A downhole accelerator, updated source-to-detector spacings, and greater detector efficiency are key features of the new IPL Integrated Porosity Lithology tool that enhance the accuracy of formation evaluation, especially neutron porosity measurements.

The IPL tool’s reduced sensitivity to clays and dolomitization, and improved vertical resolution make it ideal for evaluating thin beds, shaly sands, mixed-lithology carbonates and micaceous sands. Epithermal neutron porosity measurements—not sensitive to fluid salinities—can be made without a chemical source, and they can be corrected for tool standoff.

The tool consists of three sondes (next page):
• The Hostile Environment Natural Gamma Ray Sonde (HNGS) determines thorium, uranium and potassium concentrations with better accuracy, precision and reduced borehole effects than previous tools. It can log twice as fast, thanks to bismuth germanate crystal scintillation detectors, which are more efficient than conventional sodium iodide detectors.
• The Accelerator Porosity Sonde (APS) measures epithermal neutron ratio porosities, the formation capture cross section (sigma), and the epithermal neutron slowing-down time using one thermal and four epithermal neutron detectors. The pulsed 14-million electron volt (MeV) accelerator generates neutrons with enough energy to allow epithermal neutron detection and improves wells site safety by eliminating the need for a radioactive source.
• The Litho-Density sonde measures compensated bulk density and photoelectric factor. Magnetic shielding for the photomultiplier tubes and high-speed electronics improve the stability of the measurement.

The most innovative part of the IPL tool string is the APS sonde, in which an accelerator replaces the chemical neutron source, and the detector geometry is altered to reduce lithology effects, increase sensitivity to gas in shaly reservoirs and reduce borehole effects. It also provides a neutron porosity measurement with vertical resolution comparable to density and resistivity measurements. Understanding the impact of these improvements requires a brief discussion of the neutron porosity measurement.

Traditional neutron porosity tools, such as the CNL Compensated Neutron Log tool, emit 4.5-MeV average energy neutrons from a radioactive source. These neutrons are detected after losing energy in billiard-ball type elastic collisions with formation nuclei. Generally, the count rate at a neutron detector is inversely proportional to the amount of hydrogen in the formation. When the hydrogen content is high, many neutrons are slowed and captured—the count rate will be low and porosity high. When the hydrogen con-
tent is low, fewer neutrons are absorbed and more reach the detector. The count rate will be high and porosity low.

Conventional neutron porosity devices measure the ratio of neutrons counted by a detector close to the neutron source (the near detector) to those counted by one farther from the source (the far detector). This near-to-far ratio is less sensitive to environmental effects than the count rate from a single detector. The ratio is converted to porosity using laboratory calibrations and expressed on logs in porosity units (p.u.) for a limestone matrix.

Interpretation can be complicated by three factors: formation atom density, clays and gas. An increase in formation atom density, which relates to the matrix density of the formation, increases neutron scattering. This reduces the number of neutrons reaching the detector and elevates the measured porosity. In clays, the additional hydrogen content of hydroxyls increases the apparent porosity reading. The combined boost in porosity readings from these two factors is called the shale effect. Another phenomenon, the gas or excavation effect, causes reduced or even negative porosity readings. It occurs when some pore space contains gas, which contributes far less hydrogen to scatter neutrons than does water. Consequently, the count rate is higher and measured porosity lower.

There are two types of neutron porosity detectors—epithermal and thermal—named for the energy levels of the neutrons they detect. An epithermal detector counts neutrons with energies from a few tenths of an eV to approximately 10 eV; a thermal detector counts neutrons with energies around 0.025 eV. Thermal neutron detectors have higher count rates, and so better counting statistics, than epithermal detectors. However, elements in the formation such as chlorine or boron can capture thermal neutrons, causing an inflated apparent porosity reading by lowering count rates. Epithermal neutrons, on the other hand, will not be captured, so an epithermal porosity sonde gives truer readings. The challenge in epithermal neutron porosity detection has been to develop a source that produces enough high-energy neutrons to ensure statistically meaningful count rates.

The APS sonde combines the best of both epithermal and thermal neutron techniques by using an accelerator. The accelerator emits eight times as many neutrons with three times as much energy as the conventional logging source. The increased neutron population makes epithermal neutron detection possible without compromising counting statistics.

Like previous epithermal neutron porosity tools, the APS sonde contains near and far epithermal detectors
The neutron population decreases as the formation atom density increases. At short source-to-detector spacings, the effect is reversed because neutron backscattering dominates. At intermediate source-to-detector spacings, in the crossover zone, the detector is not sensitive to formation atom density. Characterizing the epithermal neutron population in this way guided the placement of the near, array and far detectors shown at the bottom of the figure.

In practice, the near-to-array measurement, which has a vertical resolution of 1 ft [30 cm], is used to determine formation porosity. The near-to-far measurement, which exhibits greater shale and gas effects, gives a response similar to that of the CNL tool. When the density measurement is not used in clean formations, comparing the two responses identifies the gas effect on the near-to-far reading, and flags gas-bearing beds. In shaly formations, the additional boost in apparent near-to-far porosity caused by the increased atom density of clay minerals is used to improve the evaluation of clays.

The epithermal array detectors are used to monitor and correct the effects of tool standoff. The thermal detector determines sigma by detecting neutrons rather than gamma rays, as with conventional pulsed neutron tools. This, as well as detector shielding from the borehole, improves vertical resolution and provides a sigma value relatively free from borehole effects.

A log example from Rogers County, Oklahoma, USA shows how the IPL tool string improves formation evaluation.
in shaly sand reservoirs (left). The left track contains sigma and tool standoff from the APS sonde and the uranium-free gamma ray log from the HNGS sonde. The right track contains the near-to-array and near-to-far porosities; the bulk density and long-spaced photoelectric effect from the Litho-Density tool; and for comparison, a CNL thermal neutron porosity log made during a separate run. In the left track, the IPL sigma curve shows good correlations with the uranium-free gamma ray curve at bed boundaries. The computed tool standoff reads close to zero over the section, indicating good tool string eccentricization and borehole integrity.

The near-to-array porosity and gamma ray logs indicate a gradual upward decrease in clay across two shale intervals, from 730 to 685 ft and 668 to 655 ft. The near-to-far porosity log reads 4 to 8 p.u. higher than the near-to-array reading in the shales, which is to be expected because of the clay’s increased atom density.

Across the same intervals, the CNL thermal neutron porosity log reads higher than the near-to-array porosity (an epithermal measurement) because of thermal absorbers in the formation and increased formation atom density. The effect of thermal neutron absorbers is quantified by the APT Accelerator Porosity Tool formation sigma measurement, which is 26 to 40 capture units (c.u.) over the shale intervals. A correction factor of about –6 p.u. must be applied to the CNL porosity curve to account for the additional thermal absorption, using published sandstone charts. After such a correction, the CNL porosity would be close to the APS near-to-far porosity.

A second log example, recorded in clean sands, shows how the APS sonde can detect gas without the use of a
radioactive source (above). This is especially desirable for wells in which mudcake or borehole rugosity compromise the quality of shallow density measurements, or where tool sticking is a problem.

The IPL curves shown in the right track are density, the near-to-array neutron porosity plotted on a limestone-compatible scale and the near-to-far neutron porosity. The difference between the porosity measurements (blue shading) corresponds to the gas effect and correlates well with the conventional density-neutron separation indicating gas (pink shading). In shaly sands, this technique does not work because the increased formation atom density of shales obscures the gas effect from the far detector. Instead, an APS porosity-sonic overlay, which also correlates with a neutron-density overlay, can identify gas.

Use of APS near-to-array and near-to-far porosities to determine gas in a clean sandstone.

Acknowledgements and Further Reading

For help in preparation of this focus, thanks to Paul Albats, Darwin Ellis and Peter Wraight, Schlumberger-Doll Research, Ridgefield, Connecticut, USA; and Jean-Rémy Olesen, Hugh Scott and James Thornton, Schlumberger Wireline & Testing, Houston, Texas, USA.

In this focus, IPL (Integrated Porosity Lithology, CNL (Compensated Neutron Log), Litho-Density, and APT (Accelerator Porosity Tool) are marks of Schlumberger.

For further reading:

Coiled Tubing Takes Center Stage

For many years, coiled tubing (CT) operations occupied the twilight zone of a fringe service offering niche solutions to specialized problems. However, over the past five years, technological developments, improved service reliability, gradually increasing tubing diameter and an ever-growing need to drive down industry costs have combined to dramatically expand the uses of coiled tubing (above). Today for example, coiled tubing drills slimhole wells, deploys reeled completions, logs high-angle boreholes and delivers sophisticated treatment fluids downhole. This article will look at the technical challenges presented by these services and discuss how they have been overcome in the field.1

When it comes to coiled tubing, there can be few doubters left. What was once a fringe service has moved to center stage in the oilfield theater of operations.

For help in preparation of this article, thanks to Von Cawvey and Lamar Gantt, ARCO Alaska Inc., Anchorage, Alaska, USA; Dave Ackert, Dowell, Montrouge, France; Larry Leising, Dowell, Rosharon, Texas, USA; Bart Thomeer, Dowell, Sugar Land, Texas; David Baillie, Schlumberger Wireline & Testing, Montrouge, France; Mark Andreychuk, Wayne Murphy and Doug Pipchuk, Dowell, Red Deer, Alberta, Canada. In this article, SLIM 1, DLL (Dual Laterolog Resistivity), Litho-Density, SRFT (Slimhole Repeat Formation Tester), RST (Reservoir Saturation Tool), Pivot Gun, Power Pak and FoamMAT are marks of Schlumberger. SPOOLABLE is a mark of Camco International Inc.

1. This article is an elaboration of a speech given by Roberto Monti, President, Schlumberger Dowell: “Cost-Effective Technology Levers to Improve Exploration and Production Efficiency” presented at the Offshore Northern Seas Conference, Stavanger, Norway, August 23-26, 1994.
Drilling Slimhole Wells

Slimhole wells—generally those with a final diameter of 5 inches or less—have the potential to deliver cost-effective solutions to many financial and environmental problems, cutting the amount of consumables needed to complete a well and producing less waste.2 Other benefits depend on what kind of rig drills the well. Compared to conventional rigs, purpose-designed smaller rotary rigs can deliver slimhole wells using fewer people on a much smaller drill site, which cuts the cost of site preparation and significantly reduces the environmental impact of onshore drilling.3

Coiled tubing drilling combines the virtues of a small rig with some unique operational advantages, including the capability to run the slim coiled tubing drillstring through existing completions to drill new sections below. There is also the opportunity to harness a coiled tubing unit’s built-in well control equipment to improve safety when drilling potential high-pressure gas zones. This allows safe underbalanced drilling—when the well may flow during drilling.4

Although there were attempts at CT drilling in the mid-1970s, technological advances were needed to make it viable. These include the development of larger diameter, high-strength, reliable tubing, and the introduction of smaller diameter positive displacement downhole motors, orienting tools, surveying systems and fixed cutter bits. Furthermore, currently available coiled tubing engineering software enables important parameters to be predicted, such as lock-up—when tubing buckling halts drilling progress—available weight on bit, expected pump pressure, wellbore hydraulics and wellbore cleaning capability.5

It was not until 1991 that the first positive results of CT drilling were seen with the deepening of a vertical well in France by Schlumberger Dowell and Elf Aquitaine, and the drilling of two horizonal reentry wells in West Texas, operated by Oryx Energy Co.6 Today, experience has been built up, technology development continues and the number of wells drilled worldwide is set to increase rapidly (above, right).7

More than two thirds of 1994’s expected 150 CT-drilled wells will be injection or shallow gas wells—including steam injection wells in California and pilot wells to relieve pockets of shallow gas in Lake Maracaibo, Venezuela. However, these wells tend to be no deeper than 1640 ft [500 m] and take only one day to drill.

Through-tubing reentry in underbalanced conditions is a category of CT drilling that may grow significantly. Reentering wells without pulling the production string is a cost-effective way of sidetracking or deepening existing wells.

The development of through-tubing, reentry underbalanced drilling is of great interest in the Prudhoe Bay field on the North Slope of Alaska, USA, where operator Arkco Alaska Inc. has an alliance with Dowell to develop coiled tubing technology.8 The alliance has already scored a number of technical and commercial successes. For example, a 600-ft [180-m] horizontal section extended using underbalanced CT drilling, resulted in production three times greater than predicted rates (see “Prudhoe Bay CT Drilling Reentry Well,” next page).

Wells in Prudhoe Bay are drilled in clusters from pads—the same way that they are drilled from platforms offshore. The logistics of supplying and servicing an extreme location are also similar to those encountered in the North Sea. However, with about 1200 wells—of which Arkco operates half—Prudhoe Bay benefits from potential economies of scale.

As with any mature operation, there is a need to extend field life and gain incremental reserves at a cost that reflects today’s oil price. While the primary aim is to devise a strategy for low-cost well redevelopment, a secondary aim is to improve the productivity of horizontal wells by reducing formation damage associated with conventional overbalanced drilling.

In line with these objectives, candidate wells for CT drilling are divided into two classes:

• the replacement of waterflood wellbores that have corroded because of the high carbon dioxide content of the water
• horizontal sidetracks to replace conventional gravity drain wells, tapping new zones and improving recovery.

Four years ago, Arkco began sidetracking the existing wells using conventional Arctic rigs. The corroded tubing was pulled and new well sections drilled. Arkco realized that this was going to be a necessary procedure for the future, but that conventional technology was going to incur considerable costs. Using a traditional Arctic rig to enter a Prudhoe Bay well, drill the sidetrack and run a completion costs over $1 million—as many as 800 sidetracks may be needed in Arkco’s Prudhoe Bay unit.

The goal of the Arkco-Dowell alliance is to develop a lower cost alternative to conventional rig sidetracks. To date, promising results show that CT sidetracks can ultimately be performed at half the cost of rig operations. (continued on page 14)


OIlfield Review
Drilled in 1980, Well 2-16 had been worked over a number of times but despite two matrix stimulation treatments had become a poor producer. As such, it was shut in 50% of the time. To alleviate this, operator ARCO decided to use underbalanced CT drilling to exploit a horizontal section of the relatively poor-quality reservoir—pay zone permeability is about 50 millidarcies (md).

A rig was used to pull the completion hardware and sidetrack out of the existing casing in the deviated well, drilling until the wellbore was at 90° and had just entered the target formation. Prior to the start of coiled tubing operations, the rig was used to set a 7-in. liner and install a 4 1/2-in. production string including gas-lift hardware.

