Acoustic emission — an ear to the ground

Hydrofracturing is one of the most commonly used methods of increasing production from low reservoir permeability reservoirs. It is crucial for siting producing wells, predicting water breakthrough and planning of waterflood and enhanced oil recovery (EOR) projects. But until recently, there has been no way of predicting how the induced rock fractures will propagate away from the well.

The Formation MicroScanner* tool can be run into open holes before and after hydrofracturing to investigate the fractures. In cased hole, analysis of a full waveform sonic log from the Array-Sonic* tool may provide some fracture information. Variations in the quality of casing cement, however, may affect the data making interpretation difficult. Both these measurements cannot "see" more than a few inches into the formation and thus cannot indicate the direction and extent of fracture development far from the borehole.

However, a more comprehensive fracture analysis may now be possible using the acoustic emission (AE) technique. This method has recently been used successfully in several different parts of the world at depths up to 11,000 feet (3,350 meters). Basically, the technique involves listening to the sounds emitted from rocks during hydrofracturing. Low-frequency sound, generated when rock cracks, is detected by geophones placed in the well being fractured or in nearby wells.

Three-component borehole seismic tools with triaxial geophones are necessary for AE work. During openhole surveys, the tool is clamped to the wall by mechanical locking arms. In cased holes, either locking arms or strong magnets are used. Clamping couples the sensors tightly to the formation and permits the cable to be slackened, thus eliminating noise transmission from the surface.

During rock fracturing, cracks open perpendicular to the earth's minimum stress direction (above). The
acoustic wave motion generated by the fracturing has characteristic particle motion directions and frequencies which can provide fracture information. The compressional wave, with most of its particle motion in the fracture plane, indicates the induced fracture's direction. Shear waves, if detected, can give a better determination of the fracture's extent.

Finding the fracture's direction of propagation depends on knowing the geophone's orientation. This can be found by setting off check shots at known surface locations and observing the directions of the incoming compressional wave arrivals recorded by the triaxial sensors. The seismic source is offset from the well to ensure production of horizontal wave motion measurements. With this procedure, fracture orientation can be determined to within 3 degrees (above). A compass-pendulum system and a downhole gyroscope have been also used for this purpose; but the additional tool mass, however, may degrade the geophone response. This problem can be avoided by using the recently introduced Combinable Seismic Imager (CSI*) tool whose geophones are relatively unaffected by changes in the configuration of the main tool.

A three-part schematic demonstrating the directions of wave fronts from a seismic source and the acoustic emissions from induced fractures. The left portion shows hydraulic fracturing in operation and also depicts a seismic pulse traveling from an offset surface source toward a three-component downhole seismic tool. The central plots show the geometry of shear and compressional wave fronts emanating from the fracturing operation and the surface source, in relation to the triaxial geophones. The hodo- gram on the right shows how the wave front arrival angle is determined from a pair of horizontal geophone signals (x and y).

Acoustic waves arrivals at the geophones are crossplotted to determine their incoming direction. Plotting the geophone response to the compression- al wave on the x axis against that for the y axis at simultaneous times produces a hodogram. Compressional waves are shown with the rock particles moving in the wave's direction (above, left). On the horizontal axes, the crossplot of the signals indicates the horizontal component of the compression- al wave's direction. The angle with respect to the vertical component (z) can be found in a similar way. Once the angle of the x and y axes relative to the known source position has been determined, the source of the fracture's acoustic emissions can be similarly defined.
A continuous recording of signals from the triaxial receiver in the injection well. Identifying the direction of wave front motion, is difficult since the first wave arrivals of the events are not clear.

In single-well experiments, using only the injection well, this technique can indicate the orientation of the induced fracture plane. Data obtained from the triaxial receivers during the fluid injection phase of a hydrofracturing job show considerable background noise in signals from all three axes (below). The rose diagram, or polar plot, for these data, compiled from hodogram directions of selected events on the x and y axes, is shown (right). The postulated fracture direction coincides with the most frequently observed azimuth direction. Data from an observation well about 160 feet [50 metres] away (next page) is less affected by environmental and borehole noise.

Discrete events appear on all three axes, and their origins are in a plane through the injection well. The direction of the first motion in these events depends on the position of the acoustic emission source relative to the receiver. But because this direction of motion is difficult to identify in the data, an ambiguity of 180 degrees remains in the directional results (above, right). This ambiguity can be resolved by taking data in two or more wells and extending the directions indicated by their respective rose plots until they intersect.

If, in addition to compressional wave motion, shear modes are also detected (previous page), the arrival time delay between the two waves indicates the distance from the well at which the fracturing is occurring. The velocity of both compressional and shear waves can be measured in the wells using full waveform sonic tools such as the Array-Sonic tool. These velocities and the measured arrival time differences can thus add distance to the azimuth data.

AE location methods are based on the assumption that both compressional and shear waves propagate in a straight line. Since this is not true for heterogeneous or anisotropic media, a more reliable method...
has been developed based on calibrations of the system using perforation shots in nearby wells. By knowing the distances and observing the time difference between compressional and shear arrivals from the same shot, it is possible to measure velocity factors associated with the wave propagation directions between the fracture well and observation well. These factors can then be used to calculate the distances to microseisms in various directions, thus essentially taking anisotropy into account.

There is still much to be learned about microseism-induced acoustic emissions and the relationship of the detected sound to fracture propagation. Specifically, more research needs to be carried out on an array of topics: acoustic emissions and their mechanism of generation; how emission energy separates into compressional and shear waves; how and why the wave train character changes with the nature of the fractured rock and the observation period; and how to better relate the detected acoustic emissions to the fracture parameters, especially in anisotropic and inhomogeneous formations. More detailed answers to these questions will lead to improved data acquisition methods and interpretation procedures.—JT, GC

Further Reading and Acknowledgements


For assistance in preparing this focus, thanks to Carl Poster, Dubai, UAE.
Drilling fluids for horizontal wells

Drilling the first horizontal wells was slow and trouble-prone, costing several times a vertical or normally offset deviated well in the same reservoir. Today, drilling a horizontal well is almost routine and costs just 1.3 to 1.5 times a conventional well. At the heart of this improvement is better management of drilling fluids.

The main challenges the mud engineer faces in horizontal drilling are wellbore stability and cuttings removal. Wellbore stability depends on maintaining a chemical and physical balance between formation and mud. Chemical stability in a horizontal wellbore is no different from that in a vertical well. But physical stability becomes progressively more precarious as deviation increases and is most critical when the borehole becomes horizontal. As deviation increases, the wellbore increasingly bears the earth’s vertical stress—in contrast to the horizontal stress born by a vertical well. A heavier mud is needed to prevent hole collapse, evidenced at the surface by curve-shaped cuttings. But then, fracturing and lost circulation become more likely. As wellbore collapse pressure approaches that of the fracture gradient (above) the mud engineer must maintain mud weight somewhere in between.

During planning, the mud engineer can estimate this safe mud-weight window by reviewing offset well logs and fracture gradient data, and noting local experience with lost circulation and tight hole. Core analysis giving in-situ stress would also be used if available. A continuous prediction versus depth of the safety margin is provided by the Mechanical Stability (MSL) log, which estimates wellbore stresses and associated failure related to hole angle from compressional and shear sonic, formation density and gamma ray logs run in nearby wells (see "Horizontal Drilling Comes of Age," page 22).
Drillers must ensure that the equivalent circulating density (ECD), as well as its static density, is within safe limits. ECD, the effective density of a moving fluid, is slightly more than static density because of the friction pressure drop in the annulus. ECD depends on pump rate and fluid viscosity. Since pump rates are generally high in horizontal wells to clean hole, maintaining ECD within limits means keeping viscosity low. The main cause of elevated viscosity is low-gravity solids, so the mud engineer must carefully monitor the solids control equipment and ensure low-gravity solids are kept to a minimum.

Three phases of horizontal well cleaning. The top section acts like a vertical well; the middle section accumulates cuttings on the low side, but they may slip downward; the bottom section simply accumulates cuttings.

Cuttings removal, the second challenge for the mud engineer in horizontal wells, divides into three phases (above):
- Where hole deviation is less than 25 degrees, the wellbore behaves as if vertical, and laminar mud flow combined with conventional choice of pump rate to get the cuttings moving uphill provides satisfactory hole cleaning.
- At deviations up to about 65 degrees, cuttings may accumulate on the low side of the hole and even slip back down the hole when the pumps stop, causing stuck pipe. This section is the most difficult to clean, requiring turbulent flow and annular velocities from 200 to 250 feet (60 to 75 meters) per minute. In unconsolidated formations that erode under constant turbulent flow, hole cleaning can be ensured by intermittently injecting low-viscosity pills of mud into an otherwise mostly laminar circulation. The low-viscosity pill, made by adding dispersant to mud, promotes local turbulent flow.
- At hole deviations greater than 65 degrees, cuttings accumulate on the low side of the borehole but do not slip. Larger cuttings settle first and are harder to move. Turbulent flow combined with pipe rotation is the most effective method of churning up the cuttings bed and cleaning the hole.

In the planning stage, the mud engineer gathers all available facts about the hole, such as bit sizes, casing depths and well profile and also about the formation—its mechanical integrity and pore pressure. This permits calculating mud rheology and flow rate needed to keep the hole clean in the three sections, laminar in the top section and turbulent in the bottom two. Mud rheology at downhole temperature and pressure may be tested in the laboratory.

During drilling, the mud engineer uses several techniques to check how well the hole is being cleaned. In one technique, hole-cleaning efficiency is estimated by measuring the discharge from the solids control equipment and comparing it with what would be expected given the hole size and the rate of penetration. This material balance approach works only over long sections of the well; otherwise the uncertainty in hole diameter leads to inaccuracies. In another technique, the hole-cleaning performance of a turbulent pill is monitored by measuring the pill's rheology when it returns to surface. The thicker the pill, the more solids it has picked up.

Once a cuttings bed starts forming on the low side of the well, solids control becomes a major challenge for the mud engineer. The cuttings spend more
Cuttings stranded in the horizontal section get ground to fines by the rotating drillpipe.

Fine solids in the mud also create a thick mudcake, constricting the deviated hole and increasing the possibility of stuck drillpipe—stuck pipe is more likely in a horizontal well than in a vertical well, because of the dramatically larger area of reservoir exposed to the wellbore. The key to controlling mudcake is minimizing filtrate invasion. One way to reduce fluid loss is to minimize hydrostatic pressure using the lowest possible mud weight, but the mud should not be so light as to cause wellbore instability. A good solution is to use a sized weighting material. The solids must be compatible with the formation—for example, acid-soluble calcium carbonate—and have the right size to bridge formation pores.

Also prominent on the agenda for the horizontal mud system is lubricity. Large side forces experienced while drilling at high angles result in greater frictional drag and increased chances of stuck drillpipe. Therefore, best results are achieved with oil-base muds that provide lubricity. If environmental considerations dictate use of water-base muds, special lubricity additives may be needed.

Estimates vary as to how many horizontal wells will be drilled in the future, but all point to a massive increase. Mud management for horizontal wells, therefore, will continue to evolve. —CF

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Exploiting Reservoirs with Horizontal Wells: the Mærsk Experience

Danish-based Mærsk Olje og Gas A/S transformed prospects in their Dan field by drilling horizontal wells and then hydraulically fracturing them. No operator had previously fractured a horizontal well. Understanding their motivation, following their learning curve, experiencing their taste for innovation is to capture the spirit of the horizontal well revolution sweeping the industry.

