Corrosion costs US industries alone an estimated $170 billion a year. The oil industry, with its complex and demanding production techniques, and the environmental threat should components fail, takes an above average share of these costs.  

Corrosion—the deterioration of a metal or its properties—attacks every component at every stage in the life of every oil and gas field. From casing strings to production platforms, from drilling through to abandonment, corrosion is an adversary worthy of all the high technology and research we can throw at it.

Oxygen, which plays such an important role in corrosion, is not normally present in producing formations. It is only at the drilling stage that oxygen-contaminated fluids are first introduced. Drilling muds, left untreated, will corrode not only well casing, but also drilling equipment, pipelines and mud handling equipment. Water and carbon dioxide—produced or injected for secondary recovery—can cause severe corrosion of completion strings. Acid—used to reduce formation damage around the well or to remove scale—readily attacks metal. Completions and surface pipelines can be eroded away by high production velocities or blasted by formation sand. 

Hydrogen sulfide \([\text{H}_2\text{S}]\) poses other problems (next page). Handling all these corrosion situations, with the added complications of high temperatures, pressures and stresses involved in drilling or production, requires the expertise of a corrosion engineer, an increasingly key figure in the industry.

Because it is almost impossible to prevent corrosion, it is becoming more apparent that controlling the corrosion rate may be the most economical solution. Corrosion engineers are therefore increasingly involved in estimating the cost of their solutions to corrosion prevention and estimating the useful life of equipment. For example, development wells in Mobil’s Arun gas field in Indonesia have been monitored for corrosion since they were drilled in 1977.

Production wells were completed using 7-in. L-80 grade carbon steel tubing—an \(\text{H}_2\text{S}\)-resistant steel—allowing flow rates in excess of 50 Mscf/D \([1.4 \text{ Mscm/D}]\) at over 300°F \([150^\circ\text{C}]\). High flow rates, \(\text{H}_2\text{S}\) and carbon dioxide \([\text{CO}_2]\) all contributed to the corrosion of the tubing. Laboratory experiments simulated the Arun well conditions, alongside continued field monitoring. These help find the most economical solution to the corrosion problem.  

The results showed that the carbon steel tubing would have to be changed to more expensive chromium steel or to corrosion-resistant alloy (CRA).
The Basic Corrosion Cell

By recognizing corrosion when it does occur, and by understanding the mechanisms involved, corrosion engineers may begin to eliminate corrosion by design.

The basic galvanic corrosion mechanism follows the principle of a battery. A typical battery requires two dissimilar metals connected together and immersed in an elec-


For an easier read:


Farooqul MASZ and Holland S: “Corrosion-Resistant Tubulars for Prolonging GW1 Well Life,” paper SPE 21365, presented at the SPE Middle East Oil Show, Manama, Bahrain, November 16-19, 1991.
Corrosion cell. The basic corrosion cell is formed by two dissimilar metals immersed in an electrolyte joined by a conductor. One electrode will tend to corrode more readily than the other and is called the anode. The anode loses positive metal ions to the electrolyte leaving free electrons and a net negative charge. At the other electrode, called the cathode, free electrons are taken up by ions in the electrolyte leaving a net positive charge. Free electrons can travel from anode to cathode along the conductor. The electrolyte then completes the circuit.

All metals have a tendency to dissolve or corrode to a greater or lesser degree. In this case, the metal with the greater tendency to corrode forms the negative pole and is called the anode. When the two are connected, the other metal forms the positive pole, or cathode.

Loss of positive metal ions from the anode causes a release of free electrons. This process is called oxidation. The buildup of electrons generates an electrical potential, causing them to flow through the conductor to the cathode. At the cathode, excess electrons are neutralized or taken up by ions in the electrolyte. This process is called reduction. As long as reduction reactions predominate, no metal is lost at the cathode. The anode will continue to corrode as long as the electric circuit is maintained and the metal ions are removed from solution by combining with other elements to make up corrosion products.

Anodes and cathodes can form on a single piece of metal made up of small crystals of slightly different compositions. The electrolyte may simply be water (right). The electrolyte may be next to each other or separated by large distances—sometimes tens of kilometers.

The electrolyte (below). All metals have a tendency to dissolve, going into solution as Fe++. As each Fe++ ion is formed, two electrons are left behind, giving that area of the metal a small negative charge. If nothing happens to remove Fe++ ions around the anodic site, the tendency to dissolve will diminish. In oil production, Fe++ ions are removed by reacting with oxygen [O₂], hydrogen sulfide, or carbon dioxide. The corrosion products are precipitates or scales of rust—iron oxide [Fe₂O₃ • H₂O], iron sulfides [FeSx] or iron carbonate [Fe₂CO₃]. While this is happening, the electrons migrate to the cathode. At the cathode surface, they reduce oxygenated water to produce hydroxyl ions [OH⁻] or reduce hydrogen ions to produce hydrogen gas [H₂].

Identifying the Causes and Applying Controls
There are many sources of corrosion and many more methods of slowing the process down. This section looks at different parts of the industry and identifies typical corrosion problems and some of the solutions (next page).

Offshore structures—On surface equipment, the simplest solution is to place an insulating barrier over the metal concerned. Offshore installations are often painted with zinc-rich primers to form a barrier against rain, condensation, sea mist and spray. The zinc primer not only forms a physical barrier, but also acts as a sacrificial anode should the barrier be breached.

Offshore structures are also protected in other ways. The zone above the high tide mark, called the splash zone, is constantly in and out of water. The most severe corrosion occurs here. Any protective coating or film is continually eroded by waves and there is an ample supply of oxygen and water. Common methods of controlling corrosion in this zone include further coating and also increasing metal thickness to compensate for higher metal loss.

The part of the structure in the tidal zone is subjected to less severe corrosion than the splash zone and can benefit from cathodic protection systems at high tide. Cathodic protection works by forcing anodic areas to become cathodes. To achieve this, a reverse current is applied to counteract the corrosion current. The current can be generated by an external DC source—impressed cathodic protection—or by using sacrificial anodes.

The rest of the structure—exposed to less severe seawater corrosion—is protected by cathodic protection. However, crustaceans and seaweed attach to the submerged parts adding weight that may increase stress-related corrosion. This mechanism occurs when the combined effects of crevice, or pitting, corrosion and stress propagate cracks leading to structural failure. However, a covering of life does restrict oxygen reaching metal, and so reduces corrosion.

Other forms of structural stress are also important. Low-frequency cyclic stress—resulting from factors such as waves, tides and operating loads—can allow time for corrosion within cracks as they are opened. Modeling and accounting for these stresses are therefore an extremely important part of corrosion prevention.
The bottom of a jackup rig or production platform sinks into the seabed and is attacked by H$_2$S produced by sulfate-reducing bacteria (SRB). However, cathodic protection also shields this part of the structure and, because of reduced oxygen supply, the protection current required tends to be less than for the rest of the rig.

**Drillpipe corrosion**—While a well is being drilled, stress is applied not only to the rig structure, but also to the drilling equipment. Drillpipe is probably the most harshly treated of all equipment. It is exposed to formation fluids and drilling mud, subjected to stress corrosion and erosion by cuttings. Joints of drillpipe are made from hardened high-strength steel and are likely to suffer from fatigue failures started by deep corrosion pits caused by oxygen, either from the mud itself or from being stacked wet. Drillpipe is sometimes coated internally, with baked resins or fusion bonded epoxies, to counteract corrosion. Once this coating has disappeared, however, corrosion can be rapid. A common area where drillpipe leaks or washouts occur is in the threaded drillpipe connections called tool joints. The (continued on page 11)
Corrosion encountered in petroleum production operations involves several mechanisms. These have been grouped into electrochemical corrosion, chemical corrosion and mechanical and mechanical/corrosive effects.

**Electrochemical Corrosion**

*Galvanic Corrosion (Two Metal)*—Two dissimilar metals in a conductive medium develop a potential difference between them. One becomes anodic, the other cathodic. The anode loses metal ions to balance electron flow. Because metals are made up of crystals, many such cells are set up, causing intergranular corrosion. Problems are most acute when the ratio of the cathode-to-anode area is large.

*Crevice Corrosion*—Much metal loss in oilfield casings is caused by crevice corrosion. This localized form of corrosion is found almost exclusively in oxygen-containing systems and is most intense when chloride is present. In the crevice, metal is in contact with an electrolyte, but does not have ready access to oxygen.

At the start of the reaction, metal goes into solution at anodic sites and oxygen is reduced to hydroxyl ions at cathodic sites. Corrosion is initially uniform over the entire area including the crevice. As corrosion continues in the crevice, oxygen becomes depleted and cathodic oxygen reduction stops. Metal ions continue to dissolve at anodes within the crevice, producing an excess of positive charges in solution. Negatively charged chloride (or other anions) now migrate to the developing anodes to maintain electroneutrality. They act as a catalyst, accelerating corrosion. At this point, crevice corrosion is fully established and the anodic reaction continues with ferrous ions [Fe++] going readily into solution (right).

Pitting corrosion is another form of crevice corrosion where a small scratch, defect or impurity can start the corrosion process. Again, a buildup of positive charges occurs in a small pit on the metal surface. Chlorine ions from a saline solution migrate towards the pit. These, coupled with the formation of hydrogen ions, act as a catalyst causing more metal dissolution.

*Stray-Current Corrosion*—Extraneous AC and DC currents in the earth arriving at a conductor will turn the point of arrival into a cathode (above). The place where the current departs will become anodic, resulting in corrosion at that point. A DC current is 100 times more destructive than an equivalent AC current. Only 1 amp per year of stray DC current can corrode up to 20 lbm [9 kg] of steel. Cathodic protection systems are the most likely sources of stray DC currents in production systems.
Barnacle-type corrosion. As tubing corrodes in a hydrogen sulfide and water environment, iron sulfide scale builds up. This is porous and is also cathodic with respect to the steel tubing. An intervening layer of iron chloride \([\text{FeCl}_2]\) is acidic and prevents precipitation of FeS directly onto the steel surface. This establishes a pit-forming corrosion cell.

Chemical Corrosion

Hydrogen Sulfide, Polysulfides and Sulfur—Hydrogen sulfide \([\text{H}_2\text{S}]\) when dissolved in water, is a weak acid and, therefore, it is a source of hydrogen ions and is corrosive. (The effects are greater in deep wells, because the pH is further reduced by pressure.) The corrosion products are iron sulfides \([\text{FeS}_x]\) and hydrogen. Iron sulfide forms a scale that at low temperatures can act as a barrier to slow corrosion. The absence of chloride salts strongly promotes this condition and the absence of oxygen is absolutely essential. At higher temperatures the scale is cathodic in relation to the casing and galvanic corrosion starts. In the presence of chloride ions and temperatures over 300°F \([150\,\text{°C}]\) barnacle-type corrosion occurs, which can be sustained under thick but porous iron sulfide deposits (above, right). The chloride forms a layer of iron chloride \([\text{FeCl}_2]\), which is acidic and prevents the formation of an FeS layer directly on the corroding steel, enabling the anodic reaction to continue. Hydrogen produced in the reaction may lead to hydrogen embrittlement.

Carbon Dioxide—Like \(\text{H}_2\text{S}\), carbon dioxide \([\text{CO}_2]\) is a weakly acidic gas and becomes corrosive when dissolved in water. However, \(\text{CO}_2\) must hydrate to carbonic acid \([\text{H}_2\text{CO}_3]\)—a relatively slow process—before it becomes acidic. The corrosion product is iron carbonate (siderite) scale. This can be protective under certain conditions. Siderite itself can be soluble. Conditions favoring the formation of a protective scale are elevated temperatures, increased pH as occurs in bicarbonate-bearing waters and lack of turbulence, so that the scale film is left in place. Turbulence is often the critical factor in the production or retention of a protective iron carbonate film. Siderite is not conductive, so galvanic corrosion cannot occur. Thus corrosion occurs where the protective siderite film is not present and is fairly uniform over the exposed metal. Crevice and pitting corrosion occur when carbonic acid is formed. Carbon dioxide can also cause embrittlement, resulting in stress corrosion cracking.

Strong Acids (direct chemical attack)—Strong acids are often pumped into the wells to stimulate production by increasing formation permeability in the near wellbore region. For limestone formations, 5 to 28% hydrochloric \([\text{HCl}]\) acid is commonly used. For sandstones, additions of hydrofluoric acid—normally up to 3%—are necessary. In deep sour wells where HCl inhibitors lose effectiveness, 9% formic acid has been used. Corrosion control is normally achieved by a combination of inhibitor loading and limiting exposure time, which may range from 2 to 24 hr. If corrosion-resistant alloys are present (austenitic and duplex stainless steels), concern for stress-corrosion cracking (SCC) and inhibitor effectiveness may rule out the use of HCl. In addition to spent acid, other stagnant columns such as drilling and completion fluid, may also be corrosive.

Concentrated Brines—Dense halide brines of the cations of calcium, zinc, and, more rarely, magnesium are sometimes used to balance formation pressures during various production operations. All may be corrosive because of dissolved oxygen or entrained air. In addition, these brines may be corrosive because of acidity generated by the hydrolysis of metallic ions. Corrosion due to acidity is more severe with dense zinc brines. More expensive brines of calcium bromide are now often used at densities above 14 lbm/gal \([1.7\,\text{gm/cm}^3]\) to avoid long-term exposure to zinc chloride \([\text{ZnCl}_2]\) brines.
Hydrogen embrittlement and stress corrosion. Rust tubercle. Tuberculation is a complex localized process that forms a nodule-like structure. It often forms in a region of low fluid velocity where a deposit of sludge or rust can shield a part of the metal and reduce the oxygen available to that area. The portion of steel exposed to water with low oxygen concentration becomes anodic and corrodes at a faster rate than the rest.

Mechanical and Mechanical/Corrosive Effects

Cavitation—This type of metal loss—often grain by grain—is due to high-pressure shock waves, generated from the collapse of minute bubbles in high-velocity fluids impinging on nearby metal surfaces. Cavitation metal loss is usually found on pump impellers developing too low a suction pressure.

Erosion—This is direct metal removal by the cutting action of high-velocity abrasive particles. Erosion failures (washouts) are seen in drillpipe when leaks (loose connections or a corrosion fatigue crack) allow drilling mud to flow through the wall under high pressure. Erosion of flowlines at bends and joints by produced sand is probably the other most common occurrence of metal erosion in the petroleum industry.

Erosion Corrosion—When erosion removes the protective film of corrosion products, corrosion can occur at a faster rate. Erosion corrosion may play a role in CO₂ corrosion. Under mild flow conditions, sand may also cause erosion corrosion. This type of corrosion is also seen in anchor chains where corrosion between links proceeds quickly.

Corrosion Fatigue—This results from subjecting a metal to alternating stresses in a corrosive environment. At the points of greatest stress, the corrosion product film becomes damaged allowing localized corrosion to take place. Eventually this leads to crack initiation and crack growth by a combination of mechanical and corrosive action. Because of this combined action, corrosion fatigue is greater at low stress cycles that allow time for the corrosion process. Welded connections on drillships, drilling and production rigs and platforms are subject to this type of corrosion.

Sulfide Stress Corrosion—Production of hydrogen results from sulfide stress cracking (SSC). SSC occurs when a susceptible metal is under tensile stress and exposed to water containing hydrogen sulfide or other sulfur compounds—generally under anaerobic conditions. Corrosion cells generate FeS and atomic hydrogen. The amount of metal loss is small and the FeS layer thin. The layer of FeS promotes the movement of hydrogen into the metal, usually into impurities at the grain boundaries. Penetration of hydrogen into the body of the metal reduces ductility. Accumulations of hydrogen at imperfections generate tremendous pressure. For hard high-strength steel the combination of lack of ductility and internal stress superimposed on the tensile stress causes the metal to break and crack (right). Penetration of molecular hydrogen can also lead to blistering.

Chloride Stress Cracking (CSC)—While under tensile stress, austenitic stainless steels can fail by cracking when exposed to saline water above 200°F [95°C].

Stress Corrosion Cracking (combined with SSC, CSC and corrosion fatigue)—CSC is an example of a broad range of stress-corrosion cracking, defined as corrosion accelerated by tensile stress. This type of corrosion starts at a pit or notch, with cracks progressing into the metal primarily along grain boundaries.
threads provide ideal places for crevice corrosion, which can also occur in scars left on the tool joints by makeup tongs. A special grease, commonly known as dope, lubricates the threads and helps prevent corrosion.9

**Mud corrosion**—Drilling mud also plays a key role in corrosion prevention. In addition to its well-known functions, mud must also remain noncorrosive. A greater awareness of corrosion problems has come about by the lower pH of polymer muds. Low pH means more acidic and hence more corrosive. Oil-base muds are usually noncorrosive and, before the introduction of polymer muds, water-base muds were used with relatively high pH of 10 or greater. So when polymer muds were introduced, corrosion from mud became more apparent.

Dissolved gases are the prime cause of corrosion in drilling fluids. The most common are oxygen, carbon dioxide and hydrogen sulfide. Oxygen, even in concentrations as low as 1 part per million (ppm), is capable of causing serious damage (top).

Oxygen can enter the mud system at many points, especially at the surface mixing and storage tanks, and at the shaker screens. Other entry points are at the centrifugal pumps, desanders and desilters. As a result, the mud is usually oxygen-saturated before it reaches the mud pumps. Sodium sulfite- or ammonium bisulfite-based oxygen scavengers, such as Dowell’s IDSCAV, are routinely used in mud systems. These chemicals bond with oxygen in the mud to reduce its corrosivity.