With 2-in. CT through the 4 1/2-in. production tubing, a 3 3/4-in. diameter open hole was drilled. Artificial lift was used to reduce the hydrostatic pressure of the mud in the annulus and therefore the bottomhole pressure during drilling, creating an underbalanced situation.

Nearly 600 ft of horizontal section was drilled through two target sands separated by a thin shale layer. Drilling proceeded smoothly until a measured depth of 11,933 ft [3637 m] was reached; at that point, penetration slowed and the hole became sticky.

There had been indications of an acceptable production rate from the interval already drilled so the well was put on production. Short-term testing yielded some 3500 barrels of oil per day (BOPD), about three times that expected from a conventionally drilled horizontal well in the area. The well was completed barefoot for an extended test period with a view to running a slotted liner later (above). From the start of CT drilling operations to first production took 11 days.

The openhole size was limited by restrictions in the production string and 3 3/4-in. natural diamond bits were employed. Above the bit, the bottomhole assembly (BHA) included:

- a 2 7/8-in. motor with a bent housing, a check valve and a nonmagnetic collar
- a SLIM 1 measurements-while-drilling (MWD) system and gamma ray log
- an orienting tool to change the tool face downhill and steer the drilling—needed because it is not possible to rotate the coiled tubing.

The Dowell orienting tool is actuated by pulling...
off bottom slightly and reducing the rate of drilling fluid pumped through it to create a pressure differential of at least 1000 psi inside the tool’s indexing section. Then, by increasing the pump to the maximum rate allowed by the motor, the tool face is changed by a 30° increment.

However, once drilling starts, reactive torque—which tends to twist the BHA clockwise—will alter the actual orientation of the BHA. To allow for this, before the tool angle is adjusted the effect of reactive torque is measured by simply tagging bottom at the intended weight on bit (WOB) and rotation speed. Once the extent of reactive torque has been measured, the tool face may be altered accordingly. Reactive torque may also be used to fine-tune the tool face—the higher the WOB, the greater the reactive torque.

A key element of underbalanced drilling is the deployment of the drilling assembly into a live well. To do this, the BHA was divided into three segments (next page, right), the longest of which was just over 30 ft [9 m]. These were introduced
Bottomhole assembly divided into three segments, each short enough to be run in hole using the lubricator system.

The well is now producing about 4000 BOPD—by comparison, the best well in the area had previously produced 1200 BOPD.

For ARCO, the well helped prove a number of technologies: support equipment was field tested; deployment procedures and equipment were shown to be effective for long tool lengths; the Anadrill SLIM 1 MWD and gamma ray logs provided reliable directional surveys; steering with the Dowell orienting tool proved effective; and the responses of the three bent-motor BHAs run during the job helped to better indicate the directional capabilities of CT drilling.

Running in hole for Prudhoe Bay CT drilling jobs. The first of the three BHA sections was installed inside the lubricator in easily handled subsections no longer than 18 ft [5 m]. With the well’s master valve closed, the lubricator—containing the BHA connected to the coiled tubing—was made up to the top of the wellhead blowout preventers (BOP) and pressured up to wellhead pressure. The valve was then opened and the first BHA segment run in hole using the coiled tubing.

The 2 7/8-in. gripper pipe rams of the double-ram BOPs and the annular BOPs were closed around the BHA to ensure isolation from wellbore pressure. After the pressure inside the lubricator was bled down, the CT was disconnected and the lubricator was detached from the BOP and lifted off.

The second segment was then installed into the lubricator with enough protruding below to allow its make-up to the joint of the first section left protruding above the annular preventer. Hydraulic tongs were used to tighten the connection between the first and second segments and the lubricator was stripped over the joint and made up once again above the BOPs. With the pressure equalized, the annular and gripper BOPs were released and the BHA run in hole. The third segment was added in a similar way.
The second objective of improving productivity employs underbalanced drilling in new, low-permeability zones. Underbalanced drilling offers the opportunity to minimize formation damage incurred during drilling and to optimize the productivity of the completion. As the first case study shows, the technique does seem to offer some benefits.

Underbalanced drilling sometimes helps alleviate other problems like differential sticking. Oil production during drilling helps the string slide better and aids hole cleaning by carrying cuttings to surface more effectively.

Drilling and directional control equipment for through-tubing CT drilling is largely proven, although systems require continued refinement and improvement. As higher build rates are achieved, slimmer CT directional tools may be necessary to accommodate through-tubing operations in some existing wells.

Bit selection must match the geology, motor specifications and the maximum allowable pumping pressure, while at the same time offer viable rates of penetration with less weight on bit and higher rotation speeds than is normal. Polycrystalline diamond compact (PDC) bits are commonly used in medium-to-soft formations, and thermally stable diamond or natural diamond bits for harder formations.

A positive displacement mud motor is used to rotate the bit. Most CT drilling is performed using motors with a diameter less than 3½ in, such as Anadrill’s 2 7/8-in, PowerPak steerable motor.

For directional control, Dowell uses an orienting tool operated by mud-pump flow rate to alter the tool face. Anadrill’s SLIM 1 MWD system coupled with a gamma ray log is used to monitor the wellbore’s progress through the formation in real time. Data are transmitted to surface using conventional mud-pulse techniques.

There are systems available that use wireline inside the coiled tubing. These can transmit directional data to surface at a higher rate than mud-pulse tools and hold the potential to provide electrical power to activate downhole tools. However, installation and maintenance of the cable increase drilling costs.

In case the bottomhole assembly gets stuck, a hydraulic or shear release tool allows the coiled tubing string to be disconnected and recovered in one piece. A flapper valve just above the disconnection point prevents any wellbore pressure from entering the CT string.

It would, however, be wrong to say that all the mechanical challenges of drilling have been met. For example, transmitting sufficient weight to the bit can be problematic. Since it is impossible to rotate the CT from surface, it is often difficult to overcome axial friction along the length of the CT, particularly in deviated wells. Because of this, the weight applied at surface frequently becomes “stacked up” against the borehole wall instead of reaching the bit. This phenomenon is well known for slide drilling, but is exacerbated by the flexibility of the CT and increases with the sidetrack angle.

Numerous solutions have been proposed, including hydraulically activated “crawlers” that grip the borehole wall and pull the CT into the hole, and hydraulic thrusters that apply weight by pushing on a slip joint or piston just above the bit. As yet, neither system offers a complete solution.

Another area under intense development centers on using CT techniques to mill a window in the existing casing and sidetrack out of the well. In 1992, ARCO Oil & Gas was involved in a West Texas well where coiled tubing was used to plug back the well, mill a window and drill new wellbore. The challenge today is to achieve all this through tubing.

A conventional kick-off technique uses a whipstock plug—a long, inverted steel wedge that is set in the wellbore and diverts the drillstring toward the side of the hole to initiate a sidetrack. To achieve this through tubing on Prudhoe Bay wells requires a whipstock that will pass through the 3½-in. minimum restriction inside the tubing but sit firmly and reliably inside the casing below that has an inside diameter (ID) of more than 6 in. So far, this has proved difficult to achieve. Various solutions have been proposed and are being field tested. One system uses an articulated whipstock that unfolds once it has passed through the tubing, enabling it to reach across larger ID casing.

10. The Danish Underground Consortium is a consortium of Mærsk Olie og Gas, Shell and Texaco. Mærsk is the operator.
11. Externally upset equipment has its tool joints on the outside, irregularly increasing the outside diameter of the completion string.
Delivering Coiled Tubing Completions

The availability of larger CT—up to 3½-in. diameter—has sparked interest in another major advance: underbalanced coiled tubing completion. Like CT drilling, this uses the coiled tubing unit’s well control capability to safely run the completion. There are two basic CT completion options.

One choice is externally upset completion strings, which incorporate traditional completion hardware like gas-lift mandrels, landing nipples, sliding sleeves and safety valves in the CT string. To safely run these strings into a live well, a window system may be employed. This window allows the BOPs and the injector head to be separated, giving enough room for the coiled tubing to be cut and the various completion devices installed. While this is happening, the annular and ram BOPs seal off any pressure from the well below (below).

A more rapidly deployable alternative is to use compact completion equipment that may be placed inside the tubing itself.

More it is liable to suffer from fatigue during horizontal drilling.

But another important parameter affects CT durability: the internal tubing pressure at the time of bending. The higher the pressure, the greater the fatigue. This, too, is related to the tubing diameter because internal pressure depends on the flow rate required to drive the downhole motor, which is a fixed value depending on the motor type and diameter. Larger diameter tubing can achieve the required flow rate at a lower internal pressure than its smaller counterpart, thus reducing fatigue.

In short, there is an optimum tubing size for any flow rate, and therefore for any given motor. All these factors, and many others, are taken into consideration by Dowell’s design software when planning the drilling program and choosing the bottomhole assembly and CT type. To date, the reduced life expectancy of coiled tubing larger than 2½ in. limits its use for CT drilling in horizontal wells.

Delivering Coiled Tubing Completions

1. The availability of larger CT—up to 3½-in. diameter—has sparked interest in another major advance: underbalanced coiled tubing completion. Like CT drilling, this uses the coiled tubing unit’s well control capability to safely run the completion. There are two basic CT completion options.

2. One choice is externally upset completion strings, which incorporate traditional completion hardware like gas-lift mandrels, landing nipples, sliding sleeves and safety valves in the CT string. To safely run these strings into a live well, a window system may be employed. This window allows the BOPs and the injector head to be separated, giving enough room for the coiled tubing to be cut and the various completion devices installed. While this is happening, the annular and ram BOPs seal off any pressure from the well below (below).

3. A more rapidly deployable alternative is to use compact completion equipment that may be placed inside the tubing itself.

Delivering Coiled Tubing Completions

The availability of larger CT—up to 3½-in. diameter—has sparked interest in another major advance: underbalanced coiled tubing completion. Like CT drilling, this uses the coiled tubing unit’s well control capability to safely run the completion. There are two basic CT completion options.

One choice is externally upset completion strings, which incorporate traditional completion hardware like gas-lift mandrels, landing nipples, sliding sleeves and safety valves in the CT string. To safely run these strings into a live well, a window system may be employed. This window allows the BOPs and the injector head to be separated, giving enough room for the coiled tubing to be cut and the various completion devices installed. While this is happening, the annular and ram BOPs seal off any pressure from the well below (below).

A more rapidly deployable alternative is to use compact completion equipment that may be placed inside the tubing itself.

Delivering Coiled Tubing Completions

The availability of larger CT—up to 3½-in. diameter—has sparked interest in another major advance: underbalanced coiled tubing completion. Like CT drilling, this uses the coiled tubing unit’s well control capability to safely run the completion. There are two basic CT completion options.

One choice is externally upset completion strings, which incorporate traditional completion hardware like gas-lift mandrels, landing nipples, sliding sleeves and safety valves in the CT string. To safely run these strings into a live well, a window system may be employed. This window allows the BOPs and the injector head to be separated, giving enough room for the coiled tubing to be cut and the various completion devices installed. While this is happening, the annular and ram BOPs seal off any pressure from the well below (below).

A more rapidly deployable alternative is to use compact completion equipment that may be placed inside the tubing itself.
CT Drilling Offshore Denmark

The first successful North Sea CT-drilled well employed “just balanced” drilling to deliver 3½-in. open hole.

This is the first of a number of wells to determine the usefulness of CT drilling for the Danish Underground Consortium’s North Sea wells. Some 3309 ft [1008 m] of horizontal 3½-inch wellbore was successfully drilled into the chalk formation using 2-inch coiled tubing at a maximum deviation of 89°. This was more horizontal length than was planned and the measured depth at the completion of the drilling was 11,000 ft [3352 m].

For this first attempt, the coiled tubing unit was located on the jackup rig Mærsk Endeavour, which drilled to approximately 7690 ft [2344 m] measured depth where the 95/8-in. casing was set and cemented. The casing shoe was drilled out and a 4½-in. completion string was run to just below the casing shoe.

Drilling was restarted using 2-in. coiled tubing (above). Although CT drilling took 19 days for the 3309-ft section, most of this time was spent in the first few hundred feet where unexpected, Danish drilling. The vertical (top left) and horizontal (bottom right) plans of the Gorm field CT-drilled well using the Dowell orienting tool in conjunction with Anadrill’s SLIM1 MWD system. Drilling using 2-in. coiled tubing commenced just below the completion, at 7690 ft. The angle was built to approximately 85°, which was then held until the bottom of the reservoir was approached when the inclination was increased to 89°. The total horizontal displacement from the rotary table was 4766 ft. The azimuth was built from 160° to a maximum of 203° before turning back to the left.

The photograph (top right) shows the CT injector head in the rig’s drawworks. The photo at the bottom left is an aerial view of the CT equipment on the deck.
Chert beds were encountered. Several bits were used in this formation including natural diamond and PDC bits, both of which were ineffective. Diamond speed mills and finally small tricone insert bits were used to drill the last feet of chert to get into the reservoir. While drilling through the softer formation in the reservoir, a PDC bit was used and it took just 7 days to drill the final 2600 ft [792 m].

The intention had been to drill the reservoir underbalanced. However, true underbalance proved difficult to maintain as the hole tended to slough, creating sticking problems. Therefore, most of the drilling took place with the gas lift creating a “just balanced” situation. This was aided by a surface read-out gauge that relayed the pressures at the bottom of the completion tubing. However, the final 1000 ft [300 m] of well were drilled underbalanced.

Reservoir fluids entering the mud were handled at surface using conventional surface test hardware—such as chokes, separators and heat exchangers. This is an element of the operation that operator Mærsk believes needs further development.

Both 27/8-in. and 31/8-in. motors were employed to good effect. Since it was necessary to steer along the entire 3300-ft section, several trips were made to adjust the motor angles.

As with the Alaskan wells described on pages 11 and 19, directional control was achieved using the Dowell orienting tool in conjunction with the SLIM 1 system. The orienting tool worked well, although it was sometimes time-consuming. When gas lift was used during drilling, the mud in the annulus became lighter than the mud inside the CT. Consequently, it took longer than usual to orient the tool face because each time the pumps were shut down, the heavier fluid flowed to equalize pressure with the lighter before downhole hydrostatic pressure stabilized.