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When the oil industry recession hit its low in 1987, Mærsk Olje og Gas A/S began an experiment designed to ensure its continued growth into a major North Sea oil producer. Mærsk Oil, an A.P. Møller affiliate operating on behalf of a partnership of A.P. Møller, Shell and Texaco, initiated oil production from the Dan field in 1972. Situated 200 kilometers (km) [120 miles] offshore in the southwestern part of the Danish North Sea, the Dan field is an anticlinal structure about 6 km [4 miles] across and contains four producing formations totaling several hundred feet in thickness (above). Total oil in place is estimated to be two billion barrels, but recovery factors are low, around 10 percent. The formations are medium-porosity chalks—18 to 36 percent porosity—with very low permeability, typically less than 1 millidarcy (mD).

Mærsk Oil began its Dan field development with a six-wellhead platform, and then

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boosted production with two more six-wellhead platforms, in 1975 and 1976 respectively. The increase was short-lived. Even with the benefit of hydraulic fracturing, the chalk simply would not yield enough oil. Production steadily declined (above).

In an effort to boost production, Maersk Oil established two more platforms each with 12 wellheads and began drilling into the northwestern half of the anticline, called A block. (The downdropped A block is separated from the southeastern, upthrown B block by a northeast-southwest fault zone.) Deviated up to 60 degrees and hydraulically fractured, these 24 new wells went on stream in 1987, increasing production at first to 30,000 barrels of oil per day (BOPD). Unfortunately, production declined rapidly, the economic effects being exacerbated by a steadily weakening crude market. Maersk Oil was thus faced with implementing an altogether holder scheme.

Back in 1978, Maersk Oil reservoir engineers had studied the then revolutionary idea of tapping the tight chalk with horizontal drainholes. Recognizing numerous technical problems, the advantages seemed distinctly attractive. A horizontal drainhole could drain thousands of feet of reservoir compared with hundreds of feet drained by a conventional well. Fewer wells would be required, costing less money, and valuable space on platforms could be saved.

Following the lead of Shell researchers in The Hague, The Netherlands\(^2\) and of F.M. Giger at the Institut Français du Pétrole,\(^1\) the engineers compared the productivity index (PI) expected from a horizontal well with that of a conventional, hydraulically fractured well. In the center of the Dan field, such a well would have a PI about twice that of a conventional fractured well, while at the flanks the PI advantage would be marginal. In general, the increased cost of drilling the horizontal well did not seem worthwhile. A fractured horizontal well, on the other hand, looked promising. Several fractures regularly spaced along the well offered a four- to six-fold increase in PI. This seemed particularly inviting outside the gas cap on the reservoir flanks, where induced fractures would not act as a gas conduit into the production stream.

In 1978, however, few horizontal wells had been drilled anywhere, and none had been fractured. Horizontal wells were being drilled to tap naturally fractured reservoirs and were completed either openhole or with unencemented slotted liner. Cementing and perforating conventional liner in a horizontal well, necessary to isolate zones for hydraulic fracturing, was regarded as too difficult. By 1986, though, Maersk Oil decided that cementing would work and that it was time to attempt the industry's first horizontal, hydraulically fractured well. The initial commitment was to drill and evaluate three horizontal wells.

The First Three Wells
A period of careful planning covered all aspects of the operation. Wellbore trajectory, wellbore stability, bottomhole assembly (BHA) design, drillstring torque and drag modeling, drilling mud specification, casing and liner selection, cement slurry design, stimulation hardware—these factors all required special attention. The first well, MBF-14, was planned to tap 1000 horizontal feet [300 meters] of the upper Maastrichtian chalk, the most permeable of the Dan field formations. The horizontal section was to be far outside the gas cap on the flanks of the reservoir in the A block. The intended stimulation was acid fracturing (next page).

It was decided to go for a long-radius hole, so conventional hardware could fit down the hole. The trajectory was planned to minimize torque and drag, with three kickoff points. The first was to be at 800 feet [240 meters] where angle would be built at
There were two BHA options for steering the hole, a steerable motor or an offset stabilized steerable turbine. The steerable motor was chosen because only it could accommodate the high mud flow rate, around 900 gallons per minute, required to clean the deviated and horizontal sections of the well. The steerable motor performed flawlessly except in the lower Danian chalk that overlies the Maastrichtian. Chert stringers in this section deflected the bit from its proper course, causing it to build angle far too fast. The well had to be plugged back and the Danian drilled with a super stiff BHA to keep the hole on track. This increased total drilling time to 66 days, which altogether was 20 more than planned.

Perhaps the most critical planning concerned cementation. Five fractures planned along the 1000-foot horizontal drainhole, would have been impossible to achieve if there were fluid communication through the cement. Research by the Horwell consultancy group, which included a physical simulation of a horizontal cement job, indicated that to prevent channel development the cement slurry must have no free water.

2 1/2 degrees per 100 feet [30 meters] to achieve a deviation of 38 degrees. This angle would carry the well to near the target where the second kickoff would take place. Angle would be built at the same rate to about 70 degrees allowing the well to proceed to the top of the chalk reservoir. At the last kickoff, the well would build to almost horizontal entering the upper Maastrichtian.

Torque and drag modeling indicated that as long as the planned trajectory was followed, standard drillpipe and collars were strong enough to transmit the necessary weight and torque to the bit as deviation increased. The horizontal sections required drill collars in the less-than-30-degree sections of the well to provide weight. In fact, MFB-14 was drilled very close to specifications, and the torque and drag encountered while drilling came within 10 percent of computer-modeled predictions.

and no sedimentation. These requirements were met by Dowell Schlumberger’s latex-based formulations.

It was also considered necessary to maximize space in the annulus to guarantee mud displacement. In MFB-14, a 5 1/2-inch liner was run in the 8 1/2-inch drainhole, with three centralizers on every two joints of liner. (In subsequent horizontal wells, a 7-inch liner was used and satisfactorily cemented.) Another precaution was ensuring that the entire liner could be rotated as well as reciprocated to maximize mud displacement. This required a special liner hanger and centralizers allowing liner movement. With these precautions, cementation in MFB-14 proved satisfactory. This was indicated first by good bond on Cement Evaluation Tool (CET)*/Cement Bond Tool (CBT*) logs and later when the five fractures were created without leakoff.

Evidence that MFB-14 had not gone completely to plan came from Tough Logging Condition (TLC*) logs run on drillpipe throughout the horizontal section, a complex procedure that has become routine on all Maersk Oil’s horizontal wells. The logs suggested that after about 330 feet [100 meters], the well trajectory had left the upper Maastrichtian chalk and entered the overlying lower Danian. This is a tighter chalk and known from experience to require propping. Interestingly, the well trajectory was on target. It was the target that was off—formation dip was one degree more than expected (below).

Stimulation plans therefore had to change. The original plan called for acid fracturing using a straddle packer with swab cups as packing elements. This was unsuitable for pumping proppant, so the five zones were perforated and stimulated using a conventional drillstem test string. This required isolating previously stimulated zones with a bridge plug set just beyond the zone to be stimulated. After stimulating the zone and killing the well, the plug was milled and a new plug set farther up the hole in preparation for stimulating the next zone. Each zone therefore required three trips in the hole, rather than the envisaged one, and this extended completion time from the planned 12 days to 40 days. MFB-14 came on stream in July 1987 initially producing 7,500 BOPD on a 90/64-inch choke, triple the rate of the best conventional well.

What was learned from MFB-14? Except for the problem of clamp stringers, drilling had been relatively uneventful. For the next well, computer modeling suggested the drainhole length could be safely extended to 3,000 feet [900 meters]; the next well, MFB-15, actually went out 2,500 feet [760 meters]. Cementing the liner had gone smoothly, so well in fact that a larger 7-inch liner was chosen for MFB-15.

The main problem was stimulation technique—the time it took and the possibility that not enough sand had got into the fractures. This seemed a likely explanation for the almost immediate drop in MFB-14’s production, to 1,000 BOPD within 2 to 3 months. The production decline was undoubtedly due also to the well entering the less productive Danian—production logs run with coiled tubing showed most of the production coming from the two fractures in the more productive Maastrichtian. To better understand the production decline, downhole pressure and temperature gauges with surface readout were installed on all future horizontal wells (next page, top).

MFB-15 was spudded in January 1988 and directed to the B-block upper Maastrichtian. The horizontal section begins under the gas cap and then goes outside it. To ensure correct placement of the well, a seismic line was shot along the projected well trajectory, and later, during drilling, a pilot hole was first drilled to the 50-percent water saturation level to identify the formation tops. As a third safeguard, the well was planned to go at exactly 90-degree deviation, parallel to and at a fixed height above the 50-percent water saturation depth. Drilling proceeded on schedule and was completed in 52 days (next page, middle).

Stimulation also experienced fewer problems. Seven acid fractures were performed along the 2,500-foot drainhole using a straddle packer assembly that reduced the number of trips per fracture to just one and the completion time to 39 days. The well came on stream at 9,000 BOPD. Production declined but not as rapidly as in MFB-14, stabilizing at 2,000 BOPD.

* Mark of Schlumberger

Trajectory of the first horizontal well in the Dan field, MFB-14, drilled in A block outside the gas cap. Chert stringers in the lower Danian (D2) caused the well to deviate too quickly, so the well was plugged back and the formation redrilled with a super stiff BHA. The well then hit the upper Maastrichtian (M1) as planned. Later, because formation dip was 1° more than expected, the well reentered the poorly producing D2, compromising productivity. MFB-14 was cased, cemented and stimulated with five sand-filled fractures—the first horizontal well ever to be successfully fractured.
MFB-13, the third horizontal well, was directed under the gas cap in B block to see if a fractured well here could produce high oil flow without gas coning. Experience in the previous wells suggested that the lower Danian formation, which overlies the Maastrichtian, would close around an acid fracture preventing gas entry. This time, no pilot hole was drilled—an intermediate logging run was used instead just after the well pierced the Maastrichtian. Drilling the 2,600-foot (800-meter) drainhole proceeded without incident. The acid fracturing was performed through a new packer assembly that set a retrievable plug just beyond each zone being fractured. This technique isolated each fracture immediately after stimulation, preventing substantial losses of completion fluid experienced in the previous well. MFB-13 came on stream in June 1988 at 4,000 BOPD and has since declined to about 2,500 BOPD.

These first three wells accelerated Maersk Oil along the horizontal well learning curve. The two-year pilot program had proved that in very low permeability formations, such as in the Dan field, fractured horizontal wells were not only possible but economical. Including the platform slot, each well cost 1.4 times a conventional well, yet produced initially three to six times more oil.

But there was still much to learn and perfect. Before drilling more horizontal wells, Maersk Oil had to better understand these wells’ performance. More work was needed to perfect the completion hardware and stimulation method. And avoiding the trajectory problem in MFB-14 required a clearer picture of where each drainhole was headed relative to the reservoir geometry.
Well Performance

Although the first three horizontal wells outperformed conventional wells, their production drop-off demanded careful analysis (right). This was particularly true for MFB-15, which was far from the gas cap and looked on paper to be trouble free. Two options were followed simultaneously: conventional semianalytical well test analysis, adapted for fractured horizontal wells; and a full-scale simulation.