Maintaining high pH is important in controlling corrosion rates by neutralizing acids caused by H2S or CO2. Hydrogen sulfide can enter the mud system directly from the formation or from thermally degraded mud products, SRBs or makeup water (above, right). Scavengers, such as sodium chromate, zinc chromate, and sodium nitrite, can quickly remove H2S. Dowell’s film-forming inhibitors IDFILM, help protect the drillstring and casing. Triazine compounds are used in products such as Dowell’s IDCIDE as biocides to control bacteria.10

**Localized bacterial corrosion.** Colonies of sulfate-reducing bacteria (SRB) form a deposit under which crevice corrosion develops. The SRBs introduce H2S into the system, which causes the corrosion.

Hydrogen sulfide will induce sulfide stress cracking (see “Corrosion Mechanisms,” page 8), so any mechanical measures to reduce stress such as decreasing torque or weight-on-bit will limit this type of failure. Surprisingly, high temperature reduces sulfide stress cracking. So if H2S is detected, it is better to take advantage of high downhole temperatures and treat the mud with the drillstring in the hole.

Corrosion control of CO2 is similar to H2S control in that pH must be raised to reduce the acid effects, and drillpipe should be coated with inhibitors. Carbon dioxide can enter the mud system several ways—directly from the formation, by thermal degradation of organic materials, as carbonates from barite or bentonite, chemical over-treatment with soda ash, or bicarbonate of soda. Calcium hydroxide can be used to precipitate carbonates to reduce CO2 levels.

**Completion**—After casing has been put in a well, it is usually cemented in place. Cement itself provides primary external protection against corrosion, especially near the surface where circulating aquifer water supplies unlimited oxygen. As a recent study on casing leaks in the Wafra field in Kuwait discovered, the type of cement used is also important. Severe corrosion occurred in wells where construction and permeable light cement were used instead of the usual Portland class G cement with additives.11 Leakage rates were higher in shallower zones where high sulfate concentrations caused the construction cement—which is nonsulfate resistant—to break down, exposing the exterior of the casing to corrosive aquifer water.

Completion design also plays an important role in preventing internal corrosion. Reducing sand production by gravel pack-
ing prevents sand blasting that causes erosion corrosion. Erosion corrosion will be more pronounced on equipment that restricts flow such as nipples, valves or sharp pipe bends. Once erosion has removed protective coatings, other forms of corrosion can start. The velocity of produced fluids has the same effect as produced sand with erosion occurring at places of turbulence and cavitation.

Stimulation programs may, inadvertently, promote internal corrosion. Depending on lithology, highly corrosive hydrochloric acid (HCl) with additions of hydrofluoric (HF) acid are used to improve near-wellbore permeability. These acids can also remove scale buildup on the inside of casing and tubing, allowing direct attack on bare metal. (Scale, produced by iron sulfide and iron carbonate deposits, restricts the corrosion process. Other types of scale are porous and do not protect.) It is therefore essential to use inhibitors and to flow the well to remove spent acid and allow pH levels to increase.

Inhibitors are mixed with acid to provide a protective film over exposed completion strings. The first generation of acid inhibitors was based on highly poisonous arsenic products, but over the years less toxic and more environmentally appropriate products have been developed. The CORBAN range of inhibitors produced by Dowell are designed for acid inhibition of most oilfield tubulars, including coiled tubing, duplex steels and other exotic alloys at up to 400 °F (200 °C).

The type and amount of inhibitor used—inhibitor loading—depends not only on the acid and its strength, but also on the metal it is protecting, the working temperature range and the protection time desired. Inhibitor loadings are determined by measuring the corrosion of samples of casing or tubing—coupons—in a corrosion-test autoclave that duplicates the well-treating environment.

Corrosion during production—Corrosion can continue inside the casing and along completion strings and pipelines during the life of a well. Gas condensate wells may produce gas, hydrocarbons, formation water, acid gases (CO2 and H2S) and organic liquids. Gas corrosion during production should be monitored with corrosion monitoring tools such as calipers and corrosion rate devices.

**Caliper Devices**
Mechanical multifinger calipers have been used for many years to measure the internal diameter of tubing and casing. The Tubing Geometry Sonde (TGS) tool has interchangeable 16-finger sections covering tubing sizes from 2 7/8 to 7 in. (7 to 18 cm). The larger MultiFinger Caliper (MFC) tool has interchangeable sections with 36, 60 and 72 arms covering casing sizes from 7 to 13 3/8 in. (18 to 34 cm). Both tools can be run in any borehole fluid and are able to measure small holes as long as a caliper passes over them. Log presentations vary and may be quite sophisticated.

**Corrosion Rate Devices**
The CPET Corrosion and Protection Evaluation Tool has four sets of three electrodes, spaced at 2-ft (60-cm) intervals along the tool (next page). The tool takes stationary measurements of potential differences and casing resistance between electrode pairs. Casing current is calculated from these measurements at each depth. By taking the difference in current between stations, the radial current density can be calculated and the corrosion rate computed. Casing thickness can also be derived by assuming casing conductivity and using the nominal casing outside diameter. A plot of casing current flow against depth, shows anodic regions where corrosion is likely to occur. If the well is cathodically protected, the log will also show the efficiency of the protection. The tool can be run successively after adjustment of the cathodic protection system current to ensure that anodes have been biased out.

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Electromagnetic Devices

The METT Multifrequency Electromagnetic Thickness Tool is used to detect large-scale corrosion. It works on the same principle as an induction tool, having a transmitter coil and a receiver coil. The transmitter generates an alternating magnetic field that induces eddy currents in the casing. These produce a secondary magnetic field that interferes with the primary field causing a phase shift. This is detected by the receiver coil. The phase shift is proportional to the total amount of metal surrounding the tool and hence the thickness of the casing. By using a multifrequency transmitter, other properties of the casing that also affect the phase shift can be measured so that thickness can be calculated. An internal caliper measurement is derived from a high-frequency field that penetrates the casing skin only. The casing inside diameter (ID) measurement is not affected by nonmagnetic scale deposits. Monitoring a well over several years using the METT tool gives the general corrosion rate.

The PAL Pipe Analysis Log tool measures magnetic flux leakage anomalies on the casing wall. Low-frequency magnetic flux is generated by an electromagnet, and pad-mounted sensors detect the anomalies. Inner wall defects are detected by inducing surface eddy currents using a separate coil array with a high-frequency signal. This helps to distinguish internal from external defects. The PAL tool is primarily used to detect casing holes.

The FACT Flux Array Corrosion Tool works on the same principle as the PAL tool, but has a more powerful electromagnet and is designed to negotiate bends down to three times the pipe diameter (3D bends).

Ultrasonic Devices

The USI UltraSonic Imager tool and the CET Cement Evaluation Tool use ultrasonic sound pulses that reflect off and resonate within the casing wall. The transit time of the first received echo gives the internal casing radius. Frequency analysis of the resonant portion of the signal provides casing thickness, allowing internal and external metal loss to be computed. The CET tool has eight transducers equally spaced in a helix around the tool to give a limited casing coverage. The more advanced USI tool has a single rotating transducer to provide full coverage. The CPET Corrosion and Protection Evaluation Tool. The CPET tool has four sets of three electrodes, each one at the end of a hydraulically operated arm. Stationary readings (inset) are taken and 12 separate contact resistances and electrode potential differences are measured.

Electrodes

Hydraulic section

Telemetry cartridge

Electronic cartridge

Electrodes

A1

A3

B1

B3

C1

C3

D1

D3

A2

B2

C2

D2

Stationary readings
CET and USI tools were developed to record cement bond and inspect the casing.

The Borehole Televiewer (BHTV) tool, Acoustic TeleScanner (ATS) and the UBI Ultrasonic Borehole Imager tool were all developed for openhole applications and employ a rotating transducer. The ATS and UBI tools use a focused transducer to show much finer detail than the CET or USI tools.

All acoustic tools are affected by dense highly attenuating muds and casing scale. They also, at present, do not work in gas-filled holes.

**Composite Logs**

Many corrosion tools can be combined to give a detailed picture of internal or external corrosion, general corrosion or pits and holes. Modern computers can present these data in many different ways according to customer requirements (above).

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Corrosive effects of sodium chloride [NaCl]. As the weight percentage of NaCl increases up to about 5%, the corrosion rate increases rapidly. Increasing the salt content above this reduces the solubility of oxygen, so the corrosion rate decreases and at about 15% NaCl, the rate is less than with fresh water.

**Typical cathodic protection installation for a pipeline.** Sacrificial anodes are buried deep underground in a hole filled with conductive material to ensure electrical continuity between the anodes through the ground to the pipeline. The circuit is completed by connecting a cable through a rectifier to the pipeline. The rectifier ensures that the cathodic protection system does not reverse, causing the pipeline to corrode.

**Capillary tube inhibitor injection.** Inhibitors are chemicals that are absorbed onto a metal surface from solution to protect against corrosion. The protective film slows corrosion by increasing anodic and cathodic polarization, reducing diffusion of ions to the metal surface, increasing the electrical resistance at the metal-electrolyte interface and by increasing the hydrogen over voltage—the voltage required to remove hydrogen and prevent a buildup stifling the corrosion process. The choice of inhibitor depends on the metal to be protected and its environment. Equally important is the method of application. Shown is a continuous injection method to protect tubing. Inhibitor is pumped down a capillary tube strapped to the outside of the tubing to a side pocket mandrel where it will then mix with production fluid and form a protective film on the inside.
tion network set up. Wells should be insulated from pipelines so that protection systems do not cause unwanted anodic regions and stray current corrosion.

Under the right conditions, iron sulfide and iron carbonate scales—the corrosion products when H2S or CO2 are present—provide protective coatings. The composition of production fluids, however, may change during the life of a reservoir so relying on natural protection may not be wise. Corrosion monitoring, in some form, should always be undertaken.

**Monitoring Corrosion**

Corrosion monitoring is just as important as recognizing the problem and applying controls. Monitoring attempts to assess the useful life of equipment, when corrosion conditions change and how effective the controls are. Techniques used for monitoring depend on what the equipment is, what it is used for and where it is located.

**Structures**—Monitoring corrosion on exposed structures is fairly straightforward and is carried out by visual inspection. More rigorous tests are required when a structure is load-bearing. Some form of nondestructive testing is used, such as magnetic particle testing to reveal cracks. Sedco Forex rigs are inspected every four years and require underwater divers or remote operated vehicles (ROVs) using still or video photography to check the condition of legs and risers. During this inspection the corrosion rate of sacrificial anodes can be assessed. Normally anodes are designed to last seven or eight years so they will have to be replaced during the typical 20-year life of a rig.

**Drillpipe**—To monitor drillpipe corrosion and the effectiveness of mud treatments, coupon rings are installed between joints (left). The rate of corrosion can then be assessed by measuring the amount of metal lost from the rings. Rates of 0.5 to 2 lbm/ft2/yr [2.4 to 9.8 kg/m2/yr] without pitting are acceptable. Drillpipe is also regularly inspected on racks by ultrasonic and X-ray techniques.

**Mud**—During drilling, mud systems are routinely monitored for chemical and physical properties. Tests specifically related to corrosion control include an analysis of oxygen, CO2, H2S and bacteria. Hydrogen sulfide is detected by measuring the total...
level of soluble sulfides. Mud filtrate can be tested further by adding acid to liberate H₂S, which can be measured using any standard H₂S detector such as a Draeger tube. Bacterial attacks can be recognized by a drop in pH, increase in fluid loss or change in viscosity. Anaerobic bacteria can turn the mud black and produce a smell of rotten eggs.

Casing and tubing—Various corrosion logging tools measure internal corrosion, external corrosion and even evaluate cathodic protection of oil wells (see “Corrosion Logging Tools” page 12). One of the most commonly used techniques has been the multifinger caliper run on either slickline or electric line. This measures the internal radius of casing and tubing using lightly sprung feeler arms. (Heavy springing can cause the fingers to leave tracks through protective scales and chemical inhibitors leading to enhanced corrosion from running the survey itself!) An improvement on contact calipers is the ultrasonic caliper (previous page, right), which uses a rotating ultrasonic transducer to measure the echo time of a high-frequency sonic pulse. The processed signal produces a map of the casing. A recent development using a specially focused transducer designed for open hole and currently under development for cased hole, shows remarkable cased hole detail (right). The perforations are clearly seen.

Wireline logging provides a good evaluation of downhole corrosion, but disrupts production and may involve pulling completions. Oil companies, therefore, like to use surface monitoring methods to indicate when downhole inspection is required.

Pipelines—Surface monitors include test coupons placed at strategic points in the flowline and also more sophisticated techniques that attempt to measure corrosion rates directly (resistance devices, polarization devices, galvanic probes, hydrogen probes and iron counts). This approach to monitoring can be hit or miss when trying to relate surface corrosion to downhole corro-

![UBI log in cased hole. This log is presented on a scale of 1:10 and shows a large hole in the 7-in. liner around X220 ft. Just above the corroded hole is a pattern of several smaller holes where the casing has been perforated. Track 1 shows the amplitude image, Track 2 the increase or decrease in the internal radius image and Track 4 shows the metal loss image. Track 3 gives a cross section of the well.](image)

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<tr>
<td>15</td>
<td>-0.1842</td>
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sion. In the past, the onset of well problems instigated monitoring. While waiting for a failure is not recommended, recovering corroded tubing or casing at least provides valuable after-the-fact information, and every opportunity is taken to find out what caused the corrosion and the failure.

Some downhole monitoring techniques have been adapted to logging pipelines. The same surface logging equipment is used, but the logging tools themselves have been made more flexible to pass around sharp bends. Short lengths of pipe may be logged by this method, but longer lengths are usually monitored by smart pigs. These are sophisticated instrument packages, which use ultrasonic, flux leakage and other electromagnetic techniques to check for corrosion. The data are usually stored in the pig itself for later retrieval. The pig is pumped along a pipeline from a specially-built launching station to a purpose-built receiving section of the pipeline. Surveys cover tens or even hundreds of miles.

Conclusion
The oil industry has invested heavily in material and personnel to try to tame corrosion and prevent metal from returning to its natural state. New oil fields benefit from predevelopment planning and the growing knowledge of all aspects of corrosion control and monitoring. Older fields will continue to benefit from the expertise of the corrosion engineer and the constant monitoring required to prevent disaster. —AM

3D Seismic Survey Design

There’s more to designing a seismic survey than just choosing sources and receivers and shooting away. To get the best signal at the lowest cost, geophysicists are tapping an arsenal of technology from integration of borehole data to survey simulation in 3D.

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QUAD-QUAD is a mark of Geco-Prakla. TWST (Through-Tubing Well Seismic Tool) is a mark of Schlumberger.

1. For the most recent worldwide figures:
2. Personal communication: Thor Sinclair.

Increased efficiency has brought the cost of marine three-dimensional (3D) seismic data to its lowest level ever, expanding the popularity of 3D surveys (above). In the past five years, oil companies have increased expenditures on seismic surveys by almost 60%, to $2.2 billion.1 However, an estimated 10% of surveys fail to achieve their primary objective—some because the technology does not exist to process the data, some because the surveys are improperly planned.2 Careful planning can result in more cost-effective acquisition and processing, and in data of sufficient quality to benefit from the most advanced processing.

But before the first shot is fired or the first trace recorded, survey designers must determine the best way to reveal the subsurface target. As basics, they consider locations and types of sources and receivers, and the time and labor required for acquisition. Many additional factors, including health, safety and environmental issues, must be taken into account. This article investigates the objectives and methods of seismic survey design and reviews field examples of state-of-the-art techniques.

The ideal 3D survey serves multiple purposes. Initially, the data may be used to enhance a structural interpretation based on two-dimensional (2D) data, yielding new drilling locations. Later in the life of a field, seismic data may be revisited to answer questions about fine-scale reservoir architecture or fluid contacts, or may be compared with a later monitor survey to infer fluid-front movement. All these stages of interpretation rely on satisfactory processing, which in turn relies on adequate seismic signal to process. The greatest processing in the world cannot fix flawed signal acquisition.
Temporal and spatial aliasing caused by sampling less than twice per cycle. Temporal aliasing (top) occurs when insufficient sampling renders a 50-Hz signal and a 200-Hz signal indistinguishable (arrows represent sample points). The 50-Hz signal is adequately sampled, but not the 200-Hz. (Adapted from Sheriff, reference 4.) Spatial aliasing (bottom) occurs when receiver spacing is more than half the spatial wavelength. With minor aliasing (left) arrivals can be tracked at near offsets as time increases, but become difficult to follow at far offsets. With extreme aliasing (right) arrivals even appear to be traveling backwards, toward near offsets as time increases. (Adapted from Claerbout, reference 6.)

Better stacking from a wide and evenly spaced set of offsets. Reflection arrival times from different offsets are assumed to follow a hyperbola. The shape of the hyperbola is computed from the arrivals. Traces are aligned by flattening the best-fitting hyperbola into a straight line, then summed, or stacked. Perfect alignment should yield maximum signal amplitude at the time corresponding to zero offset. A wide range of evenly spaced offsets gives a better-fitting hyperbola, and so a better stack.

Elements of a Good Signal
What makes a good seismic signal? Processing specialists list three vital requirements—good signal-to-noise ratio (S/N), high resolving power and adequate spatial coverage of the target. These basic elements, along with some geophysical guidelines (see “Guidelines from Geophysics,” page 22), form the foundation of survey design.

High S/N means the seismic trace has high amplitudes at times that correspond to reflections, and little or no amplitude at other times. During acquisition, high S/N is achieved by maximizing signal with a seismic source of sufficient power and directivity, and by minimizing noise. Noise can either be generated by the source—shot-generated or coherent noise, sometimes orders of magnitude stronger than deep seismic reflections—or be random. Limitations in the dynamic range of acquisition equipment require that shot-generated noise be minimized with proper source and receiver geometry. Proper geometry avoids spatial aliasing of the signal, attenuates noise and obtains signals that can benefit from subsequent processing. Aliasing is the ambiguity that arises when a signal is sampled less than twice per cycle (left). Noise and signal cannot be distinguished when their sampling is aliased.