SPOOLABLE coiled tubing completion equipment developed by Camco Products & Services is flexible enough to bend over the CT reel (above). The whole completion string may be assembled and connected to the CT at the manufacturing plant or workshop, increasing operational efficiency and safety while reducing environmental hazards. Once on location, the CT and completion hardware are simply spooled off the reel over the gooseneck and run into a live well with standard equipment.12

As with other coiled tubing-related issues, ARCO is using CT in Prudhoe Bay to broaden its completion options. ARCO ran the first completion using 2-in. coiled tubing in 1990. Today, 31/2-in. tubing is used (see “Combining CT Drilling and Reeled Completion,” page 19) and the company reports that running times for installing such completions are being cut with each job.13

For example, six Alaskan injector wells were recently completed using 31/2-in. coiled tubing. All the wells were about 9000 ft [2740 m] deep and all the completions included a 10-ft [3-m] seal assembly, landing nipples and a tubing hanger. On-location time improved dramatically with each job. The first well took 40 hours, the last just 25 hours.


October 1994
Logging and Perforating with Coiled Tubing

Like CT drilling, coiled tubing logging has come of age only in the 1990s. One of its key selling points revolves around the stiffness of the tubing, enabling penetration into horizontal and high-angle sections. Additionally, wireline inside coiled tubing offers the potential to pump fluids downhole and log at the same time.\(^{14}\)

Successful application of CT logging requires the reliable interface of the coiled tubing and logging units. Wireline log acquisition systems are driven by depth. To supply real-time depth data for CT logging, an encoder relays a depth signal from the injector head into the logging unit through a dedicated interface (above). This depth information is also used by the Dowell monitoring system that records coiled tubing and pumping parameters.

A newly designed coiled tubing head is now available to attach the logging tools to the CT. The modular head secures the cable in place, allows fluid to be circulated through a dual flapper valve during logging, and provides for electrical connection and mechanical release.

Fundamentally, a CT logging operation is not much different from its wireline counterpart. However, the tubing is stiffer than wireline so it tends not to stretch as much, and the injector head provides a stable speed. Coiled tubing may deploy most logging tools, as long as they are slim enough to fit inside the wellbore. The scope of slim-hole logging—whether the wells were drilled using CT drilling or conventional techniques—has been limited by the availability of slimhole hardware. Now that scope is broadening.

Originally, slimhole logging tools were developed to gather petrophysical information in deep, usually hot, wells that required extra strings of casing, thereby reducing the final well diameter. Alternatively, they were needed to log through drillpipe under difficult hole conditions. These rigorous environments ensured that such tools were of necessity simple, reliable and rugged.

Today, CT drilling and slimhole wells are being used, or contemplated, for a broader

---

Combining CT Drilling and Reeled Completion

Well drilled overbalanced and completed using 2-in. and 3 1/2-in. coiled tubing, respectively.

Like the well described on page 11, Well 18-23A is operated by ARCO in the Prudhoe Bay field. This time, the well was not only sidetracked using CT drilling, but also completed using 3 1/2-in. coiled tubing (right).

A rig was used to pull the completion and sidetrack out of the old wellbore, drilling toward the new well location but stopping when a horizontal inclination was achieved in the target zone. CT drilling was then used to drill horizontally through the pay zone. Because the rig did not install any gas-lift hardware, the well was drilled overbalanced. The result was a horizontal section some 800 ft [240 m] long with a 4 3/4-in. diameter.

With 2-in. coiled tubing and conventional CT well control equipment, a 2 7/8-in. preperforated, plugged liner was run and hung off in a 3-in. by 5 1/2-in. packer inside the 5 1/2-in. liner. The completion assembly—which included an indexing mule shoe, a locator seal assembly, landing nipple, two gas-lift mandrels and a second landing nipple—was installed onto the 3 1/2-in. CT and then pressure tested. The assembly was then run in hole and stabbed into the completion packer.

The well was placed on production at 3900 BOPD and that rate subsequently increased to 4600 BOPD—compared to 1200 to 1500 BOPD from a nearby conventional well.

To date, coiled tubing is most often used for production logging, sometimes combined with CT-conveyed perforation. As usual, the production logging tool string measures a range of parameters, including spinner revolution, fluid density, pressure and temperature; a gamma ray tool and a casing-collar locator are also included.

Production logging of high-angle or horizontal wells presents a tremendous challenge. For example, there may be stationary fluid, back- or cross-flow—some zones may be accepting fluid produced by other zones. Only a fraction of the fluids “seen” by the tools may actually be moving. To overcome these difficulties, the production logging program must be sufficiently flexible to respond to changes in well behavior. A typical CT production logging job involves the following steps:

• Rig up and pressure test equipment.
• Run in hole stopping to check CT weight.
• Correlate depth with a reference log using casing-collar correlation and gamma ray logs—vital because the CT tends to form a helix in the well.
• Log the well while shut in.
• Log in both directions with typically four passes at say 40, 60, 80 and 100 ft/min.

range of well types that have more sophisticated needs. To meet these needs, many standard and new high-technology imaging tools have been reengineered to operate in more restricted boreholes. For example, the DLL Dual Laterolog Resistivity tool and the combinable Litho-Density tool have been repackaged with diameters of 2 3/4 in. and 3 1/2 in., respectively.

In addition, new instruments have been designed, such as the SRFT Slimhole Repeat Formation Tester tool for sampling the formation, the sourceless RST Reservoir Saturation Tool, and the Pivot Gun for slimhole perforation. Combinability of tools and coiled tubing logging capability are standard features.
[12, 18, 24 and 30 m/min] with the well flowing. The intervals between data collection may be decreased or the logging speed increased.

- Observe well anomalies, making some stationary log measurements to look for backflow.
- Pull out of hole.

Another production-related CT logging service employs pulsed neutron logs and borax solution. The borax is pumped into the CT-production tubing annulus at a pressure above that of the reservoir but below the fracturing pressure. Because borax is more effective than reservoir fluid at slowing neutrons, pulsed neutron logs can trace where it has gone and hence confirm the location of a suspected channel and indicate high-permeability zones. With additional openhole log data, initial reservoir saturation information may also be derived.

After the production profile of a well and potential hydrocarbon saturated zones have been identified, reperforation using CT-deployed guns may be necessary (see “CT Logging and Perforation in Alaska,” right).

**Matrix Treatment**

The most traditional of all coiled tubing services is the delivery of fluids downhole. No account of the practical uses of coiled tubing would be complete without describing at least one pumping application—a role that has become more important with the proliferation of horizontal wells.

As in other areas, increasingly sophisticated pumping services are available. For example, a relatively new matrix treatment tackles an old problem, diversion. Unless a stimulation fluid is successfully diverted into the areas that most need it, the fluid will channel into the high-porosity, high-permeability formation that least requires improvement. Horizontal wells generally have a much longer reservoir section than their vertical counterparts, so the problem of diversion is proportionally more difficult. To compound this, few horizontal wells are completed in a way that allows even rudimentary zonal isolation.

Traditionally, diverting materials—like calcium carbonate or rock salt—are introduced to temporarily plug the zones of the formation taking most fluid, redirecting flow to more needy parts of the wellbore. But the plugging must be reversible—by dissolution in acid or reservoir fluids—and leave the formation undamaged. Not an easy criterion to meet.

---

**CT Logging and Perforation in Alaska**

Coiled tubing logging located zones offering potential additional production that were perforated using CT-deployed guns.

---

So far, ARCO’s sector of the Prudhoe Bay field has run 12 coiled tubing logging jobs in eight highly deviated or horizontal wells. The aims of these jobs were to obtain the production profile and verify the presence of channels using pulsed neutron logs. Where necessary, coiled tubing-deployed perforating guns were used to open up potentially productive zones.

Well 15-07A exemplifies the jobs performed in Alaska. It is a virtually horizontal well completed with a 4 1/2-inch slotted liner at a total vertical depth of 8761 ft and a measured depth of 13,545 ft.

Drilled as a sidetrack to a much older well and completed earlier this year (April 1994), the well
was found to be producing lower rates of oil at a much higher gas-oil ratio (GOR) than was anticipated. Coiled tubing logging was used to determine the source of the gas production, to identify any nonproductive intervals and to tie in with previous logs using gamma ray, casing-collar locator and temperature logs.

Gas entry was located using the temperature log (previous page). Then, using pulsed neutron logs in conjunction with borax injection, the gas-oil contact was located and a possible channel behind the 7-in. liner indicated (right).

Finally, CT was employed to perforate the 7-in. liner to contact potentially bypassed intervals. Some 20 ft [6.5m] of 2\1/8-in. guns were run in hole and detonated using a hydraulic firing head. Depth was correlated using a tubing-end locator.

The CT perforation used a new pressure-activated firing head. It allows circulation and reverse circulation before and after firing the guns. An operating piston is attached to a sleeve that locks the firing pin in place. When sufficient differential pressure is established across this piston to sever the shear pins that hold it in place, the firing pin is driven into the detonator by the pressure.

To establish this differential pressure, a ball is pumped down the tubing to form a pressure seal in the head. The ball diverts pressure to the underside of the operating piston, building up the pressure that severs the shear pins and detones the guns. Up to twelve 500-psi shear pins can be incorporated into the head.

A key advantage of coiled tubing is its higher tensile strength than wireline. So, when it comes to perforation, there is no practical weight limit to the number of guns that can be run. The main constraint on gun length is the height of the lubricator. However, the downhole safety valve may be closed and successive sections of guns run into the well and connected together.
A successful alternative employs stable foam that is generated in the “thief zones” as a diverter. Alternating stages of acid and the foam—made from water containing surfactant and nitrogen—are pumped.15 The diverter enters the formation that is taking fluid. Some 10 minutes or so are allowed for the foam to build up and, when pumping restarts with a new acid stage, a pressure increase is seen at surface as the foam ensures the acid enters some other part of the formation. Pressure gradually decreases until it is time to pump the next foam stage. Once production starts, the foam breaks down and flows out of the well leaving undamaged, acidized formation.

Coiled tubing is an ideal way of targeting the delivery of the treatment fluids to the formation, particularly in horizontal wells. Furthermore, because the volume inside CT is relatively small, a flexible treatment program may be employed, based on pressure responses observed during pumping (see “Matrix Treatment in Alberta,” right).

Looking to the Future
This tour of coiled tubing applications has concentrated on events in Alaska and the North Sea. But all over the world operators and service companies are using coiled tubing for a range of tasks that would have been inconceivable only a few years ago.

As larger diameter tubing and the availability of hardware needed to handle it become more widespread, even more services will be devised and current ones improved. For example, conventional directional CT drilling techniques will be replaced by geosteering. CT completion systems will be refined and costs reduced. Logging with CT will become more extensive. Rigless well workover operations will become increasingly widespread.

If they weren’t so busy coping with the present, coiled tubing engineers could look forward to the future with excitement. —CF

---

the coiled tubing was gradually pulled out of the hole—at about 10 ft/min (3 meters/min)—from the toe to the heel of the well. After pumping a diverter stage, the pumps were shut down for 10 minutes before the next acid was pumped.

Midway through the job, the well went on a vacuum. To maintain a positive surface pressure and gain maximum information about the treatment, it was necessary to reduce the bottomhole hydrostatic pressure. The foam qualities of the two fluids were adjusted so that the diverter was 70% and the acid 25%.

Surface pressure was plotted throughout the job to assess the success of the diversion stages. Once all the acid was pumped, the CT was run back to the toe of the well and the postjob flush was pumped to break up the foam in the wellbore and hasten the cleanup.

The well was opened up to flow with the gauges still on bottom. During cleanup, the well flowed spent acid and an estimated 21,000 gal (80 m³) of mud filtrate. Suncor believes that this mud came out of the natural fractures of the formation. Once the well was cleaned up, the well pressure and temperature were logged using the memory gauges (above).

The well is currently waiting to be brought into production, but Suncor estimates that the acid treatment reduced the pressure drop across the reservoir by 435 to 725 psi. By comparing this to pretreatment pressure and rate information, additional gas deliverability due to the treatment is likely to be 2 to 6 million scf/D.

1. Foam quality is defined as the ratio of the volume of gas in the foam to the total volume of foam—expressed as a fraction or as a percentage. So a nitrogen-water foam of 75% quality contains 75% by volume nitrogen and 25% by volume water (at downhole conditions).
Permeability—the ease with which fluids flow through rock—has long been identified as one of the most important parameters controlling reservoir performance. Yet it is one of the most difficult to measure. If permeability were the same at all places and in all directions—homogeneous and isotropic—then measuring the flow through a sample of rock would reveal its value. However, rock type and grain size may vary through a reservoir leading to variation in permeability. To complicate matters further, measuring permeability parallel to layers of sedimentary rocks may give a different value to a perpendicular measurement (left). Therefore permeability measured at the same point in the horizontal direction, \( k_h \), may be different from permeability measured in the vertical direction, \( k_v \). This directional dependency on any type of measurement is called anisotropy. A measurement, such as vertical permeability, in the same direction at two distinct points may also be different. Positional dependency is called heterogeneity (next page, bottom).

The anisotropic nature of permeability can affect any process in which a density difference exists between fluids, for example primary production below the bubblepoint, gas cycling, gas or water coning, waterfloods...
and many steam processes. It can also influence injection and production rates if the anisotropy is severe. Completion and treatment strategies must also take anisotropy into account—for instance placing perforations near oil-water or oil-gas contacts.²

The experience of British Gas Exploration & Production Ltd. emphasizes the importance of anisotropy. The company discovered six small satellite fields of the Morecambe gas fields in the Irish Sea (above).³ The Triassic Sherwood sandstone reservoirs found there are common to all the Morecambe fields and are typically 300 ft [91 m] thick. Underlying this is an extensive aquifer. Most fields have high permeability—horizontally 200 md, but with individual layers up to 18 darcies. Faults close the reservoirs on one or two sides, with dipping beds sealing the remainder.

To predict the rate and direction of water influx into the reservoir, vertical permeability must be measured. The amount of water influx will determine reserves and, therefore,

---


---

Effects of heterogeneity on recovery. Shale laminations affect the efficiency of a horizontal gas flood. In a homogeneous reservoir, the sweep efficiency is low (top). When the reservoir has discrete zones separated by permeability barriers, the efficiency is improved (middle). Isolated permeability barriers lead to the most efficient sweep (bottom).
flow rate and revenue. Underestimating reserves will give a lower flow rate and influence project economics. Overestimating reserves will probably involve penalty payments on future gas sales contracts.

A modeling study by British Gas showed that at high values of anisotropy—high vertical permeability—considerable reserves are trapped behind the rising aquifer. At the other extreme, low anisotropy—low vertical permeability—does not allow recovery of gas from unperforated layers. Optimum recovery occurs when anisotropy is large enough to retard water influx, but still small enough to drain the unperforated layers (below).

