High-Pressure, High-Temperature Technologies

E&P activity increasingly involves operations in high-pressure, high-temperature downhole conditions. This environment introduces difficult technical concerns throughout the life of a well. Scientists and engineers are developing advanced tools, materials and chemical products to address these challenges.

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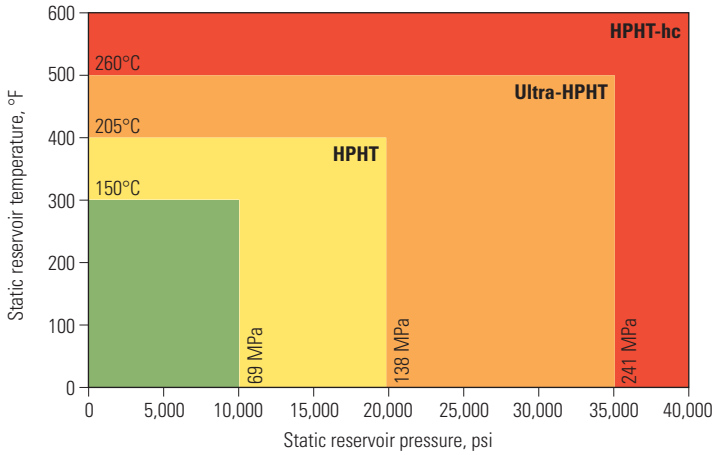
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1. Belani A and Orr S: "A Systematic Approach to Hostile Environments," *Journal of Petroleum Technology* 60, no. 7 (July 2008): 34–39.

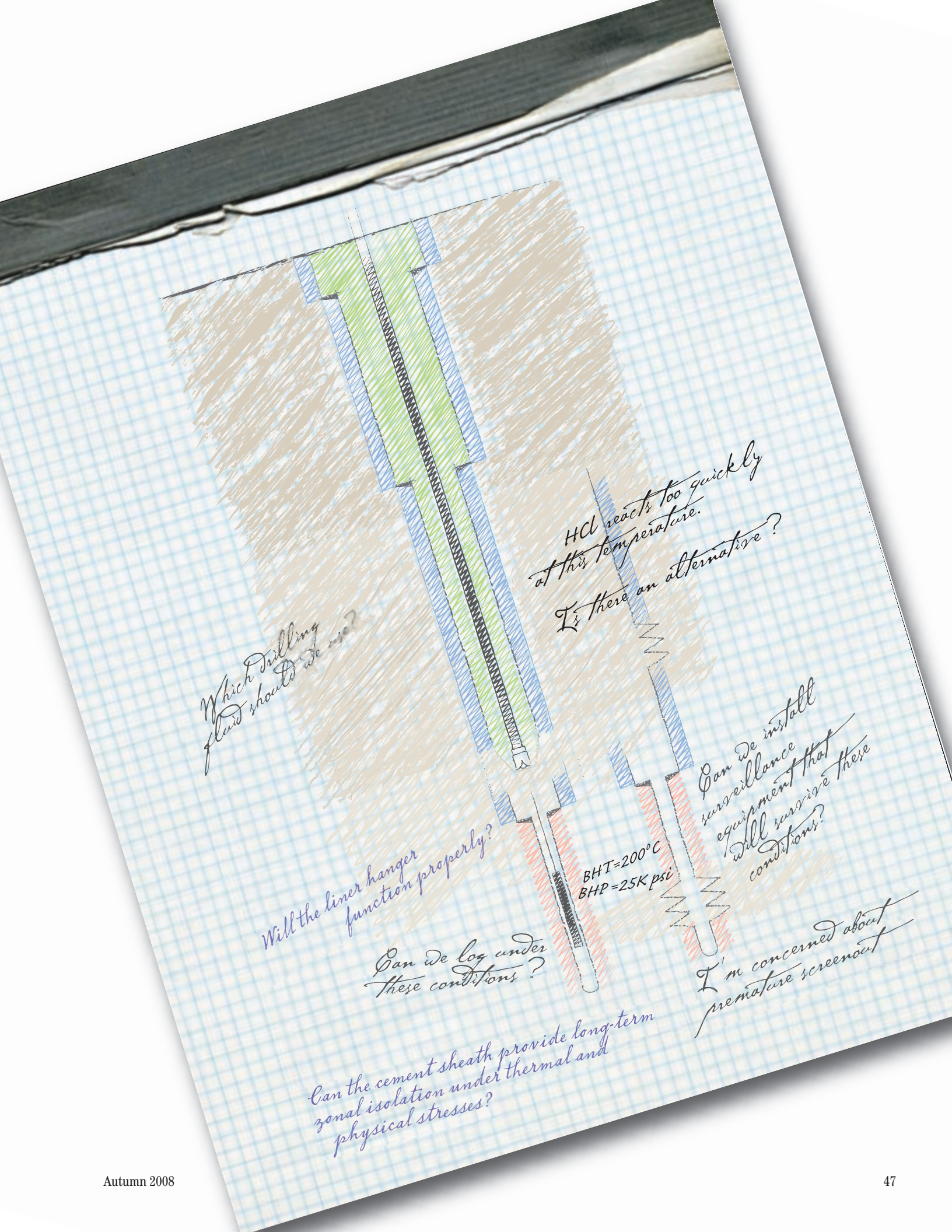
News reports continually remind us about the cost and availability of energy from fossil fuels and renewable sources. Despite remarkable growth in renewable-energy technology during the past 20 years, it is well accepted by the scientific and engineering community that the world's energy needs will continue to be satisfied primarily by fossil fuels during the next few decades. Aggressive exploration and production campaigns will be required to meet the coming demand.

Finding and producing new hydrocarbon reserves may be a difficult proposition, often requiring oil and gas producers to contend with hostile downhole conditions. Although high-pressure, high-temperature (HPHT) wells are fundamentally constructed, stimulated, produced and monitored in a manner similar to wells with less-demanding conditions, the HPHT environment limits the range of available materials and technologies to exploit these reservoirs.

The oil and gas industry has contended with elevated temperatures and pressures for years; however, there are no industry-wide standards that define HPHT conditions and the associated interrelationship between temperature and pressure. In an effort to clarify those definitions, Schlumberger uses guidelines that organize HPHT wells into three categories, selected according to commonly encountered technology thresholds (below).[1]



^ HPHT classification system. The classification boundaries represent stability limits of common well-service-tool components—elastomeric seals and electronic devices.


Which drilling fluid should we use?
HCl reacts too quickly at this temperature.
Is there an alternative?
Can we install surveillance equipment that will survive these conditions?
BHT=200°C
BHP=25K psi
Will the liner hanger function properly?
Can we log under these conditions?
I'm concerned about premature screenout
Can the cement sheath provide long-term zonal isolation under thermal and physical stresses?



^ HPHT projects around the world. During the past decade the number of HPHT projects has increased significantly; nevertheless, these projects represent only about 1% of producing reservoirs worldwide. The principal HPHT areas are found in the United States (deepwater Gulf of Mexico and deep, hot onshore wells), North Sea, Norwegian Sea, Thailand and Indonesia. In addition, thermal-recovery projects to extract heavy oil are located in Canada, California, Venezuela and eastern Europe.

In this system, *HPHT* wells begin at 150°C [300°F] bottomhole temperature (BHT) or 69 MPa [10,000 psi] bottomhole pressure (BHP). The rationale for this threshold is related to the behavior of standard elastomeric seals. Engineers who run downhole equipment in this environment have found it prudent to replace the seals before reusing the tools.

Ultra-HPHT wells exceed the practical operating limit of existing electronics technology—greater than 205°C [400°F] or 138 MPa [20,000 psi]. At present, operating electronics beyond this temperature requires installing internal heat sinks or placing the devices inside a vacuum flask to shield the electronics from the severe temperatures.

The *HPHT-hc* classification defines the most extreme environments—wells with temperatures and pressures greater than 260°C [500°F] or 241 MPa [35,000 psi].[2] Such pressure conditions are unlikely to be seen in the foreseeable future. However, bottomhole temperatures in geothermal and thermal-recovery wells already exceed 260°C.

It is important to emphasize that the Schlumberger HPHT classification scheme is not limited to wells that simultaneously satisfy the temperature and pressure criteria. If either parameter falls within one of the three HPHT regions, the well is classified accordingly. Thus, a low-pressure, shallow steamflood project to extract heavy oil lies in the HPHT-hc region because of the high steam temperature. Conversely, reservoirs associated with low-temperature, high-pressure salt zones in the Gulf of Mexico fit an HPHT classification because of the high pressure.

A vital HPHT-well parameter is the length of time that tools, materials and chemical products must withstand the hostile environment. For example, logging and testing tools, drilling muds and stimulation fluids are exposed to HPHT environments for a limited time, but packers, sand screens, reservoir monitoring equipment and cement systems must survive for many years—even beyond the well's productive life. Accordingly, this time factor has a major impact on how scientists and engineers approach product development.

Oilfield Review last reviewed the HPHT domain in 1998.[3] Since then, the number of HPHT projects has grown, and the severity of operating conditions has steadily increased (above). For example, a recent proprietary survey by Welling and Company on the direction of subsea systems and services reported that 11% of wells to be drilled in the next three to five years are expected to have BHTs exceeding 177°C [350°F]. In addition, 26% of respondents expect BHPs between 69 and 103 MPa [10,000 and 15,000 psi], and 5% predict even higher pressures.

Today, scientists and engineers push the limits of materials science to meet the technical challenges posed by HPHT wells. This article surveys tools, materials, chemical products and operating methods that have been developed for successful HPHT well construction, stimulation, production and surveillance. Case studies illustrate the application of some solutions.