A common type of coherent noise that can be aliased comes from low-frequency waves trapped near the surface, called surface waves. On land, these are known as ground roll, and create major problems for processors. They pass the receivers at a much slower velocity than the signal, and so need closer receiver spacing to be properly sampled. Planners always try to design surveys so that surface waves do not contaminate the signal. But if this is not possible, the surface waves must be adequately sampled spatially so they can be removed.

During processing, S/N is enhanced through filters that suppress noise. Coherent noise is reduced by removing temporal and spatial frequencies different from those of the desired signal, if known. Both coherent and random noise are suppressed by stacking—summing traces from a set of source-receiver pairs associated with reflections at a common midpoint, or CMP. The source-receiver spacing is called offset. To be stacked, every CMP set needs a wide and evenly sampled range of offsets to define the reflection travel-time curve, known as the normal moveout curve. Flattening that curve, called normal moveout correction, will make reflections from different offsets arrive at the time of the zero-offset reflection. They are then summed to produce a stack trace (left). In 3D surveys, with the
advent of multielement marine acquisition—multistreamer, multisource seismic vessels—and complex land acquisition geometries, reflections at a CMP come from a range of azimuths as well as a range of offsets (right). A 3D CMP trace is formed by stacking traces from source-receiver pairs whose midpoints share a more or less common position in a rectangular horizontal area defined during planning, called a bin. The number of traces stacked is called fold—in 24-fold data every stack trace represents the average of 24 traces. Theoretically, the S/N of a survey increases as the square root of the fold, provided the noise is random. Experience has shown, however, that for a given target time, there is an optimum fold, beyond which almost no S/N improvement can be made.

Many survey designers use rules of thumb and previous experience from 2D data to choose an optimal fold for certain targets or certain conditions. A fringe—called the fold taper or halo—around the edge of the survey will have partial fold, thus lower S/N, because several of the first and last shots do not reach as many receivers as in the central part of the survey (below, right). Getting full fold over the whole target means expanding the survey area beyond the dimensions of the target, sometimes by 100% or more. Many experts believe that 3D surveys do not require the level of fold of 2D surveys. This is because 3D processing correctly positions energy coming from outside the plane containing the source and receiver, which in the 2D case would be noise. The density of data in a 3D survey also permits the use of noise-reduction processing, which performs better on 3D data than on 2D.

Filtering and stacking go a long way toward reducing noise, but one kind of noise that often remains is caused by multiple reflections, “multiples” for short. Multiples are particularly problematic where there is a high contrast in seismic properties near the surface. Typical multiples are reverberations within a low-velocity zone, such as between the sea surface and sea bottom.

3. Directivity is the property of some sources whereby seismic wave amplitude varies with direction.
5. Streamers are cables equipped with hydrophone receivers. Multistreamer vessels tow more than one receiver cable to multiply the amount of data acquired in one pass. For a review of marine seismic acquisition and processing see Boreham D, Kingston J, Shaw P and van Zeeuitt J: “3D Marine Seismic Data Processing,” Oilfield Review 3, no. 1 (January 1991): 41-55.

• Reflections from source-receiver pairs bounce in a bin, a rectangular, horizontal area defined during planning. In a 3D survey a CMP trace is formed by stacking traces that arrive from a range of azimuths and offsets (top). The distribution of offsets is displayed in a histogram within each bin (bottom). The vertical axis of the histogram shows the amount of offset, and the horizontal axis indicates the position of the trace in offset.

• A fold plot showing 40-fold coverage over the heart of the survey. The edge of the survey has partial fold because several of the first and last shots do not reach as many receivers as in the central part of the survey.
Guidelines from Geophysics

Many of the rules that guide 3D survey design are simple geometric formulas derived for a single plane layer over a half-space: the equation describing the hyperbola used in normal moveout correction is one example. Others are approximations from signal processing theory. Sometimes survey parameters are achieved through trial and error. The following formulas hold for some simple 3D surveys:

- **Bin size, \( \Delta x \Delta y \),** is calculated to satisfy vertical and lateral resolution requirements. For a flat reflector, bin length, \( \Delta x \), can be the radius of the Fresnel zone or larger. The Fresnel zone is the area on a reflector from which reflected energy can reach a receiver within a half-wavelength of the first reflected energy. For a dipping reflector

  \[
  \Delta x = \frac{V_{ms}}{(4f_{max} \sin \phi)}
  \]

  where \( V_{ms} \) is the root mean square average of velocities down to the target, \( f_{max} \) is the maximum nonaliased frequency required to resolve the target, and \( \phi \) is the structural dip. Normally \( \Delta y = \Delta x \).

- **3D fold** is determined from estimated S/N of previous seismic data, usually 2D. 3D fold must be greater than or equal to

  \[
  2D \text{ fold} \leq \frac{\Delta x \Delta y}{2R_f \Delta x}
  \]

  or between the earth’s surface and the bottom of a layer of unconsolidated rock (below, left). Multiples can appear as later arrivals on a seismic section, and are easy to confuse with deep reflections (left). And because they can have the same characteristics as the desired signal—same frequency content and similar velocities—they are often difficult to suppress through filtering and stacking. Sometimes they can be removed through other processing techniques, called demultiple processing, but researchers continue to look for better ways to treat multiples.

  The second characteristic of a good seismic signal is high resolution, or resolving power—the ability to detect reflectors and quantify the strength of the reflection. This is achieved by recording a high bandwidth, or wide range of frequencies. The greater the bandwidth, the greater the resolving power of the seismic wave. A common objective of seismic surveys is to distinguish the top and bottom of the target. The target thickness determines the minimum wavelength required in the survey, generally considered to be four times the thickness. That wavelength is used to calculate the maximum required frequency in the bandwidth—average seismic velocity to the target divided by minimum wavelength equals maximum frequency. The minimum frequency is related to the depth of the target. Lower frequencies can travel deeper. Some seismic sources are designed to emit energy in particular frequency bands, and receivers normally operate over a wider band. Ideally, sources that operate in the optimum frequency band are selected during survey design. More often, however, surveys are shot with whatever equipment is proposed by the lowest bidder.

1. Normal moveout stretch is the distortion in wave-shape caused by normal moveout correction.
Another variable influencing resolution is source and receiver depth—on land, the depth of the hole containing the explosive source (receivers are usually on the surface), and at sea, how far below the surface the sources and receivers are towed. The source-receiver geometry may produce short-path multiples between the sources, receivers, and the earth or sea surface. If the path of the multiple is short enough, the multiple—sometimes called a ghost—will closely trail the direct signal, affecting the signal’s frequency content. The two-way travel time of the ghost is associated with a frequency, called the ghost notch, at which signals cancel out. This leaves the seismic record virtually devoid of signal amplitude at the notch frequency. The shorter the distance between the source or receiver and the reflector generating the multiple, the higher the notch frequency. It is important to choose a source and receiver depth that places the notch outside the desired bandwidth. It would seem desirable to plan a survey with the shallowest possible sources and receivers, but this is not always optimal, especially for deep targets. On land, short-path multiples can reflect off near-surface layers, making deeper sources preferable. In marine surveys, waves add noise and instability, necessitating deeper placement of both sources and receivers. In both cases, survey design helps reach a compromise.

The third requirement for good seismic data is adequate subsurface coverage. The lateral distance between CMPs at the target is the bin length (for computation of bin length, see “Guidelines from Geophysics,” previous page). Assuming a smooth horizontal reflector, the minimum source spacing and receiver spacing on the surface must be twice the CMP spacing at the target. If the reflector dips, reflection points are not CMPs (above, right). Reflected waves may be spatially aliased if the receiver spacing is incorrect. A survey designed with good spatial coverage but assuming flat layers might fail in complex structure. To record reflections from a dipping layer involves more distant sources and receivers than reflections from a flat layer, requiring expansion of the survey area—called migration aperture—to obtain full fold over the target.

In general, survey planners use simple trigonometric formulas to estimate optimal CMP spacing and maximum source-receiver offset on dipping targets. As geophysicists seek more information from seismic data, making the technique more cost-effective, simple rules of thumb will no longer provide optimum results. Forward modeling of seismic raypaths, sometimes called raytrace modeling, provides a better estimate of subsurface coverage, but is not done routinely during survey planning because of cost and time constraints. An exception is a recent evaluation by Geco-Prakla for a survey in the Ship Shoal South Addition area of the Gulf of Mexico (page 31).

Balancing Geophysics with Other Constraints

Acquiring good seismic signal is expensive. On land or at sea, hardware and labor costs constrain the survey size and acquisition time. The job of the survey planner is to balance geophysics and economy, achieving the best possible signal at the lowest possible cost. On land, source lines can be aligned with receiver lines, or they can be at angles to each other. Different source-receiver patterns have different cost and signal advantages, and the planner must

7. This is the criterion for resolving target thickness visually. By studying other attributes of a seismic trace such as amplitude or signal phase, thinner layers can be resolved.
8. Survey design and survey planning are sometimes used interchangeably, but most specialists prefer to think of planning as the part of the design process that considers cost constraints and logistics.
choose the one that best suits the survey (right). Once a survey pattern is selected, subsurface coverage can be computed in terms of fold and distribution of offset and azimuth. If the coverage has systematic holes, the pattern must be modified. In complex terrain, planned and actual surveys may differ significantly (left).\textsuperscript{9}

Land acquisition hardware can cost $5 million to $10 million for recording equipment and sources—usually vibrating trucks or dynamite—but labor is the major survey cost. Cost can be controlled by limiting the number of vibrator points or shotpoints, or the number of receivers. But limiting receivers limits the area that can be shot at one time. If a greater area is required, receivers must be picked up and moved, increasing labor costs. The most efficient surveys balance source and receiver requirements so that most of the time is spent recording seismic data and not waiting for equipment to be moved. Land preparation, such as surveying source and receiver locations and cutting paths through vegetation or topography, must be included on the cost side of the planning equation. In countries where mineral rights and land surface rights are separately and privately held, such as in the US, landowners must give permission and can charge an access fee. Other constraints that can affect survey planning include hunting seasons, permafrost, population centers, breeding seasons, animals migrating or chewing cables, and crops that limit vibrator source trucks to farm roads.

Marine survey planners consider different constraints. Hardware is a major cost; sources and recording equipment are a sizable expense, but additionally, seismic vessels cost $35 to $40 million to build, and

\textbf{Common source-receiver layouts for land acquisition.} The checkerboard pattern (top), sometimes called the straight-line or cross-array pattern, is preferred when the source is a vibrator truck, because it requires the least maneuvering. The brick pattern, (middle) sometimes called staggered-line, can provide better coverage at short offsets than the checkerboard, but is more time-consuming, and so costlier. The zigzag pattern (bottom) is highly efficient in areas of excellent access, such as deserts, where vibrator trucks can zigzag between receiver lines.

\textbf{Planned versus actual surveys.} A survey planned in West Texas, USA (top, left) calls for a checkerboard of receiver lines (blue) and source lines (red). The actual survey shot (bottom, left) came very close to plan. Other cities present acquisition challenges. A survey in Milan, Italy (right) used a random arrangement of sources and receivers. (Adapted from Bertelli et al., reference 9.)
tens of thousands of dollars per day to operate. Sources are clusters of air guns of different volumes and receivers are hydrophones strung 0.5 m [1.6 ft] apart in groups of up to 48, on cables up to 6000 m [19,680 ft] long. Sources and receivers are almost always towed in straight lines across the target (below, right), although other geometries are possible. Circular surveys have been acquired with sources and receivers towed by vessels running in spirals or concentric circles. Geco-Prakla’s QUAD-QUAD system tows four receiver cables and four source arrays simultaneously, acquiring 16 lines at a time. Currents and tides can cause the long receiver cables to deviate by calculable amounts—up to 30°—from the towing direction. Spacing between shotpoints is a function of vessel speed, and can be limited by how quickly the air guns can recover full pressure and fire again. Access is usually limited only by water depth, but drilling rigs, production platforms and shipping lanes can present navigational obstacles. Environmental constraints also influence marine surveys: the commercial fishing industry is imposing limits on location of, and seasons for, marine acquisition. For example, planning in the Caspian Sea must avoid the sturgeon breeding season or seismic surveys would wipe out caviar production for the year.

Transition zones—shallow water areas—have their own problems, and require specialized equipment and creative planning. Transition zones are complex, involving shorelines, river mouths, coral reefs and swamps. They present a sensitive environment and are influenced by ship traffic, commercial fishing and bottom obstructions. Survey planners have to contend with varying water depths, high environmental noise, complex geology, wind, surf and multiple receiver types—often a combination of hydrophones and geophones.

One thing all surveys have in common is that planning must be done quickly. The clock starts ticking once acreage is licensed. Exploration and development contracts require oil companies to drill a certain number of wells, spend a certain amount of money, or shoot a certain amount of seismic data before a given date. There is often little time between gaining approval to explore or develop an area and having to drill. In some cases, oil companies plan every detail of the acquisition before putting the job out to bid. In other cases, to increase efficiency, oil companies and seismic service companies share the planning. In many cases, service companies plan the survey from beginning to end based on what the oil company wishes to achieve. In the quest for cost savings, however, seismic signal is often compromised.

Cost-Effective Seismic Planning
How would 3D seismic acquisition, processing and interpretation be different if a little more emphasis were given to survey design? Geco-Prakla’s Survey Evaluation and Design team in Gatwick, England, has shown that by taking a bit more care, signal can be improved, quality assured and cost optimized simultaneously. There are three parts to the process as practiced by Geco-Prakla—specification, evaluation and design (next page). Specification defines the survey objectives in terms of a particular depth or target formation, and the level of interpretation and resolution required. The level of interpretation must be defined early; data to be used solely for structural interpretation can be of lesser quality, leading to lower

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### Data Type

#### VSP Logs or 1D Models
- **Parameters to be Determined**
  - Maximum frequencies attainable
  - Reflection response of target
  - Identification of multiples origin
  - Source peak amplitude
  - Peak-to-bubble ratio
  - Source volume
  - Source depth
  - Resolution attainable
  - Noise levels

- **Means to Determine Parameters**
  - VSP processing
  - Source modeling
  - Apply losses to source signatures

- **Process or Output**
  - Loss modeling
  - Frequency dependent losses
  - Source signature for various depths
  - Bandwidth at target
  - Target wavelet

- **Additional Parameters**
  - Source peak amplitude
  - Peak-to-bubble ratio
  - Source volume
  - Source depth
  - Resolution attainable
  - Noise levels

- **Additional Means to Determine Parameters**
  - VSP processing
  - Source modeling
  - Apply losses to source signatures

- **Additional Process or Output**
  - Loss modeling
  - Frequency dependent losses
  - Source signature for various depths
  - Bandwidth at target
  - Target wavelet

#### Logs or 1D Models
- **Parameters to be Determined**
  - Estimate spatial and temporal resolution
  - Shooting direction
  - Primary/multiple velocity discrimination
  - Required streamer length
  - Stack fold, offset and group length for optimum multiple moveout discrimination

- **Means to Determine Parameters**
  - Build geological 2D model and apply appropriate target wavelet
  - Analysis of 2D synthetic CMP gathers

- **Process or Output**
  - Modeled section
  - Synthetic CMP gathers
  - Synthetic shots
  - Migration aperture
  - Long-offset analysis
  - Normal incidence stacks
  - Statics model

#### 2D or 3D Surface Seismic
- **Parameters to be Determined**
  - Signal-to-noise ratio
  - Establish noise mechanisms
  - Near trace offset
  - Useful offset with time, stack and S/N relationship
  - Group interval
  - Crossline spacing
  - Spatial frequency
  - Spatial resolution
  - Shotpoint interval
  - Migration aperture
  - Shooting direction
  - Record length

- **Means to Determine Parameters**
  - Analysis of existing surface seismic
  - Analysis of migration requirements

- **Process or Output**
  - FK plots, filter tests
  - Refraction velocities (near surface)
  - Noise records
  - Amplitude versus time plots
  - Mute, stack, fold tests
  - Migration of synthetic zero-offset data
  - Migration of existing 2D data
  - Ambient noise estimation

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**Survey evaluation and design scheme.**

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13 Specification quantifies the geophysical parameters needed to meet the interpretation objectives: frequency content and signal-to-noise ratio of the recorded signals, and spatial sampling interval—the familiar requirements for good signal.

Evaluation of existing data, which can be done independently and concurrently, tells which geophysical parameters are obtainable—sometimes different from those stipulated by specification. The types of data evaluated include logs, vertical seismic profiles (VSPs) and 2D or existing 3D data. Existing data can provide models for simulating the effects of the geophysical parameters on new seismic data. If the required parameters are not obtainable, the survey objectives are reexamined, or respecified. The loop is repeated until a set of geophysical parameters is found that is both desired and obtainable.

In the third step, design, the geophysical parameters are weighed against other constraints. Keeping in mind the understanding gained from evaluation of existing data, survey planners select the source and receiver configuration and choose the shooting sequence and type of seismic source. These preferred survey parameters are tempered by cost, safety and environmental constraints.
Putting Planning into Practice

In 1991 Elf Petroleum Nigeria Limited put out for tender a 160-km² [62-sq mile] land survey in the Niger Delta. Working with the Seismic Acquisition Service of Elf Aquitaine Production in Pau, France, the Survey Evaluation and Design group evaluated sources and geometries for optimal acquisition. The primary target is the structure of the Ibewa oilfield at 3500 m [11,480 ft], at or below 3 sec two-way time, with secondary deeper objectives. Signal-to-noise requirements, based on previous experience, suggested the data should be 24-fold. Resolution of the target required signal bandwidth of 10 to 60 Hz and 25 m by 25 m [82 ft by 82 ft] bins. The source was specified to be dynamite, which would be fired in shot holes drilled and cased or lined to 25 m, again based on previous experience. Constraints on the survey included the high population density, potential damage to personal property and the many oil pipelines that cross the area. A roll-along acquisition pattern similar to a checkerboard was suggested in the bid, with four receiver lines to be moved as the survey progressed (below, right).