Perforating policy for these fields will also be determined by anisotropy. If it is high, only the upper reservoir layers will be perforated to avoid water production. But high vertical permeability will allow drainage of unperforated layers. If anisotropy is low, more perforations will be needed to efficiently drain the field. Reperforating wells will probably be expensive as the likely development will use subsea platforms or those not normally manned. Hence the importance of measuring vertical permeability before perforating.

The problem is that anisotropy not only depends on direction, but also may vary with scale. For example, a single crystal may have an atomic structure that is anisotropic to properties such as electric current flow or acoustic propagation. But a piece of rock formed from randomly packed crystals may be isotropic to the same properties measured at a larger scale. At still larger scales, a series of isotropic rock layers, each with different values for these properties, will behave anisotropically (above, right).4

The scale dependency of permeability anisotropy is illustrated by measurements taken by British Gas on its South Morecambe gas fields. Permeability measurements of 1-in. [2.5-cm] core plugs yield anisotropies of 0.5 to 0.3. However, vertical pressure profiles over a 400-ft [122-m] thick layer in the producing gas reservoir are consistent with anisotropies as small as 0.002.

Such extreme values are caused by layering of rock on a scale smaller than the scale of the measurement—each layer has a different value of permeability, but all contribute to the measurement. Two geological features in particular account for this type of anisotropy: crossbedding and shales (see “Oilfield Anisotropy: Its Origins and Electrical Characteristics,” page 48).

Crossbedding is the alternate layering of sands of different grain sizes or textures at an acute angle to the major depositional features. There is little difference between the mineral composition of alternating layers. Shales have small grain size and usually low permeability. Dispersed shale, for example, platy illite which blocks pore space, reduces the permeability of most formations, but does not contribute significantly to anisotropy. On the other hand, shale layers reduce or eliminate flow to adjacent formations and therefore contribute significantly to the anisotropy at some scale.5

Anisotropy is also dependent on shale continuity. For example, a continuous shale may totally isolate one zone from another, in which case the permeability anisotropy measured across the shale will be zero. If, on the other hand, the shale extends only a short distance from the well, the two zones will not be isolated. Fluid will follow a long, tortuous path around the shale, effectively decreasing the permeability measured across it. So the extent of the shale controls the permeability across it.

Earlier we said that the ratio $k_v/k_h$ is often used to quantify permeability anisotropy. A more accurate definition would be to call this ratio vertical permeability anisotropy, which is a useful concept for vertical wells where vertical permeability plays such an important role in field development. For horizontal wells, however, the permeability anisotropy in the horizontal plane becomes equally important (see “Permeability Anisotropy in Horizontal Wells,” page 28). Horizontal permeability anisotropy is caused by the depositional environment or by fractures. Where natural fractures are oriented in one direction there will be a significant difference between the horizontal permeability measured, on a reservoir scale, in the direction of the fractures and that measured normal to them. When tectonic stresses are involved, permeability anisotropies may also occur, as microfractures, aligned with the direction of maximum horizontal stress, open up in the direction normal to the stress. It is also believed that stress anisotropy may cause minor permeability anisotropies without the presence of natural fractures by distorting the pore space.

There are several different methods of obtaining permeability anisotropy, such as core analysis, well testing techniques and wireline formation tester measurements (see “Measuring Vertical Permeability,” page 30). One well testing technique—vertical interference testing—is successfully used by a wireline formation tester.

In vertical interference testing, a well is flowed at one zone, creating a pressure disturbance through the reservoir. The effects are recorded on pressure gauges some distance away at a second zone in the same well. The pressure response at the second zone depends on several factors: communication between the two zones, vertical and horizontal permeabilities, and reservoir boundaries. Transient analysis of the pressure response reveals horizontal and vertical permeabilities.

Vertical interference testing was first developed for well testing using two sets of perforations isolated by straddle packers (left). This method relies on perfect isolation between the intervals being tested—good packer seals and no casing or cement leaks—and is costly if several zones are to be tested. However, the modular design of the MDT Modular Formation Dynamics Tester tool, using various combinations of probes and packers, allows openhole vertical interference tests to be performed faster and at lower cost—although on a smaller scale (below).7

British Gas used the MDT formation tester to perform five vertical interference tests.

[Diagram: MDT tool module combination for vertical interference testing. The standard setup (left) uses a single-probe module, dual-probe module and flow control module. The single probe and the horizontal probe of the dual-probe module are used as vertical and horizontal monitors, respectively. The flow control module regulates flow through the sink probe—the second probe of the dual-probe module—into a 1000-cm³ chamber to provide the pressure pulse. A dual-packer module (center) replaces the dual-probe module when probe plugging may be a problem. A sample chamber may be used to provide a larger pulse as the vertical monitor probe is farther away in this setup. Another alternative is to use two single-probe modules (right). This provides a longer spacing—8 ft [2.44 m]—between sink and monitor, than both the standard setup and dual-packer setup.]

October 1994
Horizontal wells are excellent producers for thin reservoirs—less than 50-ft [15-m] thick—or for thicker reservoirs with good vertical permeability. The drainage pattern for an ideal horizontal well is ellipsoidal and dominated by permeability anisotropy—the half axes are related to the length of the horizontal section, the horizontal permeability and the vertical permeability.

Vertical permeability anisotropy also affects production—the larger the anisotropy, the higher the productivity index. Low vertical permeability may make horizontal wells economically unattractive. Another important issue is the horizontal permeability anisotropy. A well drilled normal to the larger horizontal permeability will be a much better producer than one drilled in an arbitrary direction or normal to the smaller horizontal permeability. Therefore, it is important to measure permeability before the horizontal section is drilled.

Most oil companies drill a vertical pilot hole to acquire as much data as possible about the target reservoir before drilling the horizontal section. These data may be used to optimize the horizontal segment length or even justify a decision not to drill the well at all.

One method of measuring vertical permeability is to perform a limited entry drillstem test after drilling the upper 10 ft [3 m] of the pilot hole into the reservoir (see “Measuring Vertical Permeability,” page 30). Once the pilot hole is complete, other drillstem tests may be designed to confirm the results of the first test or to provide additional data such as fluid contacts or parameter estimates of additional layers.

An alternative procedure is to use the MDT formation tester tool. Although the depth of investigation is limited to a maximum of about 33 ft [10 m], the MDT tool has the advantage of operational efficiency. With test points carefully selected from openhole logs, the tool may provide data for subsequent well test interpretation. For example, many horizontal wells are drilled in layered reservoirs—each layer having different properties. A drillstem test conducted in the horizontal section of the well may require a layered reservoir model for analysis—a homogeneous model would lead to wrong estimates of critical parameters such as producing length, permeability and skin factor.

Parameter estimates, calculated for each layer from MDT tool data acquired in the pilot hole, would enable a layered reservoir model to be used.

Shear sonic logging measurements in the pilot hole may be used to identify the maximum and minimum horizontal stress directions. Usually, these coincide with the maximum and minimum horizontal permeability directions. A horizontal well should be drilled parallel to the direction of minimum horizontal permeability, which has the added advantage of offering the greatest borehole stability.

Once the horizontal section is drilled, it is not too late to perform drillstem tests. However, the testing equipment needs to be flexible enough to
enter the horizontal section, otherwise it has to be set in the vertical part of the well. If this happens, wellbore storage may take so much time to dissipate that the part of the pressure transient used for estimating vertical permeability and skin—early-time radial flow—is masked.4

The MDT tool may also be used to measure permeability anisotropy in horizontal sections. The tool can be conveyed downhole into the horizontal section on drillpipe or by coiled tubing, and the probe orientation found using an inclinometry device. Mapping permeability variation along the well enables optimization of completion design, such as deciding where to place isolation packers or which sections of a cased hole to perforate.

<table>
<thead>
<tr>
<th>Core Data</th>
<th>MDT Data</th>
<th>Core Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>kv (md)</td>
<td>k_h (md)</td>
<td>kv (md)</td>
</tr>
<tr>
<td>X263</td>
<td>0.60</td>
<td>80</td>
</tr>
<tr>
<td>X242.9</td>
<td>0.45</td>
<td>55</td>
</tr>
</tbody>
</table>

Three-Probe Test in West Africa

Multiprobe vertical interference tests were conducted for AGIP Recherches Congo, West Africa, to measure permeability anisotropy and to identify permeability barriers across reservoir sections.

The tool configuration for the multiprobe formation tester consists of three probes:
- the sink probe—to induce a pressure pulse in the formation
- the vertical monitor probe located 2.3 ft (70 cm) above the sink probe and in the same vertical plane
- the horizontal monitor probe directly opposite the sink probe.

The monitor probes measure pressure transients induced at the sink probe. AGIP added sample chambers to this setup to recover clean, pressurized samples of formation water.

A typical sequence of events would be to position the tool and set all three probes (continued on page 33)
Limited Entry Well Test

A well test records the pressure response to a pulse transmitted through the reservoir. One conducted on a well drilled partially into a reservoir or one where a limited portion of the reservoir is perforated—usually the upper portion—reveals three flow regimes (right). Once wellbore storage subsides, radial flow at the perforations is seen. Transient analysis of this portion of the pressure derivative is used to calculate horizontal permeability, $k_h$, at the perforations and also skin. As the pressure wave propagates away from the well, the second regime, spherical flow, develops. The slope of the curve of pressure plotted versus the reciprocal of the square root of time curve allows calculation of spherical permeability. Spherical permeability, $k_s$, is the geometric mean of horizontal and vertical permeability, $\sqrt[2]{k_h k_v}$. Hence vertical permeability and anisotropy may be determined. When the third regime—radial flow—develops far from the well, another value for horizontal permeability can be calculated.

If permeability anisotropy is low—vertical permeability approaches horizontal permeability—then wellbore storage effects often mask the early-time radial flow. Spherical flow will also occur earlier and may also be masked.

In addition to vertical interference testing described on page 27, here are some other methods for measuring vertical permeability.1


1. Partially penetrated well test. An openhole drillstem test performed in a partially penetrated reservoir (bottom left) or partially perforated well (bottom right), reveals radial flow near the borehole (1). The flow regime develops into spherical flow (2) until the lower boundary is met. There radial flow once again develops (3). Horizontal permeability may be calculated from the radial flow regimes, and spherical permeability from the spherical flow regime. Spherical permeability is the geometric mean of horizontal and vertical permeabilities. Hence vertical permeability can be calculated.

2. Arithmetic averaging applied to permeability means adding up all permeability measurements and dividing by the number of measurements. Harmonic averaging takes into account the distance over which that measurement applies. For example, a permeability of 1 md over 5 feet and one of 10 md over 1 foot would have an arithmetic average of 5.5 md, and a harmonic average of 2.5 md—the latter being a more realistic figure.
Water Coning Analysis
As a reservoir is produced, water or gas coning may develop. Although water or gas production is usually undesirable, records of when this occurs are useful for future field development. The height of a water cone in any particular well depends on flow rate and vertical permeability (right). The critical flow rate—above which water comes into the well—and the time taken to initiate water breakthrough are used to calculate vertical permeability. These calculations may lead to adjustments of the reservoir model and influence plans for further field development.

Core Analysis
One of the more traditional ways of measuring permeability is directly on a sample of rock. Small plugs cut from cores are used—the orientation of the plug determines whether horizontal or vertical permeabilities are to be measured. After the core plug is cleaned with a solvent, brine is forced through the plug under constant pressure and the volume of emerging fluid is measured over a period of time. This gives the flow rate through the plug and hence, by Darcy’s law, permeability.

If samples are taken frequently, say every 1 ft, then average values of permeability may be computed along the well. Usually harmonic averaging is made for vertical permeability to account for variations in vertical displacement between plugs. Arithmetic averaging is made for horizontal permeability unless horizontal displacement needs to be accounted for. Results may be consistent with other ways of measuring permeability anisotropy provided that there is an absence of impermeable barriers, such as stylolites or shales. If these do occur, vertical permeability may be 10 to 100 times lower, making core data measurements unacceptable on a reservoir scale.

Formation Tester Pretests
Both single-probe and multiprobe formation testers check the integrity of packer seals when probes are set against the formation by performing a pretest for each. During a pretest, a small volume of fluid—20 cm³ in the case of the RFT—formed by setting a probe or gas plugging, damage to the formation resulting from mechanical setting of a probe or gas evolution in the near-probe region, may invalidate the data before an interpretation can even be attempted.

Formation Tester Vertical Pressure Gradient
Formation tester pressure gradients recorded in depleted reservoirs highlight permeability barriers. Under dynamic conditions, there is a component of pressure attributable to vertical flow, such as a rise in water level, within the reservoir. By measuring a dynamic pressure gradient and comparing this to the static pressure gradient—no production from the reservoir—this component can be estimated and the vertical permeability modeled.

The main drawback of this method is the need for significant production before running the formation tester, so it is not possible to use this technique prior to field development. However, these data are extremely useful when infill drilling is considered later in a field’s life.

Mobility is permeability divided by viscosity.
**Formation Tester Pulse Testing**

Better use of formation tester pressure profiles can be made with pulse testing. This consists of recording several profiles in an observation well at various stages while a nearby producer or injector is being shut in. The act of shutting in the well generates a pressure pulse that will change the pressure profile at the observation well. These changes are affected by horizontal permeability between the wells and formation heterogeneities, such as faults and impermeable zones (right). Horizontal and vertical permeabilities are calculated using a three-dimensional (3D) reservoir model for pulse-test simulation and history matching.

Prior modeling is needed to estimate the duration of the pressure pulse and the timing of the pressure gradient surveys, but the results give permeability estimates over a length and scale comparable to the dimensions of the reservoir. However, the need for two wells and long flow periods makes this method uneconomical for pre-development data collection.

**Tidal Pressure Changes**

Gravitational attraction by the sun and moon causes the rise and fall of ocean tides. To a lesser extent, the earth’s crust also deforms causing an earth tide. Ocean and earth tides induce small changes in reservoir pressure, although the mechanisms involved differ. Earth tides squeeze the reservoir, reducing its volume by about one part in one hundred million ($10^{-8}$). This causes a change in reservoir pressure. Ocean tides change the overburden pressure by reducing or increasing the head of water above the reservoir, directly changing the reservoir pressure. As the compressibility of gas is much greater than that of oil or water, the depth of a gas-liquid interface in a gas reservoir will move with pressure changes, forming a transition zone. The amount of movement is governed by vertical permeability over this zone. The length of the transition zone is measured by taking pressure readings with a formation tester. Pressures are taken regularly at several stations across the transition zone during a 12-hour tidal cycle (above, right).9

Because the pressure changes measured are small, a high-resolution quartz gauge is required. The method estimates the order of magnitude for vertical permeability and is best suited to offshore regions with significant tidal ranges.