Testing and Qualification of HPHT Technologies

HPHT conditions amplify risks that exist in conventional wells. In HPHT wells, the margin for error is greatly reduced, and the consequences of failure may be more costly and far reaching. Therefore, before field application, new products and services designed for hostile environments must be rigorously tested and qualified to withstand the tougher downhole conditions.[4] This qualification includes accelerated degradation testing aimed at calculating ultimate service life without performing several years of testing. To meet this need, the industry has built state-of-the-art facilities that allow engineers to conduct realistic evaluations (right). Many tests are performed according to standard industry methods; however, increasingly severe downhole conditions are rapidly approaching the limits of documented testing procedures.[5]

Laboratory evaluations fall into three principal categories: fluids, mechanical devices and electronics. Engineers pump a plethora of fluid systems into wells throughout their productive lives. Testing under simulated downhole conditions answers two basic questions. Can the fluid be prepared and properly placed in the well? Will the fluid be sufficiently stable to perform its intended functions? The testing protocol is often complex, involving rheology, filtration, corrosion and mechanical-properties evaluations.[6]

Mechanical devices include seals, screens and packers, along with rotating and reciprocating parts such as shafts, pistons, valves and pumps. In addition to HPHT exposure, qualification testing also includes contact with hazards such as mechanical shocks, hydrogen sulfide [H_2S], carbon dioxide [CO_2] and erosive particle-laden fluids.

Electronic components and sensors, the third element, are particularly vulnerable to high temperatures. The key challenge involves the stability of plastic or composite materials that provide modern electronics with structural integrity and insulation. Electronics manufacturers do not perform extensive R&D in the HPHT domain because the size of the HPHT electronics market is tiny compared to consumer electronics such as mobile phones. As a result, oilfield-equipment engineers must determine the operational time limit of existing electronics under simulated downhole conditions.

The availability of sophisticated test facilities, coupled with an intense R&D effort, has resulted in the development of new HPHT products and services that span all the stages of well operations. Several of these advances are highlighted in the following sections.



^ HPHT testing. Special equipment and facilities are required to evaluate fluids, mechanical devices and electronics at realistic downhole conditions. Logging tools and associated electronics can be operated in an HPHT casing simulator (*top left*) at temperatures and pressures up to 316°C and 207 MPa. HPHT consistometers (*top center*) can evaluate the thickening and setting behavior of cement slurries up to 371°C [700°F] and 207 MPa. (Photograph courtesy of Cement Testing Equipment, Inc.) A similar device for measuring the rheological behavior of drilling fluids can operate at 316°C and 276 MPa [40,000 psi] (*top right*). (Photograph courtesy of AMETEK, Inc.) For flow-assurance measurements, HPHT pressure-volume-temperature (PVT) cells (*center*) detect fluid-phase changes and bubblepoints at conditions up to 250°C and 172 MPa. For safety, engineers place the equipment in individual reinforced testing bays (*bottom left*) and control it remotely from a central facility (*bottom center*). Before shipment to the field, integrated solutions can be tested in the well at the Schlumberger Sugar Land, Texas facility (*bottom right*), rated to 316°C and 241 MPa.

2. The "hc" term comes from the steepest mountain-grade classifications used by the Tour de France bicycle race. In the French language, "hc" stands for "*hors catégorie*," essentially meaning "beyond classification."
3. Adamson K, Birch G, Gao E, Hand S, Macdonald C, Mack D and Quadri A: "High-Pressure, High-Temperature Well Construction," *Oilfield Review* 10, no. 2 (Summer 1998): 36–49.

   Baird T, Fields T, Drummond R, Mathison D, Langseth B, Martin A and Silipigno L: "High-Pressure, High-Temperature Well Logging, Perforating and Testing," *Oilfield Review* 10, no. 2 (Summer 1998): 50–67.
4. Arena M, Dyer S, Bernard LJ, Harrison A, Luckett W, Rebler T, Srinivasan S, Borland B, Watts R, Lesso B and Warren TM: "Testing Oilfield Technologies for Wellsite Operations," *Oilfield Review* 17, no. 4 (Winter 2005/2006): 58–67.
5. Organizations governing the testing and qualification of oilfield products and services include the American Petroleum Institute (API), International Organization for Standardization (ISO), NACE International (NACE) and ASTM International (ASTM).
6. For more on laboratory testing of fluids:

   Dargaud B and Boukhelifa L: "Laboratory Testing, Evaluation and Analysis of Well Cements," in Nelson EB and Guillot D (eds): *Well Cementing*–2nd Edition. Houston: Schlumberger (2006): 627–658.

   Gusler W, Pless M, Maxey J, Grover P, Perez J, Moon J and Boaz T: "A New Extreme HPHT Viscometer for New Drilling Fluid Challenges," paper IADC/SPE 99009, presented at the IADC/SPE Drilling Conference, Miami, Florida, USA, February 21–23, 2006.

   "Laboratory Techniques for Fracturing-Fluid Characterization," in Economides MJ and Nolte KG (eds): *Reservoir Stimulation.* Houston: Schlumberger Educational Services (1987): C-1–C-3.

Drilling and Formation Evaluation

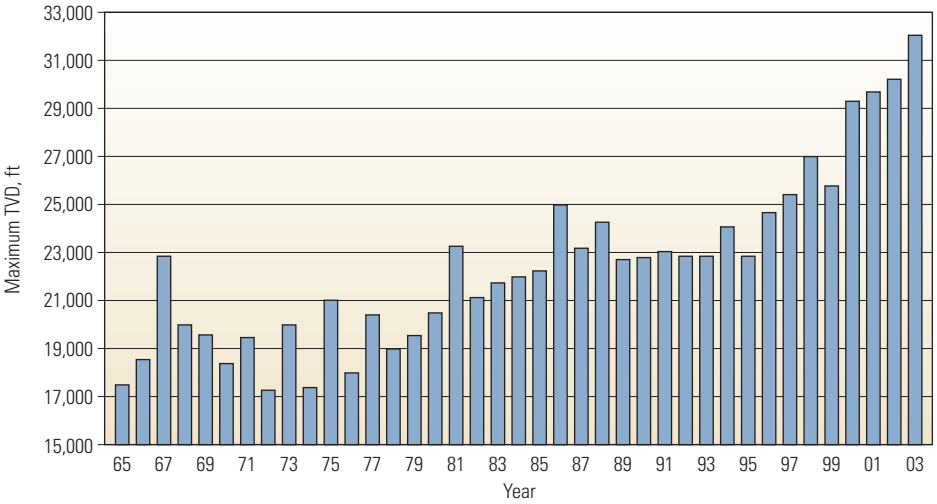
While drilling HPHT wells, engineers frequently encounter overpressured formations, weak zones and reactive shales. In addition, boreholes are often slim and highly deviated. To maintain well control, the drilling-fluid hydrostatic pressure must be high enough to resist the formation pore pressure, yet low enough to prevent formation fracturing and lost circulation. As a consequence, the acceptable fluid-density range is often small, requiring careful control of fluid circulation to avoid pressure surges that exceed formation-fracture pressures. To prevent formation damage or borehole collapse, the drilling fluid must inhibit clay-mineral swelling. The drilling fluid must also be chemically stable and noncorrosive under HPHT conditions.

During the past decade, drilling fluids based on formate salts have been displacing conventional halide-base fluids in HPHT wells.[7] Fluids containing halides are highly corrosive to steel at elevated temperatures and pose environmental hazards. Corrosion rates associated with formate solutions are low, provided the fluid pH remains in the alkaline range. For this reason, formate muds are usually buffered with a carbonate salt. Unlike halides, formates are readily biodegradable and may be used with confidence in environmentally sensitive areas.

Formates are extremely soluble in water and can be used to create invert emulsions or solids-free brines with densities up to 2,370 kg/m^3 [19.7 lbm/galUS], reducing the need for weighting agents.[8] Lower solids concentrations often improve the rate of drillbit penetration and allow better control of rheological properties. Formate brines also have low water activity; consequently, through osmotic effects, they reduce the hydration of formation clays and promote borehole stability.[9]

Statoil reported success with formate-base fluids when drilling high-angle HPHT wells in the North Sea.[10] The wells are in the Kvitebjørn, Kristin and Huldra fields, with reservoir pressures up to 80.7 MPa [11,700 psi] and temperatures up to 155°C [311°F]. Long sequences of interbedded reactive shales are also present. Despite the challenging environment, Statoil experienced no well-control incidents in all 15 HPHT drilling operations in those fields during a five-year period. In addition, control of formation clays and drilling cuttings helped maintain a low solids concentration, allowing the operator to routinely recycle and reuse the drilling fluid.

HPHT conditions present abundant challenges to scientists and engineers who design and operate formation-evaluation tools. As mentioned earlier, the most vulnerable tool components are seals and electronics. Measurement physics dictates direct exposure of most logging-tool sensors to wellbore conditions; thus, they are built into a sonde. Most sonde sections are filled with hydraulic oil and incorporate a compensating piston that balances the inside and outside pressures to maintain structural integrity and prevent tool implosion. Current sondes are routinely operated at pressures up to 207 MPa [30,000 psi].



^ Trend of maximum well depth in the Gulf of Mexico. A significant acceleration of the trend has occurred since the mid 1990s. Unprecedented bottomhole conditions are expected within the next few years, with BHTs exceeding 260°C and BHPs approaching 241 MPa.

The electronics are separated and protected inside a specially engineered cartridge section.[11] Unlike sonde sections, cartridges are not pressure-compensated because high pressures would crush the electronics inside. During a logging trip, electronic components remain at atmospheric pressure inside the cartridge housing, which must resist the external pressure. Housing collapse not only would destroy the electronics, but also might distort the tool to an extent that fishing would be necessary. Pressure protection is provided by titanium-alloy housings.