Evaluation of existing data—2D seismic lines and results from seismic source tests—warned of potential problem areas. Source tests compared single-source dynamite shots to source patterns, and tested several source depths. The tests indicated the presence of ghost notches at certain depths, leading to a reduction in signal energy within the desired frequency band of 10 to 60 Hz (above, right). The source tests also indicated source patterns were ineffective in controlling ground roll in this prospect area. Deployment of the source at 9 m [30 ft] gave a good S/N ratio at 25 to 60 Hz, but produced very high levels of ground roll. Deployment of the source below 40 m [130 ft] gave a good S/N ratio from 10 to 60 Hz and low levels of ground roll. However, such deep holes might be unacceptably time-consuming and costly.

Evaluation of existing 2D lines revealed the frequency content that could be

13. For a review of AVO see:

For more on seismic monitoring see:

14. Source patterns are groups of dynamite charges in separate holes at the same depth, fired simultaneously. The goal is to cancel low-frequency noise that travels laterally, called ground roll.
Filtered 2D data showing frequency content variation with depth. Each panel has been filtered to allow a different band of frequencies, called the passband, to pass. As the passband rises, the maximum depth of penetration of seismic energy decreases. Lower frequencies (left) penetrate deeper. Higher frequencies (right) do not propagate to deeper levels. At the target level of 3.0 sec there is still some 50 Hz energy left.

expected from seismic data in the area (above). Resampling along the 2D line at the sampling interval planned for the 3D survey confirmed that the 50-m [165-ft] receiver and shot spacings initially recommended were appropriate. Fold-reduction simulations performed on the 2D sections showed that 24-fold would be appropriate for the survey. However, a brick pattern would give better fold and offset distribution than the roll-along pattern, potentially improving the survey results. The brick pattern would also reduce the lateral offset between source and receiver line, thus reducing the potential for ground roll arriving at the same time as the reflection from the target and making the ground roll easier to handle in processing.

The complete survey evaluation and design took two months and reached the following conclusions.
1. A target bandwidth of 10 to 60 Hz is a reasonable acquisition objective.
2. Placement of sources deeper than 40 m would avoid complex processing problems and high levels of ground roll in the 3D data set. If logistics prevent locating the sources at this depth, then a fallback deployment of sources at 9 m would meet the target bandwidth criterion with minimal notching but higher levels of ground roll. Field quality control should verify there is no notch between 10 and 60 Hz.
3. A 144-trace brick pattern with 300-m [984-ft] receiver line spacing and 300-m shot line spacing would give the best offset distribution.
4. Shot and receiver intervals should be no more than 50 m.

Drilling 40-m holes for each source location was deemed impractical. Optimizing costs and logistics, the company obtained satisfactory results with a 24-m [79-ft] source depth, single-shot dynamite, and brickwork acquisition pattern.

Evaluation and design can be different in the marine setting. A case in point is the Al Shaheen location in offshore Qatar, under development appraisal by Maersk Oil Qatar AS, according to an agreement with Qatar General Petroleum Corporation (QGPC). Maersk Oil had only eight months to design and acquire a 3D survey that would provide a 25 km² [9.6 sq mile] image, requiring about 49 km² [18.8 sq mile] of full fold data, and to spud a vertical development appraisal well. Given the tight schedule—processing alone normally takes a year—Maersk Oil contracted a survey evaluation and design study based on existing VSPs and 2D surveys. This study was more extensive than the previous example, with more pre-existing data, particularly well data.

The objective of the 3D survey was to produce a stratigraphic image of the Kharaii limestones and a thin 13- to 15-ft [4- to 4.6-m] thick overlying oil-filled sand. The seismic data were to be analyzed for porosity-related amplitude variations along with small-scale faulting and fracturing to help in planning the trajectory of future horizontal wells. The acquisition vessel had already been contracted, limiting the seismic source to a 1360- or 1580-in.³ [22,290- or 25,900-cm³] air gun.

Evaluation of existing data indicated areas where special care had to be taken to ensure a successful survey. For example, high-velocity beds at the seafloor promised to cause strong multiples, reducing the energy transmitted to deeper layers and
leading to strong reverberations in the water layer. A bandwidth of 10 to 90 Hz was required to resolve the thin sands above the target and the small faults within it.

Evaluation of existing borehole data offered valuable insight into the transmission properties of the earth layers above the target and the geophysical parameters that could be obtained at the target. Comparison of formation tops inferred from acoustic impedance logs with reflection depths on the two VSPs allowed geophysicists to differentiate real reflections from multiples. Identification of the origin of multiples allowed the acquisition and processing parameters to be designed to minimize their effect. Analysis of the amplitude decrease of the VSP downgoing first arrivals quantified transmission losses (right). Bandwidth studies on the VSPs showed that frequencies in the 80- to 100-Hz range were present and being reflected at the depth of the target (above). This meant the frequencies required for thin-bed resolution might be obtainable by the 3D survey.

The study also looked into quantifying the seismic resolution of small-scale faulting (next page, top) and analyzed five different bandpass filters on VSP data showing energy present up to 80 to 100 Hz at target. Each panel passes a different band of frequencies. Coherent energy up to 80 to 100 Hz reflects from the survey objective at 0.8 sec.

![Vertical seismic profile (VSP) traces (left) analyzed for amplitude loss with depth (right). Amplitudes of first arrivals recorded in a 92-level VSP are calibrated with amplitudes of a surface reference signal to account for changes in source amplitude from level to level. The amplitude ratio from one level to the next is plotted in decibels (dB). One dB is 20 times the log of the amplitude ratio. An amplitude ratio of 100 is equivalent to 40 dB. Amplitudes expected from a surface seismic survey would normally be 3 dB less than those from a VSP, and scaled by a reflection coefficient.](image)
Resolution of thin beds and small-scale faulting. Each panel shows the modeled response of a seismic wave of 48-m [160-ft] wavelength ($\lambda$) to a different vertical fault displacing a series of thin beds of thicknesses 12 m, 24 m and 36 m. From left to right, faults with 3-m [10-ft], 6-m [20-ft], 12-m [40-ft] and 24-m [80-ft] throws correspond to $\lambda/16$, $\lambda/8$, $\lambda/4$ and $\lambda/2$, respectively. A fault throw of at least 12 m, corresponding to $\lambda/4$, can be resolved quantitatively. At less than that, existence of a fault can be detected, but its throw resolved only qualitatively.

A time slice from Maersk Oil Qatar 3D cube showing fractures and faults.

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drilling. Faults with throws as little as 8 to 10 ft [2.5 to 3 m] interpreted in the seismic data were verified by on-site biostratigraphic evaluation of the reservoir limestones.

In addition to these two surveys, Geco-Prakla has conducted more than 30 other survey evaluation and design studies, sometimes with surprising results. In one case, analysis of tidal currents led the team to propose a change of 120° in shooting direction, which would add $150,000 to the processing cost, but cut 45 days and $1,500,000 off the acquisition cost, for a savings of $1.35 million. In another study, analysis of previous seismic data showed that coherent shot-generated noise was aliased at shot intervals of 37.5 m [123 ft]. Although it would increase acquisition and processing costs, a denser shot interval of 25 m would sample the noise sufficiently to allow removal during processing. The 37.5-m shot spacing was used in the survey, giving data that required extra prestack processing costs, which did not entirely eradicate the noise.

In a study with Schlumberger Technical Services in Dubai, UAE, data from a VSP acquired just before a marine 3D survey helped optimize planning.\(^{16}\) In a deviated production well near the center of the survey, a slimhole TWST Through-Tubing Well Seismic Tool was run through tubing to the reservoir to record shots fired from the seismic source to be used in the 3D survey. The shot records allowed geophysicists to determine the effects at the depth of the target of source parameters such as air-gun volume, depth and pressure. The records also showed that at far offsets, high amplitude shear waves contaminate the traces. With a shorter receiver cable, a better survey was acquired in less time, and so for lower cost, than originally planned.

\(\text{Raytrace modeling showing strong changes in reflection paths through salt. Traces that would have a common midpoint in a flat-layered earth no longer bounce in the same bin. Salt, with its ability to deform and its high seismic velocity, creates complex structure and strong refraction, or ray bending.}\)

\(\text{Ship Shoal South Addition in the Gulf of Mexico.}\)

For the Future
Some of the advances to be made in 3D survey design have origins in other fields. VSP design routinely models seismic raypaths through complex subsurface structure, but rarely does surface seismic design account for structure. Despite considerable sophistication in 3D data processing, most 3D survey design assumes plane layer geometry in the subsurface to calculate midpoints and target coverage. But to estimate subsurface coverage adequately in complicated structure, survey designers recognize the need to model raypaths, and some are beginning to do this. Geco-Prakla has used raytrace modeling to determine coverage in a survey to image below salt in the Ship Shoal South Addition in the Gulf of Mexico (left).

Salt introduces large contrasts in seismic velocity, bending and distorting seismic rays along complex paths (top). Survey designers anticipated that a super-long receiver cable would be required to provide adequate coverage of the subsalt layers. They tested various cable lengths by shooting raypaths through a geologic model derived from 2D

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15. Migration, sometimes called imaging, is a processing step that rearranges recorded seismic energy back to the position from which it was reflected, producing an image of the reflector.

seismic data (above). Surprisingly, a standard 5425-m [17,794-ft] cable provides coverage similar to that of the proposed 8075-m [26,500-ft] cable.

Another advance may come through integration of survey design with acquisition, processing and interpretation into a single quality-assured operation. The aim is to maximize cost-effectiveness of the overall seismic survey, to supply quality-assured processed data with minimum turnaround time and optimal cost. Within Geco-Prakla, this idea is called Total Quality 3D, or TQ3D. Such surveys may be acquired on a proprietary (exclusive) or a speculative (nonexclusive) basis, or a combination of the two. For example, 75% of a 700-km² [271-sq mile] TQ3D survey in the southern UK continental shelf will be delivered as proprietary data to three oil companies. The remaining 25% is nonexclusive, and although sponsored in part by the current players in this area, the data will also be available to new players.

Defining the objectives of a TQ3D survey can be a difficult process. Rather than hazarding a guess at which reflectors in an area are the sought-after targets, Geco-Prakla planners involve proprietary and nonexclusive clients at early stages of the project. Over open acreage they examine a data base of nonexclusive 2D seismic surveys to learn about the targets.

Choosing acquisition parameters that will be optimal for the entire survey is also a challenge. It is not always practical to follow all the recommendations proposed by a survey evaluation and design study, but a judgment can be made of the impact that any decision will have on the quality of the data. Then, other options can be explored. For example, in a recent TQ3D survey, steeply dipping reflectors in 20% of the area would have been optimally sampled if the receiver spacing had been reduced from 25 m to 20 m [66 ft], but the 25% additional cost was unacceptable to clients. Having flagged this as an area where data quality could be improved, attention will be paid to processing that may help imaging of steep dips.

As oil companies and service companies strive for efficiency and acquisition of high-quality, cost-effective seismic data, more emphasis is being placed on survey design. The other pieces of the seismic puzzle—acquisition, processing and interpretation—have all benefited from advances in technology, and survey design is following the trend. Through powerful modeling and integration of log, VSP and surface seismic data, 3D survey design will become the foundation for all that follows. —LS
What Influences the Choice of Fluid?
Among the many factors to consider when choosing a drilling fluid are the well's design, anticipated formation pressures and rock mechanics, formation chemistry, the need to limit damage to the producing formation, temperature, environmental regulations, logistics, and economics (see “Critical Decisions,” next page).

To meet these design factors, drilling fluids offer a complex array of interrelated properties. Five basic properties are usually defined by the well program and monitored during drilling: rheology, density, fluid loss, solids content and chemical properties (see “Basic Mud Properties and Ingredients,” page 36).

For any type of drilling fluid, all five properties may, to some extent, be manipulated using additives. However, the resulting chemical properties of a fluid depend largely on the type of mud chosen. And this choice rests on the type of well, the nature of the formations to be drilled and the environmental circumstances of the well.

Designing and Managing Drilling Fluid

Gone are the days when drilling fluid—or mud as it is commonly called—comprised only clay and water. Today, the drilling engineer designing a mud program chooses from a comprehensive catalog of ingredients. The aim is to select an environmentally acceptable fluid that suits the well and the formation being drilled, to understand the mud's limitations, and then to manage operations efficiently within those limitations.

There are good reasons to improve drilling fluid performance and management, not least of which is economics. Mud may represents 5% to 15% of drilling costs but may cause 100% of drilling problems. Drilling fluids play sophisticated roles in the drilling process: stabilizing the wellbore without damaging the formation, keeping formation fluids at bay, clearing cuttings from the bit face, and lubricating the bit and drillstring, to name a few. High-angle wells, high temperatures and long, horizontal sections through pay zones make even more rigorous demands on drilling fluids.

Furthermore, increasing environmental concerns have limited the use of some of the most effective drilling fluids and additives. At the same time, as part of the industry’s drive for improved cost-effectiveness, drilling fluid performance has come under ever closer scrutiny.

This article looks at the factors influencing fluid choice, detailing two new types of mud. Then it will discuss fluid management during drilling.

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Shales are the most common rock types encountered while drilling for oil and gas and give rise to more problems per meter drilled than any other type of formation. Estimates of worldwide, nonproductive costs associated with shale problems are put at $500 to $600 million annually. Common drilling problems like stuck pipe arise from hole closure and collapse, erosion and poor mud condition. In addition, the inferior wellbore quality often encountered in shales may make logging and completion operations difficult or impossible.

Shale instability is largely driven by changes in stress and chemical alteration caused by the infiltration of mud filtrate containing water (next page, top). Over the years, ways have been sought to limit interaction between mud filtrate and water-sensitive formations. So, for example, in the late 1960s, studies of mud-shale reactions resulted in the introduction of a water-base mud (WBM) that combines potassium chloride [KCl] with a polymer called partially-hydrolyzed polyacrylamide—KCl-PHPA mud. PHPA helps stabilize shale by coating it with a protective layer of polymer—the role of KCl will be discussed later.

The introduction of KCl-PHPA mud reduced the frequency and severity of shale instability problems so that deviated wells in highly water-reactive formations could be...
drilled, although often still at a high cost and with considerable difficulty. Since then, there have been numerous variations on this theme as well as other types of WBM aimed at inhibiting shale.

However, in the 1970s, the industry turned increasingly towards oil-base mud (OBM) as a means of controlling reactive shale. Today, OBM not only provides excellent wellbore stability but also good lubrication, temperature stability, a reduced risk of differential sticking and low formation damage potential. OBM has been invaluable in the economic development of many oil and gas reserves.

The use of OBM would probably have continued to expand through the late 1980s and into the 1990s but for the realization that, even with low-toxicity mineral base-oil, the disposal of OBM cuttings can have a lasting environmental impact. In many areas this awareness led to legislation prohibiting or limiting the discharge of these wastes. This, in turn, has stimulated intense activity to find environmentally acceptable alternatives and has boosted WBM research.

To develop alternative nontoxic muds that match the performance of OBM requires an understanding of the reactions that occur between complex, often poorly characterized mud systems and equally complex, highly variable shale formations.

**Requisites for a Successful Drilling Fluid**

Most OBM is an invert emulsion comprising droplets of aqueous fluid surrounded by oil, which forms the continuous phase. A layer of surfactant on the surface of the water droplet acts like a semipermeable membrane, separating the aqueous solution in the mud from the formation and its water. Water will pass through this membrane from the solution with the lowest concentration of a salt to the one with the highest—osmosis (right).

A key method of maintaining shale stability using OBM is to ensure that the ionic concentration of the salts in the aqueous—internal—phase of the mud is sufficiently high, so that the chemical potential of the water in the mud is equal to or lower than that of the formation water in the shale.7 When both solutions have the same chemical potential, water will not move, leaving the shale unchanged. If the water in the internal phase of the mud has a lower chemical potential than the fluid in the formation, water will travel from the shale to the mud, drying out the rock. Unless dehydration is excessive, this drying out usually leaves the wellbore in good condition.8

In WBM, there have been many efforts to protect a water-sensitive formation from mud filtrate. One technique is to introduce a buffer in the form of blocking and plastering agents, ranging from starches and celluloses, through polyacrylamides to asphalts and gilsonites. Total control cannot be achieved in this way so specific inhibiting cations—chiefly potassium [K+] and calcium [Ca2+] ions—are traditionally added to the base water to inhibit the clay from dispersing—to stop it from breaking up when attacked by aqueous solution. This is
Basic Mud Properties

Five basic properties are usually defined by the well program and monitored during drilling:

**Rheology**—A high viscosity fluid is desirable to carry cuttings to surface and suspend weighting agents in the mud (such as barite). However, if viscosity is too high, friction may impede the circulation of the mud causing excessive Pump pressure, decrease the drilling rate, and hamper the solids removal equipment. The flow regime of the mud in the annulus is also affected by viscosity. Measurements made on the rig include funnel viscosity using a Marsh funnel—an orifice viscometer—and plastic viscosity, yield point and gel strength using a Fann 35 viscometer or equivalent.

**Density**—Sufficient hydrostatic pressure is required to prevent the borehole wall from caving in and to keep formation fluid from entering the wellbore. The higher the density of the mud compared to the density of the cuttings, the easier it is to clean the hole—the cuttings will be less inclined to fall through the mud. If the mud weight is too high, rate of drilling decreases, the chances of differential sticking and accidentally fracturing the well increase, and the mud cost will be higher. The most common weighting agent employed is barite. Density is measured on the rig using a mud balance.

