High-Pressure, High-Temperature Well Logging, Perforating and Testing

As the search for oil and gas leads to deeper reservoirs, extreme pressures and temperatures have become key considerations in reservoir development. Innovative technologies are being developed to meet the challenges of evaluating and completing HPHT wells and bringing these fields on-stream.

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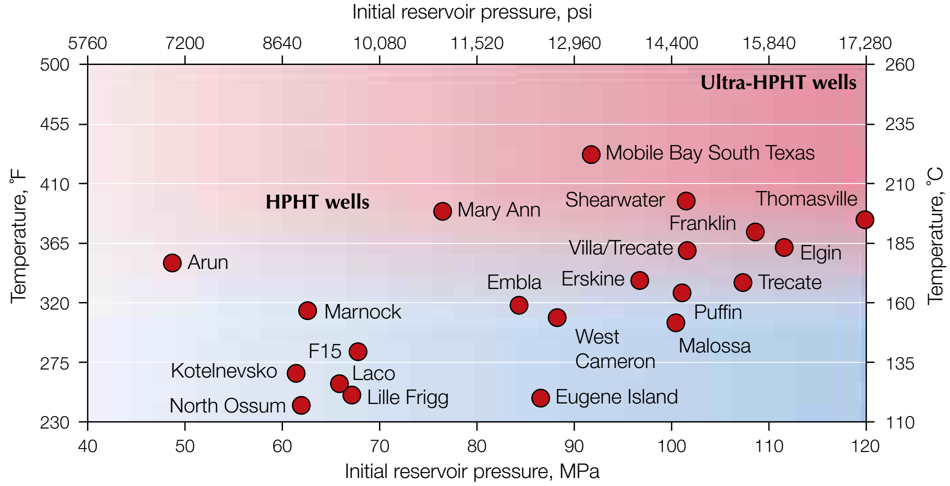
Wells completed in high-pressure and high-temperature (HPHT) environments are by their nature expensive undertakings. The risks associated with evaluating and completing a well are intensified as borehole pressures and temperatures rise. However, regardless of the dangers and expense, the number of HPHT wells is increasing in many areas of the world, including the North Sea, the Gulf of Mexico and China (*right*).

Several factors are responsible for driving the search for hydrocarbons to these hostile environments. Existing fields are becoming depleted and easier targets are scarce. The high pressure means that relatively more hydrocarbon is contained in these fields compared with normally pressured fields. Moreover, as long as the fields are large enough (as with the Erskine, Elgin, Franklin and Shearwater in the North Sea), they make commercially attractive targets even with the technical difficulties of drilling and producing.

Improved seismic techniques have enabled companies operating in the deepwater Gulf of Mexico to identify geologic structures that are much deeper and hotter than those previously drilled. Changes in the UK Petroleum Revenue Tax and the deregulation of gas sales are promoting the development of HPHT wells in the North Sea. The Erskine field jointly developed by Texaco and BP is one example.[1] Discovered in 1981 and located 160 miles [256 km] east of Aberdeen, Scotland, UK, this field was not seriously considered for development until 1994 mainly because of the expense and difficulty of dealing with the extreme conditions found in the reservoirs.

Since then, many technical challenges such as bottomhole temperatures (BHT) of 350°F [175°C] and pressures of 14,000 psi [97 MPa], wellhead shut-in pressures of 10,600 psi [73 MPa] and flowing surface temperatures of up to 300°F [150°C] were overcome. The first gas production in the Erskine field was in December 1997, and the field is expected to yield 330 Bscf [9.4 Bscm] of gas and 75 million barrels [12 million m^3] of condensate. Although it was considered a marginal discovery for many years, Erskine led the way to HPHT development in the North Sea, and set the standard for other hotter and higher pressure Central Graben projects including the Shearwater, Puffin, Elgin and Franklin fields.

Five years ago the *Oilfield Review* discussed HPHT drilling safety, testing procedures, casing and cementing technology.[2] In that article, wells with bottomhole temperatures above 300°F were considered as high temperature. Those requiring pressure control equipment rated in excess of 10,000 psi [69 MPa] or a maximum anticipated downhole pore pressure exceeding an 0.8 psi/ft [18 kPa/m] hydrostatic gradient were considered high pressure. We will adopt those definitions for this article. However, much progress in technology has been made since then.



HPHT fields. The number of HPHT wells is growing worldwide. Wells with undisturbed bottomhole temperatures above 150°C [302°F] are classed as high temperature. Those with wellhead pressure greater than 10,000 psi [69 MPa] or a maximum anticipated downhole pore pressure exceeding an 0.8 psi/ft [18 kPa/m] hydrostatic gradient are considered high pressure. Wells with bottomhole temperatures above 425°F and pressures above 15,000 psi [103 MPa] are generally regarded as ultra-HPHT.

This article looks at some of the latest developments in three key areas: logging, perforating and testing. First we will look at the latest logging tool technology designed for wells that are hotter and have higher pressures than the technical limits of "standard" HPHT tools. Then, we discuss HPHT perforating techniques and a new explosive designed to meet the needs of longer exposures at higher temperatures. Finally, we present examples of new developments in drillstem testing (DST).

HPHT Wells

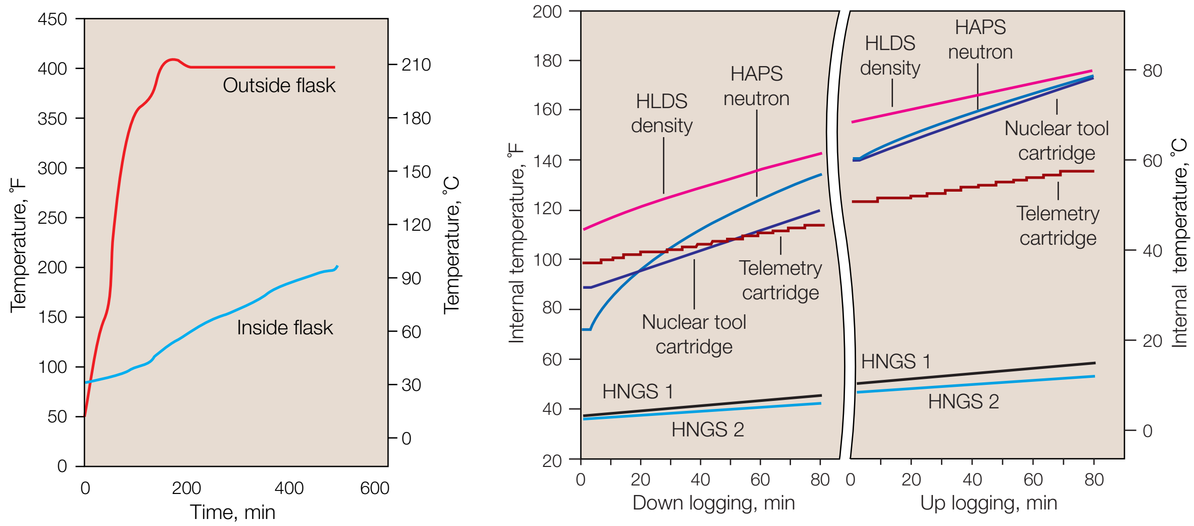
Although they are a small but growing percentage of the total number of new wells drilled, HPHT wells require downhole evaluation, testing and completion services that push the limits of instrument and tool technology. For example, the high temperatures in HPHT wells cause conventional logging tool electronics to fail. Extreme temperatures and pressures are also known to affect tool sensor responses.

One solution, putting conventional logging tool electronics in dewar flasks, has helped meet the early challenges of HPHT environments. But as operators drill wells into ever hotter environments that push beyond the safe operating envelope achieved with flasks, new technology is needed to meet the ever increasing demands of these hostile environments.

Perforating deeper and hotter wells is another difficult challenge. New perforating tools and procedures are being developed for traditional wireline, the more complex tubing-conveyed and completion-conveyed operations. The introduction of a new high-temperature explosive has led to improved performance of shaped charges; this, in turn, has resulted in greater oil and gas production, making these expensive wells economically viable.

HPHT wells are equally hard on mechanical tools and devices used in downhole production testing. Any operational failure could potentially compromise wellsite safety and lead to high environmental and financial costs. New developments in seal technology have resulted in safer and more reliable tools for testing such wells.

1. Young T: "Erskine HPHT Field Development," *SPE Review* (September 1997): 6-7.
2. MacAndrew R, Parry N, Prieur J-M, Wiggelman J, Diggins E, Guicheney P, Cameron D and Stewart A: "Drilling and Testing Hot, High-Pressure Wells," *Oilfield Review* 5, no. 2/3 (April/July 1993): 15-32.



Barriers to extreme temperatures. Dewar flask housings work on the same principle as vacuum flasks. When a flasked tool is inserted in a test oven** (left)**, external temperature rises rapidly (red curve). However, temperature of the electronic circuits inside a flask under the same conditions rises at a much slower rate (blue curve), allowing time for logging operations to be completed. Temperatures from various logging tools on a recent HPHT operation at greater than 380°F show a gradual increase throughout the job** (middle and right)**. The rate of increase for each tool depends on the power dissipated by internal electronics and insulation provided by the individual flask. Precooled HNGS detector temperatures are lowest and rise slowly because of low heat-generating components inside the flask. The power dissipated by the neutron generator in the Hostile Accelerator Porosity Sonde (HAPS) contributes to a high rate of temperature increase.

Logging HPHT Wells

Electronic components such as integrated circuits are frequently the weakest link in a logging tool's operational performance at high temperature. Typically, most electronic systems in logging tools are built from commercially available high-temperature US military specified components.

Increasing tool ratings—These commercial electronic systems are rated to 350°F for continuous operation. The temperature increase inside a logging tool depends on two factors: the heat flow from the outside environment and the heat dissipated by the power consumption of the internal components. Therefore, the use of low-power components and efficient circuit design helps reduce the internal temperature increase coming from the heat generated inside the tool.

Conventional logging tools (rated to 350°F and 20,000 psi [140 MPa]) are upgraded to high-temperature specifications by installing all sensitive electronic components in a 20,000-psi pressure-rated dewar flask housing (*above*). The dewar flasks protect the electronic circuits from excessive borehole temperatures. However, weight becomes a concern in HPHT wells because the flasks add weight to long combinations of tools. In deep HPHT wells the added cable tension from the additional weight of the flasked tools reduces the amount of pull that can be made on the cable before the limits of the weak point are reached.[3]

Electrical continuity between flasked tools is provided by selecting various thermal plug inserts, which also move electronic components away from housing-to-housing or tool connection joints—serving as further thermal isolation. Mechanical systems can be sensitive to high temperatures simply by virtue of dimensional changes caused by thermal expansion, and special attention needs to be paid to selecting and matching the size and fit of flask inserts.

The IPL Integrated Porosity Lithology tool is an example of a high-technology tool that, when flasked, can be upgraded to the hostile environments of HPHT logging operations. The APT Accelerator Porosity Tool sonde and IPL tool's common electronic cartridge are completely enclosed in a flask, as are the Litho-Density sonde detectors and electronics. The flasked Hostile Natural Gamma Ray Spectrometry (HNGS) tool has been commercially available for many years.

Other tools, such as the Hostile Environment Array Induction Tool (HAIT), are upgraded by flasking the electronics from the latest generation Slim Array Induction Tool (SAIT) and combining these with a new induction antenna coil array sonde designed to withstand extreme environmental conditions. By their nature, induction tools require the use of nonconductive materials. For HPHT versions, high-temperature composites—developed for the aerospace industry—were adapted for use downhole. All tools and components are heat qualified to temperatures expected in the HPHT wells before they are sent out for logging.

For conventional wells, the use of unspooled cable lengths of 14,000 to 30,000 ft [4300 to 9100 m] causes no significant degradation to electrical operation of the logging cable. However, in HPHT wells, the increased temperature results in an increased cable resistance and thus higher power loss, a consideration when prejob operation checks are carried out. In some wells logged in the North Sea, Schlumberger uses a special downhole transformer to allow a higher voltage to be applied with less power loss on the cable. At elevated temperatures, special logging cables are required. High-strength cable with electrical-release logging heads minimizes the risk of sticking, because those heads permit higher tension and more control on the cables.

The alternative to wireline conveyance is the TLC Tough Logging Conditions system. The TLC system uses drillpipe to convey the logging tools, which are attached to the end of the pipe and pushed to the desired logging depth. The logging cable—providing power for the logging tools and telemetry communications—is attached to the logging tools by pumping a TLC docking sub down through the pipe to connect with a special docking head at the top of the tool string. The drillpipe is then used to pull the tool out of the well while logging.