Leaks at seal surfaces or joints may also lead to flooding and cartridge destruction. Therefore, O-rings are strategically placed along the toolstring to seal connections and internal compartments. To avoid catastrophic failure of the entire toolstring, individual tools are also isolated from each other by pressure-tight bulkheads in a manner similar to those in a submarine. O-rings for HPHT applications are composed of fluoropolymeric elastomers. Viton elastomer, the most common example, is rated to 204°C [400°F]. At higher temperatures, the Viton formulation breaks down and loses elasticity. For these extreme situations, Schlumberger engineers have qualified O-rings fabricated from Chemraz elastomer—an advanced material that is stable to about 316°C [600°F] but is significantly more expensive than its Viton counterpart.[12]

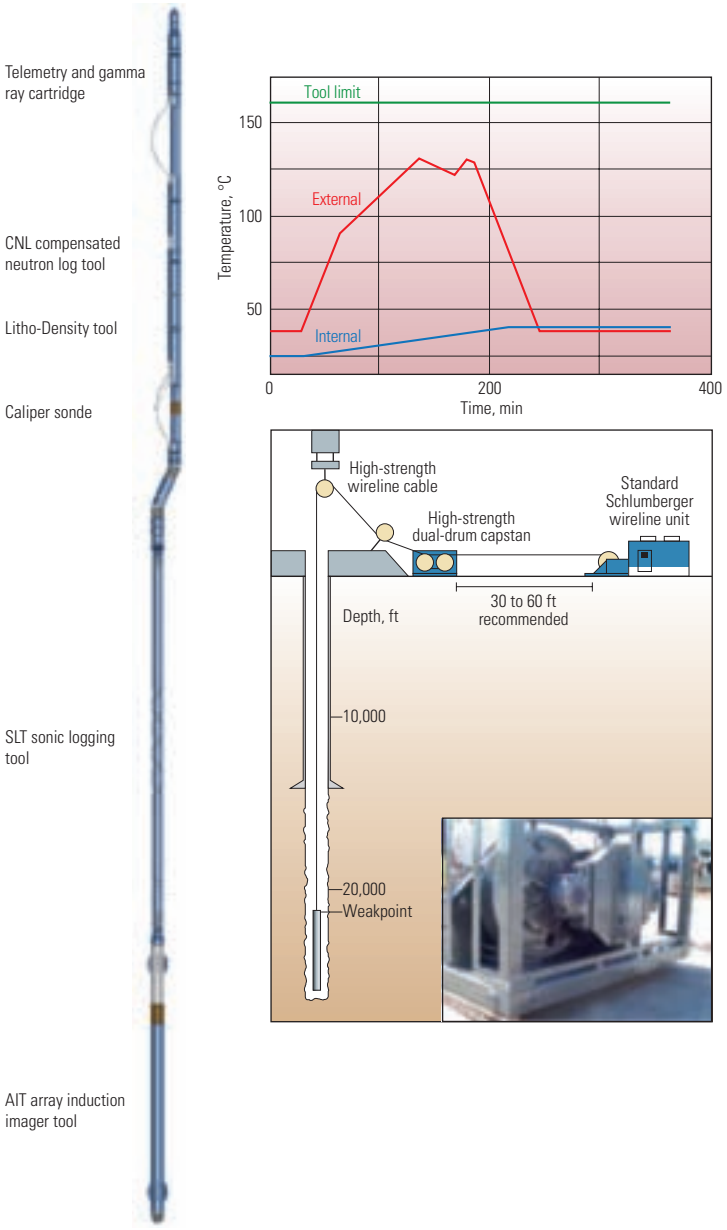
Current electronic systems for HPHT logging can operate continuously at temperatures up to 177°C. The temperature inside the cartridge is a function of the downhole temperature and internal heat generated by the electronics. When higher external temperatures are anticipated, engineers place the tool inside an insulating Dewar flask—a vacuum sleeve that delays heat transmission. Depending upon the duration of the logging run, Dewar flasks allow operations at temperatures up to 260°C. Recently, extended run times have become possible with the introduction of low-power electronics that generate less internal heat.

Since the mid 1990s, well depths in the Gulf of Mexico have increased rapidly, and BHTs and BHPs have followed suit (left).[13] Conversely, borehole size usually decreases with depth. In response to this trend, Schlumberger engineers introduced the SlimXtreme well logging platform—a miniaturized version of the Xtreme HPHT logging system (next page).[14] This service offers the same suite of measurements as its larger counterpart, packaged in a 3-in. diameter toolstring. As a result, the system can be run inside openings as small as 3½-in. drillpipe or 3⅞-in. open hole. In addition, thanks in part to

the lower external surface area of the titanium housing, the SlimXtreme toolstring can operate at pressures up to 207 MPa.

Chevron applied SlimXtreme technology in the Gulf of Mexico while logging deepwater exploratory wells at the Tonga prospect in Green Canyon Block 727. During logging runs to 31,824 ft [9,700 m], the system experienced pressures up to 26,000 psi [180 MPa] and continued to operate successfully. Another Chevron exploratory well, the Endeavour 2 in south Texas, tested SlimXtreme performance at elevated temperatures. The toolstring, incorporating portions enclosed within a Dewar flask, was able to provide reliable data to 21,800 ft [6,645 m] and 489°F [254°C].

Deep HPHT wells present additional wireline-logging challenges. Multiple runs are usually necessary to acquire the information, and small boreholes, long cables and heavy toolstrings increase the risk of the tools becoming stuck.

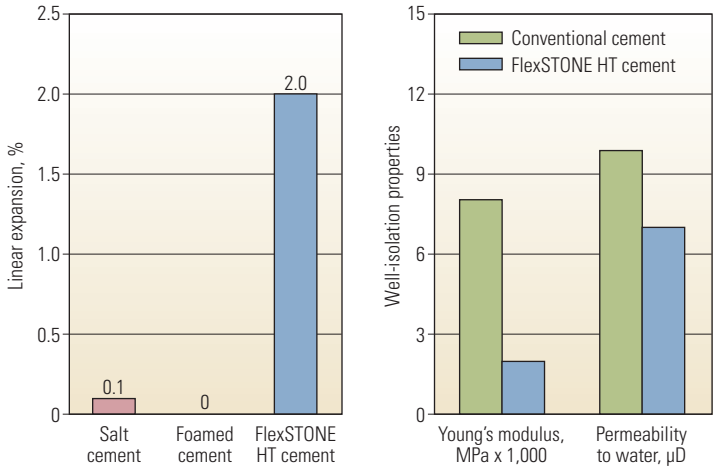


^ Equipment and software for wireline logging and sampling in HPHT wells. The SlimXtreme platform (*left*), designed for slimhole drilling in HPHT and high-angle wells, provides a complete suite of downhole measurements in boreholes as small as 3⅞-in. Engineers run the tools at speeds up to 1,097 m/h [3,600 ft/h], and data can be transmitted to the surface through wireline as long as 10,970 m [36,000 ft]. Temperature planning software simulates the logging job and predicts external (red) and internal (blue) tool temperatures versus time (*top right*). In this example, the external tool temperature rises and falls as the tool is lowered into the well and then retrieved. However, the internal tool temperature remains well below the 160°C limit (green), indicating that the electronics will be protected. These simulations are useful for optimizing the operation and ensuring tool survival. The application considers several job parameters, including well conditions, logging speed and the presence of Dewar flasks. The risk of stuck toolstrings increases when logging and sampling from deep, slim HPHT wells. A high-tension deployment system (*bottom right*) mitigates the risk by combining a standard Schlumberger wireline unit, a high-strength dual-drum capstan and high-strength wireline cable. The capstan increases the pulling force that can be exerted on the wireline, allowing retrieval of heavy toolstrings and reducing the risk of sticking.

7. Formate salts are based on formic acid—HCOOH. Sodium, potassium and cesium formate (and combinations thereof) are used in drilling-fluid applications.
8. An invert emulsion contains oil in the continuous, or external, phase and water in the internal phase.
9. Water activity (a_w) is the equilibrium amount of water available to hydrate materials. When water interacts with solutes and surfaces, it is unavailable for other hydration interactions. An a_w value of one indicates pure water, whereas zero indicates the total absence of "free" water molecules. Addition of solutes (such as formate salts) always reduces the water activity.

    Byrne M, Patey I, George L, Downs J and Turner J: "Formate Brines: A Comprehensive Evaluation of Their Formation Damage Control Properties Under Realistic Reservoir Conditions," paper SPE 73766, presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, USA, February 20–21, 2002.
10. Berg PC, Pedersen ES, Lauritsen A, Behjat N, Hagerup-Jenssen S, Howard S, Olsvik G, Downs JD, Harris M and Turner J: "Drilling, Completion and Openhole Formation Evaluation of High-Angle Wells in High-Density Cesium Formate Brine: The Kvitebjørn Experience, 2004–2006," paper SPE/IADC 105733, presented at the SPE/IADC Drilling Conference, Amsterdam, February 20–22, 2007.
11. The sonde is the section of a logging tool that contains the measurement sensors. The cartridge contains the electronics and power supplies.
12. Viton elastomer is a copolymer of vinylidenfluoride and hexafluoroisopropene, $(CH_2CF_2)_n(CF(CF_3)CF_2)_n$. Chemraz elastomer is a similar compound that contains more fluorine. Both are related to the well-known Teflon fluoropolymer.
13. Sarian S: "Wireline Evaluation Technology in HPHT Wells," paper SPE 97571, presented at the SPE High Pressure/High Temperature Sour Well Design Applied Technology Workshop, The Woodlands, Texas, May 17–19, 2005.
14. Introduced during the late 1990s, Xtreme well-logging tools record basic petrophysical measurements at conditions up to 260°C and 172 MPa [25,000 psi]. The measurements include resistivity, formation density, neutron porosity, sonic logging and gamma ray spectroscopy.

    Henkes IJ and Prater TE: "Formation Evaluation in Ultra-Deep Wells," paper SPE/IADC 52805, presented at the SPE/IADC Drilling Conference, Amsterdam, March 9–11, 1999.



^ FlexSTONE HT cement properties at 200°C compared with those of conventional cements. To ensure proper bonding between the cement/casing and cement/formation interfaces, FlexSTONE cements can be formulated to provide significantly more expansion after setting than conventional systems (*left*). FlexSTONE HT systems also offer improved zonal-isolation properties, including lower Young's modulus and lower permeability (*right*).

Fishing operations to retrieve tools from deep holes are expensive, time-consuming and precarious—possibly resulting in stuck drillpipe, tool damage or tool loss. To minimize the danger, Schlumberger engineers developed an improved tool-deployment method using high-tension cable and a capstan. The system allows rapid deployment of the logging string and much higher pulling capacity, reducing the risk of tool sticking.