---


against the formation (right), (see box “Defining the Test Intervals,” below). The integrity of each probe packer seal is checked by performing a small-volume drawdown test—a pretest. A good seal for a probe set in a permeable zone is indicated by a pressure response showing a drawdown followed by a buildup to formation pressure. Similar responses at all three probes are required before the interference test is allowed to proceed. The transient pressure data from pretests may be analyzed to obtain local permeability estimates as with previous formation testers.9

It is advantageous—but not necessary—to have a constant flow rate during an interference test, and this is achieved by the flow control module. Up to 1000 cm³ of fluid may be withdrawn from the formation at a specified flow rate during a test through either the sink probe or the vertical monitor probe—both are connected to the flowline that runs through most MDT tool modules. The flow control module chamber is reset after the test, emptying the contents into the borehole—using the pumpout module—or into a large sample chamber.

Flowing pressure at the probe must be at least 30% of the mud pressure for the flow control module to operate. In some cases, as in depleted or low-permeability formations, the pressure may be too low to sustain a flow rate. An alternative method is to open the sink probe to a sample chamber attached to the tool and estimate the flow rate. One of the AGIP tests was repeated by opening the sink probe directly to a 1-gallon (3800-cm³) sample chamber, so that the two methods of providing a pressure pulse could be compared.

Interpretation begins as tests are recorded. Communication is indicated by pressure changes at the monitor probes in response to the pressure pulse. The degree of communication is indicated by the magnitude of the pressure drop. The pressure drops at the horizontal and vertical probes provide a quick estimate of anisotropy.

Values of horizontal and vertical permeabilities come from transient analysis.10 Transient analysis involves identifying when spherical or radial flow regimes occur, choosing the location of zone boundaries from openhole logs in such a way as to be compatible with the indicated flow regimes, and, finally, estimating reservoir parameters during those flow regimes.11

One method of identifying the flow regimes present employs pressure derivative plots for which a prerequisite is the flow rate history. The interpretation of flow regimes then proceeds in a similar fashion to that during the interpretation of a well test.12

When the flow rate is unknown, an alternative method may be used. It relies on the fact that multiprobe testing measures pressure transients at two distinct locations away from the sink. Fluctuations in flow rate will influence the two pressure transient measurements in some related way. The relationship is purely a function of the flow geometry and rock and fluid properties. This

### Defining the Test Intervals

Before vertical interference tests are performed, as much information as possible must be gathered to accurately define the test intervals. Openhole wireline logs provide petrophysical information, such as porosity and fluid saturations, to define likely test zones. Geological logs—dipmeters and borehole images—help describe the depositional environment and likely reservoir structure. They also provide the fine detail required to accurately position the formation tester across potential permeability barriers. Images run after testing often show impressions left behind by formation tester probes confirming test depths.

Other petrophysical logs provide important information directly related to formation permeability. Permeability is reduced by dispersed shale and anisotropy influenced by laminated shale, so logs providing information on clay content, such as geochemical logs, should be taken into account.

Both open fractures and matrix permeability strongly affect the Stoneley wave measured by the DSI Dipole Shear Sonic Imager tool. Stoneley waves, traveling along the borehole surface, reflect from open fractures. Fracture aperture is measured using either the magnitude of the Stoneley reflection coefficient or the current density from a borehole imager. Stoneley wave slowness provides a continuous scalar measurement of permeability at the borehole wall, which may be calibrated using multiprobe formation tester permeability measurements.

---


11. Spherical flow describes flow towards a point coming from all directions, as if from the inner surface of a sphere. Radial flow describes flow towards a line as if coming from the inner surface of a cylinder. Spherical flow towards a point, such as the probe of a formation tester, will develop into radial flow, farther away from the point, as upper and lower boundaries of a producing zone are reached, forming the top and bottom of the cylinder.


---

October 1994
relationship—the G-function—may be calculated by using both pressure transients. A plot of G-function versus delta time will approach a slope of –1.5 for spherical flow and –1.0 for radial flow. This approach was used to analyze the AGIP job (left).\(^{13}\)

Once the flow regimes are identified, specialized plots may be generated for the periods of spherical flow and radial flow. Spherical analysis allows first estimates to be made for horizontal and vertical mobilities and the porosity-compressibility product. Radial analysis gives the horizontal mobility-thickness product.\(^{14}\)

The initial estimates are used in formation response models coupled to a parameter estimator to arrive at the best estimate of formation parameters and achieve the best match between observed and calculated pressures. The final match is presented as verification plots—pressure versus time and lobe plots (left). For a lobe plot, the change in pressure at the vertical monitor probe is plotted against the change in pressure at the horizontal monitor probe during both drawdown and buildup.\(^{15}\)

The separation between vertical monitor probe and sink probe—2 ft [60 cm]—did not allow AGIP to test across all zones of reduced porosity that were indicated from petrophysical interpretation of the openhole wireline logs. Several vertical interference tests were conducted over the reservoir to evaluate vertical permeability statistically. Although some dry tests were encountered, no permeability barriers were found. Results from the 1-gallon sample chamber test were in good agreement with the flow control test, and were also in good agreement with permeabilities measured by a drillstem test (DST) over this interval.

The anisotropy ratio for one reservoir from core plug data was 0.8 compared to 0.62 using the MDT tool measurements. The MDT tool results were considered to be more representative and have been incorporated by AGIP into their three-dimensional simulation model.

**Two-Probe Test in Abu Dhabi**

TOTAL used the MDT tool in four wells to measure permeability anisotropy in a Middle East carbonate reservoir prior to a pro-

\(^{13}\) Goode PA, Pop JJ and Murphy WF: “Multiple-Probe Formation Testing and Vertical Reservoir Continuity,” paper SPE 22738, presented at the 66th SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, October 6-9, 1991.

\(^{14}\) For a thorough review of pressure test analysis:
- Ehlig-Economides et al, reference 1.
- Mobility is permeability divided by viscosity.

\(^{15}\) Zimmerman et al, reference 7.

posed gas injection project.\textsuperscript{16} The tests were carried out mostly between limestone and dolomite layers where permeability barriers were expected at the lithology change.

The MDT tool configuration with two single-probe modules was used to increase the spacing between the probes to 8 ft, so that each test would cover as much formation as possible (page 27). The flow rate source was the pumpout module, which can pump mud filtrate or formation fluids from the reservoir into the borehole.

The results from the drawdown permeabilities compare well to the Stoneley permeability log recorded by the DSI Dipole Shear Sonic Imager tool and show extreme permeability heterogeneity (right).\textsuperscript{17} However, results from the vertical interference test measurements show significant differences when compared to permeability measurements from cores. The vertical interference test analysis indicates much lower horizontal permeability at the depth at which core data are available (bottom, right). High core horizontal permeability measurements are most likely caused by vugs and induced fractures and the fact that the measurements took place without overburden pressure.

Although core measurements showed vertical permeability to be almost as good as horizontal permeability, scaling up the data did not provide TOTAL with the correct value of anisotropy for their reservoir model—they had to use a much smaller value to match reservoir performance. The MDT tool test results showed reasons for this. Several MDT tests indicated the presence of permeability barriers; other MDT tests indicated that previously suspected barriers were not present. This enabled TOTAL to revise their simulation model for the gas injection program.

\textbf{A Barrier Removed?}

The importance of permeability anisotropy to sound reservoir management is not in dispute. Vertical interference testing with the MDT tool provides measurements of horizontal and vertical permeability early enough to attack problems of well completion design, stimulation planning and horizontal well trajectory. The resolution of the measurement fills the gap between that of well tests and that of core data so that reservoir models may be refined, leading to better field development strategies, such as enhanced oil recovery programs and infill well placement. —AM

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|}
\hline
Core & Depth & Permeability & Description \\
& (m) & $k_h$ (md) & $k_v$ (md) \\
\hline
1 & 2947.25-2947.50 & 2283 & 84 & Limestone, vug, induced fractures along stylolite 2 \\
(25 cm) & & & & \\
2 & 2947.62-2947.81 & 111 & 30 & Limestone, vug, oblique induced fracture \\
(19 cm) & & & & \\
3 & 2947.81-2948.00 & 663 & 24 & Limestone, vug, towards bottom \\
(19 cm) & & & & \\
\hline
\end{tabular}
\end{table}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure.png}
\caption{Comparison of MDT tool permeabilities to Stoneley permeability curve. MDT tool mobilities compare well with the Stoneley permeability curve (left-hand track), both showing extreme heterogeneity. Also shown are the positions of three MDT tool vertical interference tests alongside the openhole log volumetric interpretation (right-hand track).}
\end{figure}

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure.png}
\caption{Whole core results. The table shows the variation in permeabilities on measurements made under atmospheric conditions on three cores. The MDT tool vertical interference test conducted across the same interval gave a vertical permeability of 8.2 md and a horizontal permeability of 16.3 md. The significantly higher core permeabilities may be accounted for by scale of measurement differences and by the in-situ MDT tool measurement. The MDT tool measurement covered 8 ft of borehole compared with the 7.5-in. [19-cm] cores—the cores may not have been representative of that interval. The vugs and induced fractures contained in the cores would close under borehole pressures reducing the permeability.}
\end{figure}
For most of this century, oilfield theory and practice assumed that waves propagate equally fast in all directions. That is, rocks have isotropic wave velocities. But waves travel through some rock with different velocities in different directions. This phenomenon, called elastic anisotropy, occurs if there is a spatial ordering of crystals, grains, cracks, bedding planes, joints or fractures—essentially an alignment of strengths or weaknesses—on a scale smaller than the length of the wave. This alignment causes waves to propagate fastest in the stiffest direction.

The existence of elastic anisotropy has been largely ignored by exploration and production geophysicists—and for good reasons. The effect is often small. With standard surface seismic measurement techniques most reservoir rocks show directional velocity differences of only 3 to 5%, which may often be neglected. Moreover, processing data under the assumptions of an isotropic earth is already a challenge; the cost of adding the complications of anisotropy must be justified by improvements in the final seismic image. At most, anisotropy has usually been considered noise that must be filtered out, not as a useful indicator of rock properties.

However, with recent advances in acquisition, processing and interpretation of elastic data, the reasons for ignoring anisotropy are no longer valid. New acquisition hardware and measurement techniques designed to highlight anisotropy reveal highly anisotropic velocities in ultrasonic, sonic and seismic data. This article looks at the evidence for anisotropy, the best ways to measure it, and how to use it to enhance reservoir description and optimize development.

The two requirements for anisotropy—alignment in a preferential direction and at a scale smaller that of the measurement—can be understood through analogies. For the effect of alignment, imagine driving a car in an anisotropic city where streets in the north-south direction have a 30-mile-per-hour speed limit, while the east-west streets have a 50-mile-per-hour limit. East-west drivers will spend less time traveling a given distance than north-south drivers. And drivers will take east-west streets whenever possible. In an anisotropic rock, waves do the same thing, traveling faster along layers or cracks than across them.

For the effect of scale, a less than perfect but interesting analogy is an insect on a leaf in a forest. The insect sees leaves and branches branching off in random direc-
anisotropy is due to alignment at the particle scale or at a scale nearer the length of the wave. In the words of one anisotropy specialist, “The seismic wave is a blunt instrument in that it cannot tell us whether anisotropy is from large or small structures.”

Two Types of Anisotropy

There are two styles of alignment in earth materials—horizontal and vertical—and they give rise to two types of anisotropy. Two oversimplified but convenient models have been created to describe how elastic properties, such as velocity or stiffness, vary in the two types. In the simplest horizontal, or layered, case, elastic properties may vary vertically, such as from layer to layer, but not horizontally (left). Such a material is called transversely isotropic with a vertical axis of symmetry (TIV). Waves generally travel faster horizontally, along layers, than vertically. Detecting and quantifying this type of anisotropy are important for correlation purposes, such as comparing sonic logs in vertical and deviated wells, and for bore-

Anisotropy is then one of the few indicators of variations in rock that can—even must—be studied with wavelengths longer than the scale of the variations. For once, using 100-ft [30-m] wavelength seismic waves, we can examine rock structure down to the particle scale. However, seismic waves are unable to determine whether the anisotropy is due to alignment at the particle scale or at a scale nearer the length of the wave. In the words of one anisotropy specialist, “The seismic wave is a blunt instrument in that it cannot tell us whether anisotropy is from large or small structures.”

Two Types of Anisotropy

There are two styles of alignment in earth materials—horizontal and vertical—and they give rise to two types of anisotropy. Two oversimplified but convenient models have been created to describe how elastic properties, such as velocity or stiffness, vary in the two types. In the simplest horizontal, or layered, case, elastic properties may vary vertically, such as from layer to layer, but not horizontally (left). Such a material is called transversely isotropic with a vertical axis of symmetry (TIV). Waves generally travel faster horizontally, along layers, than vertically. Detecting and quantifying this type of anisotropy are important for correlation purposes, such as comparing sonic logs in vertical and deviated wells, and for bore-

1. Elastic anisotropy is sometimes called velocity anisotropy, travel-time anisotropy, acoustic anisotropy or slowness anisotropy.
3. The axis of symmetry is an axis around which the material may be rotated without changing the description of the material’s properties.
Wavefronts in isotropic and anisotropic materials. In an isotropic medium (top) waves emanate spherically from a point. In an anisotropic material (bottom) waves spread with different velocities at different angles.


5. Compressional waves were originally called P for primary—since they arrived first—and S for secondary. Only the P- and S-terms remain in use. Both P and S waves are known as elastic waves. Geophysicists use the term acoustic to emphasize wave propagation in a fluid, while elastic connotes propagation in a solid.

6. Specialists have developed a new terminology for waves in anisotropic media: P waves are called qP, and the two S waves are called qS1 and qS2. The ‘q’ stands for ‘quasi—’, emphasizing the fact that in anisotropic materials, particle motion in P waves is no longer exactly parallel to propagation direction, and the particle motion in S waves is no longer exactly perpendicular.


hole and surface seismic imaging and studies of amplitude variation with offset (AVO). Examples appear later in this article.

The simplest case of the second type of anisotropy corresponds to a material with aligned vertical weaknesses such as cracks or fractures, or with unequal horizontal stresses. Elastic properties vary in the direction crossing the fractures, but not along the plane of the fracture. Such a material is called transversely isotropic with a horizontal axis of symmetry (TH). Waves traveling along the fracture direction—but within the competent rock—generally travel faster than waves crossing the fractures. Identifying and measuring this type of anisotropy yield information about rock stress and fracture density and orientation. These parameters are important for designing hydraulic fracture jobs and for understanding horizontal and vertical permeability anisotropy.