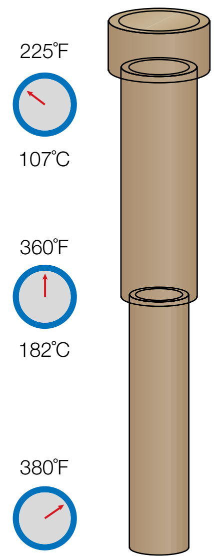
Sensors for HPHT environments—Many different sensors are used for wireline logging: antenna arrays, gamma ray detectors, neutron detectors, pressure and temperature sensors as well as ultrasonic and sonic transmitters and receivers. The extreme conditions in HPHT wells have a variety of effects on these sensors and each must be dealt with in a different way.

An example is the development of special pressure gauges for HPHT environments. Accurate pressure determination inherently requires the sensor to be exposed to the well temperature. There is a trade-off between accurate pressure measurements and elevated temperatures. Hydrostatic pressures—typically 16,000 to 18,000 psi [110 to 124 MPa]—are above the safe operating range of the CQG Crystal Quartz Gauge sensor. Currently, other pressure gauges with varying degrees of resolution, accuracy and cost are available for a variety of HPHT operations. The Well Testing Sapphire Recorder (WTSR) Sapphire gauge is rated to 200°C [393°F] and 20,000 psi and has been run in memory mode with a specially fitted and modified MDT Modular Formation Dynamics Tester tool.[4] Its resolution is similar to that of the conventional strain gauge (0.03 psi), but its dynamic response-speed and stability are much improved. Real-time readout is available for well testing applications, but not for wireline pressure readings.

The HPHT environment has always been a challenge for thermal neutron porosity logging measurements. Temperature and pressure corrections are extremely large and of opposite sense—high temperature makes the thermal neutron tools read low, and high pressure makes them read high. Increased temperature raises average neutron energy such that its cross section is diminished, leading to lower neutron absorption in the formation, which mimics lower porosity in the tool response. Increasing pressure causes the opposite effect on neutron response because of the compressibility effect on the hydrogen indices of the fluids.

The environmental corrections required for these logging measurements are the most significant source of uncertainty and inaccuracy in HPHT porosity logging. In a high-porosity formation at 350°F, the temperature correction to the thermal neutron porosity reading is nearly a factor of two. The pressure correction is also sensitive to the type and compressibility of the mud system. Pressure corrections can be more than a factor of two at 25,000 psi [172 MPa] in oil-base mud.

Problems encountered when measuring neutron porosity in HPHT environments can be avoided by using an epithermal neutron tool such as the APT sonde. Epithermal neutrons are far less sensitive to temperature effects. The net pressure-temperature chartbook corrections to epithermal neutron porosity measurements are significantly smaller—a factor of 6 at high porosity—than those for conventional thermal neutron measurements. The APT sonde, with its backshielded neutron detectors focused towards the formation, is also much less sensitive to variations in the mud system. In addition, it provides an openhole formation neutron absorption cross section Σ measurement, which helps identify shale beds and saline water-saturated zones in HPHT wells.

Borehole temperature	Well sketch	Proposed logging program	Special issues
		**10 3/4-in. hole, 9 7/8-in. casing**	
		1. Sondex–CBT–VDL–GR–CCL	
225°F / 107°C		**8 1/2-in. openhole**	
		2. HAIT–HDSI–HNGS–LEHV	DSI tool to 13 3/8-in. casing point
		3. HLDS–HAPS–HNGS–LEHV	
		4. HOBDT–HGR–AMS	Bowspring to reduce rotation
		5. MDT–HGR–LEHV	Sapphire gauge, pressures only
360°F / 182°C		**7-in. cased hole**	
		6. CBT–VDL–GR–CCL	Combine with CBT string
		7. Gyro	
		8. VSP	9 7/8-in. and 10 3/4-in. casing
		9. Sondex caliper	
		5 5/8-in. openhole	
		10. HAIT–HDSI–HNGS–LEHV	
380°F / 193°C		11. HLDS–HAPS–HNGS–LEHV	
		12. HOBDT–HGR–AMS	
		13. SRFT–HGR–LEHV	
		5-in. cased hole	
		14. CBT–VDL–GR–CCL	
		15. Gyro	Combine with CBT string
		16. Sondex caliper	9 7/8-in. and 10 3/4-in. casing

Prejob planning. Detailed plans for logging each phase of a drilling program allow the unit operator and client to get vital information for formation evaluation, while minimizing the risk of tool failure due to environmental exposure. Each logging tool provides critical information about the well and formation: induction measurements (HAIT) are used for fluid saturation; shear and compressional sonic velocities (HDSI) are used for formation porosity and determining rock properties; epithermal neutron (HAPS) and density (HLDS) are used for porosity evaluation; gamma ray (GR) helps correlate beds; and spectral gamma ray (HNGS) is used for shale corrections. Dipmeter (HOBDT) helps identify fractures and formation bedding properties, and formation pressures and fluid samples are taken with a formation tester (SRFT) and (MDT). Other tools are used for borehole navigation (Gyro), and fluid properties (AMS). A CCL identifies casing collars for depth correlation and cement integrity is evaluated with a sonic Variable Density log (VDL). Electrical release logging heads (LEHV) permit higher tension on logging cables with heavier tool strings.

This measurement is useful to correlate with gamma ray and resistivity measurements.

Elements of Success

Experience shows that advance planning and preparation are vital to the successful completion of wireline and testing operations.

Planning—Wireline and testing operations have been carried out in extremely hostile environments, where high downhole temperatures, frequently in combination with high pressure and the presence of hydrogen sulfide [H_2S], demanded the use of tools and logging equipment specifically designed for such environments. One location that has successfully met these challenges for more than 15 years is the Schlumberger base Songkhla, in southern Thailand. The hostile high-temperature environment encountered in wells at this location requires particular care and attention to detail in each job.

As with HPHT logging jobs performed in other parts of the world, early consultation with the operator is essential. All aspects of the job must be discussed, including requirements, solutions and the capabilities and limitations of the logging tools. Excellent wellsite communication is essential. Each phase of the operation is examined, including hole conditions, mud parameters and the proposed logging schedule. Logging engineers review strategies and options that may be implemented if the logging program cannot continue as planned due to operational circumstances.

Prejob planning and careful consultation also save valuable time. First, it is essential that the planned logging program be finalized well in advance of the actual operation (*above*). Three weeks or more are needed to ensure sufficient preparation for the logging

3. The weak point is a mechanical release at the connection between the logging tool and wireline cable. It is designed to prevent overtension from breaking cable.

4. Vella M, Veneruso T, LeFoll P, McEvoy T and Reiss A: "The Nuts and Bolts of Well Testing," *Oilfield Review* 4, no. 2 (April 1992): 14-27.

Ultra-HPHT Logging

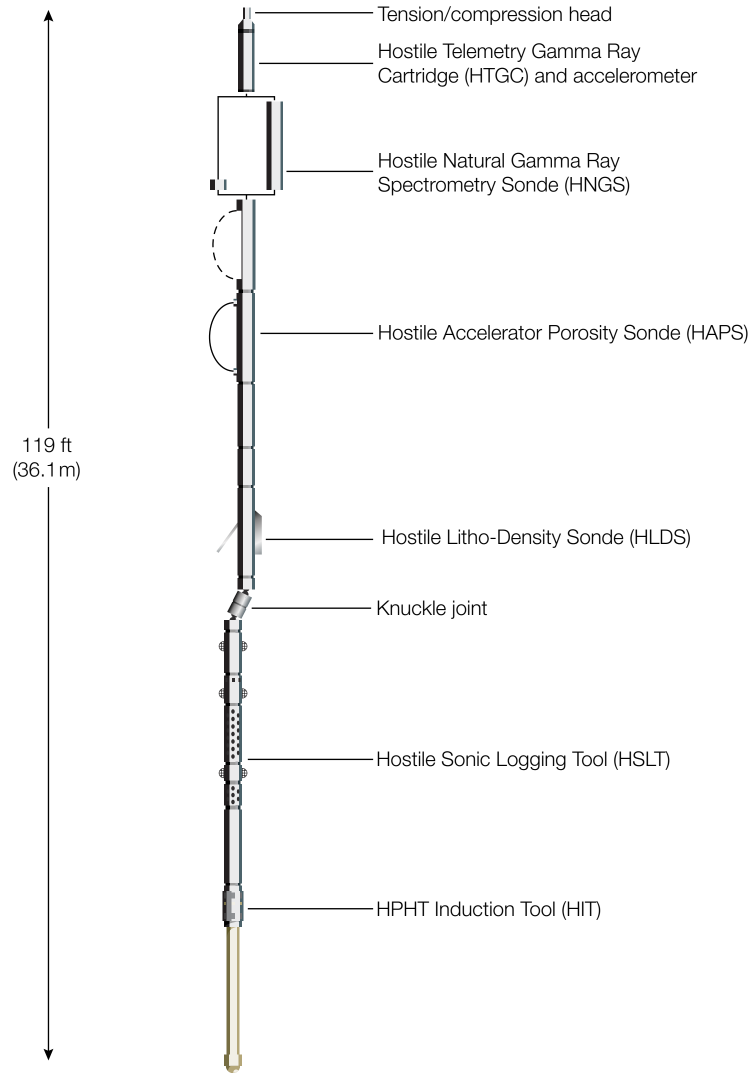
To meet the increasing demands of HPHT logging, the new Xtreme tool string is being field tested in the Gulf of Mexico and the Far East. Developed using the MAXIS Multitask Acquisition and Imaging System logging technology, the Xtreme system is capable of logging in temperatures to 500°F [260°C] and pressures to 25,000 psi [172 MPa], providing best-in-class, quad-combo service to the global HPHT and ultra-HPHT market *(right)*. The Xtreme platform performs array induction, digital sonic and some of the latest nuclear measurements in HPHT wells.

The Hostile Accelerator Porosity Sonde (HAPS) is an epithermal neutron logging tool that provides a measurement of the formation hydrogen index and Σ, the formation neutron absorption cross section. These measurements can be used together with other logging devices to provide quantitative formation evaluation.

The Hostile Natural Gamma Ray Spectrometry Sonde (HNGS) measures potassium, thorium and uranium concentrations and provides borehole corrections for potassium-based and barite-based mud systems. The high-efficiency bismuth germanate (BGO) gamma ray detectors in this tool are internally flasked and can be precooled with CO_2 prior to running in the hole, giving extended holding time. The spectral matching brings improved accuracy to the high-precision elemental outputs. The HNGS is commercial and has been logging HPHT wells worldwide.

The Hostile Litho-Density Sonde (HLDS) has new high-speed electronics that are better able to handle the large count rates experienced in high-porosity formations.

The HPHT Induction Tool (HIT) features the latest technology induction measurements with built-in standoff, a 3⅞-in. flask housing, robust electronics, five depths of investigation: 10-in., 20-in., 30-in., 60-in. and 90-in. (at 1-ft, 2-ft and 4-ft vertical resolution), with logging speeds up to 3600 ft/hr [1100 m/hr]. Spontaneous potential, mud resistivity and R_t/R_{xo} computations are also included.



□Xtreme tool string. A new fully compatible HPHT (25,000 psi, 500°F) MAXIS tool string offers the latest quad-combo logging service technology for advanced formation evaluation. New lower power electronics, improved thermal isolation design and materials extend the holding times of the state-of-the-art logging tools for increased reliability in HPHT wells.

The Hostile Sonic Logging Tool (HSLT) is a monopole sonic tool with borehole compensation at 3-ft and 5-ft spacings. Normal cement evaluation data acquisition with CBT Cement Bond Tool log and Variable Density logging are available with this tool.

