core plugs are only a few inches long. Reaction products flow out of the core before the secondary and tertiary reactions can occur and can generate precipitates. Use of 3-ft long cores has been recommended to alleviate this problem. However, obtaining sufficient formation material for long cores is difficult. Analog outcrops or sandpacks can provide sufficient material, but at the expense of potentially poor matches to formation mineralogy and sedimentology.

Long linear cores do not address the geometry problem. As injected fluid flows out from a wellbore, the cross-sectional area that it flows through increases proportionally to the radius. With the same volume flowing through a larger cross section, the flow rate decreases away from the wellbore. For an 8-in. diameter wellbore, the flow rate 3 ft into the formation is only 10% of the rate at the sandface. This slower flow rate strongly impacts the location of precipitates from secondary and tertiary reactions (next page).
The new Virtual Lab simulator overcomes the problem of unrepresentative geometry and provides guidance for successful matrix acidizing in sandstone reservoirs. It is the foundation of a system for designing acid treatments that properly accounts for the cylindrical geometry around a wellbore (see “A New Stimulation Process,” page 62). In addition, Schlumberger has created a large, proprietary database of reaction kinetics and thermodynamics to use with this simulator. This database saves clients time and money because additional tests are necessary only when a formation or a new acid formulation contains compounds that are not in the database. The need for new tests has become less common as the database has filled with reaction parameters.

Formation mineralogy can be obtained from either whole core or sidewall cores. A short-core flow test gives an estimate of the surface area of the reacting minerals in a formation. This test also provides information about core permeability and the effect of an acid on permeability as pore-blocking material dissolves. Short-core tests alone do not provide sufficient information for determining an acid treatment, but a short-core test provides data necessary to model reactions using the Virtual Lab simulator. Numerous treatment designs can be tested in the simulator, and Virtual Lab results will indicate the best design for field conditions.

From Laboratory to Field

Central to any successful acidizing treatment is accurate information about the reaction chemistry relating to formation minerals. The literature contains much of the relevant thermodynamic-equilibrium data. However, most publicly available reaction-kinetics data are from tests obtained at temperatures below field matrix acidizing conditions. Schlumberger laboratories performed batch-reactor tests at a wide range of temperatures to create an extensive proprietary database.

The database of reaction-kinetics data reduces the number of fluid formulations that it is necessary to test. However, usually at least one core-flow test is recommended to determine the reactive surface area of minerals in the formation represented by the core. More than 50 core-flow tests have been performed to validate the Virtual Lab software. This database also provides analogs for future cases in which core material is not available.

The flow test on a core sample from the Heidrun field was typical of the procedure. A small formation-core plug, 3.73 by 6.4 cm [1.47 by 2.5 in.], obtained from a well near the one to be treated, was saturated with simulated formation brine and flushed alternately with laboratory oil and brine until the effluent was clear. A laboratory engineer heated the core to reservoir temperature and flowed prefiltered test fluids through the core with a 1,000-psi [6.9-MPa] backpressure. This pressure kept any generated carbon dioxide [CO₂] in solution.

The Heidrun field study used a 9/1 mud-acid—9% HCl and 1% HF—and a ClayACID treatment. Flow rate and differential pressure data recorded every 30 s allowed calculation of permeability throughout the test. The engineer collected effluent in 10-mL plastic tubes on a regular schedule and noted any fines in the sample. After filtering and diluting with nitric acid (continued on page 64)
A new process for matrix acid stimulation relies heavily on the Virtual Lab software. Mineral-fluid reactions are simulated quickly and efficiently, so the best treatment option can be selected. Schlumberger has developed several databases in a proprietary data archive to use with the simulator.

The design process starts with a collection of well data (next page). Mineralogy, which is an important parameter for proper stimulation design, can be obtained from X-ray diffraction of core material. The other data include well completion, formation temperature, porosity, permeability, evidence relating to formation damage, and well history.

Schlumberger has created an extensive database of reaction kinetics and thermodynamics, but occasionally some specific kinetics parameters are not available. In that case, reactions monitored in a controlled environment, a batch-reactor, provide necessary data. The new results are added to the database.

As the next step, experts recommend performing at least one flow test using core material relevant for each formation to be stimulated. These core tests are also stored in the database, so a new test is not necessary if results are already available. If they are not available, and suitable core material can be obtained, then a flow test should be performed to provide data for the Virtual Lab simulator to match mineral surface area and the permeability-porosity relationship for the specific formation. Only for cases in which core tests or core material are not available should an analog to the formation be used. The core-flow database is the first place to look for such an analog.