**Fluid loss**—The aim is to create a low-permeability filter cake to seal between the wellbore and the formation. Control of fluid loss restricts the invasion of the formation by filtrate and minimizes the thickness of filter cake that builds up on the borehole wall, reducing formation damage and the chances of differential sticking. Static fluid loss is measured on the rig using a standard cell that forces mud through a screen, and also using a high-temperature, high-pressure test cell.

**Solids content**—Solids are usually classified as high gravity (HGS)—barite and other weighting agents—or low gravity (LGS)—clays, polymers and bridging materials deliberately put in the mud, plus drilled solids from dispersed cuttings and ground rock. The amount and type of solids in the mud affect a number of mud properties. A high solids content, particularly LGS, will increase plastic viscosity and gel strength. High-solids muds have much thicker filter cakes and slower drilling rates. Large particles of sand in the mud cause abrasion on pump parts, tubulars, measurement-while-drilling equipment and downhole motors. Measurement of total solids is traditionally carried out using a retort—which distills off the liquid allowing it to be measured, leaving the residual solids.

**Chemical properties**—The chemical properties of the drilling fluid are central to performance and hole stability. Properties that must be anticipated include the dispersion of formation clays or dissolution of salt formations; the performance of other mud products—for example, polymers are affected by pH and calcium; and corrosion in the well (see “Corrosion in the Oil Industry,” page 4). Measurement rig-side usually relies on simple chemical analysis to determine pH, Ca\(^{2+}\), total hardness, concentrations of Cl\(^-\) and sometimes K\(^+\).

**Mud Ingredients**

**Water**—In water-base mud (WBM) this is the largest component. It may be used in its natural state, or salts may be added to change filtrate reactivity with the formation. Water hardness is usually eliminated through treatment and alkalinity is often controlled.

**Weighting agents**—These are added to control formation fluid pressure. The most common is barite.

**Clay**—Most commonly, bentonite is used to provide viscosity and create a filter cake on the borehole wall to control fluid loss. Clay is frequently replaced by organic colloids such as biopolymers, cellulose polymers or starch.

**Polymers**—These are used to reduce filtration, stabilize clays, flocculate drilled solids and increase cuttings-carrying capacity. Cellulosic, polyacrylic and natural gum polymers are used in low-solids mud to help maintain hole stability and minimize dispersion of the drill cuttings. Long-chain polymers are adsorbed onto the cuttings, thereby preventing disintegration and dispersion.

**Thickeners**—These are added to the mud to reduce its resistance to flow and to stifle gel development. They are typically plant tannins, polyphosphates, lignitic materials, lignosulfonates or synthetic polymers.

**Surfactants**—These agents serve as emulsifiers, foamers and defoamers, wetting agents, detergents, lubricators and corrosion inhibitors.

**Inorganic chemicals**—A wide variety of inorganic chemicals is added to mud to carry out various functions. For example, calcium hydroxide is used in lime mud and calcium chloride in OBM; sodium hydroxide and potassium hydroxide (caustic soda and caustic potash) are used to increase mud pH and solubilize lignite; sodium carbonate (soda ash) to remove hardness, sodium chloride for inhibition and sodium chloride has many uses—such as increasing salinity, increasing density, preventing hydrate formation and providing inhibition.

**Bridging materials**—Calcium carbonate, cellulose fibers, asphalts and gilsonites are added to build up a filter cake on the fractured borehole and help prevent filtrate loss.

**Lost circulation materials**—These are used to block large openings in the wellbore. These include walnut shells, mica and mud pills containing high concentrations of xanthum and modified cellulose.

**Specialized chemicals**—Scavengers of oxygen, carbon dioxide or hydrogen sulfide are sometimes required, as are biocides and corrosion inhibitors.

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1. For a complete description of the traditional mud check techniques:
   2. Plastic viscosity (PV) and yield point (YP) are related parameters and follow common oilfield conventions based on the Bingham rheological model. PV is largely dependent on the type of mud and its solids content. The lower the PV, the faster the drilling penetration rate. However, this is limited by the YP, which is a direct measure of the fluid's cuttings-carrying efficiency.

For details of rheology:
achieved by providing cation exchange with the clays in the shale—the K⁺ or Ca²⁺ commonly replace the sodium ion [Na⁺] associated with the clay in the shale, creating a more stable rock that is better able to resist hydration. Hence KCl-PHPA fluids.⁹

The movement of WBM filtrate from the wellbore into the surrounding shale is controlled by the difference between the chemical potentials of the various species in the mud, and the corresponding chemical potentials within the formation. Chemical potential depends both on the mud's hydrostatic pressure in the wellbore and on its chemical composition.¹⁰

To design an effective WBM, it is necessary to know the relative importance of mud differential pressure versus chemical concentration and composition, and how this relates to the type of mud and formation. For example, if the rock is chemically inert to WBM filtrate (as is the case with sandstone), then invasion is controlled solely by the differences between the wellbore pressure and the pore pressure within the rock. But for shale, opinion varies. Some experimenters suggest that the shale itself can act as a semipermeable membrane, making the chemical components the key determinant.

Researchers at Schlumberger Cambridge Research tested Pierre shale and found that it behaves as an imperfect ion exclusion membrane and that the role of chemical differences between wellbore fluid and pore fluid is less significant than the difference in pressure between the mud and the formation.¹¹ This result is an oversimplification since it does not consider what happens after fluid invades the formation raising its pore pressure. However, it does suggest that mud weight should be kept as low as well safety and mechanical wellbore stability considerations allow.¹² These and other results are now being used to design more effective WBM systems and evaluate those that are already available (see “Strategies for Improving WBM Shale Inhibition,” page 39).

A number of relatively new types of mud systems have been introduced. For example, one route is to substitute the oil phase in OBM with synthetic chemicals. In this way, the excellent characteristics of OBM may be reproduced with a more rapidly biodegraded continuous phase than was available before. Typical synthetic base chemicals include esters, ethers, polyglycoester, linear olefins and linear alkyl benzenes. One of the chief disadvantages of these systems is that they tend to be relatively expensive compared to conventional OBM. However, such systems can still be cost-effective options compared to WBM—particularly where OBM would have been used prior to the introduction of new environmental constraints.

The State of the WBM Art
This article will now concentrate on advances in WBM technology by looking at two distinct directions of development: the use of polyols for shale inhibition and the introduction of mixed-metal hydroxides to improve hole cleaning and help reduce formation damage.

Polyol muds—Polyol is the generic name for a wide class of chemicals—including glycerol, polyglycerol or glycols such as propylene glycol—that are usually used in conjunction with an encapsulating polymer (PHPA) and an inhibitive brine phase (KCl).¹³ These materials are nontoxic and pass the current environmental protocols, including those laid down in Norway, the UK, The Netherlands, Denmark and the USA.

Glycols in mud were proposed as lubricants and shale inhibitors as early as the 1960s. But it was not until the late 1980s that the materials became widely considered. Properly engineered polyol muds are robust, highly inhibitive and often cost-effective. Compared with other WBM systems, low volumes are typically required. Polyols have a number of different effects, such as lubricating the drillstring, opposing bit balling (where clays adhere to the bit) and improving fluid flow. Today, it is their shale-inhibiting properties that attract most attention. For example, tests carried out by BP show that the addition of 3 to 5% by volume of polyglycol to a KCl-PHPA mud dramatically improves shale stabilization (below). However, a significant gap still remains between the cuttings comprising Tertiary shale—London Clay that contains about 20% smectite—that have been exposed to different muds in an aggressive dispersion test. This test is an indication of a mud’s shale stabilizing qualities rather than a simulation of downhole conditions. The weight of the cuttings before treatment is compared to the weight after-treatment (see “Strategies for Improving WBM Shale Inhibition,” page 39).

![Improving inhibition with addition of polyglycol. This chart shows the recovery of cuttings comprising Tertiary shale—London Clay that contains about 20% smectite—that have been exposed to different muds in an aggressive dispersion test. This test is an indication of a mud’s shale stabilizing qualities rather than a simulation of downhole conditions. The weight of the cuttings before treatment is compared to the weight after-treatment.](image-url)
remains between the performance of polyol muds and that of OBM.

Field experience using polyol muds has shown improved wellbore stability and yielded cuttings that are harder and drier than those usually associated with WBM. This hardness reduces breakdown of cuttings and makes solids control more efficient. Therefore, mud dilution rates tend to be lower with polyol muds compared with other WBM systems (for an explanation of solids control and dilution, see mud management, page 39).

As yet, no complete explanation of how polyols inhibit shale reactivity has been advanced, but there are some clues:

- Most polyols function best in combination with a specific inhibitive salt, such as potassium, rather than nonspecific high salinity.
- Polyol is not depleted rapidly from the mud even when reactive shales are drilled.
- Many polyols work effectively at concentrations as low as 3%, which is too low to significantly change the water activity of the base fluid.
- Polyols that are insoluble in water are significantly less inhibitive than those that are fully soluble.
- No direct link exists between the performance of a polyol as a shale inhibitor and its ability to reduce fluid loss.

Many of these clues eliminate theories that try to explain how polyols inhibit shales. Perhaps the most likely hypothesis—although so far there is no direct experimental evidence supporting it—is that polyols act as a structure breaker, disrupting the ordering of water on the clay surface that would otherwise cause swelling and dispersion. This mechanism does not require the glycol to be strongly adsorbed onto the shale, which is consistent with the low depletion rates seen in the field.

Mixed-metal hydroxide (MMH) mud—MMH mud has a low environmental impact and has been used extensively around the world in many situations: horizontal and short-radius wells, unconsolidated or depleted sandstone, high-temperature, unstable shales, and wells with severe lost circulation. Its principal benefit is excellent hole-cleaning properties.14

Many new mud systems—including polyol muds—are extensions of existing fluids, with perhaps a few improved chemicals added. However, MMH mud is a complete departure from existing technology. It is based on an insoluble, inorganic, crystalline compound containing two or more metals in a hydroxide lattice—usually mixed aluminum/magnesium hydroxide, which is oxygen-deficient. When added to prehydrated bentonite, the positively charged
MMH particles interact with the negatively charged clays forming a strong complex that behaves like an elastic solid when at rest. This gives the fluid its unusual rheology: an exceptionally low plastic viscosity-yield point ratio. Conventional muds with high gel strength usually require high energy to initiate circulation, generating pressure surges in the annulus once flow has been established. Although MMH has great gel strength at rest, the structure is easily broken. So it can be transformed into a low-viscosity fluid that does not induce significant friction losses during circulation and gives good hole cleaning at low pump rates even in high-angle wells (previous page). Yet within microseconds of the pumps being turned off, high gel strength develops, preventing solids from settling.

There are some indications that MMH also provides chemical shale inhibition. This effect is difficult to demonstrate in the laboratory, but there is evidence that a static layer of mud forms adjacent to the rock face and helps prevent mechanical damage to the formation caused by fast-flowing mud and cuttings, controlling washouts.\(^1\)

MMH is a special fluid sensitive to many traditional mud additives and some drilling contaminants. It therefore benefits from the careful management that is vital for all types of drilling fluid.

**Mud Management—Keeping the Fluid in Shape**

Selecting a reliable chemical formulation for the drilling fluid so that it exhibits the required properties is one part of the job. Maintaining these properties during drilling is another.

Circulation of drilling fluid may be considered a chemical process with the wellbore acting as a reactor vessel. In this reactor, the composition of the drilling fluid will be changed dynamically by such factors as filtration at the wellbore and evaporation at surface; solids will be added and taken away by the drilling process and the solids-control equipment; chemicals will be lost as

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**Strategies for Improving WBM Shale Inhibition**

Researchers at Schlumberger Cambridge Research, Cambridge, England, have proposed a number of strategies for developing mud formulations with improved shale inhibition.\(^1\)

### Preventing Filtrate Access

**Creation of a semipermeable membrane**—If an effective membrane can be produced on the surface of the shale by adding suitable surfactants to WBM, then water ingress could be controlled using chemical activity as in OBM. This effect was obtained, to some degree, with the direct-emulsion WBM used occasionally in the 1980s. The challenge is to identify effective surface active molecules that are environmentally acceptable, do not unduly affect other mud properties and, ideally, show low depletion rates.

**Provision of fluid-loss control**—Conventional fluid-loss control polymers produce mud filter cakes that are typically one or two orders of magnitude higher in permeability than shales. Even if fractures are present, such polymers may be effective at plugging these relatively large holes, but filter cakes are otherwise unlikely to form on shale. If they did, the shale—the less permeable of the two solid phases—would still control the rate of fluid transport. Given the small dimensions of pores in shales—one order of nanometers—fluid loss control is likely to be best achieved either by chemical reactions that greatly reduce, or even eliminate, permeability or by molecules small enough to block pore throats.

**Increasing the viscosity of the filtrate**—By increasing the viscosity of the filtrate (using for example, silicates or glycols) the rate of ingress is reduced. However, this slowing may not be sufficient to control wellbore stability and the mud may have an infeasibly high plastic viscosity.

### Minimizing Subsequent Swelling

If invasion of a WBM filtrate cannot be avoided, appropriate design of the filtrate chemistry may be used to minimize the swelling response of the shale. However, even if swelling is effectively inhibited, filtrate invasion of the shale will increase the pore pressure and add to possible mechanical failure of the rock.

**Control of ionic strength**—The salinity of the filtrate should be at least as high as that of the pore fluid it replaces.

**Choice of inhibiting ion**—Cations such as potassium should be incorporated into the formulation. These will replace ions such as sodium found in most shales to produce less hydrated clays with significantly reduced swelling potential. Any inhibitors added to the mud should have sufficient concentration to remain effective as the filtrate travels through the shale.

Although potassium ions reduce clay swelling, they rarely eliminate it. Recently, there have been attempts to find more effective cations—for example, aluminium complexes or low molecular weight, catonic polymers.

**Use of cementing agents**—An alternative approach may be to use mud additives that react with the clay minerals and/or pore fluids present in shales to produce cements that strengthen the rock and prevent failure. In field trials, silicate and phosphate salts have demonstrated the potential to cement the formation, although some drilling difficulties unrelated to wellbore stability have been reported—for example, hole cleaning.

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they adhere to the borehole wall and to cutt-
ings, and they will be added routinely at surface; formation fluids will contami-
nate the mud, perhaps causing flocculation or loss of viscosity, and oxygen may become entrained. Temperature, pressure and possi-
ble bacterial action may also have significant effects.

Under these circumstances effective man-
agement is not trivial. Nevertheless, basic process control techniques have been ap-
plied rigsider for some years to aid in the selection and maintenance of the fluid for-
mulation and to optimize the solids-control equipment—such as shale shakers and cen-
trifuges (next page). This approach is often linked to incentive contracts, where savings in mud costs are shared between contractor and operator, and has led to remarkable savings in mud costs.

For example, with a systems approach to drilling fluid management for 16 wells off-
shore Dubai, mud costs were cut in half and reduced as a proportion of total drilling
costs from 6% to 3%. At the same time, hole condition remained the same or bet-
ter—this was assessed by looking at hole diameter, time to run casing and mud usage per foot of well drilled.

Such an approach is based on three premises:

- More frequent and more precise measure-
ments, for example five mud checks per day and the introduction of advanced measurement techniques (more about these later)
- Efficient data management using mass balance techniques—which track the volumes of chemicals, hole and cut-
tings—and computerized data storage and acquisition
- Integration of the management of the solids control equipment with that of the drilling fluids.

Solids-control efficiency—the percentage of drilled solids removed versus the total amount drilled—is central to drilling efficiency and is a function of the surface equipment, drilling parameters and mud properties. For example, muds that have a lower tendency to hydrate or disperse drilled cuttings generally give higher solids-control efficiency.

The significance of solids control is that penetration rate is closely linked to the vol-
ume of solids in the fluid. The greater the amount of solids, the slower the rate of drilling (below). Mud solids are divided into two categories: high-gravity solids (HGS) comprising the weighting agent, usually barite; and low-gravity solids (LGS) made up from clays, polymers and bridging materials deliberately put in the mud, plus drilled solids from dispersed cuttings and ground rock.

The volume of HGS should be maxi-
mized, so that the total volume of solids in the mud is minimized, while still achieving the density required to control formation pressures. Therefore, drilled solids must be removed by the solids-control equipment. However, some solids become dispersed as fine particles that cannot be removed effec-
tively. In this case, the fluid must be diluted with fresh mud containing no drilled solids.

But desirable properties are not always optimum ones. For instance, zero drilled solids at the bit is desirable. However, achieving zero drilled solids would increase mud costs dramatically. It is the job of mud management to plot the optimum course. To do this successfully requires accurate and regular input data.

Traditional field practice is to measure mud density and viscosity (using a Marsh funnel) about every 30 minutes at both the return line and the suction pit. Other properties—such as rheology, mud solids, fluid loss, oil/water ratio (for OBM), pH, cation-exchange capacity, and titrations for chlor-
ide and calcium—are measured once every 8 or 12 hours (depending on drilling con-
ditions) using 1-liter samples taken from the flowline or the active pit. These determin-
ations are then used as a basis for mud treatment until the next set of measure-
ments is made.

To gain better control over the mud sys-
tem, a more meaningful monitoring strategy may be required. Simply increasing the fre-
quency of traditional measuring techniques to at least five times a day and making sam-
ping more representative of the whole mud system has improved control and signifi-
cantly reduced the amount of chemicals used to drill a well. However, new types of measurement are now available. Two new monitoring systems developed by Dowell are the MSM mud solids monitor and the FMP fluids monitoring package.

**Mud Solids Monitor**—A common indicator describing the solids content in the mud is the LGS-HGS volume ratio. This is tradition-
lionally measured using the retort, a tech-
nique that requires good operator skills, takes at least 45 minutes and often has an error margin of more than 15%.