The Xtreme tool string also features improved thermal management based on state-of-the-art, low-power electronics, a novel flask stopper design, hostile-rated materials and an increased thermal mass to slow down internal temperature rise. Most of the tools in this new tool string have shock and vibration specifications conforming to those of the Platform Express system, ensuring

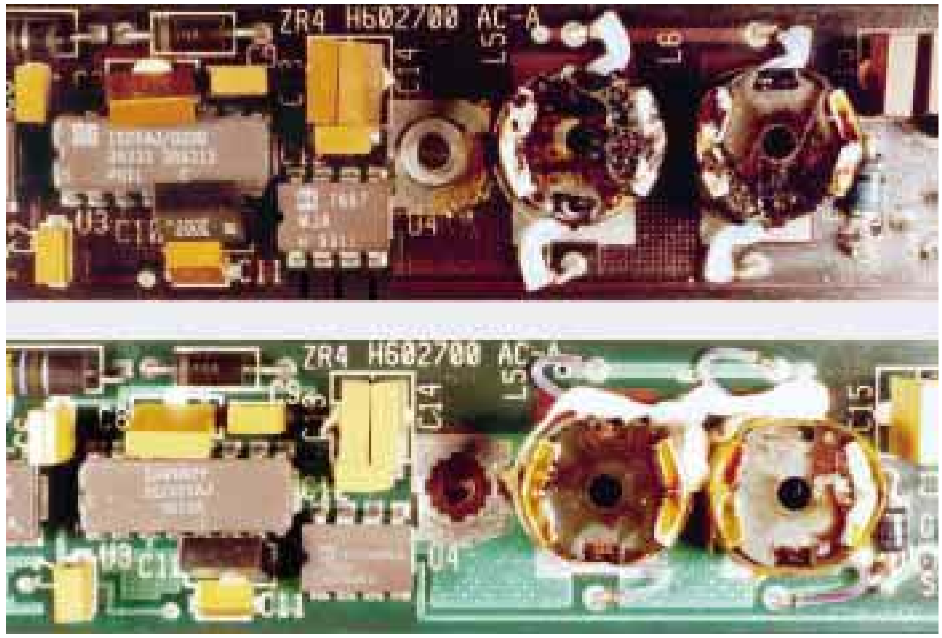
Holding times at 500°F	
Tool	**Hours**
HTGC	12
HAPS	4
HLDS	5
HSLT	6
HIT	12

□Xtreme holding times. The length of time that each tool can operate in a high-temperature well depends on the internal power dissipated by the tool electronics and the degree of thermal isolation from the hot external environment provided by the dewar flask.

reduced risk of tool failure. The new 25,000 psi dewars are rated for H_2S gas environments. The 500°F-holding times are exceptionally long for logging tools of this complexity *(above)*.

Temperature sensors in each sonde and cartridge provide a continuous monitor of internal temperature build-up during the job. The Hostile Telemetry Gamma Ray Cartridge (HTGC) is a flasked version of the SlimAccess telemetry cartridge, which features an accelerometer for real-time speed correction and a gamma ray detector. The compatibility of the telemetry system with existing high-technology logging tools allows a variety of tool string combinations depending on logging requirements. Other HPHT equipment, rated to 500°F and 25,000 psi, is available to run with the Xtreme system including knuckle joints, a slick in-line eccentralizer (ILE-E) for hole sizes from 8 to 10 in., and slip-on bow spring eccentralizer (EME-KB), for hole sizes from 10 to 20 in., and a logging head (LEH-HT), which contains an electrical controlled weak point and a tension in head measurement.

The benefits of the Xtreme tool string are elevated temperature and pressure ratings, extended holding times, ability to record a downlog, compatibility with the TLC Tough Logging Conditions system and increased reliability. The new Xtreme tool string is expected to be deployed in the field at the end of 1998.



***□Temperature effects on logging tool circuits. The damaging effects of high temperature on electronics can be seen by comparing a scorched circuit board** (top) **from a tool that was exposed to 350°F bottomhole temperatures with a new board** (bottom).*

operation, including a thorough examination of components, upgrading to temperature-qualified sensors, heat qualification, flasking electronic components, operational checks and tool master calibrations.

Next, clear contingency plans must be agreed to in advance to minimize the time that tools are exposed to high temperatures. This is especially important for scenarios in which the tool string gets stuck, or an individual tool has a functional failure without affecting the other tools. In traditional logging, when tool failure occurs, the tool string is pulled out of the hole and the defective tool is replaced. In HPHT wells, temperature exposure in the borehole is extended by tripping operations. Pulling out of the hole can take more than two hours. During this time, the tool is still exposed to borehole temperatures and the electronics in the flasks cool only slightly coming out of the hole. It is, therefore, preferable to continue logging using functioning tools while in the borehole, with plans to replace the failed tool in another run, if possible, or to use an equivalent measurement in place of the missing one.

For example, an operator may consider the gamma ray log as an essential measurement for depth correlation. In this case, if the gamma ray tool fails, depending on the formation character, another measurement such as Σ, density or neutron logs could be compared with resistivity or sonic measurements on other runs for correlation. Similar scenarios can be envisioned for other combinations of tools strings and failure modes. Thus, the prejob meeting provides an opportunity to determine strategies for solving problems such as tool failures and tool backups, as well as unexpected hole problems. The detrimental effects of temperature can be seen when the electronics of a new tool are compared with previously used circuit boards (*above*).

Engineering assistance—The support for Schlumberger HPHT tools comes from a network of major research and product centers located in Japan, the USA and France. Upgrades to tools and subsequent HPHT qualifications performed at the product centers and on-site service centers enable Schlumberger to provide the technology and expertise that clients need.

In certain locations, extreme well conditions require the use of specially designed tools. In Aberdeen, Scotland, special support for the Hostile Oil-Base Dipmeter Tool (HOBDT) and SRFT Slimhole Repeat Formation Tester tool was required, since the conditions expected for some HPHT jobs were beyond the scope of existing field equipment. The HOBDT tool electronics cartridge was installed in a flask, electrode pads were upgraded to new, higher temperature-rated materials at the field location, and the wells were successfully logged.

Other recent engineering efforts have been focused on developing more efficient and cost-effective hostile logging tools, including the Xtreme system, a new 25,000 psi, 500°F-rated quad-combo array induction and integrated porosity and lithology logging suite (see "Ultra-HPHT Logging," *previous page*). This new tool string is being used to log ultra-HPHT wells in the Far East and Gulf of Mexico.

Job preparation—Rigorous job preparation is critical to success in HPHT logging. To ensure tool reliability, every tool is qualified for logging at the expected temperature of the well. First, the electronics for each tool are heat checked to their maximum-rated temperature of 350°F. Heat cycling a tool is a long process. The electronics cartridges are placed in instrument ovens and temperatures are increased in 60°F [33°C] increments. Tools are verified to work continuously at the rated temperatures for at least a half hour.

The tools are flasked before they are used in the logging job, providing a significant increase in thermal protection from HPHT environments. Tool performance at the expected well temperature is established by calculating the temperature rise inside the dewar flask.

Any failures encountered during heat qualification are repaired and the tool is tested again until reliable operation at high temperature is attained. This may be a lengthy process. However, to limit thermal cycling of components, heat qualification is performed only when replacement parts have been installed or the time between jobs exceeds the normal quality-check period. When all tools are qualified to the expected maximum well temperature, they are given a complete tool string system check before they are dispatched to the wellsite (*below*).

As the logging operation draws near, a safety meeting is held with all personnel involved. Safety is paramount, and all participants must have a clear understanding of tasks to be performed. Finally, job preparation continues at the wellsite, where all tools are subjected to a final operational check before entering the borehole.

Efficiency—Time management at the wellsite is crucial to successful HPHT operations and data acquisition. Run-in speed and logging speed are optimized prior to the job, allowing for repeat sections, down-logging and contingency arrangements for problem holes.[5] At the wellsite, in the hours following the last circulation, the well temperature rises quickly. To reduce the risk of tool failure, every effort is made to ensure that the logging operation is performed efficiently—minimizing the time that the tools are exposed to high well temperatures.

Downward logs are recorded faster than normal and are vital in case a tool problem occurs close to the bottom of the well where temperatures are highest. The main log is recorded in an expeditious manner, but without compromising data quality. The results acquired on the uplog are compared with those acquired on the downlog to ensure the integrity of the information gathered. Before subsequent runs are made, a wiper trip may be required to reduce the borehole temperature.

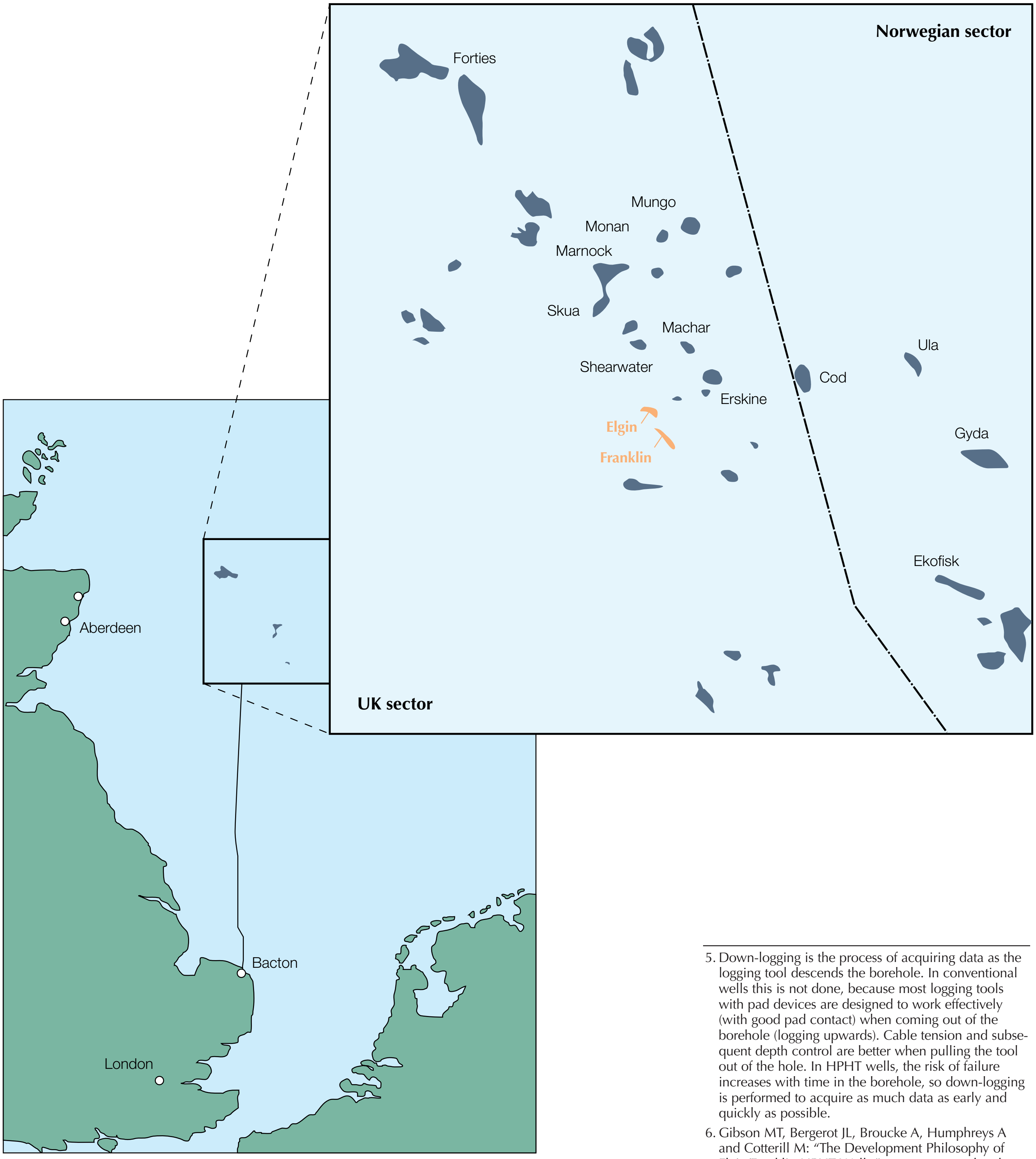
Typically, for openhole HPHT logging, power is applied to the logging string at surface to confirm tool operation. The tool is then powered down while running in, and not powered up again until it is near the casing shoe to minimize heat generation from the internal electronics within the flasks. Any logs required in the casing are performed while pulling out of the hole after acquisition of the main openhole log. Calipers and pad-contact tools are not opened until logging upwards from total depth (TD) for the main log acquisition.

Immediately after logging is completed and the data are delivered to the operator, the tools are returned to the Schlumberger facilities for intensive postjob maintenance procedures. Many sensitive components, although in working order, are routinely replaced to ensure optimum performance on subsequent logging jobs, since temperature cycling often results in failure. High temperatures are particularly wearing on O-rings and seals, and all are replaced before the tools are reassembled and tested.