With all this information collected, a Virtual Lab model can be built for the formation. It includes the effect of radial flow from the wellbore. The model can perform sensitivity studies when the well-log data indicate heterogeneity in the formation-mineral composition. Data selected from the reaction and core databases feed into the model.

A stimulation expert selects a few treatment fluids based on the information obtained for constructing the model. Each treatment option is simulated. Various injection volumes, rates and shut-in periods can also be evaluated. Uncertainties in the data can be checked by running a sensitivity analysis, which Virtual Lab software can do automatically.

With an optimal treatment schedule determined, an operator can now perform the recommended treatment.

If real-time bottomhole pressure data are available during the operation, the treatment design can be adjusted while in progress (below). If operational constraints prevent the treatment from proceeding as planned, the constraints can be put into the model and the treatment redesigned. Once the design and the operational parameters agree, the real-time data of bottomhole pressure, injection rates and fluids injected can be compared with model expectations. If there is a significant discrepancy, the model assumptions are reexamined. For example, the real-time data may provide a new insight into the type, quantity or location of damage, or may suggest that the permeability-porosity relationship in the formation differs from that measured in the core. After the model is adjusted, the redesigned treatment can continue. This ability to adjust the model in real time provides a great benefit in helping operators optimize stimulation jobs.

After the treatment, flowback and production data can be used to adjust the model one last time. The updated model for that field and reservoir is then available to optimize future treatment jobs.
The stimulation process using Virtual Lab simulation and the proprietary data archive. The process begins on the left and proceeds clockwise. Solid lines are the process steps and dashed lines are data transfers into, out of, or within the data archive. A real-time feedback loop can update the model while the crew performs the treatment.
to prevent further precipitation, the fluid samples were analyzed to determine the concentration of aluminum and silicon (below). Changes in effluent composition provided information about the type and morphology of reactive minerals in the core. The Virtual Lab simulator matched the flow-test results, providing the mineral surface area and permeability-porosity relationship.

The acid treatment did not deconsolidate the Heidrun field core and did not form precipitates, indicating that this treatment fluid was compatible with the native mineralogy. It also provided the desired permeability improvement.

**First Use of Simulator for Stimulation**

Statoil operates the Heidrun field, located in the Haltenbanken area of the Norwegian Sea, 120 km [75 miles] south of the Arctic Circle. The target well, A-48, had a deviation angle of 48° across the producing interval in the Tilje formation and was completed with an openhole gravel pack. Productivity in this zone declined after formation-water breakthrough, and worsened after a scale-inhibitor squeeze treatment. Design of a matrix-stimulation job was difficult because this was the first well in the Tilje formation to be acidized. The formation was heterogeneous, with high clay content and large clay clasts (bottom).

The treatment design was based on the core and reactor tests. During the treatment, Statoil captured samples from all fluid returns and determined the profile of ions in these fluids at each stage. With this information, Virtual Lab software confirmed that fines migration was the most likely primary damage mechanism and allowed the operator to examine the possibilities of combined damage mechanisms. This simulation showed that the final design improved permeability while limiting mineral precipitation (next page, top). The model recommended injection rates that could not be maintained during execution because of operational difficulties. A second run of the model using actual flow rates and fluid volumes indicated that the difference in fluid placement between the recommended and executed procedures was minor.

Before the stimulation treatment, the well productivity index was 20 m³/bar-d [9 bbl/psi-D] and reached 55 m³/bar-d [24 bbl/psi-D] immediately after the treatment. The productivity index over the next seven-month period averaged 42 m³/bar-d [18 bbl/psi-D]. The acid treatment successfully removed the near-well damage and controlled fines migration (next page, bottom). The Virtual Lab model optimized after treating

**Core-flow test.** The permeability response to treatment acids is measured during a Heidrun field core test. The increasing permeability during the NH₄Cl brine flush following the 9/1 mud-acid treatment indicates movement of fines out of the core (bottom). The upper plot shows elemental concentrations in the effluent. After changing injection fluids, the permeability change is seen before an effluent effect because the new fluid has to pass through the core. All the solid lines are best-fit results from the Virtual Lab model, providing essential parameters for modeling the treatment.

**Clay clasts.** The Tilje formation in the Heidrun field contains large clay clasts, apparent in the computed tomographic image (left). The section AA' includes large, dark, clay clasts (center). The lower section BB' shows clay laminae (right).