More complex cases, such as dipping layers, fractured layered rocks or rocks with multiple fracture sets, may be understood in terms of superposition of the effects of the individual anisotropies.

Identifying these types of anisotropy requires understanding how waves are affected by them. Early encounters with elastic anisotropy in rocks were documented about forty years ago in field and laboratory experiments (see “A Brief History,” page 39). Many theoretical papers, too numerous to mention, address this subject, and they are not for beginners. However, it’s easy to visualize waves propagating in an anisotropic material. First picture the isotropic case of circular ripples that spread across the surface of a pool of water disrupted by the toss of a pebble. In “anisotropic water,” the ripples would no longer be circular, but almost—not quite—an ellipse (left). Quantifying the anisotropy amounts to describing the shape of the wavefronts with terms such as ellipticity and anellipticity. In anisotropic rocks, waves behave similarly, expanding in nonspherical, not-quite-ellipsoidal wavefronts.

Waves come in three styles, all of which involve tiny motion of particles relative to the undisturbed material: in isotropic media, compressional waves have particle motion parallel to the direction of wave propagation, and two shear waves have particle motion in planes perpendicular to the direction of wave propagation (below).
In fluids, only compressional waves can propagate, while solids can sustain both compressional and shear waves. Compressional waves are sometimes called P waves, sound waves or acoustic waves, and shear waves are sometimes called S waves. The two are recognized as elastic waves. In a given material, compressional waves nearly always travel faster than shear waves.

When waves travel in an anisotropic material, they generally travel fastest when their particle motion is aligned with the material’s stiffest direction. For P waves, the particle motion direction and the propagation direction are nearly the same. When S waves travel in a given direction in an anisotropic medium, their particle motion becomes polarized in the material’s stiff (or fast) and compliant (or slow) directions. The waves with differently polarized motion arrive at their destination at different times—one corresponding to the fast velocity, one to the slow velocity. This phenomenon is called shear-wave splitting, or shear-wave birefringence—a term, like anisotropy, with origins in optics. Splitting occurs when shear waves travel horizontally through a layered (TIV) medium or vertically through a fractured (THI) medium.

Since most geophysical applications place the energy source on the surface, waves generally propagate vertically. Such waves are sensitive to THI anisotropy, and are therefore useful for detecting vertically aligned fractures. Any stress field can also produce THI anisotropy if the two horizontal stresses are unequal in magnitude. Vertically traveling P waves by themselves cannot detect anisotropy, but by combining information from P waves traveling in more than one direction, either type of anisotropy can be detected. One approach is to combine vertical and horizontal P waves—such as those which arrive at borehole receivers from distant sources. Another technique compares P waves traveling at different azimuths. Two drawbacks to these compressional-wave methods are that horizontal wave propagation is difficult to achieve except in special acquisition geometries, and that travel paths for the P waves are different, introducing into the interpretation additional potential differences other than anisotropy. Shear waves, on the other hand, allow a differential measurement in one experiment by sampling anisotropic velocities with two polarizations along the same travel path, giving a greater sensitivity for anisotropy than P waves in multiple experiments.

Compressional and shear waves of all wavelengths can be affected by anisotropic velocities, as long as the scale of the anisotropy is smaller than the wavelength. In the oil field, the scales of measurement parallel those in the analogy of the insect in a tree—a forest—the insect represents the ultrasonic scale, the tree trunk radius is similar to the sonic scale and the height of the trees is the scale of the borehole seismic wavelength. The following sections describe how anisotropy is being used to investigate rock properties at each of those scales.

### At the Insect Scale

Wavelengths in most sedimentary rocks are small—0.25 to 5 mm—for 250-kHz ultrasonic laboratory experiments, and they are four times smaller at 1 MHz. Ultrasonic laboratory experiments on cores show evidence for both layering and fracture-related anisotropy in different rock types (below). While shales generally lead the pack in the relative difference between velocities of a given wave type in fast and slow directions, experimenters no longer deliver laboratory results in such simple terms. Instead of the two numbers, P- and S-wave velocities, elastic properties are often characterized by plots of velocity variation around some axis for the P waves are different, introducing into the interpretation additional potential differences other than anisotropy.

#### A Brief History

The earliest documented observation of the effect of anisotropy on material properties is probably that of Georges Louis LeClerc, Comte de Buffon. Through countless destructive experiments on 1- to 2-inch squares of oak, Buffon discovered in 1741 that wood strength depended on how the squares were cut relative to grain orientation.

The basic concepts regarding wave propagation in anisotropic media were expanded in the 1830s by G.R. Hamilton and J. McCullagh, independently. The term ‘anisotropy’ was first used in 1879 by Rutledge to describe properties of light traveling through crystals.

Laboratory and field experiments in the 1950s detected velocity anisotropy when vertically and horizontally traveling waves were found to have different velocities. Early explanations advocated an elliptical relationship for waves traveling at intermediate angles. Ellipses were convenient because once the vertical and horizontal velocities are known, velocities at any other angle can be computed. Later laboratory and field experiments aimed at quantifying anisotropy continued to measure velocities parallel and perpendicular to perceived alignments, and many publications list anisotropies of different rock types in terms of the percentage difference between fast and slow velocities, or the ellipticity.

However, models of wave propagation in transversely isotropic (TI) media indicated that the relationship between velocities at different angles is not an ellipse, but rather a squarish nonellipse. And a new term, the anellipticity, was introduced to describe the squareness. The realization that TI materials, be they layered (TIV) or fractured (THI), are anelliptical, meant that experiments to quantify anisotropy had to be redesigned. A measurement at an intermediate angle is required to fully characterize anelliptical elastic anisotropy.

---

of symmetry (right). This variation of velocity with angle of propagation has implications for the validity of many empirical relationships that have been established, linking velocity to some other rock property (see “Valid Velocities,” below).

Since ultrasonic laboratory measurements at 0.25-to 5-mm wavelength detect anisotropy, this indicates that the spatial scale of the features causing the anisotropy is much smaller than that wavelength. The main cause of elastic anisotropy in shales appears to be layering of clay platelets on the micron scale due to geotropism—turning in the earth’s gravity field—and compaction enhances the effect (below right). The response of elastic waves to clay platelets of varying degrees of alignment has been modeled (next page, top left and right).9

Laboratory experiments also show the effect of directional stresses on ultrasonic velocities, confirming that compressional waves travel faster in the direction of applied stress.10 One explanation of this may be that all rocks contain some distribution of microcracks, random or otherwise.11 As stress is applied, cracks oriented normal to the direction of greatest stress will close, while cracks aligned with the stress direction will open (next page, bottom). In most cases, waves travel fastest when their particle motion is aligned in the direction of the opening cracks.

Measurements made on synthetic cracked rocks show such results.12 And computer simulations indicate that rock with an initially isotropic distribution of fractures shows anisotropic fluid flow properties when stressed. Fluid flow is greatest in the direction of cracks that remain open under applied stress, but the overall fluid flow can decrease, because cracks perpendicular to the stress direction, which would feed into open cracks, are now closed.13

Valid Velocities

Common practice calls for characterizing the elastic properties of a rock for correlation with other properties, such as lithology or porosity, or for rock mechanics purposes. This characterization determines density and P- and S-wave velocities. With those three numbers, most geoscientists would say the elastic behavior of the rock is completely described. They would be correct only if the rock were isotropic. And since most laboratory experiments to characterize rock core are done on reservoir rocks, typically isotropic sandstones or carbonates, anisotropy hasn’t played a major role.

But most of the rocks surrounding reservoirs—75% in most sedimentary basins—are hard-to-characterize anisotropic shales. In the most general anisotropic case, 21 numbers are required. In the simple layer-anisotropic rocks described so far, five velocities—two transversely polarized S, vertical P, horizontal P, and P at 45°—plus density, are sufficient to completely characterize the rock.

Recognizing that many rocks are anisotropic, or may become so under stress, may have implications for any empirical relationships that relate rock velocity as measured in one geometry to other properties, such as strength, porosity or lithology.
Effect of nonuniform compressive stress on microcracks. In rocks with randomly oriented microcracks (left) cracks at all orientations may be open. When stressed (right), cracks normal to the direction of the maximum compressional stress will close, while cracks parallel to the stress direction will open or remain open. Elastic waves in such a rock will travel faster across closed cracks—in the direction of maximum stress—than across open cracks.

Components of a shale model. Individual model clay platelets (top) are oriented according to the distribution measured in the shale photograph on previous page (middle). Silt particles are added (bottom) to resemble real shales.

Wavefront velocities for synthetic shales. \(q_P\)- and \(q_S\)-wave velocities are computed for a shale with all clay platelets oriented horizontally (left). The shale synthesized with a realistic clay platelet distribution shows computed velocities (right) similar to those of the real shale depicted on the previous page.

Unstressed

Stressed

Effect of nonuniform compressive stress on microcracks. In rocks with randomly oriented microcracks (left) cracks at all orientations may be open. When stressed (right), cracks normal to the direction of the maximum compressional stress will close, while cracks parallel to the stress direction will open or remain open. Elastic waves in such a rock will travel faster across closed cracks—in the direction of maximum stress—than across open cracks.

At the Tree Trunk Scale
Both types of anisotropy, TIV and TIH, are also detected at the next larger scale, approximately the size of a borehole radius, with the DSI Dipole Shear Sonic Imager tool. At this scale, the most common evidence for TIV layering anisotropy comes from different P-wave velocities measured in vertical and highly deviated or horizontal wells in the same formation—faster horizontally than vertically. But the same can be said for S-wave velocities (right). For years, whenever discrepancies appeared between sonic velocities logged in vertical and deviated sections, log interpreters sought explanations in tool failure or logging conditions. Now that anisotropy is better understood, the discrepancies can be viewed as additional petrophysical information. Log interpreters expect anisotropy and look for correlation between elastic anisotropy and anisotropy of other log measurements, such as resistivity (see “Oilfield Anisotropy: Its Origins and Electrical Characteristics,” page 48).14

Fracture-, or stress-, induced elastic anisotropy has also been detected by sonic logs through shear-wave splitting. In formations with TIH anisotropy, shear waves generated by transmitters on the DSI tool split into fast and slow polarizations (left).15 The fast shear waves arrive at the receiver array before the slow shear waves. Also, the amount of shear wave energy arriving at the receivers varies with tool azimuth as the tool moves up the borehole, rotating on its way (next page, top).

Detecting anisotropy in DSI waveform data is easy, but using the data to compute the orientations of the split shear waves is a bit trickier. If travel time and arrival energy could be measured for every azimuth at every depth, the problem would be solved, but that would require a stationary measurement. Logging at 1800 ft/hour (550 m/hr), the DSI tool fires its shear sonic pulse alternately from two perpendicular transmitters to an array of similarly oriented receivers, and the pulse splits into two polarizations. As the tool moves up the borehole, four components—from two transmitters to each of two receivers—of the shear wavefield are recorded. The four components measured at every level, along with a sonde orientation from a GPT General Purpose Inclinometer Tool measurement, can be manipulated to simulate the data that would have been acquired in a stationary measurement. These data can determine the fast and slow directions, but cannot distinguish between the two (next page, bottom).16 Including the travel-time difference information allows identification of the fast shear-wave polarization direction, which in turn is the orientation of aligned cracks, fractures or the maximum horizontal stress. In an example from a well operated by Texaco, Inc. in California, the fast shear-wave polarization direction obtained from such DSI measurements corresponds to fracture azimuths extracted from an FMI Fullbore Formation MicroImager image (page 44).

Amoco Exploration and Production used information about shear velocities to optimize hydraulic fracture design in the Hugo- ton field of Kansas, USA.17 A key parameter for hydraulic fracture design is closure stress. Closure stress is related through rock mechanics models to Poisson’s ratio, which is a function of the P- and S-wave velocities...
Changes in shear-wave arrival times and arrival amplitude with changing dipole azimuth in TIH-anisotropic layers. Shear-wave arrival times, recorded when receiver and transmitter are aligned—called inline—vary with tool orientation (left). Inset “compasses” show orientation of a pair of DSI receivers relative to fractures. At 490 ft, the receiver aligned with fracture direction (blue) records fast shear arrival before the receiver oriented perpendicular to fractures (red) records the slow. The wave amplitude recorded on the crosscomponent (middle)—blue transmitter to red receiver or vice versa—is minimal. At 487 ft, receivers are misaligned, and the arrival times are between fast and slow. Crosscomponent amplitude is maximum. At 485 ft, arrival times separate and crosscomponent amplitude decreases again. Absolute bearing of red receiver azimuth (right) shows that tool has rotated 90° relative to its orientation at 490 ft.

Simulation of stationary multiazimuth data from one four-component DSI measurement. Inline (left) and crosscomponent (right) waveforms computed from four measured traces (red). Maximum inline and minimum crosscomponent amplitudes (blue) indicate a fast shear-wave direction of 54° for this example.
of the rock. But in an anisotropic rock, it is debatable whether the fast or slow S-wave velocity should be used—a slow velocity would give a higher closure stress, therefore a higher volume of pumped fluids. The DSI tool indicated about 8% anisotropy in the shale. Amoco engineers designed a fracture job around the fast shear-wave velocity, predicting lower closure stress, and reducing pumped fluid costs from $100,000 to $35,000 per well. Pump-in closure stress tests confirmed the lower stress value indicated by the faster S-wave velocity from the DSI tool. Amoco anticipates saving $10,000 to $65,000 per well on the remaining 300 infill wells to be drilled in the field.