Well test analysis is complicated by the numerous flow regimes to be expected in a fractured horizontal well (below, right). After a very early flow regime dominated by the fractures, oil flows linearly toward the fracture faces. Analysis during this period could reveal fracture size if formation permeability is known. Gradually, the flow becomes pseudo-radial toward each fracture, and depending on fracture spacing and orientation the flows may start to interfere with one another. After a time, the interference transforms into a gross linear flow from the far formation toward the well. Analysis during this regime can yield formation permeability because the effective flow width—the distance along the horizontal drainage hole from the first fracture to the last—is known. Finally, providing no flow barriers are encountered, pseudo-radial flow toward the whole well may occur. In conventional well test analysis, this regime yields formation permeability, but in low-permeability chalk, the regime takes months or years to appear, and may never materialize.

Guidelines for interpreting well test data were established by Mærsk Oil’s partner, Shell, and promised in certain cases to even help estimate fracture orientation. But applied to the pressure data, the results looked unreliable. It was later discovered that the fractures in MFB-15 were probably closing with decreasing well pressure. This nullified an important assumption in the analysis, that fracture geometry must be fixed. Another weakness of the test analysis was its inability to deal with gas, not a problem for wells outside the gas cap but definitely a limitation for those beneath it.

Average production from five of the first six horizontal wells compared with a typical conventional well. Except for the first well, MFB-14, which tapped the wrong chalk unit, the increase in production from a horizontal well pays several times over for the increase in drilling and completion costs.

Flow regimes predicted by test analysis in fractured horizontal wells. Once the well is allowed to produce, flow is first linear toward the fracture faces. Then, as the volume of formation contributing to flow enlarges, individual flows toward fractures become pseudo-radial and begin to interfere. Flow next becomes linear toward the well. Eventually—and in very low-permeability formations this may take months or years—flow becomes pseudo-radial toward the entire well.
The second approach used a simulator developed in conjunction with the Franlab consultancy group. Because MFB-15 had not flowed long enough for the flows into adjacent fractures to begin to interfere with each other, it was considered sufficient to investigate the performance of a single fracture. Since it was also assumed that the fractures were symmetric in shape, just one-quarter of one fracture was actually modeled. The results were then multiplied by 28 to obtain total well performance.

Since the fractures were simulated as being infinitely conducting, their orientation relative to the drainhole ceased to be a factor in this attempt to understand MFB-15's performance. The issue of fracture orientation remains a bit of an enigma. The directions of the three horizontal wells cover a 90-degree spread. Thus, if the earth's horizontal stress were roughly uniform within the field area, fracture orientation should vary substantially from one well to the next; it could even be parallel to one well and perpendicular to another. To date, Maersk Oil is still unsure of fracture orientation.

The simulator, as it was initially set up using basic knowledge of reservoir properties, failed to match MFB-15's production history in two crucial ways. It reproduced neither the well's high initial production rate, nor its rapid production decline. The first discrepancy had been noted previously in conventional wells and was thought to be caused by the acid stimulation creating small fractures in the formation near the fracture face, allowing the formation to produce more freely. Grid cells near the fracture face were therefore given higher permeability than the surrounding formation initially, but to simulate closing progressively less permeability as pressure decreased. The second discrepancy was ascribed to the fracture closing as well pressure declined. A linear decrease in fracture area with pressure was therefore built into the simulator. With these two modifications, the simulator closely matched MFB-15's production history. The simulator was later refined to allow initial fracture size and formation permeability to be chosen individually for the seven fractures. These parameters were then adjusted to match flowmeter logs that showed the net flow from each fracture (below).

The main lesson learned from the simulation was that, where appropriate, fractures should be propped to prevent closure. This was inadvisable under the gas cap, but should certainly be done outside it, the case for one of the next horizontal wells drilled—MFA-17. Nine hydraulic fractures in this well took 8.1 million lb of sand, with the largest taking over 2 million lb. The operation was carried out with the largest stimulation vessel the North Sea could offer, but it still took four round-trips to bring material to the platform. Production has not declined as rapidly as in MFB-15, and it is certain that the fractures have remained open.

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**Simulation results for MFB-15.** The well's high initial production rate was closely matched by assuming that permeability near the fracture faces was increased due to matrix fracturing during stimulation. The subsequent rapid decline in flow was matched by assuming that these miniature fractures as well as the hydraulic fractures themselves closed up as bottomhole pressure declined. The pressure distribution shown comes from a simulation in which individual fracture character was tuned to match flowmeter data.
Selective Completion
The greatest challenge faced drilling the second series of horizontal wells was improving the completion/stimulation hardware. There were at least three forces urging improvement:
• to decrease completion time and consequently overall well cost—Maersk Oil stuck to the ideal that stimulating each zone had to be done in only one trip
• to reduce losses of expensive completion fluids and improve well control between stimulating different zones
• to be able to selectively open and close individual fractures once the well was producing.

It was clear that selective completions would be the key to a horizontal well development of the Dan field. Each horizontal well with multiple fractures had to be viewed as several conventional wells rolled into one, each part requiring individual control. This appeared especially true when considering a water injection scheme. Whether the injection was from horizontal wells or existing vertical ones, breakthrough to individual fractures would be unpredictable. To stop water production, it was mandatory to be able to close off producing well fractures at will.

Much thought, discussion and experimentation with Baker Oil Tools recently resulted in radically new completion hardware that permits one-trip stimulation for acid fracturing and leaves hardware downhole that allows selective opening and closing of individual zones. Further development is underway to provide one-trip perforation and stimulation when using sand.

The hardware left in place downhole comprises any number of "downhole assemblies," one per zone (below). Each assembly consists of a retrievable packer, a sliding sleeve that can be opened and closed with coiled tubing, a section of 4 1/2-inch tubing as long as the zone and a seal assembly that seats into the retrievable packer of the next assembly. The deepest assembly seats into a "ump packer" set at the end of the hole with drillpipe, and production tubing seats into the topmost assembly's retrievable packer.

Downhole assemblies are carried sequentially into the hole on a "service assembly" that comprises a retrievable packer, a length of 2 7/8-inch tubing, a circulating port and tubing-conveyed perforating guns (next page). The service assembly with downhole assembly riding piggyback are run to perforating depth, the service assembly packer is set, and the guns fired. The guns retract automatically into the service assembly, and stimulation commences. After stimulation, the service assembly packer is unseated to establish circulation. The service assembly is then lowered to stab the downhole assembly into the previous zone's downhole assembly packer or, if it is the first zone to be completed, into the sump packer. Finally, the downhole assembly packer is seated and the service assembly pulled from the hole. The process is repeated for each zone. When all zones are completed, coiled tubing is used to wash debris from the sliding sleeves and then open or close them as required.

Maersk Oil used this technique successfully on two of the second set of three horizontal wells drilled in the Dan field. Both were completed and stimulated with one trip in the hole per zone; one well was acid fractured, the other matrix acidized. Even these pilot runs resulted in savings in time and completion fluid costs. The huge sand fracturing operation in MFA-17 was completed with two trips per zone. The downhole assemblies are susceptible to damage by large sand flows; further development is required to protect the

Radically new completion hardware used in the second series of three horizontal wells in the Dan field to achieve selective zone isolation for stimulation and production. The basic component is the downhole assembly, comprising from left (below): a packer, a sliding sleeve, a length of 4 1/2-inch tubing as long as required to cover the zone, and a seal assembly. In the completed well, as many assemblies as zones are set in place, each one seated into the assembly below it (above, right). The deepest assembly seats into a sump packer; production tubing seats into the top packer.
The service assembly (left) used to carry downhole assemblies into the well (below, left). The service assembly comprises from left: a retrievable packer, a length of 2 7/8-inch tubing, a circulating port and tubing-conveyed perforating (TCP) guns that retract inside the tubing after firing.

With the guns positioned opposite the zone to be treated, the service assembly's packer is set to permit isolated perforating and stimulating. The downhole assembly is then set in place and the service assembly is released and retrieved for carrying the next downhole assembly into the well.

Selective Completion

The greatest challenge faced during the drilling of the second series of horizontal wells was improving the completion/stimulation hardware. There were at least three forces urging improvement:

- To decrease completion time and consequently overall well costs—Mann Oil stuck to the ideal that stimulating each zone had to be done in only one trip.

- To reduce losses of expensive completion fluids and improve well control between stimulating different zones.

- To be able to selectively open and close individual fractures once the well was producing.

It was clear that selective completions would be the key to a horizontal well development of the Dan field. Each horizontal well with multiple fractures had to be viewed as several conventional wells rolled into one, each requiring individual control. This appeared especially true when considering a water injection scheme. Whether the injection was from horizontal wells or existing vertical ones, breakthrough to individual fractures would be unpredictable. To stop water production, it was mandatory to be able to close off producing well fractures at will.

- Radically new completion hardware used in the second series of three horizontal wells in the Dan field to achieve selective zone isolation for stimulation and production. The basic component is the downhole assembly, comprising from left: retrievable packer, a sliding sleeve, a length of 2 1/2-in tubing as long as required to cover the zone, and a seal assembly. To the completed well, as many assemblies as zones are set in place, each one seated into the assembly below it (above, right). The deepest assembly seats into a sump packer; production tubing seats into the top packer.

- Much thought, discussion, and experimentation with Baker Oil Tools resulted in radically new completion hardware that permits one-trip stimulation for acid fracturing and leaves hardware downhole that allows selective opening and closing of individual zones. Further development is underway to provide one-trip perforation and stimulation when using sand.

- The hardware left in place downhole comprises any number of "downhole assemblies," one per zone (below). Each assembly consists of a retrievable packer, a sliding sleeve that can be opened and closed with coiled tubing, a section of 4 1/2-in tubing as long as the zone and a seal assembly that seats into the retrievable packer of the next assembly. The deepest assembly seats into a "sump packer" that lines the bottom of the hole with drillpipe and production tubing seats into the topmost assembly’s retrievable packer.

- Downhole assemblies are carried sequentially into the hole on a "service assembly" that comprises a retrievable packer, a length of 2 1/2-in tubing, a circulating port and tubing-conveyed perforating guns (next page). The service assembly with downhole assembly riding piggyback are run to perforating depth, the service assembly packer is set, and the guns fired. The guns retract automatically into the service assembly, and stimulation commences. After stimulation, the service assembly packer is unset to establish circulation. The service assembly is then lowered to stab the downhole assembly into the previous zone’s downhole assembly packer or, if it is the first zone to be completed, into the sump packer. Finally, the downhole assembly packer is seated and the service assembly pulled from the hole. The process is repeated for each zone. When all zones are completed, coiled tubing is used to wash debris from the sliding sleeves and then open or close them as required.

- Mann Oil used this technique successfully on two of the second set of three horizontal wells drilled in the Dan field. Both were completed and stimulated with one trip in the hole per zone; one well was acid fractured, the other matrix acidized. Even these pilot runs resulted in savings in time and completion fixed costs. The huge sand fracturing operations in MFA-17 was completed with two trips per zone. The downhole assemblies are susceptible to damage by large sand flows; further development is required to protect the...
sliding sleeves and other parts of the assemblies from sand erosion.

Today, horizontal development of the Dan field continues at full pace (above). Last year saw the completion of MFA-13, MFA-16 and MFA-17. At least seven more horizontal wells will be drilled this year and next. Meanwhile, Mærsk Oil is applying its horizontal technology to three other fields in Danish waters: the gas-bearing Tyra field and the oil-bearing Valdemar and Kraka fields.