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15. An acid treatment normally dissolves some cement; deconsolidation indicates that so much cement dissolved that the core matrix was no longer competent.


Matrix acid-treatment model results. The two-phase Heidrun field treatment started with a mud-acid treatment, then a flowback stage, followed by a ClayACID fluoboric phase (table). The geochemical model predicted that the treatment would improve near-well permeability (top). The total silica mineral precipitation was low, less than 2.5% of the formation volume (middle). Borosilicate precipitation, useful for stabilizing clays, peaks near the wellbore, while amorphous silica peaks farther away (bottom).

Production data for Heidrun field Well A-48. Productivity declined when water broke through, and further productivity was lost after a scale-inhibitor squeeze treatment. The acid-stimulation treatment in September 2001 restored productivity without significantly increasing the amount of produced water.
the Heidrun A-48 well provided vital information to shorten the learning curve for treatment of other wells in this complex, clay-rich formation.

**Damage Mechanisms in the Galley Field**

Operator ChevronTexaco used the new acid-stimulation process in the Galley field on the UK continental shelf. The G5 well was completed horizontally with a 650-ft [200-m] openhole section in the late Paleocene-age Cromarty formation, which comprises fine to very fine-grained, poorly consolidated, turbiditic sandstone (above). Most of the productive section has a 100-mm mesh screen in place that was originally intended for a gravel pack, but a shale section about a quarter of the way along the horizontal section collapsed. Although productive sand channels beyond the collapsed shale are accessible for flow into the wellbore, those sections could not be gravel packed.

Oil production declined steadily from an initial 7,000 B/D [1,100 m³/d], but the oil decline rate accelerated when water production increased in April 2002. Before the stimulation treatment, the well produced about 1.1 million bbl [175,000 m³] of oil and 979 MMcf [28 million m³] of gas, along with about 31,000 bbl [4,900 m³] of water. Significant recoverable reserves remained within the well’s drainage area.

The combined ChevronTexaco and Schlumberger stimulation team examined several possible damage mechanisms to explain the loss of oil production.

**Drilling-induced damage**—Filtrate invasion; invasion of a calcium carbonate bridging agent, polymer, starch and drilled solids; and filtercake plugging of the screen and sandface could go unnoticed initially in a horizontal well. However, such damage can create localized production areas, which can eventually lead to early water breakthrough, loss of screens and accelerated fines production.

**Completion damage**—The collapse of the shale section prevented a complete gravel pack, so the filtercake and mud removal in the section beyond the damage was probably extremely poor.

**Swelling clays**—X-ray diffraction mineralogy from a core sample showed that the volume of swelling clays, such as smectite, was too low to be a damage mechanism.

**Inorganic scale**—Damage from barium sulfate [BaSO₄] was expected to be small, but CaCO₃ scale could be a major source of damage. Limited data were available to quantify the volumes of scale.

**Water-holdup problems**—NODAL production system analysis results showed that water cut in this field must exceed 50% to create a significant impediment to production. The measured value of 20% shows this is an unlikely damage mechanism.

**Fines migration**—X-ray diffraction results indicated the presence of migratory clays such as chlorite and illite along with mobile quartzite particles. A pump-in test supported fines as a damage source. Permeability increased during the pump-in—that is, reverse-flow—period, as compared with the permeability during production. Further evidence of fines migration was found in the decreasing oil production with increasing water production, since water can destabilize fines and cause them to migrate. Finally, the formation is unconsolidated, and other wells in the area had experienced fines migration.

This analysis indicated that the treatment had to remove damage possibly caused by drilling, inorganic scale and migration of clays and quartzite particles. The proposed treatment started with jetting a chelating agent using a coiled tubing string with a high-pressure nozzle. This treatment, which stabilized iron and also removed CaCO₃ scale, was followed by...
which was a 9/1 organic mud acid. The Virtual Lab process provided a means to test the effectiveness of this treatment schedule.

Reaction kinetic parameters were available in the database. A core-flow test on a small plug from the Cromarty formation provided an estimation of mineral surface areas and parameters for the permeability and porosity correlation. The test showed that treatment fluids were compatible with the native mineralogy and that they increased permeability within the core sample.

The next step was to simulate the reservoir geometry using the Virtual Lab software. In this simulation, damage was assumed to be due only to fines migration. The model showed that wellbore skin factor declined steadily with the treatment, and a small quantity of amorphous silica reprecipitated near the wellbore (below).