Another important wireline operation involves acquiring fluid samples from hydrocarbon reservoirs and analyzing them downhole or at the surface. Test results provide oil companies with information necessary to decide how to complete a well, develop a field, design surface facilities, tie back satellite fields and commingle production between wells.[15] HPHT conditions increase the difficulty of downhole sampling. In addition, pressurized live-fluid samples must be safely transported to the surface and then to nearby laboratories. Sampling operations in HPHT wells are costly, especially offshore; therefore, collecting high-quality samples is crucial to justify the expense.

In 2004, Chevron began drilling exploratory wells into the Lower Tertiary play in the deepwater Gulf of Mexico (see "The Prize Beneath the Salt," *page 4*). These wells can be difficult to drill and complete, with water depths to 9,800 ft [3,000 m], total well depths exceeding 25,000 ft [7,600 m], and BHPs and BHTs often approaching 20,000 psi [138 MPa] and 392°F [200°C]. In 2006, Chevron decided to invest considerable resources and rig time to perform an extended well test (EWT) on the Jack 2 well, southwest of New Orleans and 175 mi [282 km] offshore. The long-term drillstem test (DST) was necessary to acquire vital reservoir and production information that would reduce uncertainty and risk involving reservoir compartmentalization, fluid properties and productivity. At 28,175 ft [8,588 m], the Jack 2 test would be the deepest ever attempted in the Gulf of Mexico.

Before performing the DST, Chevron selected the Quicksilver Probe fluid-sampling tool to extract high-purity formation-fluid samples. This system employs a unique multiple fluid-intake system to minimize formation-fluid sample contamination, and it operates in conditions to 350°F. Samples acquired by the Quicksilver Probe module contained less than 1% contamination after 4 hours of pumping. Fluid-properties data provided by the samples allowed the operator to make drilling and well-testing procedure adjustments that reduced the overall risk.

The Jack 2 EWT also required an HPHT perforating system. Consulting with Chevron personnel, Schlumberger engineers built a tool combination that is rated to 25,000 psi [172 MPa]. The Jack 2 perforating system incorporated a 7-in. gun capable of firing 18 shots per foot, as well as a perforating shock absorber and a redundant electronic firing head. Approximately nine months of engineering, manufacturing and testing were required to achieve full qualification. A final 90-day performance test took place at the Schlumberger Reservoir Completions (SRC) Center in Rosharon, Texas, inside a test vessel that simulated the anticipated downhole conditions. The equipment functioned properly, and Chevron engineers approved deployment of the perforating equipment to the rig.

The EWT was a success, and the Jack 2 well sustained a flow rate exceeding 6,000 bbl/d [950 m^3/d] of crude oil from about 40% of the well's net pay. This result led Chevron and its partners to request various sizes of HPHT perforating systems for additional appraisal wells nearby and future field developments elsewhere in the deepwater Gulf of Mexico.[16]

Cementing and Zonal Isolation

Providing zonal isolation in deep oil and gas wells such as Jack 2 requires use of cement systems that are stable in HPHT environments. Thermally stable cements are also necessary in steamflood wells and geothermal wells.[17] The physical and chemical behavior of well cements changes significantly at elevated temperatures and pressures. Without proper slurry design, the integrity of set cement may deteriorate, potentially resulting in the loss of zonal isolation. Unlike many other HPHT technologies, well cements are permanently exposed to downhole conditions and must support the casing and provide zonal isolation for years.

Portland cement is used in nearly all well-cementing applications. The predominant binding minerals are calcium silicate hydrates (CSH). At temperatures above about 110°C [230°F], mineralogical transformations occur that may cause the set cement to shrink, lose strength and gain permeability. This deterioration can be minimized or even prevented by adding at least 35% silica by weight of cement. The compositional adjustment causes the formation of CSH minerals that preserve the desired set-cement properties. Although silica-stabilized Portland cement systems can be used at temperatures up to about 370°C [700°F], they are susceptible to other challenges posed by thermal wells.

A thermally stable cement system may initially provide adequate zonal isolation; however, changes in downhole conditions can induce stresses that compromise cement-sheath integrity. Tectonic stresses and large changes in wellbore pressure or temperature may crack the sheath and can even reduce it to rubble. Radial casing-size fluctuations induced by temperature and pressure changes can damage the bond between the set cement and the casing or the formation, creating a microannulus. These problems are of particular concern in deep, hot wells and thermal-recovery wells employing cyclic-steam-stimulation (CSS) or steam-assisted-gravity-drainage (SAGD) processes.[18]

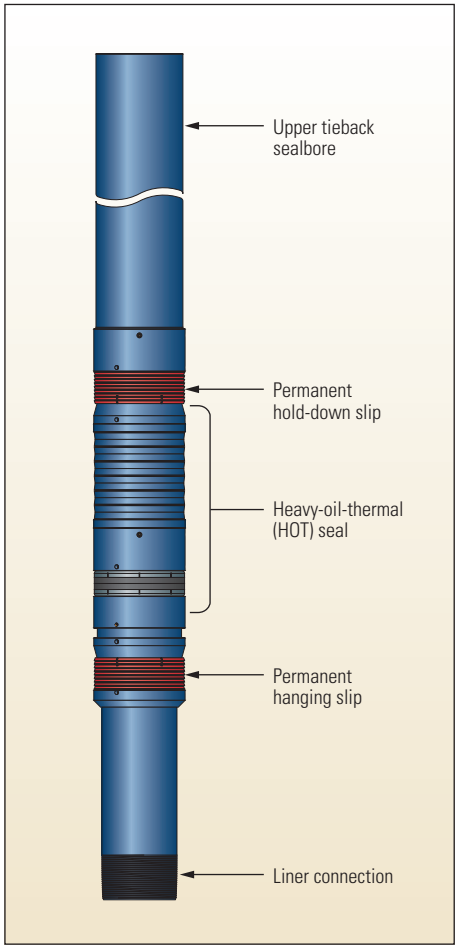
Until recently, the well cementing industry focused on one mechanical parameter—unconfined uniaxial compressive strength—to qualify a cement design. The longer-term difficulties described above led Schlumberger scientists to more thoroughly investigate the mechanical properties of set cement, along with models governing the mechanical behavior of steel pipe and rocks. They adapted the models to the geometry of a well and introduced CemSTRESS software—an application that analyzes the behavior of a cement sheath exposed to anticipated downhole conditions. This software analyzes radial and tangential stresses experienced by the cement sheath resulting from pressure tests, formation-property changes and temperature fluctuations. Along with compressive strength, the CemSTRESS algorithms consider Young's modulus, Poisson's ratio and tensile strength and help engineers determine the appropriate cement mechanical properties for a given application.[19]

CemSTRESS analysis usually indicates that cement sheaths in CSS and SAGD wells should be more flexible than in conventional systems. This can be achieved by using cements with lower Young's moduli (previous page).[20] In addition, the cement sheath should expand slightly after setting to ensure firm contact with the casing and formation. These requirements led to the development of FlexSTONE HT high-temperature flexible cement.[21] This cement is part of a family that combines the engineered particle-size concept of CemCRETE technology with flexible particles that lower the Young's modulus.[22] In addition, expansion after setting can be significantly higher than that of conventional cement systems, promoting bonding with the casing and formation.[23] The temperature limit of FlexSTONE HT cement is about 250°C [482°F].

An operator in the UK region of the North Sea had an ambitious goal of producing gas at a sustained 6.8-million m^3/d [240-MMcf/d] production rate from three wells with a BHT of 193°C [380°F].[24] Meeting this goal would require unusually high drawdown pressures, exerting significant mechanical stress on the casing, cement sheath and formation. Using CemSTRESS software, Schlumberger engineers determined that placing FlexSTONE HT cement across the production zone would provide a gasket-like seal capable of withstanding the severe environment. After cement placement, the production strings were subjected to pressure tests up to 69 MPa and drawdown tests exceeding 41 MPa [6,000 psi]. The cement sheath remained intact. After more than two years of production, there have been no well-integrity problems.

Heavy-oil projects involving SAGD wells also employ FlexSTONE HT cement extensively. An eastern European reservoir contained a particularly thick crude oil—12,000-MPa-s [12,000-cP] viscosity and a 17°API gravity. Oil mining had been the standard recovery method. To reduce production costs, the operator elected to try the SAGD method in a pilot well. This approach presented multiple well-construction concerns: 300-m [984-ft] horizontal sections at a TVD of 228 m [748 ft], temperatures approaching 250°C and stresses on the cement sheath resulting from thermal production cycles and a soft formation. FlexSTONE HT cement successfully withstood the production conditions with no loss of zonal isolation, and the operator has planned additional SAGD installations. CSS and SAGD wells in Canada, Venezuela, Egypt, Indonesia and California, USA, have also benefited from FlexSTONE HT cement.

CSS and SAGD wells require specialized, high-performance completion equipment to handle the extreme temperature cycles. Common elastomeric seals often fail, allowing pressure and fluids to escape up the casing, reducing steam-injection efficiency and increasing the potential for casing corrosion. Recently, Schlumberger engineers began using seals fabricated from a yarn of carbon fibers contained within an INCONEL alloy jacket. These seals are capable of operating at cycled-steam temperatures up to 340°C [644°F] and pressures up to 21 MPa [3,000 psi], allowing reliable deployment of thermal liner systems (above).



^ Schlumberger high-temperature liner hanger. Developed for steamflood applications, the liner hanger features seals made from carbon fiber and INCONEL alloy. The tool has permanent slips and a one-piece mandrel to minimize possible leak paths and can be rotated while running in the hole. To date, Schlumberger engineers have installed more than 150 units in Canada, with no pressure-test failures. Some of the systems have survived up to 10 thermal cycles to 343°C [649°F].