For each problem solved in this odyssey, though, fresh problems are always on the horizon. First, there is the never-ending quest to speed up any offshore operation to cut costs. Much progress has been made in reducing drilling, logging, completion and stimulation times. The next opportunity is to perform as much workover as possible with coiled tubing.

The second problem today concerns matrix acidization. The first well to be matrix acidized in the Dan field was MFA-16, which is situated under the gas cap. Experience in this well suggests that the acid seeks out one permeable entry into the formation and little else gets cleaned. All types of diverters have been tried, but the acid continues to bypass the majority of the zone being acidized. Inflatable packer tools on coiled tubing may be a solution.

A third problem is ensuring that a horizontal well sticks to reservoir pay, particularly in thin or faulted producing zones. Well trajectory can be controlled satisfactorily. The uncertainty is knowing structure and stratigraphy near the wellbore. For example, a fault unexpectedly caused the horizontal Valdemar-1 drainhole to suddenly exit the field’s thin producing formation. Measurement-while-drilling (MWD) data and microseismicity from cuts helped pull the well back to the producing formation (next page). Later, after a check-shot survey was run, it was possible to trace the well trajectory on a seismic section and observe its intersection with a fault. A check-shot measurement performed while drilling would place the well’s location on the section in real time, revolutionizing the ability to optimize hole trajectory.

A final challenge is in reservoir planning, deciding on horizontal well spacings and the role of conventional wells in injection programs—in short, generating the reservoir engineering expertise the industry has acquired over decades in conventional field development.

Horizontal wells will continue to revolutionize a certain segment of the oilfield. Much as happened in just a few years, Mærsk Oil looks forward to the innovations of the future.

—HE
Tracking well trajectory in Valdemar-1, the first horizontal well in the oil-bearing Valdemar field, situated northwest of the Dan field. The well unexpectedly met a fault and exited the target B1 formation, entering the Barremian shales. This was recognized in real time from MWD data and micropaleostratigraphy analysis of cuttings—the shale zone is clearly seen between 2250 and 3000 feet from logs run after drilling. The well was redirected down to reenter the B1 formation. The events could also be seen on a seismic section, but only after a check-shot survey was run to fix the well trajectory in two-way time. A check-shot survey while drilling might revolutionize the ability to remedy this situation.
Horizontal Drilling Comes of Age

The upswing in horizontal drilling has pushed the limits of the technique beyond what could be done a few years ago, and what could be dreamed just a decade ago. Increased efficiency, speed and control is enabling drillers to place horizontal wells for optimum reservoir drainage.

Horizontal drilling has fired the imagination of the oil industry like no other recent technological innovation. From a scattering of early horizontal drilling attempts—in the Soviet Union in the 1950s, China in the 1960s, Canada in the late 1970s and Italy in the early 1980s—the technology has moved from fringe to mainstream. Today, horizontal drilling is of unquestioned value and, appropriately applied, affords a range of benefits: increased rate of return from the reservoir, increased recoverable reserves, lower production costs and reduced number of platforms and wells per field. These benefits can be obtained from new wells or by reentering existing wells and completing them horizontally.

Horizontal wells have a higher rate of return than conventional wells because the drainage is exposed to a significantly larger reservoir area. The greater production of horizontal wells lowers their hydrocarbon recovery cost. In addition, horizontal wells increase recoverable reserves and reduce the number of wells required to sweep a field.

About one-half of horizontal wells are in formations where fractures provide most of the permeability. Because most fractures are near vertical, a horizontal well can intersect far more of them than a conventional well. About 20 percent of horizontal wells are in thin-bed reservoirs (half of horizontal wells are targeted at pay zones of thickness less than 80 feet [25 meters]). The bulk of the remainder is in marginal fields and tight carbonates. In all cases, an additional motivation for drilling horizontally is to reduce water and gas coning (next page). Horizontal wells offer this benefit because they induce lower drawdown pressure than conventional wells.

Incentives for drilling horizontally vary with the hydrocarbon province. In Europe (the North Sea and Adriatic Sea) and the Middle East, the main reasons are low permeability or a permeability anisotropy that favors horizontal drainage. A second reason is avoidance of water or gas coning. In the Far East, horizontal wells are drilled mainly to tap thin oil columns that have a gas cap or a strong waterdrive, and sometimes both. In California and Alaska, the main reason is to avoid gas coning; in the Rockies, horizontal wells improve recovery in thin beds; and in the Midwest and Texas, they maximize intersection with fractures.

It is estimated that by the turn of the century about 50 percent of wells in the USA, and 10 to 50 percent of wells in other countries, will be drilled horizontally—a wide range, owing to the newness of the technology. In the shorter term, horizontal drilling is expected to increase worldwide from about 300 wells in 1990 to up to 2500 in 1995.

For their assistance with this article, thanks also to: Jaime Bernardini, Sue Bruce, Larry Hibbard, Bernard Prevedel, Mike Sheppard and Bernard Voisin, Anadroll, Sugar Land, Texas, USA.

Reservoir characteristics (by percent of wells) for horizontal wells drilled and planned worldwide from 1978 to 1989. Horizontal wells are predominantly used in three settings: reservoirs with fractures, with potential coning problems and with thin pay zones.
Types of Horizontal Wells
The three main types of horizontal wells (below) are defined by the rate at which the radius of curvature is built: short, medium and long (see “Comparison of Horizontal Well Radii,” page 25). Short-radius wells are drilled at 1 1/2 to 3 degrees/foot [30 centimeters (cm)]; medium radius is 8 to 50 degrees/100 feet [30 meters]; and long radius is 2 to 6 degrees/100 feet. Another well type, ultrashort radius, requires very small borehole diameter and custom-made drilling tools. The small diameter and severe bend of these holes limit services that can be performed in the horizontal section. Ultrashort radius holes are used mainly for recompletion of old producers and can be thought of as an alternative to fracturing.

Medium-radius drilling is used most often on land. The technique was developed in the USA, driven by requirements to obtain the maximum horizontal length allowable within lease lines. Tools used for medium-radius drilling are usually slightly modified versions of conventional long radius equipment designed to endure increased bending and buckling loads. Compared with long-radius wells, medium-radius wells have higher precision of “landing”—the true vertical depth (TVD) at which the well becomes horizontal can be controlled more closely.

Long-radius holes were originally used on land, but now are almost exclusively offshore. These holes employ conventional drilling tools and often use steerable downhole motors (see “Horizontal Drilling Equipment,” page 26).

Today, there is a tendency in medium-radius wells to build some of the well with long-radius sections (next page). Drillers have found that reducing the build angle at the top of the well allows the hole to be drilled with less torque loss (the difference in torque applied at the surface and measured downhole) than a pure medium-radius well without reducing precision of landing. For example, the first “kickoff” (deviation from the well path) will be 1 1/2 to 2 degrees, rather than 10 degrees, and the second will be 10 degrees.

Steering the Drill Bit
Two methods are used to rotate the bit: surface drives and downhole motors. In the past, surface drive was always performed with a rotary table. But recently, it has been largely replaced by top drive offshore. The top drive system is more powerful, accommodates 90-foot stands (three drillpipes) instead of 30-foot stands and allows rotation and pumping while pulling out of the hole. In the toprive system, power is generated by a motor in the traveling block instead of at the table. The downhole source of power used in horizontal drilling is usually the positive displacement motor (PDM), powered by mud flow (page 26).

A typical surface rotated bottomhole assembly (BHA) is made of stabilizers, drill collars and measurement-while-drilling (MWD) equipment. The placement and size of stabilizers control inclination (deviation angle from the vertical). Assemblies can be designed to build angle, hold it steady or drop angle. With the use of a downhole adjustable stabilizer, a single

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*Long, medium- and short-radius horizontal wells, showing the range of build rates and radii of curvature for each. Note that the average length of the horizontal section varies with the build rate. Although each well is shown with only one build section, horizontal wells can be drilled with one, two or more build sections, and with one or two straight sections, called tangents.*
Comparison of Horizontal Well Radii

Short radius

Advantages
- More precise vertical placement of horizontal drain than medium- and long-radius wells
- Attractive on smaller leases
- Drilled from an existing well so less expensive for re-completion, since most well infrastructure (well, casing, pipeline, roads) is in place
- Because kickoff is usually below fluid contacts, less risk than medium- and long-radius wells with poor isolation between fluid zones.

Disadvantages
- Needs customized drilling equipment that is often slower to handle, less rugged than standard equipment and may not meet API guidelines
- Requires special articulated motor and bottomhole assembly
- No control over borehole azimuth (compass reading with respect to magnetic North) because no MWD tools can fit; azimuth is typically within 20 degrees
- Short horizontal drainhole, often less than 300 feet (90 meters)
- Only openhole completion
- No coring or logging services.

Medium radius

Advantages
- Less torque and drag than in short-radius wells
- Accommodates normal-size MWD tools and the SLIM11 MWD system, which has a 1 3/4-inch diameter to fit in 4 3/4-inch drill collars
- Can use downhole motor and steerable system
- Can drill a longer horizontal drainhole—average of 3000 feet (900 meters)—than a short-radius well
- Conventional coring possible
- Can be normally cased and completed.

Disadvantages
- Because of higher build rate than long-radius well, may involve more torque loss and drag and greater stress on drilling equipment
- Limited completion and workover options (if 6 1/2-inch diameter or less)
- Limited Logging While Drilling (LWD) and wireline logging options (if 6 1/2-inch diameter or less).

Long radius

Advantages
- Easiest to drill, using conventional drilling equipment and standard tubulars and casing; cost/day of services often lower than in medium- and short-radius wells
- Permits drilling the longest horizontal section—more than 5000 feet (1500 meters), with an average of 3500 feet (1070 meters)—because lower dogleg angle results in less torque loss and drag
- Accommodates all completion, stimulation, workover and gas lift equipment
- Accommodates full suite of logging services.

Disadvantages
- Often requires a top drive system, larger pumps and greater mud cuttings management capacity
- Its longer openhole section increases risk for pipe sticking, kicks and borehole damage
- Less precise control of true vertical depth placement because the wellbore starts farther from the target. This is becoming less significant with the improved ability of MWD measurements to give real-time correlation of marker beds with offset wells.

4. For a review of horizontal drilling methods:
    For an overview and history of horizontal drilling:
Horizontal Drilling Equipment

Bent housings
These provide a permanent bend in the BHA of typically ½ to 1½ degrees. They are used to build well deviation and control the horizontal trajectory.

Bits
Standard tricone bits and polycrystalline diamond compact (PDC) bits are used in horizontal wells. PDC bits can be advantageous in horizontal wells because they last several times longer, making them economic in shaly formations. Their brittleness, however, makes them less suitable for harder, sandy formations. PDC bits are also attractive in horizontal wells because they lack moving parts, eliminating the risk of fishing for lost cones. Because PDC bits tend to generate high reactive torque at the downhole motor, they are prone to departing from the planned toolface setting sooner than a tricone bit. Roller-cone bits have a greater tendency to walk, usually to the right, the direction of drillstring rotation. PDC bits with short-gauge length at low rotary speeds tend to drill straight or walk to the right. Long-gauge PDC bits at high rotary speeds, however, have been found to walk to the left. The reasons for these tendencies are not well understood.