Logging in the North Sea

Among the HPHT logging regions in the North Sea today, the Elgin and Franklin fields are the most active (*next page*). The largest HPHT development on the UK Continental Shelf, the Elgin and Franklin fields are setting new benchmarks for future projects in the oil and gas industry throughout the world.[6] Reserves are estimated to be approximately 380 million bbl [60 million m^3] of condensate and 1800 Bscf [50 Bscm] of gas.

Extensive testing for all HPHT logging tools before each job. First each tool is temperature-qualified by heating in ovens to the expected maximum downhole temperature in the well. Then the complete tool string is given an operational check in the shop before being shipped to the offshore well.



□*Elgin and Franklin fields. ELF Exploration UK PLC is currently developing the Elgin and Franklin fields in the Central Graben about 150 miles [240 km] east of Aberdeen. These fields lie within 3.4 miles [5.5 km] of each other and their proximity allows development in tandem; each field will have its own wellhead platform with production from both fields processed through one central facility.*

5. Down-logging is the process of acquiring data as the logging tool descends the borehole. In conventional wells this is not done, because most logging tools with pad devices are designed to work effectively (with good pad contact) when coming out of the borehole (logging upwards). Cable tension and subsequent depth control are better when pulling the tool out of the hole. In HPHT wells, the risk of failure increases with time in the borehole, so down-logging is performed to acquire as much data as early and quickly as possible.

6. Gibson MT, Bergerot JL, Broucke A, Humphreys A and Cotterill M: "The Development Philosophy of Elgin/Franklin HPHT Wells," paper presented at the 1995 Offshore Drilling Technology Conference, Aberdeen, Scotland, November 22-23, 1995.

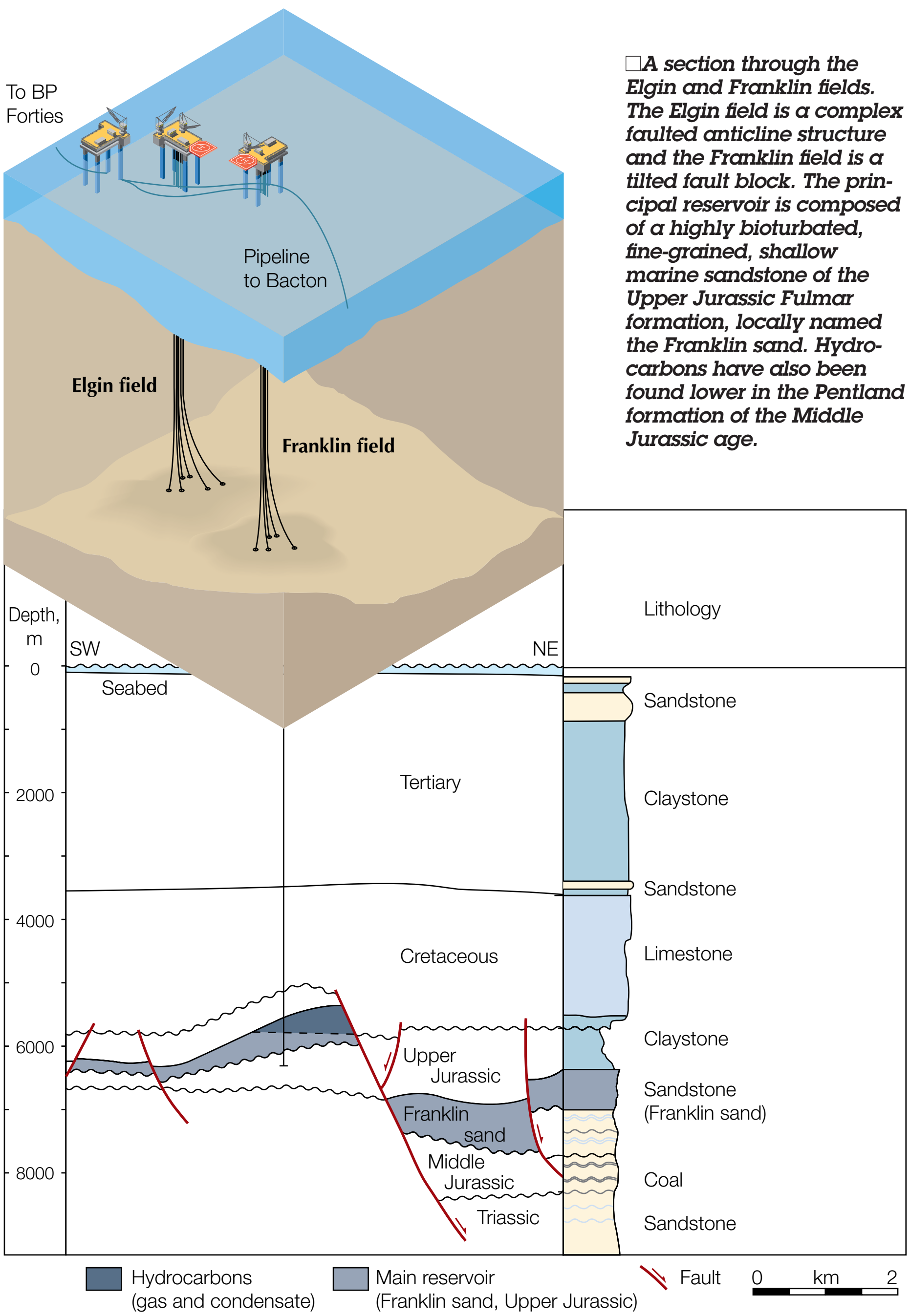
Lasocki J, Guemene J-M, Hedayati A, Legorjus C and Page WM: "The Elgin and Franklin Fields: UK Blocks 22/30c, 22/30b and 29/5b," *Abstracts*, Petroleum Geology of NW Europe (1997): 179.

Also see "Elgin/Franklin Project," produced by The Public Relations & Communications Department, Elf Exploration UK PLC, Aberdeen, Scotland.

The Elgin and Franklin fields lie in a structurally complex area in the southern part of the North Sea Central Graben basin, more than 3 miles [5 km] below the seabed (*below*). The formations in the Central Graben basin resemble a fractured bowl. Normal faulting during Cretaceous sedimentation divided the Jurassic reservoir into numerous isolated fault blocks. The deeper fault blocks have higher pressures and temperatures.

Good reservoir quality is due to significant secondary porosity preserved by extreme overpressure. These deep Elgin and Franklin fields contain high-pressure gas condensate. The combination of extreme reservoir conditions with an initial pressure of approximately 16,000 psi [110 MPa] and temperatures of 375°F [190°C] poses a considerable development challenge.

Schlumberger logged the discovery and appraisal wells in these fields, and is now involved in a four-year program of logging the ten HPHT development wells for both fields. The program consists of openhole logging in the potential reservoirs of each well—the Franklin sand and underlying Pentland sand. Cased-hole cement logging will be performed in the 13⅜-in. and 9⅞-in. casings and the 7-in. liner. Caliper logs will be run in the 9⅞-in. casing.



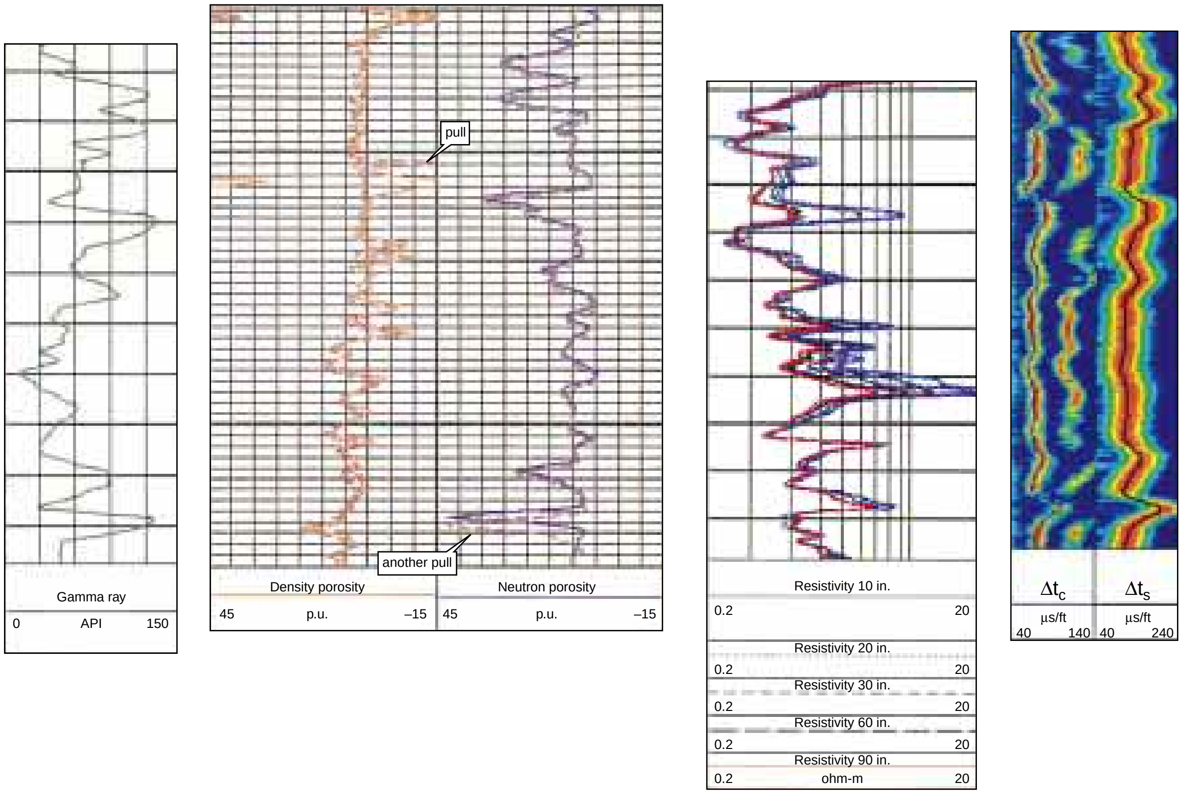
A section through the Elgin and Franklin fields. The Elgin field is a complex faulted anticline structure and the Franklin field is a tilted fault block. The principal reservoir is composed of a highly bioturbated, fine-grained, shallow marine sandstone of the Upper Jurassic Fulmar formation, locally named the Franklin sand. Hydrocarbons have also been found lower in the Pentland formation of the Middle Jurassic age.

Elgin field results—The HPHT logging results obtained in one of the Elgin development wells at 380°F [193°C] show the quality of logging repeatability in spite of the 15 to 30% increased internal tool temperatures occurring between passes (*next page, top*).[7] During two hours of logging, all electronic components and circuits in the flasked cartridges remained well below the 350°F maximum manufacturing ratings. Down-logging was acquired wherever possible to reduce thermal exposure time. However, some tools, such as pad-type tools, may exhibit poor data quality—normally closed on downhole logging—because of inconsistent pad-to-borehole contact. For these tools, a separate uphole log run is necessary, with the downhole log used as a qualitative repeat log.

The MDT tool has been successfully used in the Elgin field to acquire formation pressures in several wells with hydrostatic pressures greater than 17,500 psi [121 MPa] and bottomhole temperatures greater than 380°F. The WTSR Sapphire gauge was used in memory mode with good results. The 20,000-psi strain gauge provides a real-time evaluation and compares well with the more accurate WTSR memory data. In a formation with unknown permeability, pressure drawdown measurements are usually limited to prevent excessive differential pressures across the MDT sealing packer. Also the Aberdeen field location-modified HOBDT tool, rated to work at 410°F [210°C], was used successfully in some of the Elgin wells.

Ultradeep, High-Pressure Logging

The Gulf of Mexico is another extremely active area for HPHT logging. Surface seismic data acquired and processed by Geco-Prakla enabled EEX Corporation to identify prospective geologic structures that are much deeper and higher pressure than those previously drilled (*next page, bottom*). In a deepwater well drilled by Sedco Forex, EEX used the new Xtreme tool string to evaluate its Llano prospect in the Garden Banks, Block 386. This well, in 2663 ft [812 m] of water, reached the Lower Pliocene and Miocene reservoirs at well depths never before achieved in the Gulf of Mexico: 27,864 ft [8493 m] measured depth and 26,969 ft [8220 m] true vertical depth. A vertical seismic profile (VSP) run at 25,000 ft [7600 m] in the cased section of the well identified prospective pay zones deeper than 30,000 ft [9100 m]. Pore pressures at these depths exceed 20,000 psi, above the pressure limit of conventional HPHT logging tools.