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17. Nelson EB and Barlet-Gouédard V: "Thermal Cements," in Nelson EB and Guillot D (eds): *Well Cementing*–2nd Edition. Houston: Schlumberger (2006): 319–341.
18. Alboudwarej H, Felix J, Taylor S, Badry R, Bremner C, Brough B, Skeates C, Baker A, Palmer D, Pattison K, Beshry M, Krawchuk P, Brown G, Calvo R, Cañas Triana JA, Hathcock R, Koerner K, Hughes T, Kundu D, López de Cardenas J and West C: "Highlighting Heavy Oil," *Oilfield Review* 18, no. 2 (Summer 2006): 34–53.
19. Thiercelin M: "Mechanical Properties of Well Cements," in Nelson EB and Guillot D (eds): *Well Cementing*–2nd Edition. Houston: Schlumberger (2006): 269–288.
James S and Boukhelifa L: "Zonal Isolation Modeling and Measurements—Past Myths and Today's Realities," paper SPE 101310, presented at the SPE Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, November 5–8, 2006.
20. Young's modulus, also called the modulus of elasticity, is the ratio between the stress applied to an object and the resulting deformation, or strain. Lower Young's moduli correspond to more flexible materials.
21. Abbas R, Cunningham E, Munk T, Bjelland B, Chukwueke V, Ferri A, Garrison G, Hollies D, Labat C and Moussa O: "Solutions for Long-Term Zonal Isolation," *Oilfield Review* 14, no. 3 (Autumn 2002): 16–29.
22. For more on engineered-particle-size cements: Nelson EB, Drochon B and Michaux M: "Special Cement Systems," in Nelson EB and Guillot D (eds): *Well Cementing*–2nd Edition. Houston: Schlumberger (2006): 233–268.
23. Cement systems that expand slightly after setting are a proven means for sealing microannuli and improving primary cementing results. Improved bonding results from tightening of the cement sheath against the casing and formation.
24. Palmer IAC: "Jade North Sea HPHT Development: Innovative Well Design Generates Best in Class Performance," paper SPE/IADC 92218, presented at the SPE/IADC Drilling Conference, Amsterdam, February 23–25, 2005.
Stiles D: "Effects of Long-Term Exposure to Ultrahigh Temperature on the Mechanical Parameters of Cement," paper IADC/SPE 98896, presented at the IADC/SPE Drilling Conference, Miami, Florida, February 21–23, 2006.

Schlumberger high-temperature thermal liner hangers have been used in the Cold Lake field, where a major operator in Canada is conducting a horizontal-well CSS program.[25] With customized liners and carbon-fiber and INCONEL seals at the top of the liner, the operator has been able to achieve good steam conformance—steam intake spread evenly over the length of the horizontal well—verified by time-lapse seismic surveys over the pilot area.

Reservoir Stimulation and Production

Reservoir stimulation encompasses two major techniques: matrix acidizing and hydraulic fracturing. Both procedures bypass formation damage incurred during drilling, cementing and perforating, and they also provide an enhanced connection between the formation rock and the wellbore. The goal is to increase hydrocarbon production to levels far exceeding what would be possible under natural-flow conditions.[26]



^ Wormholes formed during a laboratory-scale matrix acidizing treatment of a carbonate-formation sample. The length, direction and number of wormholes depend on the formation reactivity and the rate at which acid enters the formation. Once formed, the wormholes carry virtually all of the fluid flow during production.

Matrix acidizing consists of pumping a low-pH fluid through naturally existing channels in the rock, at rates that are sufficiently low to avoid creating fractures in the formation. The acid dissolves soluble components of near-wellbore formation rock and damaging materials deposited by previous well-service fluids, thereby creating a more permeable path for hydrocarbon flow. Acidizing fluids are formulated to stimulate carbonate or sandstone formations.

Most carbonate acidizing involves reacting hydrochloric acid (HCl) with formations composed of calcium carbonate (calcite), calcium magnesium carbonate (dolomite) or both. As the acid flows through perforations and dissolves the carbonate rock, highly conductive channels called wormholes are created in the formation. Wormholes radiate from the point of acid injection and carry virtually all of the fluid flow during production (left). For efficient stimulation, the wormhole network should penetrate deeply and uniformly throughout the producing interval.

HCl is an effective stimulation fluid at low temperatures, but it can be problematic when used at temperatures exceeding about 93°C [200°F]. At higher temperatures, this mineral acid attacks the formation too rapidly, minimizing the depth and uniformity of the wormholes. These conditions also promote excessive tubular corrosion and require engineers to add high concentrations of toxic corrosion inhibitors. Recently, Schlumberger chemists solved these problems by developing acidizing fluids based on hydroxyethylaminocarboxylic-acid (HACA) chelating agents. Common commercial HACA compounds such as tetrasodium EDTA and trisodium HEDTA have been used in the oil field for decades, mainly as scale-removal agents and scale inhibitors.[27]

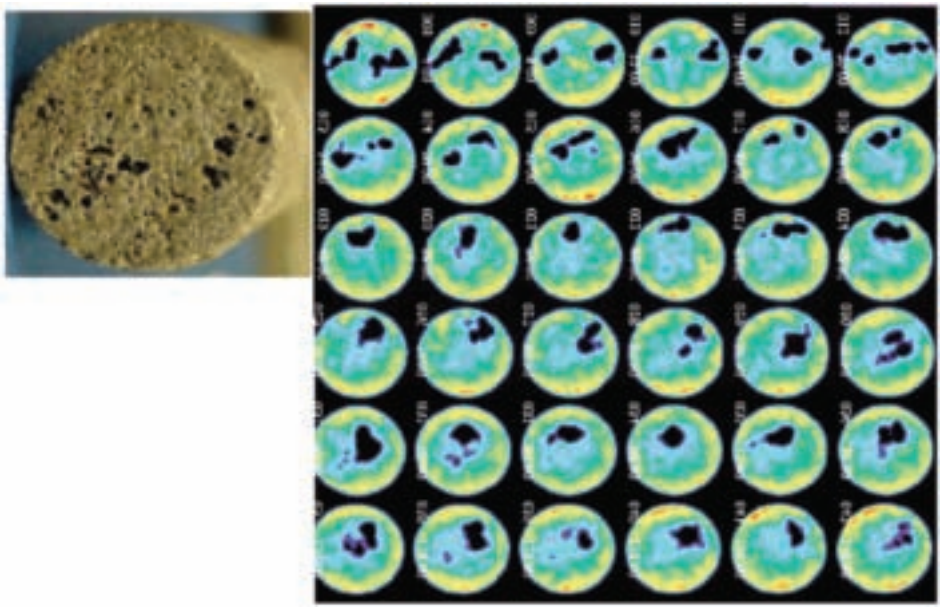
A variety of HACA compounds underwent laboratory testing at temperatures up to 200°C. The evaluation consisted mainly of coreflood tests in limestone and corrosion-rate measurements involving common tubular metals. The best performer was trisodium HEDTA, buffered to a pH value of about 4. Less acidic than a carbonated beverage, this formulation is far less corrosive than conventional mineral acids, and very low tubular corrosion rates can be achieved by adding small amounts of milder, environmentally acceptable corrosion inhibitors. With its higher pH, trisodium HEDTA reacts more slowly and creates an extensive, farther-reaching wormhole network rather than a short dominant

one (right). In addition, HEDTA fluid is far more efficient than HCl at HPHT conditions. A comparable level of stimulation may be achieved by pumping less than one-tenth the fluid volume (below right).[28]

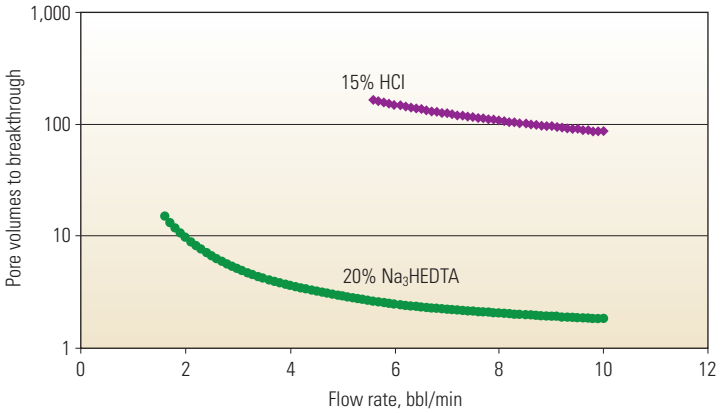
Hydraulic fracturing involves pumping large volumes of fluid through perforations and into the formation at rates and pressures sufficient to not only create a fracture, but also propagate it far beyond the near-wellbore region. The final fluid stage fills the fracture with proppant—silicate, ceramic or bauxite granules with high sphericity—leaving a high-permeability conduit between the producing formation and the wellbore.[29]

Fracturing-fluid viscosity is a critical parameter that governs fracture initiation and propagation, as well as proppant transport down the tubulars, through perforations and into the fracture. At HPHT conditions, sufficient fluid viscosity is usually achieved by preparing metal-crosslinked solutions of guar-base polymers. The most common metal crosslinkers are boron and zirconium.[30] However, viscosity attainment alone is not sufficient to perform a successful HPHT fracturing treatment. To minimize friction-pressure losses as the fluid is pumped downhole, the crosslinking reactions should be delayed until just before the fluid enters the perforations. In addition, the viscosity should not be unduly sensitive to the high-shear-rate environment commonly found in the tubulars and perforations; otherwise, the fluid will be ill equipped for fracture propagation and proppant transport, increasing the likelihood of a premature screenout.[31]

The characteristics of borate- and zirconate-crosslinked fluids are fundamentally different. Borate crosslinking arises from ionic bonds that can break under high-shear conditions; however, the bonds heal and fluid viscosity recovers when a low-shear environment is restored. Zirconate-crosslinked fluids are not as forgiving because the linkage results from covalent bonds that form only once. If the fluid crosslinks and experiences elevated shear too early, the bonds will break



^ Acidizing coreflood test with 20% Na_3HEDTA. Technicians pumped the acid through a 2.54-cm [1-in.] diameter, 30.5-cm [12-in.] long limestone core at 177°C [350°F]. The Na_3HEDTA solution created numerous wormholes that formed a complex network. The photograph of the core entrance (*left*) shows the formation of many wormholes. The CT-scan sequence (*right*) confirms that the wormhole network extends throughout the core length. The upper-left CT-scan image displays the core entrance, and subsequent core sections continue from left to right.