Downhole adjustable stabilizer
This is usually used in the straight (tangent) sections of a deviated well as a cost-effective alternative to a standard rotary system. It enables the directional driller to change the build/drop tendency of a BHA without making a round-trip to change the BHA design. The stabilizer gauge is changed downhole by varying the weight on bit, and is locked in place by controlling the flow rate.

Jars
These mechanical devices are commonly included in BHAs for freeing a stuck assembly. When a preset tension is reached, the jars trip automatically, releasing a hammer-like mechanism. The impact may bang the stuck assembly loose. Jars can be set to propel the string up or down.

MWD/LWD
MWD capabilities include mud pulse telemetry, navigation and drilling mechanics data, downhole temperature, gamma ray and formation resistivity. State-of-the-art navigation uses two triaxial systems, accelerometers to determine inclination, and magnetometers for determining azimuth. MWD measurements are used for directional drilling, geologic correlation, pore pressure prediction, and drilling mechanics interpretation to aid drilling decisions and enhance safety.

LWD data are used mainly for real-time formation correlation\(^1\) and pore pressure prediction\(^2\) with more detailed formation evaluation. The Compensated Dual Resistivity (CDR\(^2\)) and Compensated Density Neutron (CDN\(^2\)) tools provide measurements of deep and shallow resistivity, photoelectric factor (Pe), gamma ray, bulk density and a density-based caliper calculation (see “Acquiring and Interpreting Logs in Horizontal Wells,” page 34).

A mud-driven alternator powers both MWD and LWD tools and provides data transmission to the surface via mud pulses. The LWD equipment is capable of collecting more information than can be transmitted to the surface in real time, so some data are stored in downhole memory for reading when the tool is removed from the well. This permits improved log resolution and quality.

Neutral point
If the bit is held off the well bottom during drilling, the weight of the drillstring is supported at the surface by the traveling block (neglecting the effects of friction and buoyancy). The entire drillstring is under tension, which decreases from a maximum value at the surface to zero at the bit. Some of the weight is transferred to the bit when it is on the bottom of the well. This places the lower section of the drillstring under compression and the rest of the string in tension. The neutral point is where the drillstring passes from compression to tension.

Positive displacement motors
A positive displacement motor (PDM) is located immediately above the bit in a BHA (above, left). It is powered by mud displacing a helical shaft that rotates inside a rubber housing and turns the bit up to several hundred revolutions per minute. (Typical surface drives turn the entire drillstring 150 to 200 rpm).

SLIM MWD tool
This new MWD system makes real-time measurements of borehole inclination, azimuth, toolface orientation and downhole temperature. The system can be conveyed by slickline, without pulling the drillstring out of the hole.

Stabilizers
Stabilizers are used in BHAs to control borehole trajectory and prevent the BHA above the bit from touching the borehole wall, reducing the risk of getting stuck.

Top drive system
A top-drive system turns the drillpipe directly, rather than using a rotary table. One advantage is that 90-foot stands of pipe can be used, saving significant rig time handling connections. Also, while the drillstring is pulled from the hole, it can be rotated and circulation maintained, making top drive attractive for horizontal drilling. Pulling the drillstring out of horizontal bores can be difficult when material sloughs off the walls and is not removed completely by circulating mud.

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* Mark of Schlumberger
BHA can serve for building and holding, or dropping and holding. This is a cost-effective solution for maintaining inclination in straight but deviated portions of the wellbore, called tangents.

Rotary assemblies do not permit close control of wellbore azimuth (compass bearing of the wellbore with respect to magnetic North). This control is usually achieved with a downhole motor with a bent housing. When only the downhole motor is on, the bit and the moving part of the motor turn, not the drillstring. This is called sliding mode because the rest of the drillstring slides down the hole after the bit.

In sliding mode, the hole follows the direction of the bent housing on the motor, the direction in which the bit is pointing. A toolface orientation measurement in the MWD equipment tells, in real time, the bit orientation and allows its control from the surface. A typical toolface reading tells bit orientation in degrees to the left or right of the “high side,” the top of the hole. Minor adjustments in toolface are made by changing the downhole weight on bit, which changes the reactive torque of the motor and hence the orientation of the toolface. Large changes are made by lifting off bottom and reorienting the complete drillstring.

Today, the horizontal section is usually drilled with a combination of rotary and sliding modes. Whenever the surface drive is on, the steerable BHA behaves like a normal rotary BHA and maintains inclination and azimuth. Only when the bit goes off course does the driller return to sliding mode to correct the path (left). The directional driller’s goal is to drill as much as possible in rotary mode, which is much faster than sliding mode, and results in smaller doglegs (sharp bends in the wellbore) and hence less drag—the sliding friction exerted by the formation.

### Planning a Horizontal Well

Horizontal well planning begins after a thorough review of offset well data has determined the suitability of the reservoir for horizontal development. This review includes data from seismic, wireline, core and cuttings analysis and testing.

Although the literature reports many horizontal drilling successes, prudent engineers also focus on identifying and learning from mistakes. The typical failure results from insufficient planning. Knowledge of stratigraphy is usually thorough, but information may be missing on structure and petrophysics—Where are the faults? What is the predominant fracture orientation? What are the reservoir’s horizontal heterogeneities? Without identifying what is known and unknown, preparations cannot be made for each contingency. Questions that arise during drilling, such as determining whether the bit exited the top or bottom of the pay zone, may be difficult to answer if the well is drilled in a way that prohibits logging.

Ample evidence suggests that careful planning before spudding a horizontal well can mean significant savings and improved drilling efficiency and can facilitate setting of casing and completion.

Planning includes several steps (not necessarily in this order):

- Offset well data review. Because most horizontal drilling is for development of established fields, offset well data are usually available. The first step in planning a horizontal well is to evaluate well logs, drilling reports, mud logs, geologic maps and cross sections. Horizontal wells can be drilled more efficiently by knowing which drilling practices worked and which didn’t in the offset wells, how different formations responded to mud systems, how various BHAs worked and actions taken by the driller and their consequences. Review of offset and directional drilling data can take a couple of days to a week.

- Well profile selection. The well profile, the path that the well takes, is dictated by reservoir geometry, well platform location, maximum build rate, reservoir structure (dip angle and direction) and pay zone fluid distribution. These tell whether pilot holes are necessary, determine rig location for onshore wells, kickoff points, build radius, the angle of turn (changes in borehole azimuth with respect to magnetic North) required by the profile, the number and angle of tangents, length of the horizontal section and tolerance in reaching the target and in maintaining the planned profile. The well plan accounts for readily distinguished geologic markers detected on the way to the target. It must also allow for revision, in case of change in target entry true vertical depth, in kickoff points, build rate and tangent section length and angle.

- Torque and drag analysis. Torque loss—the difference between uphole and downhole torque—and drag are fundamental drilling efficiency measurements. Planning programs help optimize the well profile and minimize friction by predicting surface torque and hook loads (including drag) while drilling and tripping for given friction.

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The second step is to use the friction factors and planned BHA, casing and mud system to predict the hook load and torque for different well profiles. The ideal minimum drag profile is given by a well that changes from vertical to horizontal with a single, continuous bend, without tangent sections. Such a well would require a prohibitive number of BHA changes. The ideal profile is then adjusted with realistic build rates and tangent sections to minimize BHA changes, and to locate geologic marker beds in the tangent section above the final build section. The presence of a tangent section gives the directional driller the opportunity to change the location of the final build section if marker beds are not found where they were expected. This enables the planner to find a realistic profile that minimizes torque and drag.

Further reduction in torque and drag might be made by considering different BHA designs. The result, a theoretical output of torque and drag, is used to specify rig power and drilling equipment. This specification may be fine-tuned by simulating the torque and drag expected for doglegs of various severity.

- BHA response prediction (for both rotary drive and downhole motor assemblies). This optimizes BHA design by accounting for drillpipe type, number and placement of heavyweight and conventional drill collars, motor design, and stabilizer shape, size and placement.

The ideal steerable BHA design maximizes the time spent drilling in surface rotary mode as opposed to sliding mode and minimizes corrections made by drilling in sliding mode (next page, top). Rotary mode is more desirable because it permits a higher transfer of weight to the bit. This gives penetration rates many times greater than in sliding mode because rotation of the entire drillstring significantly reduces axial drag. In sliding mode, drag can limit total horizontal displacement.

It is often not obvious which steerable BHA design maximizes rotary drilling. In the absence of local field data, the BHA behavior can be modeled in rotary and sliding modes. However, computer modeling cannot predict real-time hole enlargement and rock strength anisotropy. These can have first order effects on BHA directional performance and are largely unknown during drilling. As experience grows in a given area, the appropriate BHA can best be identified from experience by using computerized data bases containing local drilling parameters and information describing BHA sizes and tendency to build, drop and walk.
A cost-effective solution to increase the versatility of the BHA is to use a downhole adjustable stabilizer (right). Placed in a standard rotary BHA or above the steerable system, it allows the driller to modify the build or drop tendency of the BHA. This minimizes time-consuming well path corrections, in which the driller must stop drilling in rotary mode, reorient the bit, drill in sliding mode until the well path reaches the desired inclination, then continue drilling in rotary mode. The time lost from drilling in the slower sliding mode can be significant.

- Determination of MWD requirements. The foremost requirement is reliability. Low mean time between failure (MTBF) is important in horizontal wells because of the cost of long trips to change the tool if it fails and the danger of leaving the hole exposed to the mud too long. In today's competitive environment, a typical MTBF exceeds 250 operating/pumping hours.

The next consideration is usually cost-benefit analysis. For example, in a straightforward, onshore horizontal well in a known formation, a service comprising only deviation and inclination (D&I) from a slickline-retrievable MWD tool may be appropriate. If the drillstring becomes stuck, the tool can be pulled out the hole by slickline, avoiding high “lost-in-hole” charges. For wells offshore, in a complex or poorly understood area, D&I plus MWD geologic correlation and downhole drilling mechanics measurements might be more appropriate to conserve rig time. These can be upgraded with LWD density and neutron measurements, particularly when running wireline logs in the horizontal section is difficult.

Another MWD consideration is the speed of data update during critical course corrections. The rate at which toolface orientation data are updated, for example, varies from every 3.6 seconds to nearly every minute. The fast rate becomes critical for accurate steering when using polycrystalline diamond compact bits, which generate more reactive torque at the motor. This torque makes the bit prone to diverging from the planned toolface setting sooner than a conventional bit.

Accuracy of MWD azimuth and inclination becomes especially important in

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Specifications for Anadroll MWD and SLIM1 Systems

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<tr>
<th>Parameter</th>
<th>MWD</th>
<th>SLIM1</th>
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<td>300 hrs 6302°F (150°C)</td>
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<tr>
<td>Maximum toolface orientation update rate</td>
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<td>45 sec</td>
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<td>Survey update</td>
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</tr>
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<tbody>
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<td>±1°F (±0.5°C)</td>
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<tr>
<td>Drift</td>
<td>0°-180°</td>
<td>±0.1°</td>
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<tr>
<td>Azimuth</td>
<td>0°-360°</td>
<td>±1.3° (5° inclination ±0.9° (10° inclination ±0.6° (20° inclination)</td>
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<tr>
<td>Toolface orientation</td>
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</table>

1. Specifications of Anadroll’s MWD1 and new SLIM1 MWD systems. The MWD1 system is conveyed on conventional drillpipe; the SLIM1 downhole tool is 1 3/4 inches in diameter and can be run in standard nonmagnetic drill collars with OD of 4 3/4 to 9 5/8 inches.