At the slightly larger scale of a few feet to meters, crosswell seismic surveys also sense elastic anisotropy. But while most oilfield experiments employ vertically traveling waves to study elastic properties, crosswell seismic surveys harness horizontally traveling waves. In such a survey at the British Petroleum test site in Devine, Texas, USA, a seismic source was fired in one well to 56 receiver positions in a well 100 m [330 ft] away (next page). Then the experiment was repeated at 55 other source positions. Data processing called tomography divided the area between the wells into 56x56 cells and solved for the P-wave velocity in each square, to create a tomogram. Typical tomography, solving for isotropic velocities, reconstructed an image with layer boundaries that correspond to boundaries seen in gamma ray logs. However, allowing the velocities to be anisotropic enhances the results with a clearer tomographic image between wells.18

Comparison of fracture anisotropy from fast shear-wave azimuth and from borehole images. Shear-wave logs from a California well operated by Texaco, Inc. were processed using four-component rotation to extract the azimuth and amount of anisotropy indicated by shear-wave birefringence. Minima in the crosscomponents (green filled log, first track) indicate anisotropy. Waveforms of the fast (solid line) and slow (dotted line) shear waves appear in the second track. The time window for calculations is shaded pink. Azimuthal information appears in the third track, with fast shear direction (black curve), hydraulic fracture azimuth from tiltmeter records (blue bar) and fracture azimuths seen in FMI Fullbore Formation MicroImager displays (colored squares). The amount of birefringence, here equated with anisotropy, is plotted in the fourth track, with slowness-based percentage anisotropy (green), slow shear slowness (dotted blue), fast shear slowness (red) and time-based percentage anisotropy (solid blue).
At the Tree and Forest Scales

Most of the experiments designed to capture in-situ elastic properties have been vertical seismic profiles (VSPs), at the 10-m [33-ft] wavelength scale. Specially planned VSPs reveal elastic anisotropy of both types, TIV and TIH, but mostly fracture-related TIH anisotropy via shear-wave splitting. These studies show a good correlation between fracture azimuth inferred from VSPs and from other measurements, such as borehole imager tools, regional stress data, surface mapping and experiments on cores. Conducting such studies in the marine setting offers a special challenge, because shear waves cannot be generated in nor propagate through water. VSPs can, however, record waves that have been converted from P to S by reflection or refraction. Such vertically propagating shear waves then behave predictably by splitting into fast and slow shear waves when they propagate through fractured rock to borehole receivers.

As desirable as fractures may be for enhancing fluid flow, they are undesirable in caprock shales, where vertical fractures could diminish their integrity as reservoir seals. Geophysicists are looking into ways to identify fractured and unfractured shale caprock, hoping not to see fracture-related anisotropy in them.

More sophisticated walkaway VSPs, called walkaways for short, can measure elastic properties of layer-anisotropic TIV rocks in a way that no others can. Most VSPs rely on near-vertical travel paths, the elastic properties of TIV materials, such as shales, cannot be measured in situ. The walkaway, with its large source-receiver offsets and horizontal travel paths, is able to deliver vital information about shale properties.

A walkaway survey in the South China Sea sampled a compacting shale sequence through more than 180° of propagation.

---

angles, usually impossible in all but laboratory experiments (right, top). The data revealed fine-scale layering-induced anisotropy with horizontal P-wave velocities 12% greater than vertical (right, middle).22

The elastic properties of this highly anelliptic anisotropic shale were used to understand the effects of anisotropy on seismic reflection amplitude variation with offset (AVO) analysis. Surface seismic surveys and VSPs typically involve reflections of waves that propagate within 30° of vertical. Even in TIV-anisotropic shales, these near-vertical waves would not sense much anisotropy. But in surveys designed to highlight AVO effects, waves often travel at larger reflection angles. Reflection amplitude depends on the angle of reflection, or offset between source and receiver, and the contrast between P- and S-wave velocities on either side of the reflector. In isotropic rocks, some reflectors—especially those where hydrocarbons are involved—have amplitudes that vary with angle of reflection. Some operators use this property as a hydrocarbon indicator.23

In anisotropic rocks, there is the additional complication that the P- and S-wave velocities themselves may vary with angle of propagation, again causing AVO. If a propitious AVO signature is encountered, it is vital to know how much is due to hydrocarbon and how much to anisotropy. This dilemma can be resolved by modeling, which simulates the seismic response to a given rock or fluid contrast. Modeling requires knowledge of elastic properties, and correct modeling should include anisotropy (right, bottom). But anisotropy is a scale-dependent effect, and it is best measured at a scale similar to the VSP or surface seismic experiment being modeled, such as with a VSP. Most examples of AVO modeling use sonic-scale elastic parameters—sonic log data. But it is possible to envision an anisotropy, especially if it is fracture-related, at a scale larger than the sonic wavelength but smaller than the VSP wavelength. In this case, the anisotropy may be felt by seismic waves but not by sonic waves.

Another walkaway, by British Petroleum in the North Sea, measured anisotropic
properties in a shale overlying a reservoir with an anomalous AVO signature. The elastic properties were used to model the AVO response at the interface between the shale caprock and the oil sand reservoir (right). The AVO signature seen in the walk-away data fits the anisotropic model. If the caprock had been assumed to be isotropic, a different AVO response to the oil sand would have been seen, and the sand might not have been identified as oil-bearing. The effect of the anisotropy on the interpretation of the AVO anomaly had an important bearing on conclusions drawn from a concurrent study based on 3D surface seismic data in the area.

Velocity anisotropy is also beginning to find a home in another corner of the surface seismic world, that of processing surveys to obtain images. This process, called migration, requires knowledge of the velocities of the seismic waves to assign a correct spatial position to reflections recorded in time. In the absence of measurements of anisotropic elastic properties, conventional migration schemes include a 5% fudge factor and assume elliptical anisotropy to convert stacking velocities—results from a prior processing step—to migration velocities. A knowledge of velocity anisotropy beyond the 5% fudge factor, essentially knowing the anellipticity, will become more important in turning ray seismics, as seismic waves spend more time in horizontal travel paths.

Harvesting the Forest

These two types of elastic anisotropy, TIV and TIH, impact the oilfield geoscientist as well as the anisotropist. Measurement of layer-induced anisotropic elastic properties are used to refine processing and produce clearer images or to create better models that lead to more accurate interpretation. In the long run, measuring TIV elastic anisotropy improves reservoir description, which in turn promotes efficient hydrocarbon recovery.

Measuring fracture- and stress-induced TIH anisotropy may have a more direct and far-reaching impact. Just as elastic waves are bound to travel in the direction of maximum stress or open fractures, so are reservoir fluids. The same forces that induce elastic anisotropy give rise to permeability anisotropy (see “Measuring Permeability Anisotropy: The Latest Approach,” page 24). But the tie between these two is not made routinely, nor is it fully understood.

Establishing the elastic-permeability tie for anisotropy requires geophysicists, reservoir engineers, geologists and petrophysicists to experiment with such a tie, documenting successes and failures. Today, the most basic level of anisotropic description involves only the geophysicist. The description comprises the azimuth of fracture or stress anisotropy, the degree of anisotropy in relative velocity difference, and the velocities of the two shear waves.

At a more sophisticated level the geologist and petrophysicist add the following information to make further links in the rock-fluid tie: lithology from core or logs; age of the reservoir; history of hydrocarbon maturation; azimuth and aperture of fractures seen in image logs; stress direction in the vicinity of the borehole from caliper logs or hydraulic fractures; and the effect of fluid saturation on resistivity anisotropy.

The ultimate level of integrated interpretation brings the reservoir engineer into the picture. This level adds measurement of fluid flow magnitudes and direction at the scale of the reservoir, in the region sampled by the elastic measurements. Achieving such an integrated interpretation will promote elastic anisotropy as a tool for better reservoir description and reservoir management. —LS


25. Turning rays are seismic rays that travel down, then turn up toward the surface, and reflect off the underside of a structure before returning to the surface. They show promise in imaging features below salt and other occlusive materials.


Oilfield Anisotropy: Its Origins and Electrical Characteristics

Barbara Anderson
Ian Bryant
Martin Lüling
Brian Spies
Ridgefield, Connecticut, USA

Klaus Helbig
Consultant
Hannover, Germany

Getting a grip on anisotropy of the earth can mean the difference between success and failure in reservoir evaluation and development. Accounting for the affects of anisotropy in measurements of the earth begins with understanding the geologic foundations of anisotropy—how sediments are laid down, converted to rock and deformed. Here is a summary of some geologic mechanisms for anisotropy, and some recent progress on anisotropy of electrical properties of rock formations.

Across the many disciplines of the oil field, a nearly universal phenomenon is anisotropy—the variation of a property with the direction in which it is measured. Where anisotropy arises, convenient assumptions fall. Seismic reflectors appear at the wrong depth. Seismic lines don’t tie. Waterflood programs fail. Induction logs are misinterpreted and mistaken water for pay.

As producers seek a finer comb to draw through measurements of the earth, they are changing the status of anisotropy from unwelcome guest to hard-working collaborator. Advances in theory and computing power now allow anisotropy to be factored into field development decisions. A full mathematical description of anisotropy remains difficult—for example, representing flow in three dimensions requires six variables. But accounting for the simplest effects of anisotropy is coming within reach.

What is meant by anisotropy depends on who is talking. Geophysicists generally focus on variation of seismic wavefront velocity or on the polarization of shear waves. Petrophysicists may measure resistivity anisotropy. Drillers and geologists may think first of anisotropy in rock strength or stiffness produced by earth stresses. Stratigraphers may concentrate on anisotropy of magnetic properties. And reservoir engineers need go to great lengths to characterize permeability anisotropy to plan an optimal production strategy (see “Case Study: Anisotropy for Steering Horizontal Wells,” page 50).

In all geoscience disciplines, however, there are two difficulties in dealing with anisotropy. One is that the conceptual underpinnings of anisotropy originate from the laboratory study of crystals—pure, homogeneous materials under pristine, controlled conditions. Today’s physical models of the earth draw much from this work, even though the earth is a composite, heterogeneous material sampled under anything but pristine, controlled conditions. Applying the physics of pure materials to the earth is like putting an economics professor to work on the floor of the Tokyo stock exchange. A smart one will figure out how to survive, but not without a struggle.

Physicists first met this challenge early in this century when they left the laboratory to make measurements of the earth’s subsurface. They brought with them the mathematics of materials assumed to be isotropic—having properties with the same value in all directions—and homogeneous. For the most part, the convenient assumptions held remarkably well. Where the assumptions began to fail, there arose the second difficulty with anisotropy—if you don’t have the tools to deal with anisotropy, the temptation is to ignore it or sweep it under the rug.

Assumptions about isotropy began to crack as early as the 1930s, when measurements made with electrodes laid in different directions on the earth’s surface were seen to give different results when strata were dipping when strata were flat. In geophysics, the introduction of shear wave sources in mid-1970s showed that shear wave anisotropy was often significant and could be analyzed quantitatively. A leap, however, took place in the mid-1980s, when sensors again reclined with the expansion of horizontal drilling. In vertical wells, electrical anisotropy was often...
observed to be negligible and could be ignored. With horizontal boreholes, acoustic and electrical anisotropy became obvious and demanded consideration. For many, the simple, isotropic days were ending and a new way of thinking was required.

This article gives an overview of the geologic basis of anisotropy as it is understood today in the oil field. It begins with a review of basic concepts and geologic mechanisms that produce various types of anisotropy and then focuses on recent advances in the measurement and interpretation of electrical anisotropies. Two crucial and well-characterized anisotropies—acoustic/seismic and permeability—are detailed in other articles in this issue (see pages 24 and 36).

**What is Anisotropy?**

A material is anisotropic if the value of a vector measurement of a rock property varies with direction. Anisotropy is typically used to describe physical properties, which, for the purposes of geoscience, can be thought of as parameters intrinsic to the body of the rock at a given state. The notable exception is that anisotropy is often used to describe a state of stress, which is not a property but a condition that results in anisotropy of intrinsic physical properties.

In the simplest form of earth anisotropy, a vector measurement has constant magnitude in any horizontal direction that is different from the magnitude of the vector in the vertical direction. This is called transverse isotropy in the vertical direction and derives from the early days of logging, when anisotropy was observed in vertical wells at 90° (transverse) to uniform (isotropic) flatlying beds. Resistivity, for example, would appear to be the same for any wellbore azimuth, but be different from the value in the vertical direction.

A growing usage today, especially among geophysicists, is to qualify isotropy with respect to an axis of symmetry. Transverse isotropy in a vertical well that crosses horizontal beds would be transverse isotropy with a vertical axis of symmetry, abbreviated TIV. Properties measured in a horizontal well that crosses a series of vertical fractures...
Four possible conditions for isotropy/anisotropy and homogeneity/heterogeneity. Note that what is apparent at one scale may not be apparent at another. For example, when viewed at a large scale, a sample may appear homogeneous and isotropic (lower left), yet at a small scale may be heterogeneous and isotropic (lower right). Here, heterogeneity is expressed as bed boundaries. They may represent differences in composition, such as sands and shales, or differences in grain size and packing.

Case Study: Anisotropy for Steering Horizontal Wells

Lake Maracaibo, in western Venezuela, having produced for more than 35 years, presents the challenges of a typical mature oil field. Maraven S.A., the operator of Block IV of the Bachaquero field, is planning to use horizontal drilling to produce bypassed oil and thereby increase recovery.

Part of the interval of interest is composed of elongated sands with laterally discontinuous shale layers. The lateral extent of these bodies is usually less than well spacing, so they cannot be described confidently using well data alone. Instead, scientists from Maraven and Schlumberger-Doll Research used a geostatistical method to derive a model of permeability anisotropy in the sands and shales. This provided a means to more accurately locate horizontal drainholes.

One example of the modeling uses clay weight percent, determined from gamma ray, geochemical logging, RST Reservoir Saturation Tool measurements and infrared determination of mineralogy from cores. Clay weight percent is inversely related to permeability. If clay weight percent is assumed to be isotropic, the geological model comprises bull’s-eye patterns, in which red is high clay volume and blue is low (next page, bottom). Bull’s-eyes result because the model assumes clay is evenly (isotropically) distributed around the wells.

Geostatistical analysis from 31 wells in the area indicated that the clay weight percent, and
direction observed at all points (homogeneity). If different variations were observed at different points, the bed would be both anisotropic and heterogeneous.

Fundamental to both anisotropy and heterogeneity is the concept of scale. Whether anisotropy and heterogeneity are perceived depends on sample size and sampling resolution. In fact, to say “this rock is anisotropic” is almost meaningless unless scale is also defined—that is, both the size of the sample and the resolution of the sampling method. Anisotropy, for example, can be detected only when the observing wavelength is larger than the ordering of elements creating the anisotropy. A crystal, for example, may be homogeneous above the molecular scale but highly anisotropic to larger wavelength electromagnetic and sound propagation. Many crystals together may form a homogeneous rock that is anisotropic if the crystals are aligned, or isotropic if they are ran-

<p>| Anisotropy | Heterogeneity |</p>
<table>
<thead>
<tr>
<th>Vector</th>
<th>Vector or scalar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variation in a vectorial value with direction at one point</td>
<td>Variation in vectorial or scalar values between two or more points</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Physical properties</th>
<th>Physical properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dielectric constant, magnetic properties, permeability, resistivity, rock strength, thermal conductivity, wave velocity</td>
<td>Density, dielectric constant, magnetic properties, natural gamma ray activity, neutron-capture cross section, permeability, porosity, resistivity, rock strength, saturation, wave velocity, wettability</td>
</tr>
</tbody>
</table>

A scheme for classifying anisotropy and heterogeneity in the oil field. All parameters listed as physical properties can be thought of as intrinsic to the fluid-saturated rock, and varying, to one degree or another, with composition, geometry and state (pressure, temperature, saturating fluid composition and stress). Physical properties listed in bold can be both anisotropic and heterogeneous. Whether a parameter is a physical property or a state can depend on the time frame in which it is considered. Wettability may have an imposed direction, so when viewed at the microscale, it could be anisotropic. For example, a flat, solid surface with unidirectional scratches has an apparent contact angle (quantification of wettability) dependent on direction. A small drop will be elongated, like a rugby ball, instead of spherical.