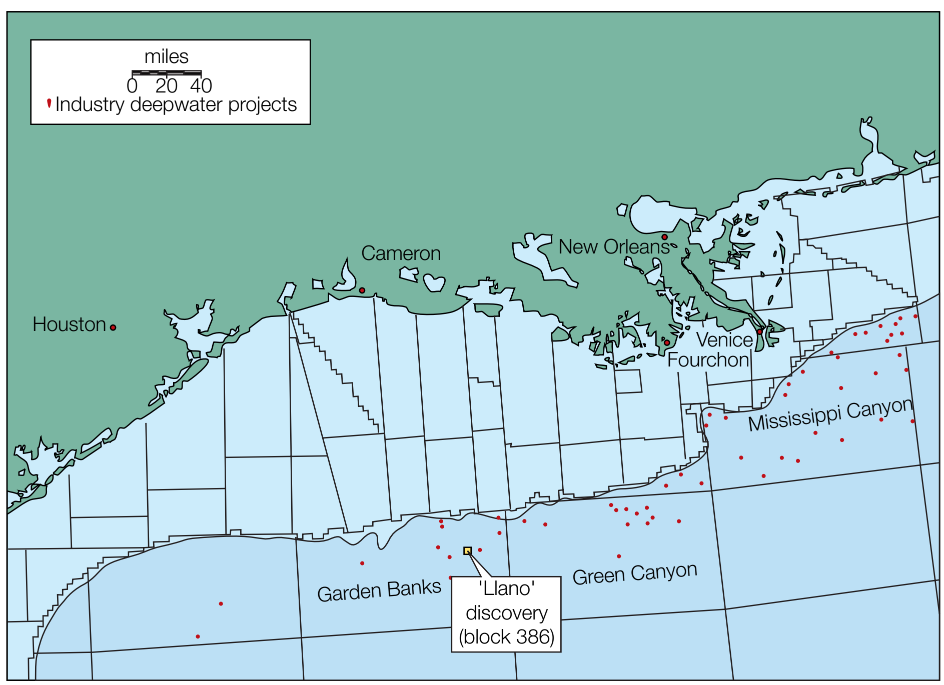


Repeat logging section of the Elgin G4 well. Results of multiple logging passes in a well at 380°F show good quality repeats in spite of the increasing internal temperature of logging electronics cartridges. Some zones in the neutron and density porosity logs (tracks 2 and 3) experienced high overpull on the second pass, causing a depth shift in the data. The gamma ray (track 1), induction (track 4) and sonic measurements (tracks 5 and 6) obtained logging down agree well with the logging up measurements.

Planning for the logging operation began months in advance with the primary objectives being reduced operational risks and maximum logging efficiency. Personnel from EEX worked closely with Schlumberger logging engineers to consider all possible contingencies. Operational challenges included issues related to logging tool conveyance, pressure limitations of downhole equipment, cable type and length, and data delivery requirements.

The high hydrostatic pressure in the wellbore could be met with the new Xtreme logging tool, which is rated to 25,000 psi. However, other tools used to log this well were sent to the Sugar Land, Texas, USA product center for pressure testing and qual-

7. Fields T: "Experiences and Developments in HPHT Wireline Logging," paper presented at the 2nd International Conference on Progress in HPHT Fields, Aberdeen, Scotland, May 20-21, 1998.



EEX well location in deepwater central Gulf of Mexico.

EEX team using the InterACT remote communications software system. Members of the EEX Llano Prospect team—Randy Haworth, Geologist and Todd Hubble, Reservoir Engineer—were able to view the logging operation remotely and in real time on a PC in their Houston office. After several sticky attempts to get past an obstruction near the bottom of the well, the on-site team decided to log out of the well. The quick decision helped prevent the tool from becoming stuck and may have saved a costly fishing job. The lower section was later re-logged with the TLC system.

ification. These included the MDT tool, the CSI Combinable Seismic Imager tool, CST Chronological Sample Taker tool, FPIT Free Point Indicator Tool and the downhole TLC equipment (*above*). To prequalify for this job, every tool was successfully pressure tested to 22,000 psi [152 MPa].

The extraordinary depth created a special challenge for tool conveyance since standard logging cables could not be used. In extra-deep wells, the weight and drag encountered with long cables are problems. In this particular well, an extra-long, high-strength cable was required to overcome the combined weight of the cable, tool string and the associated frictional cable drag encountered. A new 36,000-ft [1100-m] extra high-strength cable (7V46NTXXS) was designed and built by the Vector Product Center, Sugar Land, Texas, to meet these demands, and the offshore logging unit and logging drum were modified to hold the new cable.

Safety concerns associated with expected high cable tensions were addressed with a custom-designed wireline dual-drum capstan developed at the Schlumberger Belle Chasse, Louisiana, USA, Center (*right*). The capstan was installed between the offshore logging unit and the rig floor to reduce the cable tension necessary to spool the cable onto the logging unit. This equipment significantly reduced the risk associated with wireline-conveyed logging operations in deeper wells.

The first logging descent used the Xtreme tool string on wireline to log all but the bottom 300 ft [90 m]. The bottom section was successfully logged using the TLC system to maneuver the Xtreme tool string past obstructions to TD. Following the Xtreme logging, EEX utilized the TLC system to complete the openhole logging program. Pressure measurements were obtained with the MDT tool, and with low-shock sampling techniques twelve formation fluid samples were successfully obtained in the unconsolidated sand formations. To maximize efficiency and reduce risk to the openhole section, the DSI Dipole Shear Sonic Imager tool and additional VSP were used after the well was cased and cemented by Dowell. Prior to DSI logging and VSP, casing and cement were evaluated using the USI UltraSonic Imager and CBT logs.

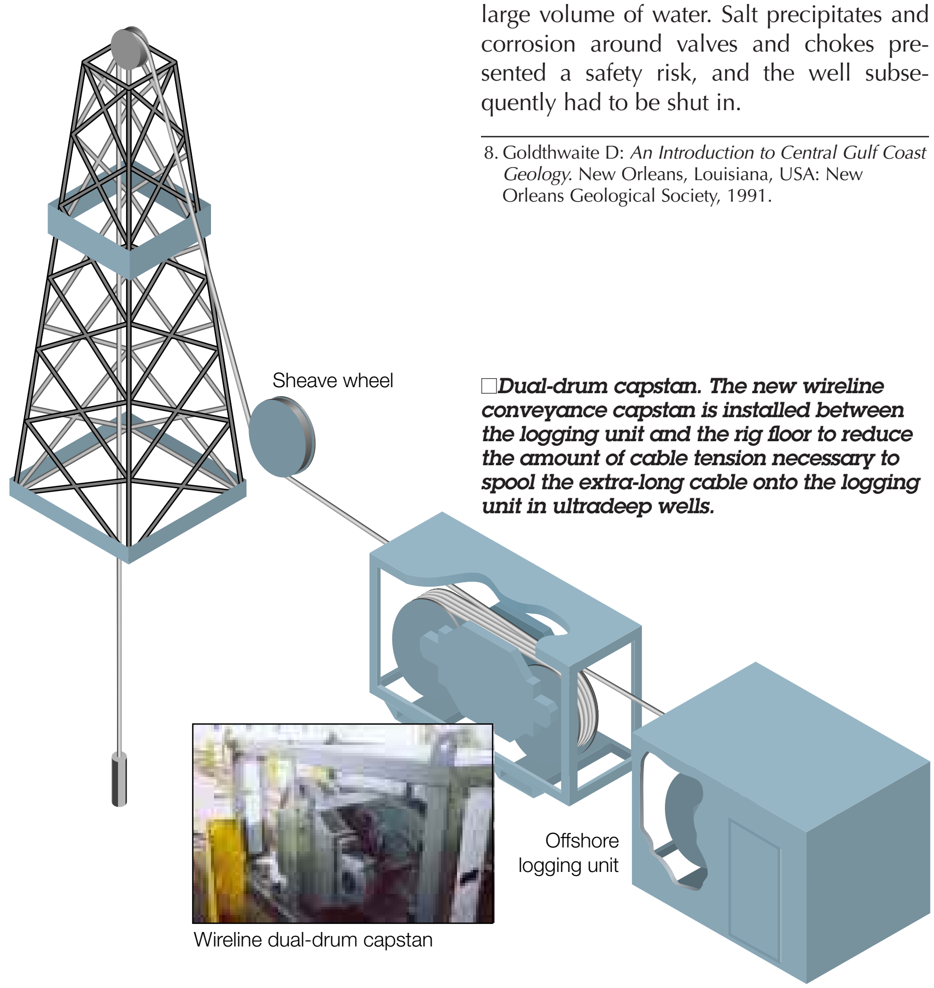
The logging results indicate the presence of several hydrocarbon-bearing sands in both the Lower Pliocene and Miocene sections. Pressure and fluid samples are being used with logging measurements to evaluate the potential of early production capability through tie-back options to other EEX facilities nearby, or the need and economics for a stand-alone production facility.

Well Intervention

Elsewhere in the Gulf of Mexico, a major operator is developing the first extensive eastern Gulf Coast postsalt deposit in the Norphlet formation. This large eolian deposit lies in a major regional unconformity and is the major deep—over 20,000 ft [6100 m]—gas play in the waters around the mouth of Mobile Bay. The Smackover formation is thought to be the hydrocarbon source. The gas is trapped in the Norphlet on salt-cored anticlines that occur on the down-thrown side of east-west trending listric faults.[8] The wells are close to land and are very productive, with high flow rates of 50 to 100 MMscf/D [1.4 to 2.9 MMscm/d] and life expectancies of 20 to 25 years. In these formations, wells are 400°F to 450°F [204°C to 232°C] with bottomhole pressures up to 19,000 psi [131 MPa]. These wells, serviced, drilled and completed from a platform, have H_2S concentrations from 1 to 3.5% as well as significant amounts of carbon dioxide [CO_2].

One well was producing water at a high rate for more than five years. With an influx of water production, there was a significant salt buildup in the tubing and at the surface. The surface facilities could not handle the large volume of water. Salt precipitates and corrosion around valves and chokes presented a safety risk, and the well subsequently had to be shut in.

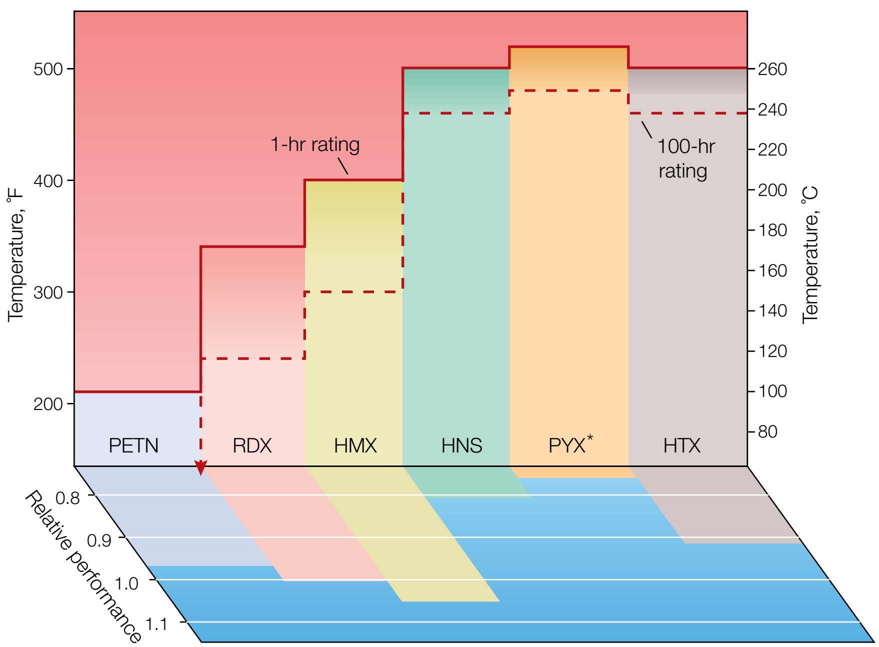
8. Goldthwaite D: *An Introduction to Central Gulf Coast Geology.* New Orleans, Louisiana, USA: New Orleans Geological Society, 1991.



Dual-drum capstan. The new wireline conveyance capstan is installed between the logging unit and the rig floor to reduce the amount of cable tension necessary to spool the extra-long cable onto the logging unit in ultradeep wells.