The Dowell MSM system takes the place of the retort. Without complicated sample preparation, it offers a 10-minute test with an accuracy of more than 95%. The basic measurement uses X-ray fluorescence (XRF). A standard software package uses the bar-
ium fluorescence and backscattering intens-
ity from XRF spectra, together with the fluid density to predict the concentrations of bar-
ium and water. From these primary outputs the LGS concentration is also determined. As an off-line measurement, XRF has the
Cleaning the mud. The cuttings-removal performance of solids-control equipment depends on many factors, including the size of the mesh for the shale shaker screen, flow rate and density of the drilling fluid, and the size of the cuttings. Deciding how to use the surface equipment also depends in part on the type of mud run.

With the shale shakers, the aim is to choose a screen mesh size that sieves out as much of the drilled solids as possible, leaving barite, which is finer, in the system. However, the finer the screen, the lower the throughput of mud and the more shale shaker capacity required. In this case, the choice is either to install an extra shale shaker or to fit a wider mesh screen allowing more of the solids to remain in the fluid that must then be diluted with new, clean mud.

Centrifuges may be used to control fines. For a low-density mud containing mostly drilled solids, the aim is to strip away as much of the solids as possible. However, if the mud is weighted, fines-control strategy depends on the liquid phase. If the liquid phase is relatively cheap (for example, a seawater-lignosulphonate mud), the barite is the most valuable part of the fluid. In this case, the centrifuge is used to remove all the barite while the rest of the fluid may be disposed of. However, if the liquid phase is also valuable (such as in OBM, KCl-PHPA or glycol muds), both phases are worth keeping. In this case, two centrifuges may be used. First, to remove the barite, which may be reused. Then, the remaining larger solids—assumed to be drilled solids—may be removed and disposed of and the liquid returned to the active system. Clearly, treating mud with the centrifuge is a lengthy process and centrifuges can typically handle only about 15% of the active system.

16. The MUDSCOPE service was originally developed by Sedco Forex, but has subsequently been offered by Dowell IDF Fluid Services.


advantages of more frequent measurement, greater precision and less dependence on operator skills (right). These data provide the basis for informed mud management decisions. For example, using the MSM package offshore Congo, inflows and outflows through the desander and desilter were monitored. From these measurements, the amount of barite and LGS being dumped on an average day was calculated. The MSM package showed that the desander and desilter were removing a lot of valuable barite and not enough of the unwanted LGS.

Analysis of the MSM data showed that in eliminating 11.5 tons [10,430 kg] of LGS per day—the capacity of the desander and desilter—some 45 cubic meters [1590 ft³] of mud were lost, requiring a maintenance treatment including 41.65 tons [37,800 kg] of barite. Based purely on the cost of the barite, it was found to be more cost-effective to dispose of 60 cubic meters [2120 ft³] of mud and dilute the remaining system with new mud requiring only 23.25 tons [22,900 kg] of barite, saving $3339 per day. These findings may vary if mud component costs are included in the analysis—many inhibitive muds have high-value liquid phases—and if the environmental impact of dumping the mud is considered.

Fluid Monitoring Package—At the heart of the system is an in-line skid that continuously monitors the rheology, density, pH, temperature and electrical conductivity of the mud (above). Data are stored on hard disk and may be viewed on screen in real or deferred time and on hard copy. Data correlate with data obtained using standard rig equipment, but of course they are continuously delivered.

For example, rheology is measured using three pipe rheometers. Each of these coiled pipes has a different length and diameter and therefore exerts different shear on the sample of mud as it passes at a known rate through the pipe. Pressure drop on entering and leaving each pipe may then be equated to shear stress. So that data are presented in a form that is comparable to traditional information, shear rate and shear stress are converted to equivalent Fann 35 viscometer readings (next page, left). From these, plastic viscosity and yield-point readings may be derived. However, while mud rheology is traditionally measured at constant temperature, the FMP continuous measurement is made as the mud temperature fluctuates during drilling.

The FMP service is currently being field-tested in Europe and Africa. In one field trial lasting five weeks, the FMP was tested on two well sites for over 915 hours. The system was exposed to three different mud systems—formate, KCl-gypsum, and NaCl saturated—and a wide temperature range—10°C to 79°C [50°F to 174°F]. The tests showed that the hardware is capable of withstanding the rugged demands of drilling, and yielded useful mud logs (next page, right).
Future Developments

It is still early days for these techniques, but such measurements, and others in development, will furnish the information required to help control a fully automated mud processing plant.21

Joint industry field trials are already under way to automate mud management. The aim is to deliver a system with automated solids-control equipment, automated addition of mud chemicals, continuous monitoring of key mud parameters, automated mud system valve control and tank lineup, and central monitoring of integrated process control. A demonstration system has been installed on the semisubmersible rig Sedco 712, working in the UK sector of the North Sea, to allow full-scale evaluation.22

However, it is clear that the driving force for automated mud processing, and other future developments, must be more cost-effective drilling, improved employee health and environmental compliance, and enhanced well performance. —CF

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Comparison of PV Readings Using FMP and Fann Viscometer

Comparison of plastic viscosity (PV) data gathered in the field from KCl mud using the FMP skid with that generated the traditional way using a Fann 35 viscometer.

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22. The demonstration project is being undertaken by Sedco Forex, Dowell, Thule Rigtech and Marine Structure Consultants (M.S.C.) bv. It is partially funded by The Commission of European Communities Thermie project, Shell UK Exploration and Production, Conoco (UK) Limited and BP International Limited.


By late 1984, after several years’ research, Marathon Oil Company laboratories in Littleton, Colorado, USA established a new polymer-gel system to block high-permeability channels within a reservoir and improve oil recovery. Previous attempts using less sophisticated chemistry had failed because the chemicals had become unstable at reservoir conditions and also were partially toxic. But now the chemistry looked right. During the next three years, Marathon performed 29 treatments with the new system in nine of its fields in Wyoming’s Big Horn basin. Fourteen treatments were in carbonate formations, and 15 were in sandstones.

The greatest success occurred when injection wells were treated. The Big Horn reservoirs are known to be naturally fractured and the injected polymer-gel system most likely filled much of the fracture system between injector and neighboring producer. This would force subsequent water.

Two examples of production reversal during Marathon Oil Company’s conformance control campaign in Wyoming’s Big Horn basin. In each case, Marathon injected a polymer-gel system into an injector and noted the production response in adjacent producers. Both examples show a dramatic reversal of both declining oil rate and increasing water/oil ratio (WOR)—see straight-line trends in top figure. On average, each extra barrel of oil derived from their series of 29 treatments cost Marathon just $0.34.


The UK Department of Trade and Industry’s estimate of improved oil recovery (IOR) potential in the UK North Sea and the proportion expected to be produced with conformance control.

Drive to enter the matrix rock or fractures untouched by the treatment and push out oil. In many cases, a declining production in the neighboring producer was dramatically reversed, staying that way for several years (previous page).

Overall, the 29 treatments yielded 3.7 million barrels more oil than if the treatments had never been done, at a total cost of just $0.34 per barrel. Considering the price of oil at the time ranged from $30 to $24, Marathon had got themselves some very inexpensive production and a clear signal that the age of conformance control had begun.

**What is Conformance Control?**

In the context of a reservoir produced with some kind of external fluid drive, conformance describes the extent to which the drive uniformly sweeps the hydrocarbon toward the producing wells. A perfectly conforming drive provides a uniform sweep across the entire reservoir; an imperfectly conforming drive leaves unswept pockets of hydrocarbon. Conformance control describes any technique that brings the drive closer to the perfectly conforming condition—in other words, any technique that somehow encourages the drive mechanism to mobilize rather than avoid those hard-to-move pockets of unswept oil and gas.

In the pantheon of techniques to improve oil recovery, conformance control is relatively unambitious, its goal being simply to improve macroscopic sweep efficiency. Most enhanced oil recovery (EOR) techniques, for example, also strive to improve microscopic displacement efficiency using a variety of surfactants and other chemicals to prize away hydrocarbon stuck to the rock surface. Conformance control is also less expensive than most EOR techniques because the treatments are better targeted and logistically far smaller.

Another factor also favors conformance control. By redistributing a waterdrive so it sweeps the reservoir evenly, water cut is often dramatically reduced. For many mature reservoirs, treatment and disposal of produced water dominate production costs, so less water is good. Environmental regulations also push oil companies to reduce water production. In the North Sea, residual oil in produced water dumped into the ocean is restricted to 40 ppm, an upper limit increasingly under pressure from the European Community. In environmentally sensitive areas such as the Amazon rain forest, water disposal is also a major issue.

In a recent survey by the British Government Department of Trade and Industry (DTI) that reviewed the full spectrum of improved oil recovery (IOR) techniques and their potential for the UK North Sea, conformance control accounted for a possible further 500 million barrels of oil (above).

This constitutes 10% of the total IOR potential of more than five billion barrels and contributes to raising final oil recovery from the 43% obtained using primary and conventional secondary recovery methods to 54%, an increase of 11%. Unlike many of the IOR techniques reviewed by the DTI, conformance control technology was judged mature enough to use immediately.

Conformance control during waterflooding covers any technique designed to reduce water production and redistribute waterdrive, either near the wellbore or deep in the reservoir. Near the wellbore, these techniques include unsophisticated expedients such as setting a bridge plug to isolate part of a well, dumping sand or cement in a well to shut off the bottom perforations, and cement squeezing to correct channeling and fill near-well fractures. Deep in the reservoir, water diversion needs chemical treatment.

Initially, straight injection of polymer was tried but proved uneconomical because of the large volumes required to alter reservoir behavior and because polymers tend to get washed out. The current trend is gels, which if correctly placed can do the job.

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Gelling System Chemistry

Phillips pioneered the first polymer gels for conformance control in the 1970s. Since then, research into gelling systems has been maintained at an intense level. Polymer gel systems start as a flowing mixture of two components—high-molecular weight polymer and another chemical called a cross-linker. At some trigger, each cross-linking molecule, tiny compared with the polymer molecule, starts attaching itself to two polymer molecules chemically linking them together. The result is a three-dimensional tangle of interconnected polymer molecules that ceases behaving like a fluid and can eventually constitute a rigid, immobile gel.

The trick in designing these systems is finding chemicals that are insensitive to the chemistry of gelling systems, the predominant method of blocking permeability and redistributing water-drive, and then illustrate the care successful proponents of the technique must exercise in choosing and implementing treatments. Whether the chemistry is robust enough to go where it is intended, deep in the reservoir, and that it is formulated correctly to actually gel. The combination of these challenges is daunting and explains conformance control’s checkered history. If the technique is more widely accepted today, it is only because these challenges are now recognized, not because they are resolved.

We’ll next look at the chemistry of gelling systems, the predominant method of blocking permeability and redistributing water-drive, and then illustrate the care successful proponents of the technique must exercise in choosing and implementing treatments. That the chemistry is robust enough to go where it is intended, deep in the reservoir, and that it is formulated correctly to actually gel. The combination of these challenges is daunting and explains conformance control’s checkered history. If the technique is more widely accepted today, it is only because these challenges are now recognized, not because they are resolved.

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Partially hydrolyzed polyacrylamide (PHPA) and with its negatively charged carboxylate groups becomes susceptible to ionic cross-linking.

Efficient cross-linkers are trivalent metal ions such as aluminum, Al\(^{3+}\), and chromium, Cr\(^{3+}\). These can be packaged either as simple inorganic ions in solution or within soluble chemical complexes in which the trivalent ion is associated with small inorganic or organic molecules that bond covalently.

There have been innumerable systems developed since the 1970s, too many to describe, so we will concentrate on the evolution of a particularly promising system that uses the synthetic polymer called polyacrylamide (PA). This readily available polymer comprises a carbon-carbon backbone hung with amide groups, possibly tens of thousands of them to provide molecular weights in the millions (below). In its pure state, the polymer is electrically neutral, seeming to preclude any cross-linking through ionic bonding. However, when mixed with a little alkaline solution, such as sodium hydroxide, or when subjected to elevated temperature, some of the amide groups convert to carboxylate groups. Each of these carries a negative charge. The proportion of amide groups that convert to carboxylate is called the degree of hydrolysis (DH) and typically varies from 0 to 60%. In this form, the polymer is called partially hydrolyzed polyacrylamide (PHPA) and with its negatively charged carboxylate groups becomes susceptible to ionic cross-linking.


5. For a general review:

groups on different polymer molecules, or possibly on the same molecule (above). Relatively few cross links are needed to ensure that the polymer-cross-linker mixture gels.

The chemical environment deep in an oil reservoir, however, often conspires to wreck this idealized picture. In the case of aluminum sulfate, cross-linking is very much pH dependent. While the mixture remains acidic, no gel forms so the treatment fluids can be safely injected into the reservoir. But when the fluids hit the reservoir, pH rises rapidly and gelling occurs immediately. The system therefore worked only very near the wellbore and suffered from total lack of control—gelling time was entirely at the mercy of the reservoir environment.

Toward the 1980s, Cr$^{3+}$ rather than Al$^{3+}$ was tried as the cross-linker, not because it provided better cross-linking, but because it promised better gelation control. The technique to achieve this, though, was not to use Cr$^{3+}$ directly but rather Cr$^{6+}$. This ion is inert with respect to cross-linking but can be reduced to Cr$^{3+}$ using a variety of reducing agents that could be injected with the treatment fluids. In theory, this would allow the system to be injected deep into the formation before gelling.

In practice, however, there were three problems. It was difficult to provide sufficiently long gelation times at high temperature; the whole system was sensitive to H$_2$S—itself a reducing agent; and, worst, Cr$^{6+}$ was recognized as toxic and even carcinogenic. These problems appeared to be resolved in the mid 1980s when an environmentally friendly, controllable chromium system was developed at the Marathon Petroleum Technology Center in Littleton, Colorado, USA.

Scientists there had the idea of packaging Cr$^{3+}$ as the metal-carboxylate complex, chromium acetate. The acetate group has a structure very similar to the carboxylate groups on PHPA polymer (right). Thus, the Cr$^{3+}$ ion is attracted to both the acetate ligand within the complex and the carboxylate groups on the PHPA polymer. This slows the

Marathon’s MARCIT gel in three final states depending on concentration, from left: tonguing gel, intermediate strength gel and rigid gel. (Courtesy of Marathon Oil Company.)

“Chemical linking of partially hydrolyzed polyacrylamide polymer (PHPA) molecules with trivalent metal ions, indicated generically as M$^{3+}$.”

cross-linking process and ultimately gives the chemist effective control over gel time.

Substantial laboratory testing showed that the behavior of the PHPA-chromium acetate system was insensitive to pH from about 2 to 12.5, relatively insensitive to ions in formation fluids, and untroubled also by H₂S and CO₂. Furthermore, it could be formulated to give a wide range of gel strengths and gel times at temperatures up to 124°C (255°F) and even higher. Marathon now licenses this system in two forms. Its MARCIT system using PHPA polymer with a molecular weight of more than five million is designed for filling and blocking fractures, as used for example in the Wyoming trials (previous page, bottom left). Its MARA-SEAL system using PHPA with a low molecular weight in the mere hundreds of thousands and lower DH has reduced pre-gel viscosity and is designed for filling and blocking matrix reservoir rock.

The chemistry and physics of polymer gels are complex and often controversial. One point of dispute is whether polymers such as PHPA, even with relatively low molecular weights, as in MARA-SEAL, can be successfully injected through narrow pore throats into reservoir matrix rock. Marathon’s laboratory tests suggest they can, although reservoir conditions may not have been duplicated exactly. Others believe that because of the interaction of the polymer with the pore walls and the very size of the polymer molecule, the systems have difficulty negotiating small pore spaces, limiting injection. The need for matrix-filling gel systems, though, is not in dispute.

BP Exploration and ARCO are currently testing a system comprising PHPA and an aluminum-based cross-linker that is hoped will reach deep in the matrix reservoir of the Kuparuk field in Northern Alaska. The cross-linker is another metal-carboxylate complex, aluminum citrate. But unlike chromium acetate, this links the PHPA in two distinct temperature-controlled stages (right). In the first stage which occurs rapidly in cold water, each aluminum citrate

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molecule bonds to just one polymer carboxylate site. In the second stage, which occurs only above 50°C [122°F], the aluminum citrate complex can attach to a second carboxylate group thereby cross-linking two polymer molecules and contributing to produce a gel network. Because the cross-link itself contains carboxylate groups and these have an affinity for water molecules, the formed gel may flow in a beaker, yet provide an adequate permeability block in porous rock.

BP and ARCO’s strategy is to pump the system into the reservoir through injection wells, where the cooler temperature of the injection water will promote only the first-stage reaction, resulting in a pumpable fluid of low viscosity. Then, as the fluid permeates deep into high-permeability sections of the reservoir and experiences higher temperatures, the second-stage will kick in and enough of a gel will form to divert water-drive to less permeable zones. In preparation for field tests, BP conducted an extensive computer simulation of the temperature distribution and likely flow patterns of the polymer-gel system within the reservoir, and also laboratory studies of the system injectability through 190-ft [58-m] long slimtubes packed with sand (below). It is too early to tell whether their ambitious plan is working in the field.

The problem of injecting polymer gel systems through the narrow pore spaces of matrix is multifaceted and has been a focus of a three-year Department of Energy project at the New Mexico Institute of Mining and Technology in Socorro, New Mexico, USA.8 At the pore scale, there are three main issues. First, some of both the polymer and cross-linker will get adsorbed onto the pore walls during injection. In itself, fluid retention is not a problem as long as most of the treatment fluid reaches its destination deep in the reservoir. More serious is if the absorptivity rates of the two components are different. Then, the volumetric ratio of polymer to cross-linker will change as the treatment invades the formation, possibly compromising control of gelling time. BP’s aluminum citrate system may overcome this hazard because the cross-linker makes its first attachment to the polymer before injection, rendering the two components inseparable.