- Horizontal wells (above). Small discrepancies throughout build and tangent sections can sum to large discrepancies at target entry. For example, in a well starting its first build at 3 degrees/100 feet, entering a 200-foot (60-meter) tangent at 45-degree inclination, and a second build at 10 degrees/100 feet, a discrepancy of 0.2 degrees translates into a 14-foot (4-meter) discrepancy in TVD. This could be critical in some formations, such as the Bakken shale in the Rockies, where a typical target thickness is about 7 feet (2 meters).

- Selection of customized horizontal tools. These include the downhole adjustable stabilizer and specially designed stabilizers that avoid excessive drag and hanging, double-bend motors and motors with custom stabilizer blade or skid pads to perform at a specific build tendency, nonmagnetic heavy-duty drillpipe to avoid dragging and higher (compressive) strength drillpipe.

- Placement and setting of jet(s) (see “Horizontal Drilling Equipment,” page 26). Experience has shown that in horizontal holes, two jets can be used, one in the vertical section and the second in the horizontal section that strikes up only. The two-jet arrangement is used because the vertical jet may not have enough power to free a stuck BH.A.

- Determination of casing design. Torque and drag analysis helps determine if casing can be run in hole and if it can be reciprocated and rotated during cementing.

- Hydraulic computation. In horizontal wells, cuttings tend to form a bed on the low side of the borehole (see “Drilling Fluids for Horizontal Wells,” page 8). This can be removed by ensuring the mud is in turbulent flow in the annulus and by keeping the pipe moving. Modeling the hydraulics of the mud/BH.A system can help select drilling equipment and mud-pumping rates to optimize bit and annulus cleaning and cuttings transport.

- Evaluation of horizontal borehole stability. Boreholes can fail by fracturing or sloughing. Fracturing occurs when the rock’s tensile strength is exceeded. Sloughing, the more common mode, occurs when the rock’s shear strength is exceeded. Because stresses imposed by drilling fluids are different from intrinsic stresses in the rock, and because chemical changes can occur from mud/formation interactions, deformation or failure of the borehole wall can occur during drilling.

- Mechanically borehole stability can be estimated with rock failure models, which predict the maximum and minimum mud weights between which drilling can safely proceed without inducing tensile failure of the well from excess mud weight, or sloughing from insufficient mud weight (next page and page 8). The method identifies in-situ stresses in the formation from offset wireline logs, calculates stresses that will occur at the borehole wall when the well is drilled directionally, and substitutes these borehole wall stresses into shear and tensile failure criteria to see if failure will occur.

In Anadroll, all of these planning steps are coordinated by the Drilling Planning Center (DPC) manager at the onshore computing center in communication with the client at the base office. At the field support level, Schlumberger activities in horizontal wells are coordinated by the Horizontal Integration Team (HIT). The group addresses client needs in horizontal wells by collecting, analyzing, and dispatching information from worldwide sources.

Monitoring & Controlling Horizontal Drilling

Progress during drilling is continuously compared with the well plan. As new data become available during drilling, modifications in the well plan are made where appropriate. Contingency plans are then enacted when changes from the optimum plan arise, such as a BH.A that does not perform as expected, or unforeseen failures or deformations are encountered. Monitoring and control are made using three families of measurements: MWD directional data, MWD drilling mechanics data and LWD data. Processing and analysis of these data are performed at the surface using a data acquisition and interpretation system.

MWD directional data—inclination, azimuth and toolface orientation—are used to monitor drilling and check that it follows the well plan. A problem in predicting steerable system behavior is that inclination data come from at least 60 feet (18 meters) behind the bit. By the time the driller obtains inclination data and takes corrective action, the bit may have veered off target. The Downhole Torque (DTOR) measurement, because it is made at the bit, helps improve directional control in sliding mode. Keeping DTOR constant helps maintain constant toolface orientation.
Mechanical Stability (MSL) Logs for wells deviated 0° and 50°. The Fracture Initiation Pressure, or pressure at which tensile failure would occur, is plotted in the left and bottom tracks. In the center tracks, the area between the limits for shear failure is shaded black. In the right and top tracks, the Fracture Initiation Pressure and limits for shear failure are combined to indicate the recommended range of mud weights.

In this example, the Fracture Initiation Pressure is greater than the maximum pressure for shear failure, so the shear failure and max/min tracks are identical. The lower boundary of the shear curve is always the same as the lower boundary on the max/min curve. The upper boundary of the max/min curve is the upper boundary of either the shear failure or fracture initiation pressure curve, whichever is lower. The range of recommended mud weights decreases significantly for the 50° case—in general, the possible range of mud weights decreases with increasing deviation. Comparing the shear failure and max/min tracks in the vertical well at 2672 meters shows that sloughing would be the expected mode of failure. Because the zone is relatively thin, it probably would not create significant drilling problems.

If the zone at about 3520 meters in the 50° well were thicker or the anticipated failure were caused by fracturing and loss of circulation, the well trajectory might need to be revised to cross the zone at a lower deviation angle. Differences in recommended mud weights in different zones in the well might also be used to determine casing points. Wellbore failure through chemical reactions of the mud with shale sections is controlled in the same manner as for vertical wells. Experience has shown that MSL results tend to be conservative and are best used to pinpoint zones where problems could occur. (After Bruce, reference 10.)


The Downhole Weight on Bit (DWOB) measurement allows better control of the steerable assembly when used in rotary mode, because weight applied to the bit affects bending of the assembly and hence its building or dropping tendency. In sliding mode, the DWOB measurement is particularly useful because of high drag, which invalidates measurements from the surface.

The DTOR measurement can also be used to determine downhole motor efficiency and motor failures (left). Large increases in reactive torque can indicate cone locking.

Monitoring and control of drilling is also enhanced by two real-time interpretation programs, the Mechanical Efficiency Log (MEL) and the Sticking Pipe Indicator (SPIN) computations. These computations make use of drilling mechanics data—DWOB and DTOR measurements, surface weight on bit, surface torque, rotations per minute (RPM) and rate of penetration (ROP).

The MEL computation determines the efficiency with which shales are drilled in real time, evaluates the state of bit wear, detects locked cones, and can also improve PDC bit performance. The SPIN program computes sliding friction (drag) and rotating friction acting on the drillstring.
while on bottom. A separate "trip monitor" computes drag while tripping. The results can be used to recognize incipient drillstring sticking early enough to allow correction—wiper trips, circulating, mud conditioning or reaming. Periods of poor drilling response can be minimized by differentiating formation changes from drillstring sticking above the MWD sensors. SPIN computations also can be used to quantify the effectiveness of hole conditioning (previous page, right and below right). The friction factors are computed foot by foot while drilling. Because they replace offset well assumptions with real data from a horizontal well, they can enhance postdrilling analysis by fine-tuning torque and drag modeling for future wells.

Marker beds can be identified while drilling to determine the best location for kickoff and casing points. The earliest identification can be made from mechanical properties of the rocks. If a marker bed is harder or softer than surrounding formations, it can be identified from changes in ROP and DTOR measurements. The identification can be confirmed and clearly correlated in offset wells using MWD gamma ray and resistivity measurements.

Post-drilling evaluation with the operator helps guide subsequent drilling in the area. For example, updates are made on wellbore friction, BHA and bit performance and the geologic map. This follow-up and analysis increase local knowledge and shorten the learning curve, resulting in faster, more efficient drilling on the next well. —MF


Use of MEL and SPIN computations to evaluate the effectiveness of a "short trip"—running the drillstring up to the casing shoe to condition the well. Note that before the trip, the driller is trying to keep the DWOV value constant to maintain good penetration rate. After the trip, less SWOB is needed to maintain the same DWOV value, indicating that the trip improved the condition of the well. This is also shown in the top track: drag is reduced after the trip, suggesting that the hole is in better condition, with fewer cuttings. Drag increases with depth but does not exceed the precleaning value. Friction changes are negligible. In the bottom track, excess torque (XSTO—torque above that expected to drill the formation) was identified as due to the PDC bit becoming undergauge and the first stabilizer cutting into the formation. This was confirmed when the bit was pulled out of the hole and found to be about 1/8 inch undergauge.
Acquiring and Interpreting Logs in Horizontal Wells

In the realm of horizontal wells, there are two kinds of operators: those who know the former group—it summarizes logging and log interpretation strategies in interpreting logs than you do in the conventional well? For brevity, we cover interpreting logs from a horizontal well requires a new way of thinking, since established interpretation models may not work. Interpretation transforms assume radial symmetry around the wellbore, whereas in the horizontal well, radial anisotropy is the very thing you’re looking for.

So new is the interpretation of horizontal logs, however, that there is yet no interpretation manual. It is being written now, in fields from Venezuela to New Zealand, from the North Sea to Canada. But this we know: logging tools work the same way whether they are standing up (the posture for which they were designed) or lying down. The challenge is to understand what logs mean when the tools lie parallel to bedding and when invasion is asymmetric, due to gravity effects or permeability anisotropy. This calls for learning new log interpretation language—or more precisely, learning the idiomatic expressions of horizontal logs.

Today’s typical horizontal well is drilled in an established field, where petrophysical properties have been studied for years. Consequently, the operator has already done formation evaluation in conventional wells and so focuses on formation recognition in the horizontal well. Here the chief concerns are usually reservoir geometry and structure: Are we still in the pay zone or have we entered the shale? If we exited the pay, did we go through the top or bottom? What is the shape, dip and lateral continuity of the pay zone? Where are the fluid boundaries? If we crossed a fault, are we on the upthrown or downthrown side? Are we crossing fractures? How many?

Answers to these questions come in real time while drilling from cuttings analysis (microfacies/paleontology), from measurement while drilling (MWD) readings (gamma ray, resistivity, direction and inclination, and drilling mechanics) data and logging-while-drilling (LWD) measurements (dual resistivity, natural gamma ray spectroscopy, neutron porosity, formation bulk density and photoelectric factor, Pe). They come later from wireline logs run with the Tough Logging Conditions (TLC)1 system. If the well is completed with casing or slotted liners, production logs can be run with coiled tubing (CT).2 When flow is restricted to the casing, production logs can answer questions about fluid flow and properties: Where are the fluid and gas entries? How many are there? Which zones are big contributors? Are there thief zones? Is the fluid oil or water? What is the flow rate? What is the fluid saturation near the wellbore?

MWD/LWD Interpretation

Measurement while drilling provides reconnaissance and correlation aid to drilling decisions and enhance safety. Several capabilities of MWD measurements aid formation recognition. Formation correlation is enhanced by real-time presentation of lithology, updated during drilling, inferred from gamma ray, resistivity and drilling mechanics data and verified from cuttings analysis. Real-time lithology segmentation (sand versus shale) is computed from the

1. The MWD short normal resistivity measurement is gradually being replaced with the LWD compensated resistivity measurement, which has improved response over a wider resistivity range and a higher vertical resolution.
2. Anadrl’s MUD system makes seven measurements. The drilling mechanics components are downhole torque (DTOR) and downhole weight on bit (DWOB) measurements, surface weight on bit (SWOB), rate of penetration (ROP) and rotations per minute (RPM).

† Mark of Anadrl
* Mark of Schlumberger
zontal Wells

thoroughly log the horizontal section, and those who project log data only from pilot holes. This article is about horizontal wells and addresses the question: In the horizontal well, what do you do differently in obtaining and only real-time measurements while drilling, openhole wireline logs and production logs.