To get the well back on-line, the water source had to be identified and cut off. In most wells, the diagnostics would include a neutron log, and WFL Water Flow Log or PLT Production Logging Tool measurements. Water could be stopped with a PosiSet plug and cement or one of the Dowell suite of specialty fluids applied through coiled tubing. However, in a 410°F, 20,000-ft deep well with significant H_2S and CO_2 concentrations, normal operating practices do not apply. The New Orleans, Louisiana, USA Production Enhancement Group (PEG) assisted by analyzing alternative solutions. With wireline logs and production gas/water ratios (GWR) and the GWR rate of increase, the water source could be characterized—channeling, coning or a rise in the water table—and isolated.

After the water source was found lower in the reservoir, a gamma ray and casing collar locator were used to determine current total depth and establish a platform to dump a special cement blended by Dowell, sealing up to half of the perforated interval (see "High-Pressure, High-Temperature Well Construction," *page 54*). A 2% potassium chloride [KCl] solution was pumped to push the cement slurry into the open perforations. The Dowell cement laboratory in New Orleans prepared the special cement slurry. Special care was taken to prevent particles from falling out of the cement mixture and plugging the bailer. The well was cemented with ten runs of 40-ft [12-m] bailer, followed by pumping of KCl brine. Water production decreased proportionally after the well intervention, and all indications are that the cement plugs were successful. HPHT logging and intervention continue to provide solutions to enhance production of the remaining reserves.



* A system test is recommended above 435°F.

Comparison of oilwell perforating explosive ratings. The ability of oilwell perforating explosives to withstand high-temperature exposure without sacrificing performance is improving. For example, HTX offers about a 5 to 10% increase in relative penetration over HNS and even more of an increase over PYX explosive. Test systems demonstrate consistently high HTX performance even after exposure to high temperatures (440°F) for long periods of time (200 hr).

New High-Temperature Explosive

In every well, perforating is a critical component of the completion process. But it can be a particular challenge in HPHT wells. The deep, high-pressure wells contain high-strength formation rock that reduces perforating charge penetration, making them difficult to complete.

The productivity of a given reservoir depends primarily on the near-wellbore pressure drop. This pressure drop is governed by wellbore drilling damage. Perforating parameters such as perforation length, diameter, phasing, shot density and perforation damage are factors that determine how well the wellbore drilling damaged zone is bypassed. Shaped charges have proved the most effective means for producing the network of pathways needed to economically drain hydrocarbons from a reservoir.

Millions of shaped charges are shot each year in wells with perforating guns in downhole conditions that range from benign to hostile—with temperatures approaching 500°F or more. Downhole temperatures limit the choice of explosives that can be used to manufacture shaped charges.

The most commonly used oilwell perforating explosive is RDX, which is limited to temperatures of 340°F [171°C] for a 1-hr exposure in a carrier gun (*left*). HMX is used for temperatures up to 400°F. For more hostile wells, shaped charges made with either HNS or PYX explosives have been used. HNS has a 500°F, 1-hr temperature rating, and PYX has a slightly higher temperature rating. However, both HNS and PYX high-temperature explosives lack the performance of lower temperature explosives (RDX or HMX), although HNS typically demonstrates slightly more penetration than does PYX. The reduction in performance is a consequence of both the molecular chemistry of the explosive and practical manufacturing difficulties in pressing and handling powdered HNS and PYX.

A new high-temperature explosive, called HTX—for High-Temperature eXplosive—has been developed for the perforating industry. This formulation overcomes performance disadvantages that exist with HNS or PYX. Today, HTX is replacing HNS and HMX as the most commonly used high-temperature explosive. There are four commercial HTX charges available and more are on the way. HTX charges are rated at 500°F for 1 hr and have recently been tested to 440°F for 200-hr continuous operation—long enough for most tubing-conveyed perforating (TCP) operations.

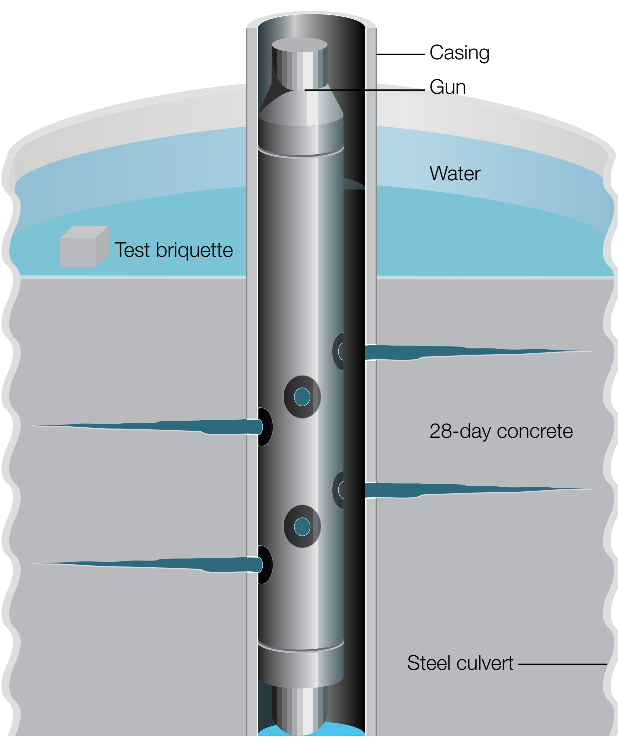
HTX HNS TATB

Scanning electron microscope (SEM) photographs of HPHT explosive powders. HTX *(left)* ***is a processed explosive that combines two high-temperature explosives—HNS and TATB—into a fine-grained plastic-bonded formulation that is suitable for manufacturing shaped charges. The production grades of HNS*** *(center)* ***and TATB*** *(right)* ***are first processed to reduce their particle size by mechanical grinding.***

What is HTX?—The HTX explosive combines two common high-temperature explosives, HNS and TATB, into an improved formulation that has better performance than each component has individually (*above*). TATB is an impact-insensitive, high-temperature explosive with a high-energy output at its optimum pressed density. The military use TATB in missiles because it is extremely safe to handle and very difficult to detonate. HNS is an impact-sensitive, high-temperature explosive that has a lower energy output mainly because it has a lower pressed density. HNS is easier to detonate than TATB. Both TATB and HNS have similar temperature ratings. Many tests with guns loaded with HTX- and HNS-shaped charges have shown no degradation in performance at 500°F for one hour, and up to 460°F for 100 hours. This meets all high-temperature explosive requirements of good time-temperature ratings and good performance.

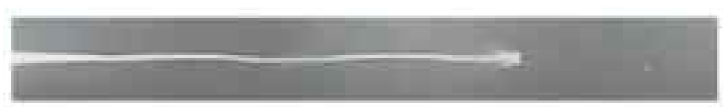
Improvements in performance have been seen not only in terms of statistics, but also in the quality and consistency of manufactured charges (*below*). X-ray photographs show straighter jets indicating greater shaped charge symmetry—a result of pressing a uniform explosive pellet. The latest Enerjet charge, the 2⅛-in. Power Enerjet, HTX, shoots 24.7 in. into an API target compared to 21.6 in. with the HNS at a lower shot density.

More than 40 wells have been perforated with HTX charges in many countries including the Gulf of Mexico, North Sea, Indonesia, Malaysia, Thailand, Argentina and Australia.

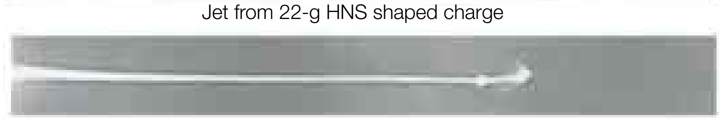


Gun system			API-43 (section 1) penetration, in.	
Type	Diameter, in.	Explosive weight, g	HTX	HNS
Enerjet	2.125	15	24.7*	21.6*
HSD	2.875	19	21.3	20.0
HSD	3.375	22	25.3	21.3
HSD	4.720	21	22.2	21.9

* Shot at 6 shots per foot (spf). HNS charge was shot only at 4 spf.



Jet from 22-g HNS shaped charge



Jet from 22-g HTX shaped charge

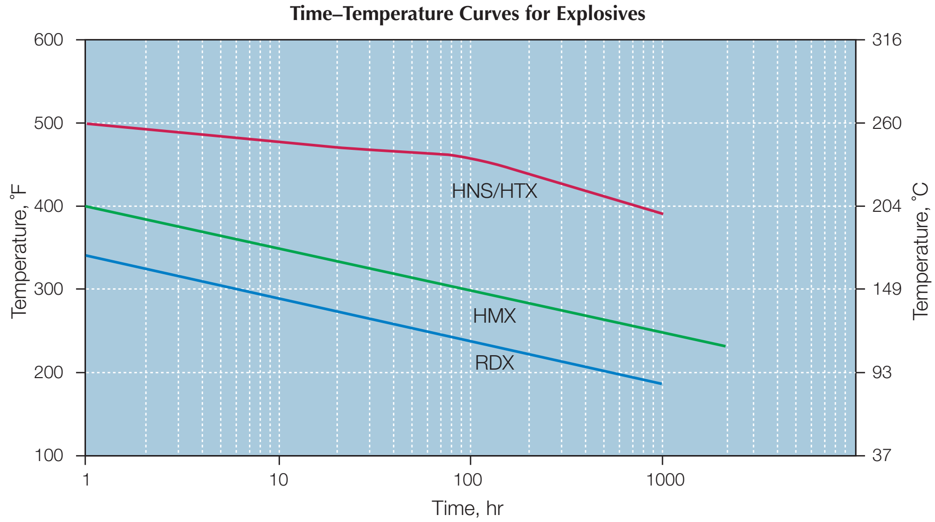
HTX versus HNS penetration performance. Test shots in casing and concrete targets *(left)* ***at ambient pressure and temperature of the recently released commercial HTX gun systems show that the overall performance of HTX explosives is consistently better*** *(top right)* ***than the HNS explosive systems it replaces. The material properties of HTX explosives lead to improved manufacturing and better quality shaped charges. As a result, the explosives are less susceptible to residual mechanical stresses from manufacturing. This leads to higher quality—straighter—and more consistent perforating jets*** *(bottom right).*

HPHT guns—The HPHT perforating challenge is not restricted to explosives, but also to guns and other hardware. Guns must be built to survive powerful detonations but they must also be able to withstand high pressures, and do this at elevated temperatures.

Components used in guns must also be compatible with explosives. For example, plastic components give off gases that react with explosives. Under normal conditions this is not a problem, but as temperatures increase and the exposure time to these temperatures increases, sufficient gas can be given off to cause charges to misfire.

Schlumberger routinely changes plastic components to a more expensive plastic that does not give off gases for HPHT perforating—essentially whenever HTX charges are used. Similarly, greases and lubricants react adversely with explosives. This creates a bigger problem as every component in the guns has to be degreased. Special lubricants have to be used for O-ring seals and hardware has to be protected from corrosion. Job preparation is therefore critical.

The Program to Evaluate Gun Systems was introduced by major oil companies—Agip, Arco, BP, Chevron, Conoco, Elf Aquitaine, Exxon, Mobil, Pogo, Texaco and Unocal. The program establishes procedures for verifying explosives, hardware and accessories such as casing collar locators and adapters. Schlumberger has special guns verified to this standard. The verification process tests equipment to 1.05 times the working pressure rating and 18°F [10°C] above its temperature rating. Systems verified are all for wireline perforating. However, similar testing is carried out on equipment for TCP operations. For HPHT and other critical wells, components are carefully matched to minimize machined tolerances. Thorough testing is undertaken to ensure maximum reliability.



Temperature-time ratings of shaped-charge explosives. To establish a baseline performance, shaped charges are shot at ambient temperature. The performance is based on depth of penetration in a steel target. Then they are shot at elevated temperatures, and the ratings specify that there is no degradation in performance at the elevated temperature. Exceeding the ratings by only a few degrees is sufficient to show signs of outgassing and decomposition resulting in loss of performance. At the next level of degradation the explosive will start to burn. Taking HMX and RDX above 300°F and going well beyond the time limits may result in autodetonation. Other explosives are not known to autodetonate.

Beating the Clock

In designing HPHT perforating, job timing is crucial. Shaped charges must be built and arrive on location on time for optimum performance, and the guns need to be loaded in a timely fashion. Shaped charges are also sensitive to humid conditions as the liners absorb moisture, and will lose performance with exposure.

If the guns are conveyed with wireline, then the length of time that equipment is in the hole before the guns are fired must be taken into account. What if the equipment gets stuck in the hole? What happens if there are problems with pressure control equipment that forces a delay in the job? The time element for these contingencies must be factored into the job design.