Therefore the horizontal permeability, have a horizontal anisotropy of 3:1—value in the $x$ plane is three times that of the $y$ plane. Analysis of azimuthal variations in permeability indicated the principal axis of the anisotropy is at 340°. Factoring these data into the reservoir model converted the bull’s-eyes into ellipses, with the main axis at 340°. The results of this model were transferred to a fluid flow simulator and indicated favorable locations for horizontal drainholes along the axes of these elongated sands. Orientation of these sand bars derived from this geostatistical method agrees with that derived from regional well data. The proof will come from the drilling program, scheduled to begin in early 1995.
Where Does Anisotropy Come From?

Anisotropy in the earth develops during deposition and during processes that take place after deposition. In clastic sediments, anisotropy can arise during and after deposition. In carbonates, anisotropy is controlled mostly by fractures and diagenetic processes, and so tends to arise after deposition. Anisotropy in carbonates may be predetermined during deposition, as evidenced by layering on seismic sections of slope deposits. Layering is thought to be induced by subtle changes in carbonate mineralogy, produced by variation in carbonate balance in the atmosphere and water. Changes in carbonate mineralogy result in changes in both texture and diagenetic potential, and consequently porosity and permeability.

For anisotropy to develop during deposition of clastics, there needs to be an ordering of sediments—in essence, some degree of homogeneity, or uniformity from point to point. If a rock were heterogeneous in the five fundamental properties of its grains—composition, size, shape, orientation and packing—anisotropy could not develop because there would be no directionality to the material. Anisotropy at the bedding scale that arises during deposition therefore may have two causes. One is periodic layering, usually attributed to changes in sediment type, typically producing beds...
of varying material or grain size. Another result from the ordering of grains induced by the directionality of the transporting medium. The cause of this ordering and the ultimate architect of this deposition-related anisotropy is gravity.

Deposition of clastics always begins with movement of grains under the influence of gravity. Whether carried by water or by wind, grains tend to align in the direction of least resistance to the movement of air or water. At a gravel beach face, for example, repeated washing by waves may form oblong pebbles, and orient them with their long axes parallel to the wavefront. This kind of grain alignment can set up a preferential rock stiffness in one direction and a weakness 90° to that direction. Eolian sands, for example, may have a greater grain-to-grain strength in the downwind direction. There is also evidence that postdepositional tectonic deformation can result in shortening in one direction, changing the azimuthal distribution of grain assemblages.

Under the action of gravity and transport, grains will also undergo sorting—separation by shape, weight or size. On riverbeds, the heaviest minerals concentrate where current velocity slows, typically in the troughs of riverbed dunes. In eolian deposits, different parts of a migrating dune are associated with distinct types of grain alignment and packing, each giving rise to different permeability anisotropies. Postdepositional tectonic deformation can result in shortening in one direction, changing the azimuthal distribution of grain assemblages.

In all depositional settings, variation in transport energy produces variation in the degrees of grain orientation, packing and sorting. Because topography varies laterally, deposition of clastics always begins with movement of grains under the influence of gravity. Whether carried by water or by wind, grains tend to align in the direction of least resistance to the movement of air or water. At a gravel beach face, for example, repeated washing by waves may form oblong pebbles, and orient them with their long axes parallel to the wavefront. This kind of grain alignment can set up a preferential rock stiffness in one direction and a weakness 90° to that direction. Eolian sands, for example, may have a greater grain-to-grain strength in the downwind direction. There is also evidence that postdepositional tectonic deformation can result in shortening in one direction, changing the azimuthal distribution of grain assemblages.

In all depositional settings, variation in transport energy produces variation in the degrees of grain orientation, packing and sorting. Because topography varies laterally,

8. Clastics are rocks composed of broken fragments of other rocks that have been transported some distance.
9. Diagenesis is all the physical, chemical and biological changes undergone by a sediment after deposition.
12. Lynn HB: “Field Measurements of Azimuthal Anisotropy: First 60 Meters, San Francisco Bay Area, CA, and Estimation of the Horizontal-to-vertical permeability (K_h/K_v) of 170, caused mainly by laminations of shale (light-colored layers) in a sandstone matrix. The Navajo sample is a clean sandstone with a remarkably high permeability anisotropy of 276 caused by variation not in composition but in grain size and packing. Dark bands are tightly packed fine grains stained by ferric oxide. Light red intervals are more loosely packed larger grains. The Cutbank sample has a permeability anisotropy of only 2.7. Here, alternating dark and light layers are the result of changes in abundances of chert and other silicates. Anisotropy is caused by small but sudden changes in grain size and therefore sudden changes in porosity. (From Auzerais et al, reference 17.)
so does transport energy. This produces lateral gradients in sediment texture, composition, and geometry. Over time, stacking of lateral gradients produces a vertical gradient.17

Many causes of anisotropy induced after deposition are lumped under the heading of diagenesis—the physical, chemical, or biological alteration of sediment after deposition and during and after lithification.18 Compaction by overburden pressure can cause rotation of grain axes into the horizontal plane.19 Compaction and dewatering of muds cause clay platelet alignment that gives rise to the pronounced anisotropy of shales (page 40, bottom). Realignment of muds may also result from their fracturing or plastic deformation. Grains can also undergo significant alteration from pressure solution—dissolution of grains at their contact points, causing flattening of formerly pointy contacts. This rearrangement of grain material results in reduction of pore space and welding of grains.20 Pressure solution in carbonates can develop stylolites—tight, usually horizontal sawtooth surfaces that consist of the insoluble residue of dissolved material. Stylolites can act as laterally extensive flow barriers and appear as highly conductive (dark) layers on resistivity imaging logs. In sandstones, pressure solution features are not usually confined to narrow bands, but are dispersed over a larger volume, typically increasing with depth.

The third type of diagenesis, induced by burrowing animals, can take place in either carbonates or sandstones, and either enhance or undo depositional anisotropy. For example, burrows can perforate a clay layer, making a former flow barrier permeable. Burrows may also be confined to an already permeable sand, increasing its permeability and thereby amplifying the permeability contrast between a sand and a shale.

In the evaluation of anisotropy, diagenetic changes can’t be ignored because they may significantly alter anisotropies established during deposition. For example, the control of grain orientation and packing over pore geometry, and thereby over permeability, may be destroyed by quartz overgrowth and clays that develop in place (right). This means that a model of permeability anisotropy may be flawed if it is based only on the depositional environment. The exception, however, may be laminated beds. Here, diagenetic plugging of pores and pore throats may reduce permeability, but may not alter permeability anisotropy.21

Moving up from the grain-pore scale, the next level of feature is bedding. A bed is a typically defined as layer thicker than 1 cm that is distinguishable from layers above and below by a break in lithology, a sharp physical break, or both. Of significant interest to the reservoir engineer is the effect of bedding scale geometry, namely, a common phenomenon called crossbedding (next page).

A crossbed is a single layer or a single sedimentation unit consisting of internal laminae inclined to the principal surface of sedimentation.22 Crossbedding is caused by migration of wave ripples on a sediment surface. Settings in which crossbeds develop include lateral shifting of tidal channels on intertidal flats, channel fill, beach and bar migration, and eolian dune migration.

Crossbedding is of interest chiefly because when all crossbeds in a formation have one orientation, they have a much greater influence on fluid flow anisotropy than effects at the pore scale. Permeability is significantly lower across crossbed boundaries than along them. This permeability anisotropy does not arise from variation in material, since crossbedded formations are fairly uniform lithologically. Instead, it arises from large variation in grain size and therefore layering of high and low permeability.

The next scale up from bedding is folding and fracturing. Folding can reorient directional permeability established during deposition and initial diagenesis.23 At the reservoir scale, however, the influence of folding on anisotropy may be a second-order effect. The first-order effect on anisotropy is fracturing, which can be associated with folding. Fractures tend to concentrate near the apex of folds, although they may concentrate elsewhere, since their distribution is governed by the strain distribution in the fold.24 Fractures are distributed somewhat by the mechanical properties of the rock, tending to concentrate in low-porosity formations, which are more brittle.

Fracturing is a leading contributor to anisotropy induced postdepositionally, especially in carbonates. Either open or filled with porous breccia, fractures form zones with physical properties sharply different from those of the surrounding rock. Fractures by definition also have a well-defined directionality. These two features together—contrasting properties and directionality—make them potent generators of anisotropy at a scale as large as whole reservoirs, or as small as a core plug.

Healed, or mineralized, fractures have the same well-defined directionality as open fractures, but may not contrast as sharply with properties of the surrounding rock, and so may not generate anisotropy that is as pronounced or as detectable. For example, if the mineralizing material has an acoustic impedance or resistivity close to that of the surrounding rock, the fracture may not produce detectable anisotropy of acoustic wave velocity or resistivity. Most of the interest in anisotropy induced by open fractures centers on their effect on seismic energy and on fluid flow.25

A Closer Look at Electrical Anisotropy

Of all the investigations into anisotropy in the oil field, some of the most intriguing recent work has been in the oldest arena of anisotropy—resistivity measurements. The earliest observations of anisotropy were noted by discrepancy between surface measurements in different directions. Later, discrepancies were noted between surface and borehole measurements, and between induction and laterolog measurements.26 Several papers have reviewed advances in interpreting anisotropy from wireline resistivity measurements.27 Now, much attention is focused on harnessing anisotropy interpreted from logging-while-drilling (LWD) measurements. Here is a brief description of electrical anisotropy and a historical perspective on some recent developments.

In electrical anisotropy, resistivity depends on the direction of current flow in the rock.
The effect of anisotropy on resistivity logs depends on the angle between the borehole and formation. In a vertical well crossing flat-lying beds, an induction tool measures horizontal resistivity, the current flowing parallel to bedding. Vertical resistivity, the current flowing normal to bedding, is always at least as much as, if not more than, horizontal resistivity. Therefore the notion of a single number for true resistivity, \( R_t \), becomes less useful as electrical anisotropy increases. A more descriptive approach is to think of two resistivities—\( R_v \), vertical and \( R_h \), horizontal. With increasing well deviation, the contribution from the vertical component becomes stronger.

In a horizontal well through flat-lying beds, resistivity logs read higher because the contribution of vertical resistivity reaches a maximum. This, combined with polarization horns, results in correlation difficulties. This year, a new method was published that derives both a vertical and horizontal resistivity from the two LWD resistivities and worked for laminated or shaly formations: the deep and shallow LWD resistivity measurements each respond differently to anisotropy and therefore separate.

This year, a new method was published that derives both a vertical and horizontal resistivity from the two LWD resistivities and worked for laminated or shaly formations: the deep and shallow LWD resistivity measurements each respond differently to anisotropy and therefore separate.

TIV isotropic resistivity. The authors showed that in anisotropic beds logged at dips above 30°, the shallow and deep resistivity measurements become a combination of vertical and horizontal resistivities. The shallow LWD resistivities behave differently from wireline induction resistivity in dipping beds. The code modeled the likely CDR Compensated Dual Resistivity response for any dip angle. The modeling code provided a good first approximation, and worked for

27. See Oilfield Review, reference 2.
28. To avoid the ambiguity of using the horizon as a frame of reference, vertical resistivity is sometimes called transverse resistivity and horizontal resistivity is called longitudinal resistivity.
Electrical anisotropy

that corresponds to “Rt” in offset vertical log. Because it is the horizontal resistivity directional well log with the vertical well LWD resistivity, however, reconciles the resistivities are higher than the vertical well grain size, irreducible water saturation. The anisotropy is thought to be due to variation in grain size and the close cousin of the anisotropy is the horizontal resistivity of the shale laminations.35

Without this processing, the original LWD resistivities are higher than the vertical well induction resistivity. The derived horizontal LWD resistivity, however, reconciles the directional well log with the vertical well log. Because it is the horizontal resistivity that corresponds to “Rt”, in offset vertical wells, this horizontal resistivity is used for correlation and to keep the borehole trajectory in anisotropic pay zones.32 A similar approach to correct for resistivity anisotropy has been developed.33

Considering the case of laminated sand-shale resistivity, Hagiwara, now at Halliburton, has proposed another similar method using the horizontal and vertical resistivities of laminated sand-shale sequences to determine sand resistivity and net-to-gross ratio, making the simplifying assumption that the shale laminations are electrically anisotropic.34

In a parallel development, James Klein at ARCO Exploration and Production Technology has been studying the petrophysics underlying electrically anisotropic reservoirs. Building on work by Chemali and colleagues at Halliburton, he proposed a method to disentangle the resistivity of sand laminates (taken as being isotropic) from the anisotropic contribution of shales in a laminated sand-shale sequence. Input parameters are the volume of shale laminations, dip angle, and both the horizontal and vertical resistivity of the shale laminations.35

Klein’s on-going work, however, extends the understanding of electrical anisotropy beyond shales and sand-shale sequences.36 He has been investigating the origin of electrical anisotropy in clean, seemingly homogeneous sandstones as observed by Leake, formerly of Oxy USA, and Shray and Luling, both of Schlumberger. The key insight concerns what appears to be homogeneous sandstone consisting of layers with more or less constant porosity but varying grain sizes and capillarity.37 While this sandstone is isotropic when 100% water saturated, it becomes anisotropic when desaturated to reservoir conditions.

Klein and collaborator David Allen of Schlumberger Wireline & Testing in Sugar Land, Texas, USA are investigating this theory and its implications. Preliminary work suggests that resistivity anisotropy may be related to grain-size variation and therefore to permeability anisotropy. Less dramatic, but equally illuminating, is that resistivity anisotropy in the water leg will usually be different from that in the oil leg, as well as different in the invaded zone and uninvaded formation. These linkages between resistivity and permeability anisotropies are the fuel for exciting work. Resistivity anisotropy, once a bothersome headache, may one day provide clues to deeper understanding of permeability.

—JMK

31. Moran and Gianzero, reference 27.
37. Capillarity is the action by which surface tension draws fluid into the interstices of a material.