The second issue is polymer elasticity. Polymers being long, complex molecules exhibit a degree of elasticity that makes how they move somewhat dependent on their surroundings. For example, the viscosity observed in a free polymer solution will not necessarily be mirrored when the same polymer is trying to squeeze through a pore throat (left). In general, polymer elasticity inhibits the progress of treatment fluid through porous medium. Third, there is the question of pore throats actually becoming blocked by microclusters containing several polymer molecules—these may develop prior to bulk gelling.9 All three issues are being researched and to an extent represent the key to leaping from laboratory evidence to certainty on what happens in the field.

**Inorganic Gelling Systems**

An alternative gelling system that guarantees injectability into matrix rock uses simple inorganic chemicals that have flowing properties nearly identical to those of water. Inorganic gels were discovered in the 1920s and are used to this day for plugging lost circulation, zone squeezing and consolidating weak formations. Their failing for conformance control has been a very rapid gelation time, but recent innovations using aluminum rather than silicon have resolved this problem. An example is the DGS Delayed Gelation System developed by the Schlumberger pumping company, Dowell.10

The DGS system comprises partially hydrolyzed aluminum chloride that precipitates to a gel when an activator responds to temperature and raises the system pH above a certain value (next page). A gel materializes because aluminum and hydroxyl ions link with each other in such a way as to form an amorphous, irregular three-dimensional impermeable network. The DGS system is quite insensitive to the subsurface environment, except for the caution that divalent anions in the formation water, such as sulfates and carbonates, SO₄²⁻ and CO₃²⁻, can enter the system and affect the gel structure. Conformance control with the DGS system has been tried with success from Australia to South America (see “Profile

Besides their inherent ability to deeply permeate matrix rock, inorganic gels have another advantage over their polymer-based cousins. If the treatment fluid gets incorrectly placed causing a deterioration in reservoir performance, inorganic gel can be removed with acid. Of course, the acid has to be able to reach the gel to be able to remove it. Polymer gels, on the other hand, cannot be dismantled easily and are therefore usually in place for the duration.

If deep penetration in matrix is one key factor in the conformance control debate, another concern is contamination of the gelling system through contact with ions in the formation water. As noted, the DGS system may be adversely affected by divalent anions. PHPA, on the other hand, both before and after gelling may be affected by divalent cations such as Ca\(^{2+}\), which are relatively ubiquitous in formation waters. Ca\(^{2+}\) ions associate with the carboxylate groups in PHPA causing free polymer to precipitate. This becomes more of a problem as the degree of hydrolysis of the polymer increases, and DH can increase with increasing temperature. Research initiated at Phillips Petroleum Co. and pursued further at Eniricerche SpA, Italy’s national research center for the oil industry situated near Milan, has identified other polymer types that may offer better protection from ionic attack yet still be susceptible to ionic cross-


Profile Modification Using DGS Gelling System

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The following two conformance control case studies describe a producer that is watered-out from coning (Venezuela) and water injectors that have poor injection profiles (Australia).

Venezuela

In Venezuela, oil company Corpoven, S.A. has been evaluating several gelling systems at its national research center INTEVEP. Laboratory analysis narrowed its choice to the inorganic DGS system of Dowell and Pfizer Inc.’s FLOPERM system. The FLOPERM system uses a monomer called melamine—a monomer comprises a single chemical group from which polymer is built—and an organic covalent-bonding cross-linker, in this case formaldehyde, to form polymer gels in situ. In the field, Corpoven tried the DGS system in two wells, the FLOPERM system in one well, and both systems in a fourth well with each system restricted to a different producing zone.

The most successful treatment was in one of the two wells receiving the DGS system only. The treatment was designed to block water coning at the bottom of an oil producer in a zone 6 ft [2 m] thick. The reservoir was an 80-md limestone at 9145 ft [2787 m]. Downhole static temperature was 140°C [284°F], high for most commercially available gelling systems.

During a period of 10 hours, 300 barrels of DGS treatment fluid were pumped through tubing and packer into the watered-out zone at 0.5 bbl/min. Simultaneously, diesel fuel was pumped down the annulus above the packer into the overlying oil zone to prevent the treatment fluid from entering the oil zone. The treatment fluid was then displaced with 78 barrels of water and allowed to gel for a week.

When the well was put back on production, oil production increased more than 2.5 times and water cut had dropped 25%. Eleven months later, 36,000 additional barrels of oil had been produced and water cut was still 15% less than before the treatment.

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The following two conformance control case studies describe a producer that is watered-out from coning (Venezuela) and water injectors that have poor injection profiles (Australia).

Venezuela

In Venezuela, oil company Corpoven, S.A. has been evaluating several gelling systems at its national research center INTEVEP. Laboratory analysis narrowed its choice to the inorganic DGS system of Dowell and Pfizer Inc.’s FLOPERM system. The FLOPERM system uses a monomer called melamine—a monomer comprises a single chemical group from which polymer is built—and an organic covalent-bonding cross-linker, in this case formaldehyde, to form polymer gels in situ. In the field, Corpoven tried the DGS system in two wells, the FLOPERM system in one well, and both systems in a fourth well with each system restricted to a different producing zone.

The most successful treatment was in one of the two wells receiving the DGS system only. The treatment was designed to block water coning at the bottom of an oil producer in a zone 6 ft [2 m] thick. The reservoir was an 80-md limestone at 9145 ft [2787 m]. Downhole static temperature was 140°C [284°F], high for most commercially available gelling systems.

During a period of 10 hours, 300 barrels of DGS treatment fluid were pumped through tubing and packer into the watered-out zone at 0.5 bbl/min. Simultaneously, diesel fuel was pumped down the annulus above the packer into the overlying oil zone to prevent the treatment fluid from entering the oil zone. The treatment fluid was then displaced with 78 barrels of water and allowed to gel for a week.

When the well was put back on production, oil production increased more than 2.5 times and water cut had dropped 25%. Eleven months later, 36,000 additional barrels of oil had been produced and water cut was still 15% less than before the treatment.

Profile Modification Using DGS Gelling System

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When the well was put back on production, oil production increased more than 2.5 times and water cut had dropped 25%. Eleven months later, 36,000 additional barrels of oil had been produced and water cut was still 15% less than before the treatment.
linking. One solution is to use synthetic polymers in which some amide groups are replaced by a more inert chemistry that cannot hydrolyze to carboxylate and therefore remain vulnerable to wandering divalent cations (right).

Part of the Eniricerche effort is directed toward improving the temperature rating of polymer gel systems. Chemical process always speeds up with elevated temperature, and this makes gelling increasingly difficult to control. The most interesting result to date in improving gelation control at high temperature is through use of chromium malonate, yet another metal-carboxylate complex, as cross-linker. Malonate, which has two carboxylic groups as opposed to the single group in acetate or citrate, appears to extend gelation time by an order of magnitude (below). As a bonus, surplus malonate uncomplexed with chromium seems to retard gelation even more and also scavenges those divergent cations such as Ca\(^{2+}\) that can precipitate the PHPA polymer.

A final challenge in designing polymer gels is ensuring long-term stability. Most gels run the risk of dehydration, a process called syneresis that causes shrinkage and loss of conformance. But it remains an open question how serious this shrinkage can be, and which gelling system, if any, is least affected. As with many other aspects of gelling systems, syneresis remains an active field of research.

![Malonate, suggested as a stable complex with chromium for cross-linking, also acts as a calcium divalent cation scavenger.](image)

### Treatment Fluid Placement

After chemistry, the second major hurdle in conformance control is placement of treatment fluid. This shifts attention from the chemist to the reservoir engineer who must ask and be able to answer some tough questions: Given a reasonably functional polymer-gel system, what factors determine whether a reservoir will benefit from treatment? And if a reservoir seems a good candidate, how should the treatment proceed? Via producers or injectors? And using some kind of zone isolation or none? Candidate selection is how the reservoir engineer’s challenge is paraphrased.

The three-year Department of Energy project at the New Mexico Institute of Mining and Technology has directed attention to most of these questions, and some guidelines have emerged. For example, if the treatment fluid is pumped into injection wells—which according to numerous case studies seem to give better results than producers—theoretical studies show that zone isolation is mandatory when attempting to inject gel into matrix rock porosity but not important when filling fracture porosity. This is because if a matrix reservoir is filled with gel in the wrong places, there is literally no conduit remaining for production. However, in a fractured reservoir where gel fills the fractures, the matrix rock still remains for producing oil.

Ultimately, computer simulation can be invoked to test whether a proposed treatment is likely to work. But this requires more than simulation of reservoir fluid flow. Also needed is a chemical simulator that models how the gelling system reacts with...
the reservoir environment and how gelling constituents react with each other. As reported earlier, BP Exploration performed such a computer simulation in its planning for treating the Kuparuk field with a PHPA-aluminum citrate system. Another fluid-flow/chemical simulator, called SCORPIO, is offered by AEA Petroleum Services, which is based in Dorchester, England. This simulator is currently being used to investigate the feasibility of polymer-gel conformance control in several North Sea fields.

The prudent operator, of course, will temper sophisticated modeling with a good dose of common sense. In addition, it does not hurt to have enough injection and production data available to fully comprehend how the reservoir will react if prodded. Surprisingly, reservoir production data can be sparse and poorly documented. Frequently, production data are known for groups of wells tied to a common pipeline and not for individual wells. However, this was not the case in the Wertz field in Wyoming, USA for which Amoco Production Co. began contemplating a series of conformance control treatments in mid-1991 (below).16

**Case Study**
The Wertz field was a model implementation of a CO2 tertiary flood, and, as a result, field performance had been copiously documented. Not only were individual producers and injectors monitored daily, but flow rates of the three phases present—oil, water and CO2—were also measured. These measurements were made in special substations, one substation for every dozen wells or so, each with elaborate and automatic apparatuses for sampling each well’s flow in or out and the flow’s breakdown into three phases.

The Wertz producing formation is a 470-ft [143-m] thick aeolian sandstone at an average depth of 6200 ft [1890 m], with 240 ft [73 m] of net pay having 10% porosity and 1.3-md permeability. The formation is believed to have some fractures and is oil wet. Sixty-five wells over 1600 acres are used for production and many more than that have been drilled for injection—alterating water and CO2 injection, commonly referred to as water-alternating-gas (WAG) injection. By mid-1991, the field’s fate literally hung in the balance. The field’s total production had dropped precipitously to 4000 BOPD from 12,000 BOPD in 1988, a steeper than expected decline during tertiary flooding.

After trying several other techniques to halt the decline, Amoco turned to conformance control, eventually completing 12 treatments using Marathon’s polymer gel technology. Ten treatments were in injectors and two in producers. Some treatments were aimed at blocking matrix porosity and some aimed to place gel in reservoir fractures. We’ll highlight one example of each, illustrating with injector treatments since these were the more successful. In some cases, the treatments extended the life of a pattern by two years. Overall, Amoco estimates that for a total cost of $936,000, the treatments have yielded an increase in producible reserves of 735,000 barrels—that is $1.27 per barrel.

A crucial preliminary step in all these treatments was candidate selection—the compilation and review of data to determine a well’s suitability for treatment (next page). Although any field information could be relevant, five data types were deemed particularly important. They were:

![Structure of Amoco’s Wertz field at Bairoil, Wyoming, USA. Conformance control treatments performed in well #84 gained 110,000 additional barrels of oil production via neighboring producing wells #125 and #127. A treatment in well #120 gained 140,000 additional barrels of oil production via neighboring producing well #142.](image-url)
• Pattern reserves. If the pattern reserve data indicated that secondary and tertiary flooding had pushed out most of the oil, there was no reason to try further production enhancement with conformance control.

• Historical fluid-injection conformance. If an injection well historically showed a poor injection profile, the corresponding pattern was obviously a candidate for conformance improvement. In the Wertz field, Amoco used radioactive tracer surveys to log injection profiles.

• Three-phase offset production data. If producing wells in a pattern showed a cyclic water and CO₂ production that correlated with cycles in the nearby injection well, then it was likely this communication was through an unusually high-permeability channel. The pattern therefore required conformance control.

• Breakthrough time during the cyclic correlation—essentially the time for water or CO₂ to travel between injector and neighboring producer. This helped estimate the size of treatments designed to fill the fracture space between the wells.

• Well history information—specifically the history of all previous attempts to improve conformance in the well, and why they did or did not work. This information prevented unnecessary workover expense.

The first well treated was #84, an injection well on the west flank of the field that fed producers #125 and #127. This well seemed to satisfy the five criteria. An estimated 226,000 barrels of reserves remained in the pattern; injection conformance was poor with no water and very little CO₂ entering the upper part of the well; injection cycling was clearly visible in #125 and #127, with documented breakthrough times of 12 and 14 days, respectively; and previous conformance control attempts with sand had failed because of behind-pipe channeling between the upper and lower parts of the well.

The well seemed to require a blocking of the high-permeability matrix in the lower

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Amoco’s process logic for picking conformance control candidates in the Wertz field. (Adapted from Borling, reference 16.)
Injection profiles for water and CO₂ in well #84 before and at various times after the gel treatment, which was confined to the high-permeability zone at the bottom of the well. The treatment dramatically improved injection conformance. (Courtesy of Amoco Production Co.)

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Zone of suspected high permeability
zone and also of the behind-pipe channel. Amoco opted for Marathon’s low molecular-weight polymer-gel technology, and in addition, mechanically isolated the target interval to avoid losing treatment fluid to the upper zone, a necessary contingency that consumed 55% of the total treatment cost. Altogether, 650 barrels of the PHPA-chromium acetate mixture were pumped at 4 barrels a minute, in a two-stage operation taking one day.

As with all their subsequent conformance control operations, round-the-clock precautions were taken to avoid any environmental contamination by the treatment fluid and to ensure the treatment fluid was being injected in the correct proportions. In addition, fluid issuing from the production wells was monitored to ensure that the treatment fluid did not somehow bypass the matrix and get produced. Finally, samples of the treatment fluid taken in the field confirmed that a rigid gel formed after a few hours.

One month after the treatment, injection conformance in well #84 showed spectacular improvement with 57% of injected water entering the upper zone (previous page). Two months later, during a CO₂ cycle, 79% of the CO₂ was entering the upper zone. The situation was just as good after ten months, when Amoco decided to shut off the entire bottom zone with sand. This forced all injection to the upper zone, and injection profiles thereafter indicated conformance to be practically uniform throughout that zone—a textbook example of injection conformance.

Meanwhile in producing well #125, which had been previously shut in because it produced only water, oil started appearing and production was up to 150 BOPD after twelve months; the water/oil ratio (WOR) decreased to 40 (above). Later, oil production began to slip and well #125 was shut in. Nevertheless, the conformance treatment prolonged the life of this producing well by 30 months, furnishing an additional 80,000 barrels of oil.

In producing well #127, oil production rose from 45 BOPD before the treatment to 150 BOPD after. During the same time, WOR dropped from 80 to nearly 20. The improvement lasted 30 months, five of which were unfortunately interrupted by facility breakdowns. Altogether, the well produced an extra 30,000 barrels of producible reserves.

The first treatment Amoco performed with large volumes of a high-molecular weight polymer-gel system was in well #120. This well appeared to be in direct communication with neighboring producer #142, as evidenced by a very rapid one-to-three-day breakthrough time for CO₂ injection. Corroborating a rapid communication between the wells was the behavior of well #142. Oil rate as soon as #120 started injecting. Other factors favoring a gel treatment for #120 included an estimated 209,000 barrels of missed reserves, poor injection conformance with nearly 90% of the water entering a suspected mid-pay fracture, and a well history showing that earlier treatments using in-situ surfactant foam had failed to improve conformance.

The treatment in #120 was altogether of a different scope than the matrix treatment in #84. First, treatment volume totaled 10,000 barrels and took seven days to pump, at the rate of one barrel per minute. This volume was estimated to be enough to completely fill the fractures between the two wells. Second, no mechanical isolation was used because the treatment fluid was expected to be able to enter only the targeted fractures. After waiting a few days to let the system gel, well #120 was once again put on alternating water and CO₂ injection. As measured by tracer surveys, the conformance for both fluids was significantly improved (next page, top).

Production at #142 still responded to the water-CO₂ cycling, indicating that the gel had not completely filled the fracture system and that therefore some communication remained, but oil rate improved, reaching 275 BOPD more than it would have wit-
out treatment. WOR dropped to 30 where it remained for more than two years (right). Altogether, the treatment prized out of the tired reservoir an additional 140,000 barrels of oil.

Amoco’s strategy in the Wertz field never included sophisticated computer simulation to pick conformance candidates. Rather, it relied on unusually complete field documentation and a well thought-out, methodical approach for candidate selection. In a small, well understood field, Amoco succeeded in making conformance control an economic success. The next years will see whether this success can be extended to larger fields—in the Alaskan North Slope, the UK and the Middle East, for example—that are entering their twilight years and where the economics are on a significantly larger scale.

Meanwhile, the chemists remain at their desks, fine-tuning their understanding of gelling, seeking a better polymer, and moving out to new systems such as polymer-gel foams. Conformance control is here for the duration as long as oil fields continue to produce water.

—HE
A lobster dinner brings out the explorationist in us all, providing a tasty lesson in how to boost recovery. A novice seafood lover may settle for the tail. Extra work and some specialized tools (a nutcracker and lobster fork) yield substantial rewards from the claws and legs. To recover that elusive delicacy roe, however, requires motivation, experience and knowledge of lobster anatomy.

Maraven, S.A., one Venezuela’s three national oil companies, is going for the hard-to-get roe in Block 1 of Lake Maracaibo, Venezuela (above). Forty years of production there has left isolated pockets of hydrocarbon, known as attic oil, in the tops of structural and stratigraphic traps. Recovering this attic oil with vertical wells is not usually cost-effective because the thin layer

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**Teamwork Renews an Old Field with a Horizontal Well**

An integrated services approach to drilling a horizontal well in Lake Maracaibo, Venezuela brought new life to a watered-out, mature field. A crossdisciplinary cast of geoscientists from Maraven, S.A. and Schlumberger overcame complex geology and landed a successful horizontal drainhole where previous attempts by other companies had failed.