If TCP is considered, then the time frame is many hours longer. A whole series of operations must be done before shooting the guns. Frequently, the driller needs the time to set up monobore completion equipment downhole, insert packers, change fluids in the well, rig down the blowout preventer (BOP) stand, rig up the Christmas tree, set up surface lines and hook up separators. Then the guns are shot. The time needed to get downhole and set up downhole test equipment means that the guns can be downhole for several days, and sometimes weeks. For HPHT operations, the whole completion program must be built around the exposure time of the explosives.

At the Limit

Shaped charges have a shelf-life of five years, including a high safety margin. However, the chemical breakdown in a confined explosive produces not only gas, but also heat—the reactions are exothermic. At room temperature, the reaction is so slow that the extra heat dissipates. There is no detonation or explosion, and the charges will perform to specifications when fired.

As the temperature rises, more heat is generated by breakdown than can be dissipated. This is the situation for explosives in a gun system sitting in a hot well waiting to perforate the well after a long series of downhole production tests. If held at high temperature for an extended period, the shaped charge develops hot spots. This leads to more violent events—ranging from outgassing, to low-order detonation or even autodetonation.

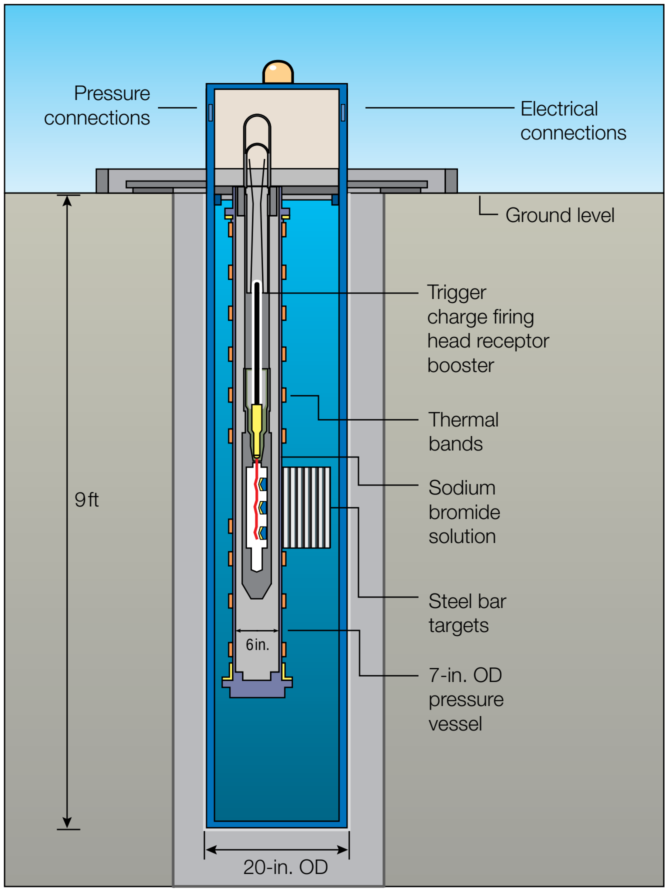
Low-temperature explosives, such as PETN, RDX and HMX are less stable and are more likely to autodetonate or break down violently when taken beyond safe operating limits. High-temperature explosives like HNS, TATB, PYX and HTX are relatively insensitive to extreme temperature and less likely to autodetonate. But they are more likely to burn.

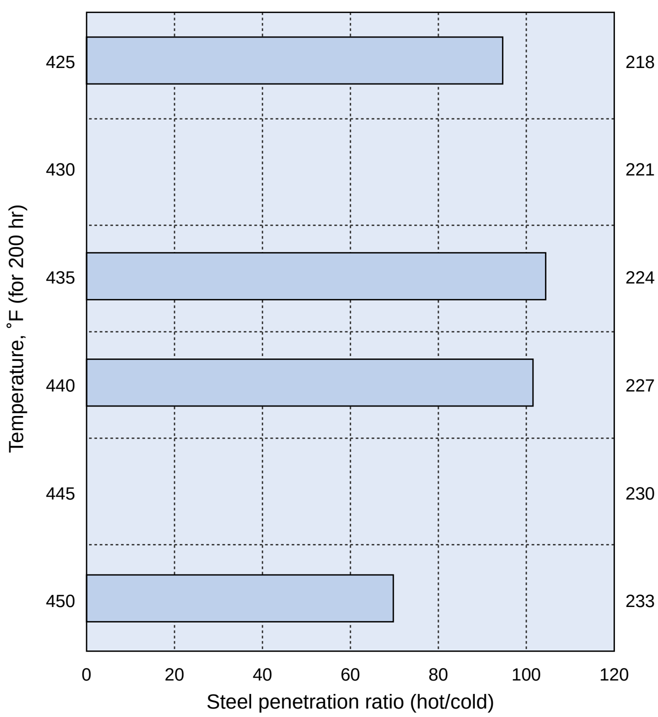
Shaped charges have a safe operating range controlled by temperature and time (*above*). Many tests on explosives at elevated temperatures verify the temperature-time curves used by the perforating industry. Operate below the safe operating limits, and explosives will perform normally. Go above the limit, and the performance degrades rapidly.

Extensive thermal tests have been conducted to establish a temperature and time rating for both HTX and HNS charges. These tests were made using procedures outlined in API gun test procedures.[9] To determine an explosive's thermal rating, test shots are made in steel targets at both ambient and

9. *American Petroleum Institute Test Procedures,* APT-43. Washington, DC, USA: American Petroleum Institute, 1991.

***The effect of temperature on perforating performance. Concrete explosive test pits lined with 20-in. casing** (top) **are used for extended HPHT testing at simulated well temperatures and pressures. Electrical, water and air pressure systems are used to service heaters and pressure pumps. Performance can be measured by the depth of penetration into a control target—steel bar targets—the deeper the better. Temperature ratings are determined by standard API procedures that compare the performance of test shots made in steel targets at both room temperature and specified elevated temperatures** (bottom).*





specified elevated temperatures. The test results show that charges made with HTX and HNS explosive can withstand constant exposure to a temperature of 440°F for up to 200 hr and still give 100% performance (*left*). After that time, thermal decomposition of the explosive begins to affect the performance of the charge by reducing its penetration, and if held long enough at these temperatures, these explosives burn benignly.

HPHT Slickline Perforating

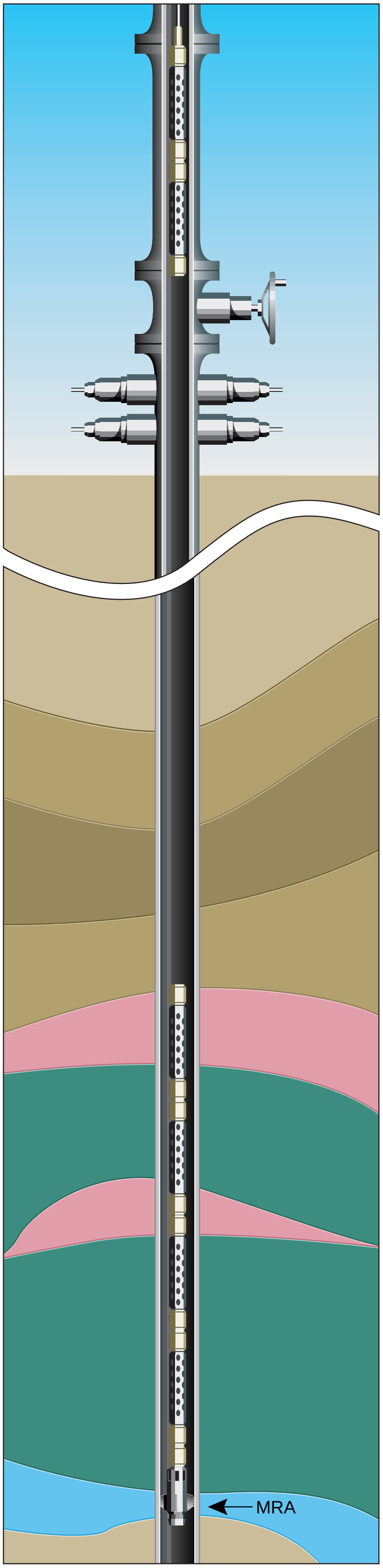
A new perforating technique called the GunStack system has been developed for HPHT wells in the North Sea, where slickline and wireline were the only systems available for deploying guns (*next page, left*). When long reservoir intervals—up to a few hundred feet—are perforated, the weight of the guns required to perforate such intervals exceeds the limit of a single wireline or slickline trip in the hole. This requires multiple gun runs. Normally, only the first set of perforations can be done with underbalanced pressures.[10] However, by stacking the guns with successive trips in the borehole, operators are able to perforate long intervals underbalanced.

The GunStack system was used on five of the Texaco Erskine HPHT development wells. In these wells, a Mechanical Release Anchor (MRA) or a Monobore Automatic eXplosive Release anchor (MAXR) was run in the borehole on wireline with a gamma ray and casing collar locator for depth correlation. The anchor was positioned at the bottom of the formation to be perforated. This provides the platform for stacking the individual gun assemblies, and can also be used to locate memory gauges for recording pressure and temperatures as the well is flowed.

The individual gun assembly sections, charged with HTX explosives, were run in on wireline or slickline to complete the entire perforated interval. The final gun assembly contained a receptor for the firing head. After the entire gun assembly was completed, a Trigger Charge-Hydraulic Delay Firing (TCF-HDF) head was run in and latched inside the top of the gun assembly. Then the slickline was pulled to the surface, and the well was pressurized to initiate the firing head system.

The firing head delay allowed time—30 to 45 minutes—to adjust well pressures to give the desired underbalance conditions. The firing head then detonated the entire gun assembly—perforating the entire interval in underbalanced conditions. After the wellhead pressures stabilized, the slickline was used to retrieve the firing head and gun assemblies from the well.

10. Underbalanced pressures are desired when perforating, because they allow for cleaner holes and better fluid production. See Cosad C: "Choosing a Perforation Strategy," *Oilfield Review* 4, no. 4 (October 1992): 54-69.



The MAXR has an explosive release that retracts the holding slips and allows the MAXR and entire gun assembly to drop into the rathole. This leaves the perforated interval clear and reduces the safety risks of extra slickline runs needed in the borehole. A rathole was not available on any of the Erskine wells because Texaco did not want to risk crossing formation or pressure boundaries with deeper drilling.

HPHT Well Testing

Traditional HPHT well testing uses heavy (kill-weight) mud or clear metal-based brine for the annular fluid. These fluids frequently cause severe operational difficulties, involving high well costs incurred with required tie-back strings, corrosion, and other safety and environmental concerns.[11] Experience shows that the use of heavy mud may cause lost rig time—averaging several days per test—due to excessive gel strengths or barite sag.

High gel strength muds—required to hold heavy barite particles in suspension—can reduce or prevent annular pressure transmission required to operate DST tools, and barite sag (drop-out of particles due to insufficient gel strength) can block off DST tools and TCP gun operating ports.[12] The preparation of the mud systems is therefore especially critical to the success of DST.

One alternative, favored by some operators, is to change kill-weight mud to heavy brines. Clear, metal-based brines avoid the problems of barite settlement, plugging testing valves and pressure transmissibility. On the other hand, these heavy brines are extremely corrosive (zinc bromide), and expensive (cesium formate), and pose personnel safety issues (burns) and environmental hazards (spillage offshore).

Testing with seawater—In the last few years, the use of seawater for underbalanced well testing has improved the operating reliability of DST tools and TCP guns, which in turn provides improved safety and financial returns. A number of operators have moved to this system for both 10,000 psi and 15,000 psi [103 MPa] environments.

Seawater has important advantages over kill-weight fluid. First, it is cheap, readily available and disposable in the offshore environment. Because it's a clear fluid, it allows downhole tools to operate in a friendly environment, avoiding transmissibility and mud-settlement problems (*below*). Finally, it reduces the need to run a tie-back string to surface to protect the casing string which is required when testing with a kill-weight fluid. This is a major cost saving and an important factor in being able to reuse the well as a field development producer.

Seawater also has certain disadvantages. The well must be circulated to seawater, and a substantial inflow test must be conducted prior to running the DST string. Also, there is faster gas migration and the subsequent risk of a gas kick in the well.