^ Comparing the acidizing efficiency of 15% HCl (purple) and Na_3HEDTA (green) at 177°C. This graph shows the amounts of acidizing fluid (expressed in pore volumes) required to radially penetrate 30.5 cm [12 in.] into a 30.5-m [100-ft] interval of 100-mD carbonate formation with 20% porosity. The results indicate that, regardless of pumping rate, trisodium HEDTA is more than one order of magnitude more efficient than HCl.

25. Smith RJ and Perepelecta KR: "Steam Conformance Along Horizontal Wells at Cold Lake," paper SPE/PS-CIM/CHOA 79009, presented at the SPE International Thermal Operations and Heavy Oil Symposium and International Horizontal Well Technology Conference, Calgary, November 4–7, 2002.
26. For more on reservoir stimulation: Economides MJ and Nolte KG (eds): *Reservoir Stimulation,* 3rd Edition. New York City: Wiley, 2003.
27. Chelating agents, also known as sequestering agents, are compounds used to control undesirable reactions of metal ions (such as Ca, Mg and Fe). For example, they form chemical complexes that do not precipitate during acidizing treatments, thereby preventing formation damage. EDTA and HEDTA are acronyms for ethylenediaminetetraacetic acid and hydroxyethylenediaminetriacetic acid.

    Frenier WW, Fredd CN and Chang F: "Hydroxyaminocarboxylic Acids Produce Superior Formulations for Matrix Stimulation of Carbonates at High Temperatures," paper SPE 71696, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.
28. Frenier WW, Brady M, Al-Harthy S, Arangath R, Chan KS, Flamant N and Samuel M: "Hot Oil and Gas Wells Can Be Stimulated Without Acids," paper SPE 86522, presented at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, February 18–20, 2004.
29. For more on hydraulic fracturing: Economides and Nolte, reference 26.
30. Crosslinks are bonds that link one polymer chain to another. Boron and zirconium interact with guar-base polymers, forming linkages that increase the effective polymer molecular weight by several orders of magnitude and dramatically increase the fluid viscosity.
31. Screenout occurs when proppant particles bridge the perforations and block further fluid ingress. This condition is accompanied by a sudden treatment-pressure increase. A premature screenout occurs when the fracture volume is insufficient, when less than the desired amount of proppant is placed in the fracture, or both.

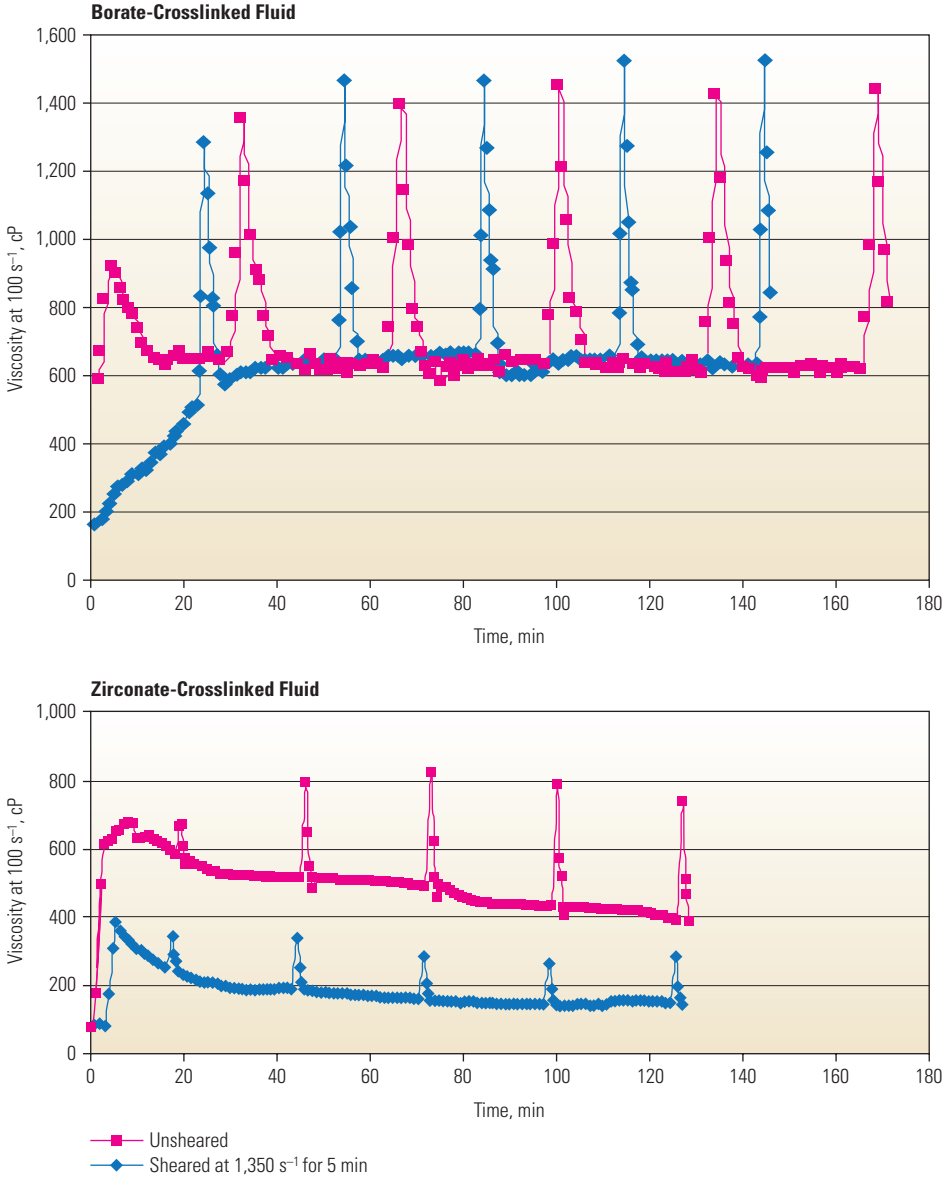
irreversibly, fluid viscosity will decrease, and the screenout probability will increase (below). Therefore, it is vital to control the timing and the location of crosslinking.

Although less forgiving, zirconate-crosslinked fluids have been used almost exclusively in HPHT fracturing treatments, mainly because they are thermally more stable than borate fluids. Despite steady advances in fluid design, achieving sufficient crosslink control with zirconate fluids has remained elusive. The crosslinking reactions are temperature-sensitive, and predicting circulating temperatures inside tubulars of HPHT wells is often difficult.

Chemists solved these problems by combining the best features of borates and zirconates into one system—ThermaFRAC fracturing fluid. The new dual-crosslinker fluid, based on carboxymethylhydroxypropyl guar (CMHPG), features two crosslinking events—an early low-temperature reaction involving borate, and a secondary temperature-activated one involving zirconate. Borate crosslinking provides low shear sensitivity, and zirconate bonding contributes thermal stability (next page).[32] Fluid preparation is simpler and more reliable because additives previously used to stabilize and control traditional zirconate-only fluids are no longer necessary. Laboratory tests have demonstrated suitable performance at temperatures from 200° to 375°F [93° to 191°C].

South Texas has long been a major center of HPHT activity, and operators there have come to rely heavily on new technologies to solve problems. Producing reservoirs are deep and must frequently be stimulated through long tubing strings or slimhole completions. This well geometry is problematic for two main reasons. First, treatment pump rates must be reduced to minimize friction-pressure losses and decrease the number of pump trucks at the wellsite.[33] Lower flow rates limit the fluid pressure that engineers may apply to initiate and propagate a hydraulic fracture. Second, fracturing fluids experience high amounts of shear as they flow through small-diameter tubulars, and zirconate-base fluids are particularly susceptible to premature deterioration. Dual-crosslinker fluids have successfully addressed these problems.

One example involves a well that suffered casing collapse after a fracturing treatment. Workover operations to restore communication and production were unsuccessful, and the operator's only remaining option was to sidetrack the wellbore and install a slimhole completion. The operation involved lowering 12,200 ft [3,719 m] of 2⅜-in. tubing from surface to the producing interval and then cementing it in place. Wellbore integrity was a serious concern because of damage resulting from the workover operations. In addition, the operator was worried about friction-pressure losses and high leakoff rates arising from fluid diversion into the existing fracture. The thickness of the producing sandstone interval was 46 ft [14 m], and the BHT was 310°F [154°C].