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In this article, Charisma, CemCADE, CDN (Compensated Density Neutron), CDR (Compensated Dual Resistivity), DSI (Dipole Shear Sonic Imager), ELAN (Elemental Log Analysis), Impact (Integrated Mechanical Properties Analysis Computation Technique), EARTHQUAKER and MicroSFL are marks of Schlumberger.


of oil in place increases the likelihood of water coning.

Taking a new approach, an integrated team of geoscientists from Maraven and Schlumberger planned, drilled and completed VLA-1035—Lake Maracaibo’s first successful horizontal well—gaining an eight-fold increase in oil production over vertical wells in the same reservoir.

The motivation for VLA-1035 was provided when Maraven’s parent company Petroleos de Venezuela, S.A. (PDVSA) launched a development program for Lake Maracaibo. The plan called for generating 11 billion barrels of additional oil reserves through new wells, horizontal development and reworking of older wells. Although horizontal drilling had been considered in Lake Maracaibo since 1986, attempts by other companies to drill horizontal wells were unsuccessful because of the complex geology or completion problems.

Yet, horizontal drilling seemed the only way to produce from Block 1. A vertical well typically produced 150 barrels of oil per day (BOPD). Most older wells had been shut in as uneconomic, and the wells that were on line typically produced no more than 150 barrels of oil. Some recent wells began producing water immediately, others made water within two months. Early breakthrough of water was inevitable because of the reduced vertical height of pay, reduced reservoir pressure and increased relative permeability of water to oil.

The Planning Stage

In early 1992, Maraven began assessing the economic and technical feasibility of drilling a horizontal drainhole to recover remaining reserves. Reservoir engineers evaluated production histories to identify regions with recoverable oil and later modeled drainhole performance. Geophysicists used three-dimensional (3D) seismic data, having vertical resolution of tens to hundreds of feet, to obtain a big picture of the reservoir and identify prospective sands. Geologists and sedimentologists examined cores and logs, with vertical resolutions on the order of inches to one foot, to identify sands and model their orientation, continuity and distribution. Petrophysicists working with sedimentologists integrated log and core data with drilling records, including bit and mud data, for 33 wells in the area. This provided an understanding of the mechanical stability of the formation, fluid distribution, oil-water contact location, and flagged possible drilling difficulties.

They targeted reservoir VLA-8° in Block 1, bound on the west by the Icotea fault. It contains a region of low dips (2° to 10°) called El Pilar and a region of high dips (30° to 45°) called the Attic (left). Since 1954,
VLA-8 has produced 42 million barrels of the estimated 118 million barrels of oil in place. This production reduced reservoir pressure from 3200 psi to 1800 psi at 6700 ft [2040 m] in some areas and raised the oil-water contact. Water coning has been a problem from the beginning, with the average water cut in the field increasing from 20% in 1960 to 85% by 1991 (previous page, top). The influx of water moves hydrocarbons toward the top of traps, creating isolated pockets of oil. Because of the extensive production in the field, normally desirable high permeability zones had water, whereas low-permeability zones still contained oil.

The Attic is considered the last opportunity for development in Block 1. Three-dimensional seismic data, shot in 1990 and covering 235 square km [91 square miles], revealed the structural complexity of the fold and fault systems that bound the reservoir, and also stratigraphic features within the pay sands. The steeply dipping flanks are difficult to image seismically because a mud layer at the bottom of Lake Maracaibo absorbs high-frequency seismic energies.

Well-tie sections, time slices and 3D cube displays from Schlumberger’s Charisma workstation contributed to understanding the structure (right). Productive sands in the Attic are in the C-6 and C-7 horizons, which have each been divided into three intervals—upper, middle and lower. In addition, seismic attribute sections were generated on the workstation and interpreted. Seismic attributes, such as signal phase and polarity, can reveal subtle characteristics of a seismic trace. In this case, instantaneous phase sections were particularly helpful in confirming the continuity of the C-7 structure. But the steep dip of the beds prevented determining an exact location of the C-7 reservoir.

2. George D: “Lake Maracaibo to Undergo Major Revi-
nalization, $9.6 Billion for Development During the
Next Four years,” Offshore/Oilman 52, no. 9 (Septem-
Seismic Data Processing,” Oilfield Review 3, no. 1
Hansen T, Kingston J, Kjellesvik S, Lane G, l’Anson K,
Naylor R and Walker C: “3-D Seismic Surveys,” Oil-
field Review 1, no. 3 (October 1989): 54-61.
4. In Lake Maracaibo, Maraven names reservoirs after
the name of their discovery well. In this case, the well
VLA-8 discovered the reservoir VLA-8. Maraven num-
ers wells sequentially. Wells in Block 1 have the pre-
fix VLA, those drilled in Block 2 have the prefix VLB,
etc. VLA-1035 occurs in Block 1 and is the 1035th
well drilled by Maraven in Lake Maracaibo.
Maraven was especially interested in the massive C-7 sands, 60 to 200 ft [18 to 60 m] thick, products of deltaic and fluvial depositional environments (above, middle). Target sands appeared to be the C-7 upper and lower intervals, with the initial preference by Maraven for the lower one.

Their next step was putting the seismic, log and core data into a reservoir model that would help identify the drainhole’s position in the sand for maximum production. Modeling performance of the proposed horizontal drainhole in the C-7 sands was accomplished with a black-oil reservoir simulator. Based on log and core analysis, the model comprised a partially anisotropic reservoir with a horizontal permeability of 250 md and a vertical to horizontal permeability ratio, $K_v/K_h$, of 0.5. In the model, the reservoir was bounded on one side by an aquifer and on the other by the Icotea fault. Assuming that no more vertical wells would be shut in and that water cut would stabilize, Maraven calculated that existing conventional wells would recover only 18% of the remaining reserves.

To find the most productive drainhole location, Maraven modeled performance for four horizontal drainholes, with lengths of 584 ft [178 m], 884 ft [307 m], 1200 ft [366 m] and 1600 ft [488 m], in the upper, middle and lower sands. The 1200-ft drainhole in the C-7 lower sand performed best. Overall, reservoir modeling showed that a horizontal well would recover 40% to 160% more oil than a vertical well (top).

After analyzing the seismic interpretation and the reservoir simulation, Maraven geoscientists concluded that a horizontal drainhole could not be drilled without additional information from a pilot well. First, they needed to pinpoint the top and thickness of C-7 with respect to the Icotea fault. Second, they needed to better define the oil-water contact. At this point, they negotiated with Schlumberger to manage drilling the pilot well and the subsequent drainhole under Maraven supervision. As Maraven and Schlumberger geoscientists worked together on the project, specialists from both companies refined the initial geologic and reservoir engineering studies.

Coordinating the project was Anadroll’s Bill Losso, who had worked with Schlumberger’s Horizontal Integration Team (HIT), which pioneered an integrated-services approach to drilling horizontal wells. The HIT group found that a coordinator was essential to facilitate communication between disciplines and act as a catalyst for decision making.

The program for drilling and completing the horizontal well took about 10 weeks (next page, top). Each task in the program was listed chronologically with its projected duration and status. This helped identify both progress and problem areas. Maraven and Schlumberger geoscientists involved in the planning met weekly to share information, discuss interpretations and make recommendations. Once drilling began, these weekly meetings gave way to daily sessions at a “mission control” center in Lagunillas, 20 miles [32 km] from the offshore rig but linked to it by phone, fax and data transmission lines. Every morning at 9:00, the team met to discuss drilling or completion operations—whatever was planned for the next 48 hours. The team needed to achieve a consensus on drilling decisions and be on call round the clock during critical operations. To keep team members and interested parties informed, the project coordinator prepared and distributed weekly updates—one-page summaries that highlighted progress and issues to be resolved.

Prompt and frequent communication was critical for weaving together the expertise of Maraven and Schlumberger specialists. This synergy resulted in well-informed decisions and has become a blueprint that Maraven is using in other projects (next page, bottom).

Drilling the Pilot Hole

The plan called for an 8½-inch pilot hole deviated 55°, with three possible drainhole trajectories to follow (above, left). Log data from the pilot well would be used to pick the best drainhole location. In addition to determining the drainhole trajectory, drilling the pilot hole gave the team an opportunity to learn how directional drilling equipment behaved in the VLA-8 formation.
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<td>Start drilling, run conductor pipe to 13¾-in. casing point</td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>

- Indicates task completed
- Official decision needed here to mobilize rig/services

Well spud date: 31 August

Ten-week planning schedule for drilling VLA-1035, as of August 5, 1992.

Organization of the integrated services team.
The well was drilled vertically to a kickoff at 5350 ft [1630 m], then with a build of 6°/100 ft [2°/10 m] to 50° deviation using a steerable bottomhole assembly (BHA) (right). CDR Compensated Dual Resistivity and CDN Compensated Density Neutron measurements were added to correlate in real time with log data from nearby wells. LWD logs were later complemented by a suite of wireline measurements comprising a resistivity log, two porosity logs, a gamma ray log and the DSI Dipole Shear Sonic Imager log. Tool sticking in the build section of the pilot well, attributed to overbalance caused by low reservoir pressure, precluded logging with a dipmeter tool. The lack of dip information near the well created a formidable challenge when it came time to drill the horizontal drainhole.

Log data from the pilot well were fed into the ELAN Elemental Log Analysis program, which fits openhole log measurements to a formation model comprised of mineral and pore fluid combinations (page 66). The ELAN results showed that the C-7 upper sand, with higher clay content than the other sands, had lowest effective porosity, but the highest hydrocarbon saturations. Logs of the shaly C-7 upper sand indicated oil in the top 40 ft [12 m], with a water leg in the clean sand section below (next page). Consequently, the team directed their attention to the C-7 upper rather than lower sand.

Next, petrophysicists used the Impact Integrated Mechanical Properties Analysis Computation Technique program to evaluate whether the C-7 upper sand could support a horizontal drainhole (page 67). The Impact program processes a variety of data—including bulk volume analysis from the ELAN output, vertical and horizontal stresses derived from logs and core measurements, and density logs—to calculate the stress field at the borehole wall for a given well inclination and direction. More importantly, it establishes safe mud weights along the trajectory in the borehole. The mud-weight range indicates the degree of difficulty and expense associated with drilling a horizontal well.

Vertical stress was derived from log measurements of the cumulative density of overlying sediments. Horizontal stresses were obtained using differential strain-curve analysis. In this technique, strain gauges are attached to a core sample, which is then encased in a silicone plug and compressed hydrostatically. Hydrostatic compression closes microcracks that developed when the core was removed. Measuring strain while these cracks close gives the ratio of the horizontal stresses.

Analysis of DSI data gave the compressional and shear velocities needed, along with the bulk density, to compute the dynamic elastic moduli. These computations matched the elastic moduli measured on cores prior to strain curve analysis. The Impact analysis showed the zone to be competent and drillable at high angles.

In finalizing the horizontal trajectory, the team correlated pilot log data with offset data from two nearby wells, which showed that the C-7 upper dipped up about 5° from the pilot well, then flattened out and eventually started dipping down. A 6°/100 feet build to 95° was planned to intersect the target sand at 6380 ft [1945 m] true vertical depth (TVD). Markers that could be identified with the LWD gamma ray or resistivity sensors were chosen to verify the approach to horizontal.

**Drilling the Horizontal Drainhole**

The drainhole was geosteered with an LWD system, providing real-time gamma ray and resistivity logs. Density and neutron porosity data were recorded in downhole memory and used to locate gas, which, if detected, would affect completion strategies. A sedimentologist at the rig analyzed drill cuttings to monitor the location of the drainhole in the target.

The pilot hole was plugged and opened up to allow setting 9½-in. casing at 6062 ft [1848 m]. When drilling began, the close interaction between Maraven and Schlumberger geoscientists was important in allow-
The pilot-hole logs were used to construct a dipping, “layer-cake” resistivity model that could simulate the LWD resistivity response in a drainhole for any depth and deviation. These simulated tool responses would guide the LWD interpreter in advising the driller once real-time LWD logs were available. When simulated and measured resistivities differ, the model is modified by adjusting the dip of the bed with respect to the borehole angle or the depth of the structure. This process is repeated until the simulated and measured resistivity measurements match, indicating the correct model for the depth and dip of the structure.

As the horizontal section began, early correlations between the simulated and real-time LWD measurements indicated a steeper dip than expected. To compensate, the team increased build angle from 6°/100 ft up to 16°/100 ft. Even so, the drainhole exited the

(continued on page 68)

5. The Impact program helps analyze borehole stability, design fracture jobs and predict sanding.


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CDR time-lapse overlay. Superimposing the Laterolog shallow, CDR shallow and CDR deep resistivity measurements (right track) taken during and after drilling allows monitoring of invasion. Changes in the resistivity measurements can be used to identify fluid types. Oil is indicated by the lower Laterolog resistivity readings after invasion of fresh mud has occurred. Water is indicated where the LWD resistivity measurements are lower than the Laterolog shallow measurement.
ELAN results for the pilot well. The C-7 upper sand showed less effective porosity than the C-7 middle and lower sands because of its higher clay content, but its hydrocarbon saturations were the highest. Resistivity measurements taken during and after drilling allowed the invasion profile to be established.
Impact analysis, calculated from the 50° deviated pilot well, used to determine mud weight guidelines for drilling wells deviated 50° and 90°. The caliper log in Track 1 shows some hole collapse that correlates with mud weight below the minimum limit. Track 2 displays three elastic parameters calculated from acoustic and density measurements. The range of values for Poisson’s ratio, 0.2 to 0.3, and Young’s Modulus, 3 to 4, indicates a somewhat weak, unconsolidated formation. Still, the formation is strong enough to support a horizontal drainhole. Mud weight guidelines, calculated for deviations at 50° and 90°, are in Track 3. Track 4 shows the volumetric interpretation of lithology and pore fluids.
oil section at 6748 ft [2057 m], striking water (below). The driller jacked up the inclination to 100° to steer the wellbore up toward the oil bottom. Once it was found, the hole was plugged back. LWD logs from this drainhole provided the team with dip information crucial for revising the formation model. The team accounted for the effects of azimuthal changes and high transverse dips relative to the well path, caused by the beds dipping up about 35° toward the fault. Any change in azimuth to the left would cause the drainhole to lose elevation in the oil section. A turn to the right would cause a gain in elevation.

The revised strategy was to land the drainhole in the upper section of the target. Once there, a 95° inclination would follow the dip until the CDR curve indicated the well path exiting into overlying shale. The azimuth would be closely controlled.

The new drainhole entered the top of the sand at 6750 ft [2057 m] with an inclination of 87.6°. Logs across the target sand from the pilot were then used to navigate the drainhole, with gamma ray and resistivity measurements from the LWD tool as indicators. The top of the C-7 upper interval contains a series of thin sands and shales each with an identifiable gamma ray signature (next page, below). Alternating changes in sand and shaliness as found from the pilot were assigned letters from “a” to “k”—“a, c, e...” indicated sands, “b, d, f,...” indicated shales. As the wellbore progressed, correlations indicated that the drainhole had penetrated sandy “a” through shaly “f.” Then the team decided to steer up to avoid hitting water. By subsequently drilling from “e” back to “a” and briefly out the top of the sand, they were able to confirm the exact location of the drainhole in the sand. This correlation of sedimentological facies between pilot and drainhole proved to be a powerful geosteering technique. The drainhole reached its planned displacement with 1112 ft [339 m] of net pay sand.

**Completion and Production**

Several factors influenced the completion of VLA-1035. The overall strategy was to produce through slotted liner, but this hinged on the ability to slide the slotted section to total depth (TD). Also, the slotted section needed to be centralized to avoid extensive slot plugging. An openhole gas section below the 9 5/8-in. shoe found with the CDN log needed to be hydraulically sealed from oil production. In addition, low reservoir pressure of 1200 psi required artificial lift for production.

Consequently, 7-in. casing with the lower section slotted for production, rather than liner, was set to surface (next page, top). This would provide the pushing power to reach total depth and guarantee gas isolation. CemCADE cementing design and evaluation software analysis was used to determine pump rates, fluid volumes, surface pressures and centralizer calculations for cementing. The 7-in. casing was run to the bottom of the hole, and an inflatable external casing packer was placed above the slotted section to isolate the gas. A port collar placed at the top of the horizontal slotted section directed the cement first into the packer and then up the annulus between the 7-in. casing and the openhole and 9 5/8-in. casing. After the packer was inflated, cement was pumped 1500 ft [457 m] above the 9 5/8-in. shoe to provide the hydraulic seal. Finally, 3 1/2-in. tubing equipped with two gas lift mandrels was run.

During the first two weeks of production, chokes ranging from 3/8 in. to 1 in. were tested, with the largest diameter yielding 2456 BOPD. With a 5/8-in. choke, the well averaged 1400 BOPD and a 4% water cut in the first five months and continues to produce 1000 BOPD with a 12% water cut today.

Maraven has since drilled two additional horizontal wells with Anadrill in Lake Maracaibo, including a reentry well, and is studying the optimal length of a horizontal drainhole. In 1994, Maraven plans to drill...
11 horizontal wells, building to 36 in 1999. By the year 2000, horizontal wells are predicted to account for 20% of oil production in Venezuela.

Today, the rapid growth of technology coupled with greater cost control make it difficult for any one oil company to have the expertise to conduct a project like drilling VL-1035. Everyone involved in the project—some two dozen specialists—agreed that the spirit of teamwork between operator and contractor was the key to success.

According to Leonardo Beloso, Maraven’s production manager who had the ultimate authority in the project, “When a common objective is defined, and both groups are aware of the goal and understand that success is possible only through teamwork, then we are 90% there. Good luck is the other 10%.” —TAL