Mechanical Efficiency Log (MEL) computation, which is based on drilling mechanics measurements (see "Horizontal Drilling Comes of Age," page 22).

In all lithology-related MWD computations, measurements made closest to the bit arrive at the surface first. As drilling progresses, more measurements become available and can be combined to enhance interpretation confidence. Typically, downhole weight-on-bit and downhole torque are measured within a few feet of the bit, followed by the gamma ray, resistivity, and direction and inclination measurements. The schematic (left and below left) shows the log between formation strength, determined from drilling mechanics measurements.

Use of MWD measurements close to the bit to identify marker beds (above) and the MWD gamma ray measurement to find the top of the pay sand while drilling into a horizontal section (left). The logs show two marker beds (coal seams) in a horizontal North Sea well. Their identification was critical to entering the reservoir correctly. Marker bed 2 was identified using the drilling mechanical data (Formation strength [FORS]), the resistance of the formation to penetration by the bit) available at the bit with MWD. The marker beds were crossed at 90° to vertical and the well trajectory built at 3° per 100 feet on leaving marker bed 2 (angle not shown to scale). Knowing the location of these beds allowed the driller to enter the thin pay sand horizontally, 100 feet below the final marker bed. The crossplot (left) shows a transition of gamma ray readings, indicating the approach of a sand/shale boundary in the build section of a horizontal well. After this transition is crossed, the gamma ray measurements can be calibrated in terms of the distance to the top of the sand. The driller can then use this calibration to steer a path that remains within the sand. This technique requires sufficient gamma ray contrast between the pay sand and the overlying shale.

For their generous assistance with this article, thanks to Rob Badry, Schlumberger of Canada, Calgary, Alberta, Canada; Dave Best, Steve Bonner, Mike Evans, Jacques Helenka, Martin Lilting and Richard Rosthal, Schlumberger Logging While Drilling, Sugar Land, Texas, USA; Yves Chauvel, Chris Clavier and Philippe Theys, Services Techniques Schlumberger, Montreouge, France; Gavin Clark, Schlumberger International Coordination Committee, Houston, Texas, USA; Lance Davis and Rene Vermeere, Société de Prospection Electrique Schlumberger, The Hague, The Netherlands; David Dudlyke, Schlumberger Logging While Drilling, Aberdeen, Scotland; Tom Fett, Schlumberger Well Services, Corpus Christi, Texas, USA; Barbara Anderson and Peter Coode, Schlumberger Doll Research, Ridgefield, Connecticut, USA; Manfred Habie and Barry Nicholson, Schlumberger Norge, Stavanger, Norway; Lars Knudsen, Schlumberger Offshore Services, Esbjerg, Denmark; Jacques Maratier, Schlumberger Operations, Dallas, Texas, USA; Bernhard Prevedel, Mike Sheppard and Bernard Voisin, Anadrol, Sugar Land, Texas; DeWayne Schnoor, Schlumberger Well Services, Anchorage, Alaska, USA; Julian Singer, Schlumberger Surengo, Caracas, Venezuela; and Jim White, Schlumberger Log Services, Aberdeen, Scotland.
Acquiring and Interpreting Logs in Horizontal Wells

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ments made near the bit, and gamma ray, which is made farther up the drillstring. These real-time evaluations of drillstring and bit status can make the difference not only in drilling efficiency and safety, but between success and failure in placement of the horizontal drainhole.

Logging–while-drilling tools are engineered into drill collars and positioned as close to the bit as possible to provide measurements for real-time formation evaluation. Schlumberger introduced this technology in 1988 as a joint service of the Anadrill and Wireline divisions.

Today, LWD services are run in horizontal wells to increase drilling efficiency, maintain hole stability and provide early formation identification. They also provide insurance logging over the zones of interest.

In horizontal holes, both LWD and wireline log interpretation are affected by three conditions: standoff, laminations and the borehole being roughly parallel to bedding. Standoff affects the density measurement; laminations and the borehole being roughly parallel to bedding affect the resistivity measurement. An operational limitation of LWD in horizontal wells has been the high rate of mud flow, needed to overcome extra drag on the cuttings created by the horizontal drainhole. The Compensated Dual Resistivity (CDR) tool has been modified to accommodate the higher mud flow rates. Modification of the Compensated Density Neutron (CDN) tool is under development. Both tools may be run in "washdown" mode, when mud flow rates are not as high as during drilling.

The standoff problem in horizontal holes is of particular interest for the LWD density measurement because its accuracy requires good "sensor" contact with the formation. This is achieved by conveying gamma rays through a special stabilizer with windows cut in the fins. As long as the fins graze the formation, the measurement is valid. But in enlarged horizontal boreholes—many of which are thought to be oval, with the long axis vertical—the fins stand off from the formation during part of the rotation (above). The measurement therefore becomes an average of mud and formation densities.

A technique, called the rotational density algorithm, has recently been developed to cope with this effect. The technique uses a statistical analysis of tool response based on the standard deviation of the measurement variance while the tool is rotating. When formation density is greater than mud density, the algorithm basically takes formation density as the minimum reading—occurring when the rotating sensor is nearest the formation—and the mud density as the minimum reading—occurring when the rotating sensor is farthest from the formation. When formation density is less than mud density, the algorithm chooses the minima for formation density.

The statistical analysis also provides a differential caliper—hole size minus bit size—that is zero for in-gauge holes and increases as the hole enlarges (next page). The precision of this density caliper is about 1/8 inch (3 millimeters [mm]), its range about 1½ inches (38 mm).

One limitation, affecting both LWD and wireline density measurements, could be a pronounced difference in formation density above and below the tool, for example, if the tool lies along a bed boundary. This will result in erroneous indication of hole enlargement. Here, cuttings analysis, resistivity, photoelectric factor and drilling mechanics measurements may indicate facies changes that would suggest marked vertical density variation.

The rotational density algorithm also allows correcting log distortion caused by threaded borehole, a spiral-like rugosity thought to be produced by mechanical forces acting on the steerable bottomhole assembly. Threading may be aggravated by low-speed, high-torque drilling. Threaded borehole is not unique to horizontal wells, but may be more common than in conventional wells. Elf Petroland has observed threaded borehole producing a trebling effect on the MicroSFL* and density logs.

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An LWD log (top) from a horizontal well in the North Sea, and the accompanying Elemental Log (ELAN) analysis. The shaded area in the bottom track shows the difference between stabilizer size and hole size, the density caliper. This would normally be the difference in hole and bit sizes, but an undergauge stabilizer was used in this well. The wiggles in the caliper and $\Delta \rho$ logs from about X850 meters to the bottom of the interval shown indicate a threaded borehole. The minor difference around X850 meters between the neutron and maximum bulk density (corrected density) could be caused by a vertical variation in density if the sand is dipping. In the second track from the bottom, the difference between the average (uncorrected) bulk density and the maximum bulk density (corrected) is clearly shown.
Wireline neutron-density logs affected by threaded borehole have recently been interpreted using an elaborate filtering algorithm (far right and next page).

In horizontal holes, the CDR measurements, like wireline resistivity measurements, are affected by two conditions: a small angle (but not zero degrees) between the borehole and bedding plane, and lamination of the formation.

When the bedding plane and borehole cross at an angle less than 30 degrees, the shallow CDR measurement shows a horn effect (right, below right and page 41). This horn is created by polarization directly at the bed boundary. It therefore serves as a high-quality bed boundary indicator for large resistivity contrasts in dipping beds. The size of the horn increases with increasing resistivity contrast, with increasing dip angle (when the angle between the tool and bed boundary interface gets smaller), and, usually, when the absolute resistivity of the beds decreases.

In laminated beds, the classic problem persists: finding true resistivity, \( R_{th} \), for the bed the tool is in and for a number of beds above and below the tool. Laminated thin beds have a resistivity anisotropy, with lower resistivity in the bedding plane than normal to bedding. Modeling shows that in vertical boreholes, both deep and shallow CDR measurements read the volume average conductivity parallel to the bedding plane. But as the angle between the tool and the bed boundary decreases, the effect of resistivity anisotropy increases; the deep and shallow measurements separate, with the shallow reading more resistive than the deep.


Making Sense of Threads

Modulation of neutron and density logs in the horizontal interval of a Canadian well exhibits large excursions on the density log (on the order of 0.2 g/cm³) and having a period of about 3 feet (1 meter). The top display shows the logs after Weiner filtering, the bottom before filtering. The caliper shows that the 3-foot wavelength ruggedness is no deeper than about 1/6 inch (6 mm). The Weiner filter must be tailored individually for each log measurement, but enables the client to derive meaningful information from logs that initially appear useless.

The logs, obtained at a 1.2-inch sampling rate, are from a Canadian sandstone bed of relatively constant porosity. The density log was first processed with conventional filtering, which relies mainly on running averages of counting rates. This filtering attenuates high-frequency noise that corresponds to events on the log of short wavelength—much less than 3 feet. But because density log excursions in this well occurred at a 3-foot period, this filtering failed to correct the log response. Conventional filtering could not be customized to attenuate only a single frequency (such as that of the periodicity, 3 feet). Other frequencies would also be attenuated, resulting in excessive smoothing of log response.

John Kovacs, account manager with Schlumberger of Canada in Calgary, Alberta, enlisted assistance from Darwin Ellis, of Schlumberger-Doll Research in Ridgefield, Connecticut, USA to find a correction.

From the power spectrum of the raw log data, Ellis verified the periodicity of the density excursions at about 3 feet. This periodicity is produced by a ruggedness of the same length, the cause of which is uncertain. However, because periodicity of the ruggedness does not change with rate of penetration, it is probably related to the spacing between components of the bottomhole assembly (BHA), possibly between the drill bit and the first stabilizer, and between the first and second stabilizers.
David Dudlyke of Schlumberger Logging While Drilling, in Aberdeen, Scotland, offers this explanation for the periodicity:

Directional drilling makes use of BHAs with a bent sub. When the drillpipe is not rotated, the bit cuts a curved path defined by the bent sub angle. But when both the bit and drillpipe are rotated, the bit spirals through the earth, cutting a roughly straight path. The moment this happens, the near-bit stabilizer (usually located behind the bit 1 to 3 feet [1 to 1 meter]) starts to function as a node. This causes the bit to wobble and cut a slightly oversize hole. When the near-bit stabilizer moves into the enlarged hole after 1 meter or so, it begins to wobble in the extra space. The stabilizer stops acting as the node and the bit then starts to act as a node. It therefore returns to drilling in-gauge hole, until the stabilizer moves back into in-gauge hole, at which point the bit starts to wobble and cut oversize hole again. This process shapes the borehole into a series of undulating ridges and valleys, like a corrugated culvert pipe. The periodicity of this phenomenon is twice the distance between the near-bit stabilizer and the bit. Its modulation depends on the bent sub angle and on the weight on bit, which causes some flexure of BHA behind near-bit stabilizer (the greater the weight on bit, the greater the amplitude).

The spacing between ridges and valleys on the borehole wall is about the same as the source-detector spacing of the density tool. Therefore, when either the source or the detector is over a valley at a given moment, the tool is trying in vain to correct for measuring the mud in the valley. Density maxima indicate a condition of pad standoff; minima are readings of the formation.