A PLT Production Logging Tool run just before the main stimulation treatment was analyzed in real time and indicated no production from the gravel-packed channel sand. The first half of the productive interval beyond the shale section produced oil with a 50% water cut, and the second half produced dry oil at a low rate. Since water was not coming from an isolated zone, it was not possible to stimulate oil production alone.

The first treatment stage was jetting a chelating agent along the entire wellbore. This stage mechanically cleaned the wellbore and increased the oil production rate to 1,000 B/D [160 m³/d] with a water cut of 40%. Flowback after the treatment was slower than planned because of operational problems. A postjob Virtual Lab simulation showed that the effect of this additional fluid-residence time was a small increase in silica precipitation that would have minimal effect on productivity.

The complete treatment increased oil production to 3,000 B/D [480 m³/d], 15 times the pretreatment production rate. The water cut increased slightly to 45%. After three months of production, the well produced oil steadily at 1,500 B/D [240 m³/d].

The productivity increase was better than that predicted by the geochemical simulation. The model had assumed that the main cause of damage was fines migration, but it is possible that the dominant damage came instead from CaCO₃ scale or residual drilling and completion fluids. Real-time bottomhole-pressure readings and an analysis of the flowback fluids were not available. Had they been, the Virtual Lab simulator could have estimated the contributions of the various damage mechanisms, further improving future jobs in the field.

### Sensitive Clays in the Gulf of Thailand

Several fields operated by ChevronTexaco in the Gulf of Thailand have similar lithologies. The productive sandstone formations have HCl-sensitive clays in proportions greater than 15%, and the reservoir temperature exceeds 250°F [120°C]. The formation also contains carbonate minerals. The primary damage mechanisms are swelling of smectite and other clays and migration of clays such as kaolinite-illite and illite-smectite mixtures. These clays can either line or fill pore spaces.

Conventional matrix acidizing—using mud-acid and ClayACID treatments—was ineffective in restoring well productivity in this area.²² In April 2002, Schlumberger used a new clay-stabilizing acid in this field, a ClayACID formulation using an organic acid in place of the HCl. The clay-stabilizing acid is designed to permanently stabilize a formation containing high percentages of silt and clay, while minimizing secondary and tertiary reactions. The treatment deposits a layer of borosilicate glass that immobilizes the clays. The formulation was successful in four of six treatments, and the production increase was stable for at least six months after treatment. Nevertheless, a posttreatment analysis indicated that a better methodology for selecting candidate wells could yield improved results.

The second stimulation campaign, carried out in 2003, used the Virtual Lab software for prestimulation analysis to improve results. The geochemical model inputs included a mineral composition of 9% carbonate minerals, 18% clay—illite, mixed illite and smectite, kaolinite and chlorite—and 6% feldspar. The large proportions of these minerals, in conjunction with the high reservoir temperature, make treatment design difficult.
The geochemical simulation tested preflushes of both 10% acetic and 5% formic acid to remove near-well carbonate minerals from the formation. The two formulations provided similar skin reduction, so acetic acid was used because it was more readily available at the time. The model indicated the optimal preflush volume and the optimal clay-stabilizing acid volume (above). The simulation showed that the borosilicate coating that stabilizes clays extended about 1 ft [0.3 m] into the formation with the optimal clay-stabilizing acid treatment, but that additional clay-stabilizing acid did not extend the protected zone significantly.

ChevronTexaco planned the second phase of clay-stabilizing acid stimulations based on optimized acid volumes from the Virtual Lab simulator. Stimulation jobs on one oil-producing well and three gas producers were successful and showed significant production increases (right). This use of the new stimulation design process increased profitability from the stimulated wells. The fluid system, customized for the specific lithology in the Gulf of Thailand wells, provided a lasting solution.

**Reacting to the Future**

The new stimulation process, including the Virtual Lab simulator, provides a tool to improve well performance in sandstone formations. Sandstone matrix acid treatments are complex, and the success rates are historically low. The new process with the software and proprietary databases as its basis assures a much higher ratio of successful matrix acid treatments.

Determining formation mineralogy is an important first step in the process. If data such as the ELANPlus Elemental Log Analysis are available, they can be used with the Virtual Lab software. In addition, the growing databases for geochemistry and flow properties will provide more analogs for locations lacking core material.

The Virtual Lab software is a general-purpose geochemical simulator and is not restricted to solving for matrix acidizing in sandstones. The tool could be used for carbonate acidizing, carbon dioxide sequestration and water-compatibility testing. Schlumberger continues to expand the reaction database, increasing the variety of problems that this geochemical software can solve for the industry.

—MAA