Benefits	Disadvantages
• Low-cost annular fluid	• Faster gas migration
• Reduced annular hydrostatics	• Unconventional well kill
• No tie-back liner required	• Multizone testing
• Increased heat dissipation, therefore higher flow rates possible	• More time-consuming (change-out fluids and inflow testing)
• Enhanced data quality	
• Less environmental impact	
• Good pressure response for reliable tool operation	

Cost and benefits of seawater testing. An important reason for changing to seawater is increased operating reliability of DST tools and TCP guns, which in turn provides improved safety and operating efficiency. Safety review studies show that well testing with seawater offers lower risk than with heavy mud.

The GunStack system. This system allows guns to be placed in the well one section at a time to build up a long string. A rig is not required. First, a mechanical release anchor (MRA) is set below the interval to be perforated. Then individual gun sections are stacked on top of the MRA. After perforating, the gun sections and MRA are retrieved one section at a time.

11. Any potential tubing leak with kill-weight fluid would result in a high downhole pressure that would rupture the casing string.
12. DST tools are generally operated by annular applied pressure; pressure applied at surface has to reach the downhole tools to move operating pistons to either open test valves or circulating valves. The pressure loss through the heavy mud systems can result in insufficient pressure reaching the tools to allow proper operation. The settlement of solids from the mud system during the test can result in partial or complete failure of the downhole tools, resulting in poor data or no data being obtained.

Nevertheless, results of a documented hazard-review for seawater testing proved that if recommended precautions are adhered to, the actual well test using seawater is, in fact, safer than using heavy mud.[13]

Pushing the limits—HPHT well tests in the past encountered pressures up to 15,000 psi and temperatures up to 400°F. Current DST tools and TCP guns and accessories have functioned well within these working parameters. However, the pressures and temperatures encountered testing HPHT wells are increasing.

The move to higher pressures and temperatures has resulted in special designs and more rigorous testing to qualify equipment for a particular task. The duration of the DST has also increased: in the past the typical duration was approximately five days; now tests of up to 10 to 14 days are being performed. The choice of elastomer seals used in DST and TCP equipment for extended well testing at elevated pressures and temperatures is critical. Recent qualification tests of the DST equipment have taken place with temperatures of 410°F to 425°F [210°C to 219°C] at pressures of 16,500 psi [114 MPa] for a duration of 13 days.

New ultra-HPHT J-tools being pulled out of the test vessel after qualification testing.

As with all HPHT tests, the preparation of testing and perforating equipment is a key element in the success of the project. Equipment qualification tests following the planned sequence of events, full quality inspection of the systems and assembly by competent personnel lead to a successful operation resulting in good data quality.

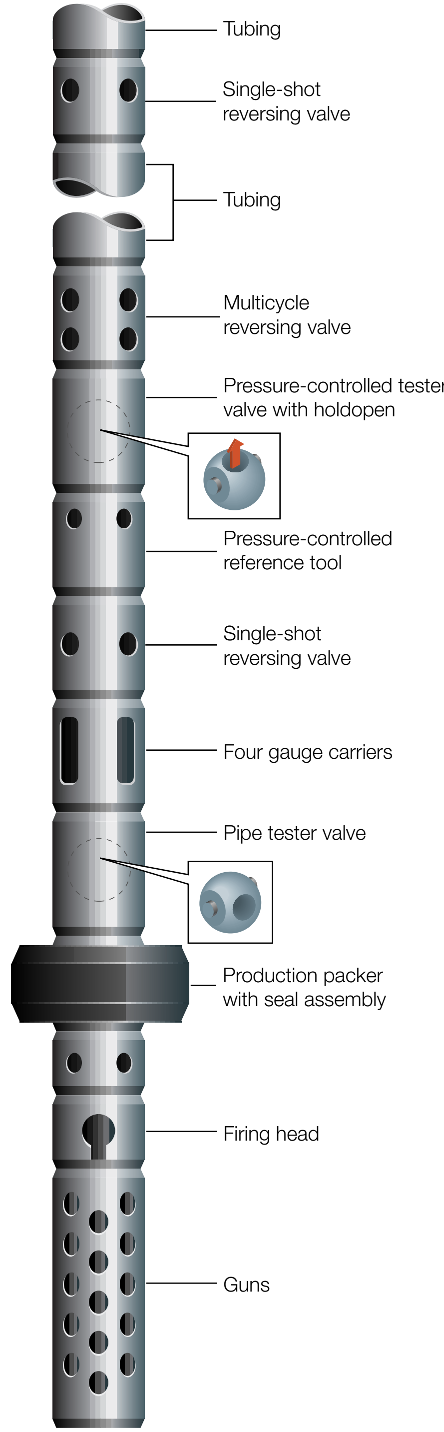
Many HPHT wells have been tested with special tools like the Schlumberger PCT-F Pressure Control Tester string developed specifically for HPHT applications (*right*). This mud-immune tool string provided the DST done for Texaco on the North Sea Erskine field. It can handle up to 29,000 psi [200 MPa] tubing pressure, and 25,000 psi annulus pressure with a 15,000-psi [103-MPa] differential pressure (between the tubing and casing annulus) at 425°F, and is rated for H_2S service. Special versions of these tools can handle differential pressures of up to 17,500 psi at 425°F.

Ultra-HPHT—Wells with temperatures exceeding 425°F, are considered ultra-HPHT, especially those with bottomhole pressures greater than 15,000 psi.

The equipment required for this environment has been simplified to include single-shot tools to allow tubing-pressure testing with single downhole shut-in and circulating well-killing options. The use of multifunction tools is limited because of the reliability of the sliding seals at higher temperatures. Perforating systems are also being modified to meet demands of ultra-HPHT environments.

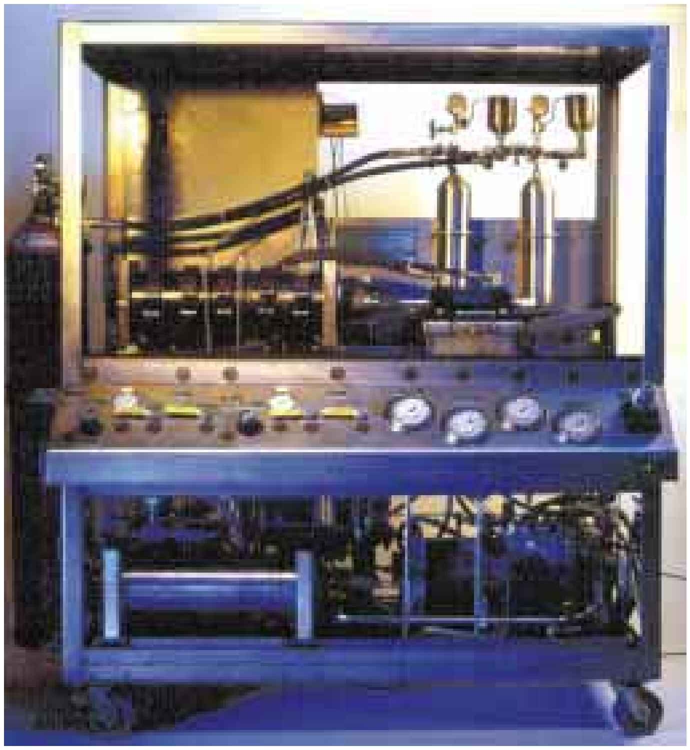
Petroleum companies and service contractors are routinely entering joint studies to more thoroughly assess the operational limits of tools and equipment designed for HPHT service. These studies have led to better definition of equipment specifications as well as retrofitting or re-engineering of tools and tool components to ensure performance in increasingly hostile environments. Developing new downhole testing equipment engineered to ultra-HPHT well conditions requires special test facilities. Facilities at Schlumberger Perforating and Testing (SPT) center in Rosharon, Texas include pressure-testing vessels that can take DST tools up to 36.5 ft [11 m] long at 30,000 psi [207 MPa] and 450°F [232°C] (*left*).

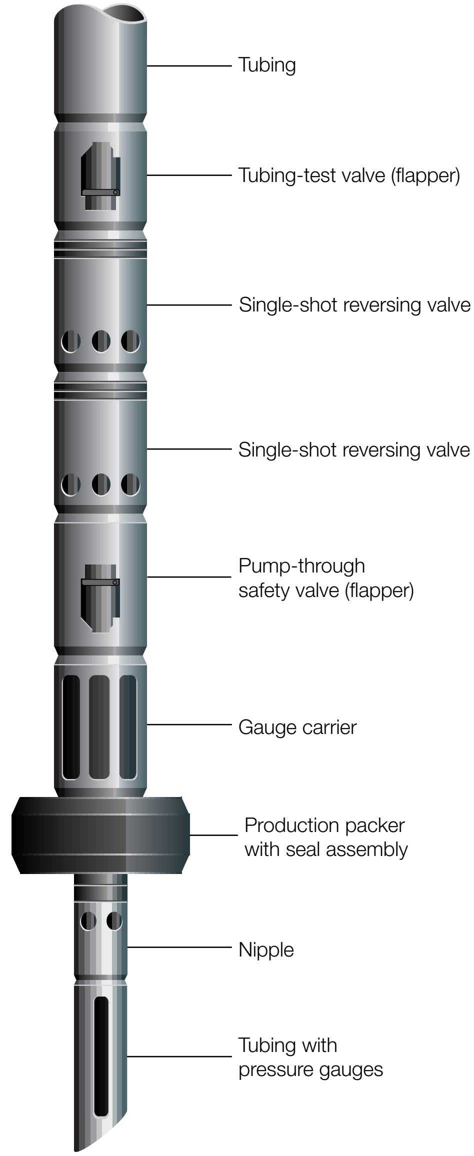
13. Flikkema H, Wiggelman J and Winter K: "Well Testing with Seawater as the Test Fluid," paper presented at the SPE High Pressure/High Temperature Update Seminar, Aberdeen, Scotland, March 14, 1995.



PCT-F string for HPHT DST. The standard HPHT downhole testing tool, rated to 15,000-psi differential pressure at 425°F, was used to test many deep, high-profile wells in the North Sea. These tools are manufactured using H_2S-rated materials. An innovative mud immune system isolates the internal parts of the tools from mud solids, keeping them protected and lubricated in an oil bath. Typically, these tools have been used in wells at HPHT conditions for up to 12 days without failure.

□*Seal test machine. This machine has been built to test different configurations of seals under worst-case fluids situations (oil and completion fluid on opposite sides) and pressure differences. Since elastomers may be compromised by different fluids, they must be tested under different conditions. A well test sequence of operating cycles can be simulated and driven by a computer. Seals are mounted on a mandrel and moved to simulate the tool valve opening and closing with different pressures on either side. Changing pressure and tool motion cycles simulates operation in downhole conditions.*





□*J-string for ultra-HPHT wells. This new tool string was developed for ultra-HPHT applications. The main challenge has been to develop reliable seals for temperatures up to 500°F. The tools are based on single-shot designs for reliability and use advanced seal technology. They are not affected by mud solids and are compatible with both kill-weight and underbalanced fluids.*

As an example of special development to meet operator needs, a new tool string was designed to work in ultra-HPHT wells in the Far East and the North Sea. The main challenge has been to develop reliable seals for temperatures up to 500°F (*above*). SPT has just finished extensive qualification tests of the latest Ultra-HPHT DST tool strings, called the J-string. Based on previous designs, but with completely new seal packages, the J-string consists of simple single-shot tools: a flow-control safety valve, the Pump Through Flapper Safety Valve (PFSV); a test valve for tubing, the Tubing Test Valve (TTV); and a reversing valve, the Single-Shot Reversing Valve (SHRV) (*right*).

The valves are activated by pressuring up on the annulus to rupture disks set to specific pressures. A typical job sequence would consist of opening the TTV after pressure testing the tubing, then shutting in the well with the PFSV at the end of the flow period, and finally, opening the SHRV to reverse out and kill the well.

The Lessons Learned

Oil and gas companies are drilling wells to higher pressures and temperatures, and service companies are being asked to provide logging and completion operations to meet their needs. Each well provides lessons that can improve performance on subsequent wells—essential to long-term financial and technical success. Careful planning from the outset is essential. During logging, and at every phase of the completion operation, considerations must be given to schedule, time management, and contingency strategies, as well as safety issues. Understanding the unique characteristics of each well, the equipment used and the objectives of the operation helps reduce risks and ensure success. One operator compared HPHT operations with conventional wells: "Logging and completing HPHT wells is like a space shuttle mission compared to taking a commercial airline flight. Technology and people make the difference." —RCH