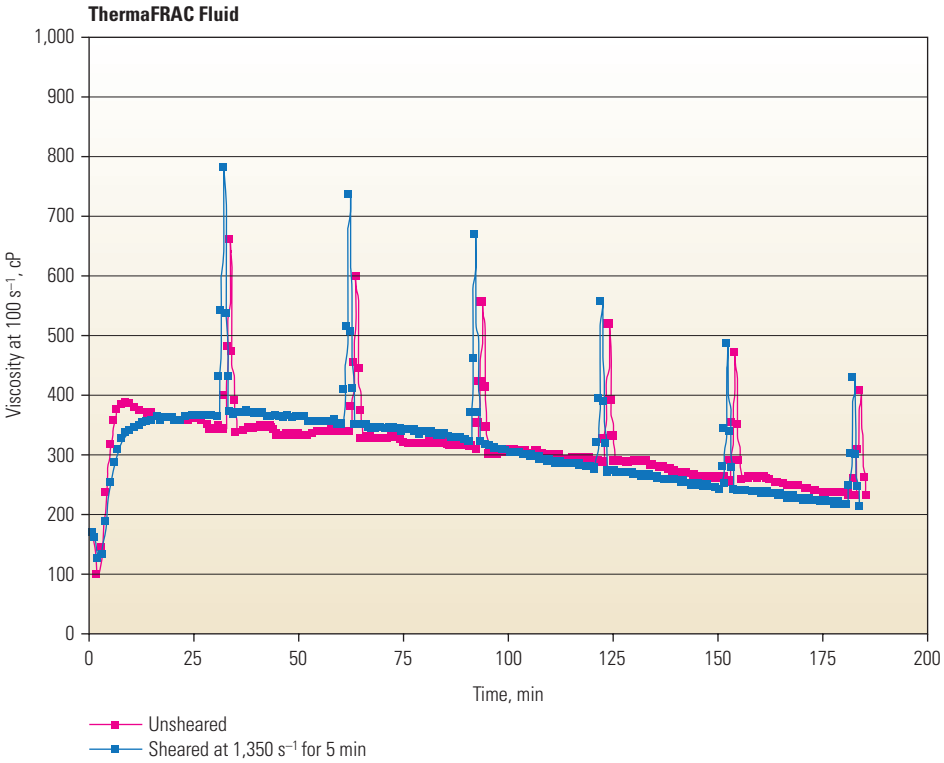
^ Shear-history behavior of guar fluids crosslinked by borate and zirconate compounds. Rheological testing of fracturing fluids involves two principal devices: a shear-history simulator and a viscometer. The shear-history simulator exposes fracturing fluids to shearing conditions they would experience while traveling down the tubulars toward the perforations. The viscometer measures the fracturing-fluid viscosity at various shear rates, temperatures and pressures. Shear-history studies determine how shearing in the tubulars would affect fluid viscosity. Technicians measure and plot the rheological behavior of two identical fluids—one that has undergone pretreatment in the shear-history simulator (blue) and one that has not (pink). Test results show that, after prolonged exposure to a high-shear-rate environment in the shear-history simulator, the borate-crosslinked fluid recovered and achieved the same viscosity as its counterpart that did not experience pretreatment (*top*). The viscosity plots eventually overlapped. On the other hand, the zirconate-crosslinked fluid permanently lost viscosity after pretreatment in the shear-history simulator (*bottom*). This effect would increase the potential for screenout. The baseline viscosities on the plots correspond to a 100-s^{-1} shear rate. The periodic spikes denote shear-rate ramps in the viscometer up to about 300 s^{-1}. Viscosity measurements at various shear rates allow calculation of additional rheological parameters that engineers use to optimize fracturing-fluid designs.

The operator approved a ThermaFRAC treatment that addressed the anticipated difficulties. The pad volume was unusually large—65% of the total job—and the CMHPG concentration was high—45 lbm/1,000 galUS [5.4 kg/L]—to compensate for the high leakoff rate.[34] To minimize friction pressure, the maximum pump rate was 12 bbl/min [1,908 L/min]. The proppant slurry placed 62,000 lbm [28,120 kg] of 20/40-mesh resin-coated bauxite at concentrations up to 8 lbm/galUS [961 kg/m^3] of fracturing fluid. Following the success of this treatment, the operator applied dual-crosslinker fluids in additional slimhole applications, including one in which 295,000 lbm [133,810 kg] of 20/40-mesh ceramic and resin-coated ceramic proppant were placed into a 74-ft [22.6-m] interval through 11,600 ft [3,536 m] of 2⅞-in. tubing. At this writing, more than 60 ThermaFRAC treatments involving 11 operators have been successfully performed in south Texas, at bottomhole temperatures between 121° and 191°C [250° and 375°F].

The new fracturing fluid has also been used to stimulate a gas-bearing HPHT sandstone reservoir in northern Germany. The average formation depth is 4,550 m [14,930 ft] TVD, and the BHT is approximately 150°C. BHPs vary from 25 to 30 MPa [3,630 to 4,350 psi], and the formation-permeability range is 0.1 to 5 mD. In this area, engineers usually perform fracturing treatments through a dedicated tubing string with the rig in place. To save money, the operator wanted to begin stimulating wells without the rig, pumping the treatment through the final well-completion string.

Fracturing fluids are usually prepared with ambient-temperature mix water. However, pumping a cool fluid through a finished completion would cause sufficient tubular contraction to exert excessive stress on packers and jeopardize zonal isolation. Therefore, to minimize thermal effects, it would be necessary to preheat the mix water to 50°C [122°F]. Zirconate crosslinking is temperature-dependent, and it was unlikely that reliable rheological control would be possible with a traditional single-crosslinker system.

To develop a solution, engineers conducted fluid-design experiments at the Schlumberger Client Support Laboratory in Aberdeen, Scotland. This facility has testing equipment that can simulate both the thermal environment and the shear environment anticipated in the German well. Test results showed that the dual-crosslinker fluid would allow sufficient leeway to design a treatment compatible with the operator's cost-saving goal.



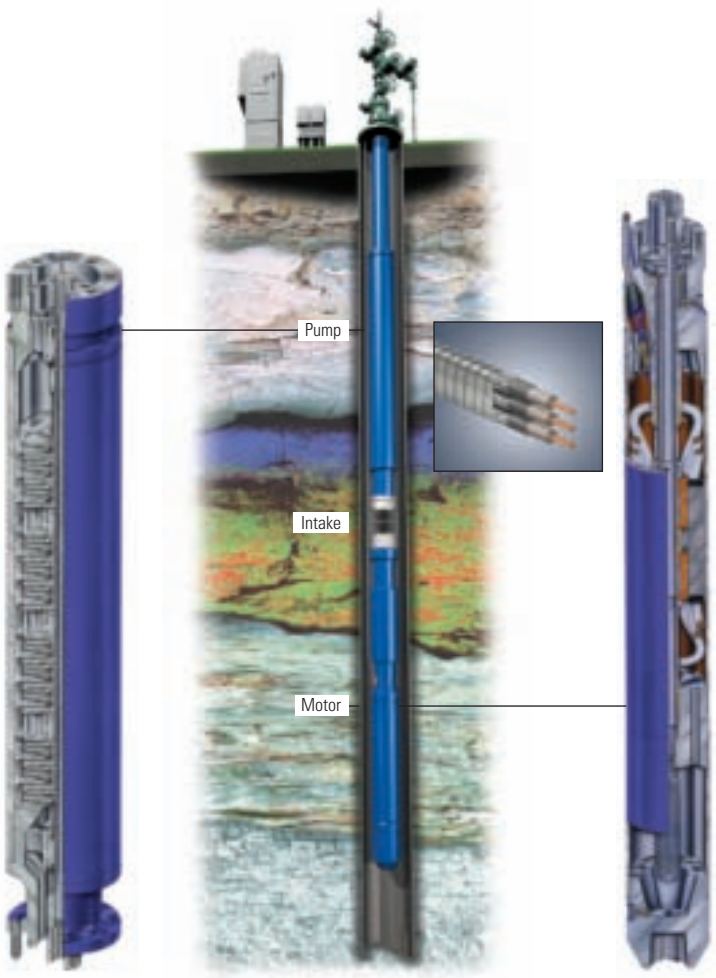
^ Shear-history behavior of ThermaFRAC fluid at 135°C [275°F]. After prolonged exposure to a high shear rate in the shear-history simulator, the viscosity of ThermaFRAC fluid does not change significantly.

Engineers performed the ThermaFRAC treatment in a well with a 30-m [98-ft] producing zone, pumping 184 m^3 [48,600 galUS] of fluid with a CMHPG loading of 4.8 kg/m^3 [40 lbm/1,000 galUS], and placing 32 metric tons [70,500 lbm] of 20/40 resin-coated high-strength proppant in the fracture. The resulting fracture conductivity in this well was 250% higher than those of offset wells treated with conventional single-crosslinker fluids, and the production rate was 30% higher than the operator's prediction. Consequently, the operator has chosen this fluid to stimulate seven more wells in this region.

Certain types of HPHT reservoirs would not benefit significantly from matrix-acidizing or hydraulic-fracturing treatments. Perhaps the best examples are heavy-oil deposits, in which the preferred stimulation method involves oil-viscosity reduction by steam injection. Steam generation comprises approximately 75% of the SAGD operating expenses. Reducing the steam/oil ratio (SOR) and maintaining an optimal production rate are keys to improving profitability. Reducing steam input saves energy costs, decreases produced-water volume and treatment expenses, and curtails associated CO_2 emissions. A 10 to 25% SOR reduction may be achieved by using electric submersible pump (ESP) systems.

ESPs allow reservoirs to be produced at pressures that are independent of wellhead or separator pressures, thereby increasing steam-injection efficiency and decreasing the production cost by at least US $1.00 per barrel of produced oil. Numerous Canadian operators, including Encana, Suncor, ConocoPhillips, Nexen, TOTAL, Husky and

32. Guar gum, a powder consisting of the ground endosperm of guar beans, is used extensively as a food thickener. Guar-gum derivatives are purified and functionalized products with good thermal stability. Common derivatives for hydraulic-fracturing applications include hydroxypropyl guar (HPG) and carboxymethyl-hydroxypropyl guar (CMHPG).
33. Friction-pressure loss is the pressure decrease arising from frictional losses that occur as a fluid passes through pipe. The pressure decrease is mainly a function of pipe diameter, pipe length, fluid rheological properties and flow rate. High friction reduces the available fluid pressure at the pipe outlet.
34. Fracturing treatments consist of two fluid stages. The first stage, the pad, initiates and propagates the fracture. The second stage, the proppant slurry, transports proppant down the tubulars, through the perforations and into the fracture.



^ REDA Hotline550 ESP artificial lift system. The multicomponent toolstring can be used in wells with BHTs up to 218°C (*center*). The heart of the system is the centrifugal pump, equipped with silicon- or tungsten-carbide bearings for durability at extreme temperatures (*left*). The number of stages can also be adjusted according to the completion requirements. The pump motor employs metal-to-metal seals to provide a heat-resistant mechanical barrier to fluid entry (*right*). Cables that transmit power to the motor and data to surface are protected by insulating armor composed of heavy galvanized steel, stainless steel and corrosion-resistant Monel alloy (*inset*). As of November 2008, the Hotline550 system is operating in more than 100 Canadian thermal wells.

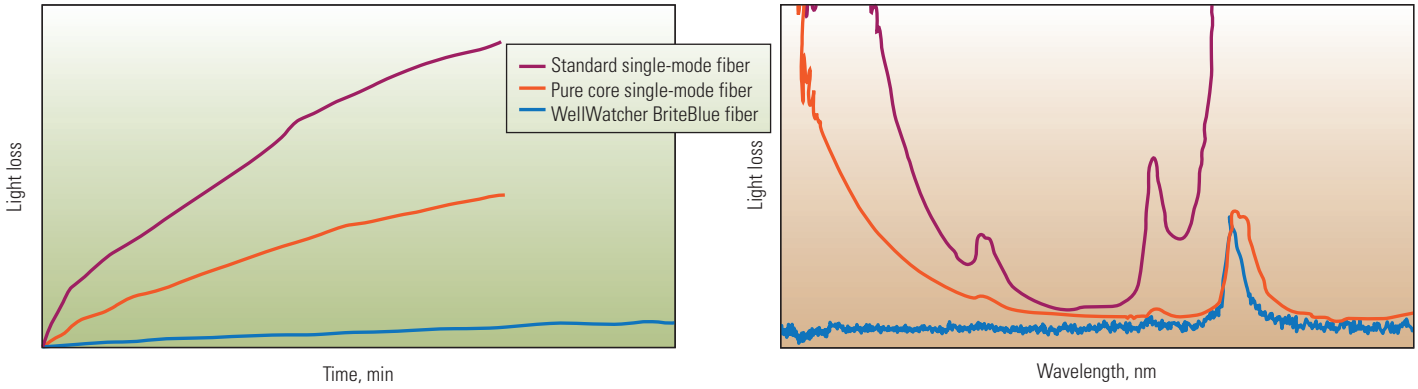
Blackrock, have installed the REDA Hotline550 high-temperature ESP system in steam-injection wells (left). Rated to operate continuously at up to 288°C [550°F] internal motor temperature, or 218°C [425°F] bottomhole temperature, the equipment employs high-temperature thermoplastic motor-winding insulation and is designed to compensate for variable expansion and contraction rates of the different materials in the pump. Many of these installations have operated continuously for more than two years.

Surveillance

Maintenance of an optimal reservoir-temperature distribution is vital to efficient heavy-oil production from SAGD or CSS wells; therefore, engineers need to acquire real-time temperature information to make necessary steam-injection or production-rate adjustments. For more than a decade, WellWatcher distributed temperature sensing (DTS) systems have been capable of transmitting data to surface by laser signals that travel through Sensa fiber-optic cable.[35] However, conventional DTS systems do not function properly in an HPHT environment.

Most optical fibers begin to degrade when exposed to hydrogen, which occurs naturally in wellbores. This degradation accelerates at high temperatures, detrimentally affecting signal transmission and measurement accuracy. At temperatures above 200°C, conventional optical fibers exposed to a hydrogen-pressured environment may become unusable within days.

Schlumberger and Sensa engineers responded by developing WellWatcher BriteBlue multimode optical fiber from a material that is more thermally stable and chemically resistant to hydrogen (below).[36] An improved version, WellWatcher Ultra DTS system, is equipped with



^ Hydrogen effects on optical-fiber performance after HPHT exposure. Accelerated testing methods determine the high-temperature performance of WellWatcher BriteBlue multimode fiber (blue) compared with that of conventional single-mode optical fibers (red and orange). Light transmittance of the multimode fiber deteriorates at a significantly lower rate (*left*), allowing the fibers to transmit data for years after installation. Unlike the single-mode fibers, the new fiber material maintains the ability to transmit light throughout the useful wavelength range (*right*).



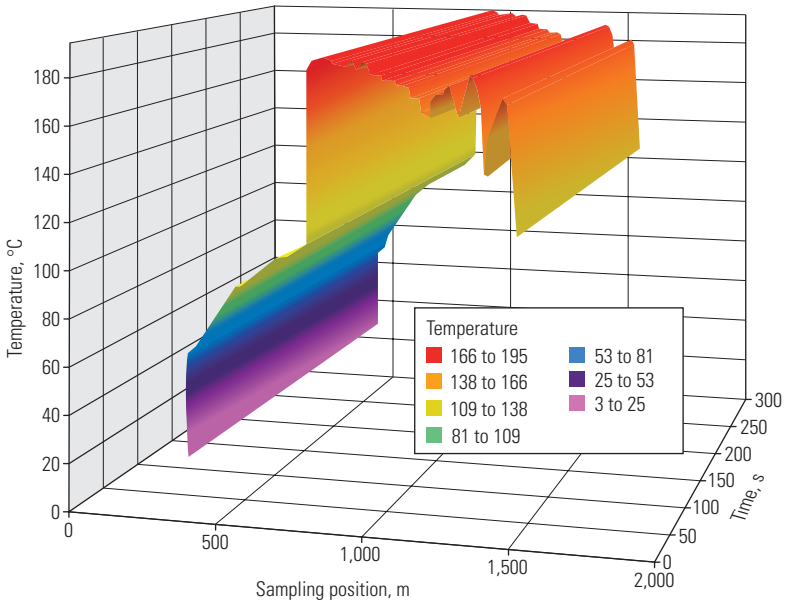
^ WellWatcher BriteBlue fiber installation in a heavy-oil well. Engineers pump the fiber through a conduit inside a coiled tubing string (*inset*) that is hung from the surface across the producing interval.

the new fiber and can measure temperatures with ±0.01°C [±0.018°F] accuracy over distances up to 15 km [9.3 mi] with a 1-m [3.3-ft] spatial resolution.

Since 2007, the new fiber-optic system has been installed in Canadian steamflood completions with BHTs up to 300°C [572°F] (above). So far, no discernable reduction in fiber or measurement performance has been observed, and the temperature data are providing operators with reliable guidance for deciding how to adjust steam injection and oil production to achieve maximum efficiency (right).

35. Al-Asimi M, Butler G, Brown G, Hartog A, Clancy T, Cosad C, Fitzgerald J, Navarro J, Gabb A, Ingham J, Kimminau S, Smith J and Stephenson K: "Advances in Well and Reservoir Surveillance," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 14–35.

36. Multimode optical fiber is mainly used for communication over relatively short distances, such as within a building or a campus. Typical multimode links support data rates up to 10 Gbits/s over distances up to a few kilometers. Multimode fiber has a higher "light-gathering" capacity than single-mode optical fiber and allows the use of lower-cost electronics such as light-emitting diodes or low-power lasers that operate at the 850-nm wavelength.



^ SAGD-well temperature profile acquired by the WellWatcher BriteBlue system. Optical fibers transmit temperature data to surface at a 1-m [3.3-ft] resolution. The sharp temperature increase indicates that steam injection is effectively confined to the horizontal interval between about 900 and 1,500 m [2,950 and 4,920 ft].

Service Domains				Maximum temperature	10 kpsi	12.5 kpsi	15 kpsi	17.5 kpsi	20 kpsi	22.5 kpsi	25 kpsi	27.5 kpsi	30 kpsi	32.5 kpsi	35 kpsi
Drilling and Evaluation	Drilling	RSS		150° C											
		Formate drilling fluids		155° C											
		MWD		175° C											
	Evaluation	Petrophysics	LWD	175° C											
			Wireline (SlimXtreme platform)	260° C											
		Reservoir	LWD	150° C											
			Wireline	260° C											
		Geology	LWD	150° C											
			Wireline	175° C											
		Geophysics	LWD	150° C											
			Wireline (SlimXtreme platform)	260° C											
		Testing	**DST**	215° C											
			Tubing conveyed perforating	200° C											
			Quicksilver Probe tool	260° C											
Development	Cementing	Additives	Retarder	249° C											
			Fluid loss	249° C											
		Test		316° C											
		Evaluation		260° C											
		FlexSTONE HT cement		250° C											
	Stimulation	Fluids		230° C											
		Hydraulic-fracturing monitoring		175° C											
		HEDTA acidizing fluid		205° C											
		ThermaFRAC fluid		190° C											
	Completions	Upper	Subsurface safety and isolation valves	200° C											
			Packers	218° C											
			Flow control	175° C											
		Lower	Screens	175° C											
			Fluids	150° C											
			Tools	175° C											
			Thermal liner hanger	340° C											
Production		**Perforating**		260° C											
		Monitoring	Permanent	175° C											
			WellWatcher Ultra system	300° C											
			Production logging	200° C											
	Artificial lift	ESP	**REDA Hotline550 ESP**	218° C											

HPHT >150°C or 10 kpsi
Ultra-HPHT >205°C or 20 kpsi
HPHT-hc >260°C or 35 kpsi

^ HPHT products and services summary. The range of products and services for HPHT wells spans the productive life of a well. The color codes indicate how technologies fit into the HPHT, ultra-HPHT and HPHT-hc schemes. Products and services highlighted in this article are shown in boldface.

Future HPHT Technology Developments

Significant technologies introduced during the past decade are allowing operators to confidently address numerous challenges posed by HPHT projects (above). As HPHT activity continues to grow and well conditions become more severe, more advanced devices and materials will be required.

Engineers are working to translate the advances realized with HPHT wireline logging to the MWD/LWD environment. The measurement systems must not only withstand elevated temperature and pressure, but also perform reliably when exposed to shocks and vibrations associated with drilling operations. The goal is to reduce drilling risk by enabling better well placement, improved borehole stability and a decreased number of required trips.

Current chemical research involves extending the useful range of additives for primary and remedial cementing, as well as stimulation fluids, into the HPHT-hc realm. This work includes developing novel sealants for plugging and abandoning HPHT wells at the end of their useful lives, and ensuring long-term isolation to prevent fluid flow between subterranean zones or to the surface. In addition, research is underway to develop completion equipment fabricated from materials with better resistance to corrosive fluids and gases.

Extensive operator involvement in equipment design and manufacture, as well as chemical-product development, is not typical for standard wells; however, operator participation will be crucial to the success of future ultra-HPHT and HPHT-hc operations. Cooperation between operators and service companies will be vital for proper qualification testing, manufacturing, assembly, testing and installation. Schlumberger scientists and engineers are committed to participating in this cooperative process, helping the industry at large advance the technologies necessary to meet the world's growing demand for energy. — EBN