To complicate matters, the 3-foot rugosity rides on a fluctuation of much longer wavelength, about 75 feet (23 meters). The cause of this longer wavelength modulation is unknown. The modified Weiner filter attenuates high frequency noise with minimal smoothing at lower frequencies. To the Weiner filter Ellis added a “notch” filter that attenuated frequencies corresponding to the 3-foot period. This produced a correctly shaped log curve, but offset at too high a value because the amplitude of the counting rates still reflected the long wavelength modulation. To account for this modulation and adjust counting rates to the no-standoff condition, Ellis subtracted half the difference between the upper and lower envelopes of the counting rates. This produced a correct, interpretable density log. A similar technique was successfully applied to the neutron log.

Although the Weiner filter solved this problem, its practicality for general field applications remains to be tested. Unlike conventional filtering, the Weiner filter must be calculated for each log because it changes shape based on the noise level of the data. It requires no more computer time to run, but preparation of log data for Weiner filtering is time-consuming.

For their assistance with this example, thanks to Darwin Ellis, Schlumberger-Doll Research, Ridgefield, Connecticut, USA and John Kevac, Schlumberger of Canada, Calgary, Alberta, Canada. Thanks also to David Curwen and Ron Heleta, Canadian-Hunter Exploration Ltd., Calgary, Alberta; Charles Case, David Rossi and Charles Watson, Schlumberger-Doll Research; and Chris Morris, Schlumberger of Canada, Calgary, Alberta.
Making Sense of Threaded Horizontal Borehole in Canada

David Outfylde of Schlumberger Logging
White Drilling Co., in Aberdeen, Scotland, offers this explanation for the periodicity:

- Directional drilling makes use of BHA's with a bent sub. When the drillpipe is not rotated, the bit cuts a curved path defined by the bent sub angle. But when both the bit and drillpipe are rotated, the bit spirals through the earth, cutting a roughly straight path. The moment this happens, the near-bit stabilizer (usually located behind the bit ½ to 3 feet [1 to 1 meter]) starts to function as a node. This causes the bit to wobble and cut a slightly over-size hole.

- When the near-bit stabilizer moves into the enlarged hole after ½ to meter or so, it begins to vibrate in the extra space. The stabilizer stops acting as a node and the bit then starts to act as a node. It therefore returns to drilling a gauge hole, until the stabilizer moves back into the gauge hole, at which point the bit starts to wobble and cut over-size hole again. This process shapes the boarhole into a series of enduring ridges and valleys, like a corrugated culvert pipe. The periodicity of this phenomenon is twice the distance between the near-bit stabilizer and the bit. Its modulation depends on the bent sub angle and on the weight on bit, which causes some fluctuation of BHA behind near-bit stabilizer (the greater the weight on bit, the greater the amplitude).

- The spacing between ridges and valleys on the borehole wall is about the same as the source-detector spacing of the density tool. Therefore, when either the source or the detector is ever a valley at a given moment, the tool is trying to scan for the mud in the valley. Density maxima indicate a condition of poor standoff; minima are readings of the formation.

- To complicate matters, the 3-foot resistivity rides on a fluctuation of much longer wavelength, about 75 feet (23 meters). The cause of this longer wavelength modulation is unknown.

- The modified Weiner filter attenuates high frequency noise with minimal smoothing of lower frequencies. To the Weiner filter, noise is added a "riffle" filter that attenuated frequency corresponding to the 3-foot period. This produced a correctly shaped log curve, but offset at too high a frequency because the amplitude of the counting rates still reflected the long wavelength modulation. To account for this modulation and adjust counting rates to the no-standoff condition, Ellis subtracted half the difference between the upper and lower envelopes of the counting rates. This produced a correct, interpretable density log. A similar technique was successfully applied to the neutron log.

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The CDR tool responds to a laminated zone, such as a 50:50 mix of sand and shale, only when the angle between the tool and the beds is at least 30 degrees (above). In deviated pilot holes or in the early build section of horizontal wells, \( R_s \) has been estimated using shale resistivity obtained from a nearby well. If that is not available, the electromagnetic modeling (ELMOD) package may be useful in modeling \( R_s \) for the measured response. 

In addition to these effects of the horizontal environment on LWD logs, the CDR deep measurement in horizontal wells may also detect fluid saturation changes some vertical distance away. In one North Sea horizontal well, which was designed to run about 13 feet [4 meters] above the oil/water contact (OWC), the deep resistivity would occasionally drop below the expected 100-ohm-meter value. This drop could be correlated with the well trajectory. When the well dipped 6 to 10 feet [2 to 3 meters], the resistivity would also drop. Subsequent production confirmed the proximity of the water zone, as the water cut built up earlier than expected, then stabilized.

Elf Petroland has observed a similar effect, not due to the approach of a fluid contact, but to the approach or penetration of a layer with a different water saturation. Petroland used this information to correct the direction of the drainhole.

**Wireline Interpretation**

Because wireline tools will not "fall" in highly deviated and horizontal wells, they are usually conveyed with the TLC system. In this system, conventional wireline tools are attached to the end of drillpipe and pushed to the intervals of interest. They are often joined to the drillpipe with a swivel head to allow preferential pad orientation. A tool turner sub is added when tools must rest on the borehole floor (below). Power is conveyed to the tools, and data returned to the surface, by wireline cable. The cable is pumped through a side entry sub and down the drillstring where it wet connects to the downhole equipment. Although logs obtained with the TLC system are comparable to those from conventional wireline tools, drilling must be stopped to obtain data. The range of measurements available with the TLC system, however, is wider than that now available with MWD/LWD systems.

The frontier of horizontal wireline log interpretation is being charted mostly in Europe, where operators often run many LWD to obtain detailed information about reservoir properties and geometry. In this environment, wireline logs are run to address questions of geometry (raised on page 34) and questions not fully answered by other techniques:

- What is the distance from the borehole to the oil-water and gas/oil contacts (GOC)?
- What are the lateral variations in reservoir properties—such as porosity, permeability in carbonates, shale volume, facies, pressure and saturations—and in reservoir geometry—length, thickness and dip of each interval?
- What is the nature of fractures—how many are there and what is their spacing, strike and dip?

In addressing these questions for horizontal wells, two properties of tool response are important: depth of investigation and whether the measurement sees all around the borehole or is focused in one direction, usually down. Here are some caveats that operators have discovered in interpreting wireline measurements in horizontal holes.
Induction and Laterolog

Because these measurements probe several feet into the formation, they are affected by vertical heterogeneities above and below borehole. When resistivity is high, the deep induction may be influenced by formations far from the borehole. Typically, resistivity is affected by neighboring shale beds, which complicates determination of fluid saturation. Resistivity may also be suppressed by nearby beds with a higher water saturation.

Petrophysicists with Mærsk Oil & Gas AS, an operator in the North Sea Danish sector, developed a useful technique for determining water saturations in a horizontal well drilled in a highly laminated limestone/shale sequence. The technique bypasses shale suppression and bed geometry effects on induction logs by estimating saturations using saturation-height functions established in nearby conventional wells.

Saturation-height functions express water saturation as a function of the vertical distance between the drainhole and the free water level of the reservoir, together with facies variations such as porosity and shale volume. Assuming the saturation development in the horizontal drainhole is governed by the same free water level and facies variations as established in conventional wells, the functions can be used to estimate saturations in the horizontal well from shale and porosity log indicators.

Establishing a useful saturation-height function requires that the conventional wells have the full range of logged saturations and porosity development. The data should also show little scatter and be representative of undepleted conditions in the reservoir. Mærsk Oil has applied this technique in only one field, since all of its other horizontal wells have been drilled in massive, homogeneous chalks, in which the induction log is not influenced by bed geometry or shale suppression.

A method for obtaining the resistivity of beds neighboring the horizontal borehole, and their vertical position relative to the borehole, has been developed by Julian Singer, of Schlumberger Surenc, Caracas, Venezuela. Singer measures resistivity and thickness of layers in nearby conventional wells. Using the ELMOD program, he then computes induction log response in the horizontal hole for various positions of the hole relative to the bed. He adjusts the bed thicknesses and resistivities and the borehole depth until the simulated and measured logs match. Because the method is overdetermined—has more variables than independent data—more than one solution is possible. It does, however, provide a range of likely interpretations.

As with the LWD resistivity measurements, dipping beds in horizontal wells smear induction response over great distances (above). In general, the induction is a less effective locator of bed boundaries than the deep CDR measurement (next page, above left and right). In massive, clean chalks, however, where interference from neighboring beds is unlikely, the induction can be used to track a progressive zonal facies change or identify bed boundaries. An example of this application with conventional TLC-conveyed resistivity logs is Mærsk Oil's MFB-17 horizontal well. A clear boundary can be seen between the good quality Danian D1 reservoir and the poor quality Danian D2 (next page, bottom).

Sometimes the shoulder bed effect can be an asset. In the Rospo Mare field in Italy, where Elf Aquitaine pioneered modern horizontal well technology, shoulder bed effect was used to identify the lower

8. For reviews of shoulder bed effects and corrections in horizontal wells:
Effect of bedding dip calculated for the deep induction response run on the ELMOD program (left) and on CDR and wireline logs (right). Wireline response shows the induction is nearly useless in horizontal beds. (From Clavier C: "Formation Evaluation in Horizontal Wells," presented at the Houston Geotech 90, Houston, Texas, USA, February 25-March 1, 1990.) The LWD example is from a well deviated 65°. The angle between the bedding and borehole is 18°. Circles on the log show where the induction's greater depth of investigation is influenced more than the CDR response by shoulder bed effect, produced by thin beds at high dip.

Induction log response showing the boundary between the Danian D1 and D2 chalk formations (lower Tertiary) in a Maersk Oil North Sea horizontal well in the Dan field. The logs were acquired with the TLC system. The induction log units are, from top to bottom, 20 to 0.2 ohm-m. The boundary pick was made based on the porosity logs. The slight offset between the neutron-density and the induction is due to bed geometry and difference in the measurements' depths of investigation. Separation of the neutron and density curves is due to the presence of oil-base mud.
boundary of the cap rock. By noting the rise and fall of the shoulder bed effect, Elf could follow the cap rock for a few meters in the horizontal section.

An unusual feature observed on induction logs in horizontal wells is a “gas effect,” noted by Petroland in its Zuidwal gas field in offshore Netherlands. Petroland found the induction sometimes reading higher in horizontal gas wells than in offset conventional wells penetrating the same intervals. This is particularly pronounced with the deep induction. This is thought to occur because invasion occurs differently in a horizontal than vertical well (next page). The difference in invasion is caused by a dramatic contrast in vertical and horizontal permeabilities in the Zuidwal field—horizontal permeability is 50 to 100 times greater than vertical. Vertical permeability in the Zuidwal field is controlled by thin 4- to 8-inch [10- to 20-centimeters (cm)] siltite layers in the producing sands. These layers limit the vertical reach of invasion and confine it to a relatively thin horizontal plane. In horizontal wells, consequently, the induction measurement probes mostly vertically, across bedding and sees into less invaded, more resistive regions. Resistivity therefore reads higher because the less invaded, gas-rich zone is being sensed.

Petroland has also noted that a relatively thin bed (16 feet [5 meters]) with a low water saturation sandwiched between layers with a high water saturation will draw down the induction reading. Petroland has noted that this phenomenon produced a 1.3-ohm-m drop in resistivity.

Neutron-Density
Special considerations in acquiring and interpreting these logs in horizontal wells relate mostly to the tool measurements being focused downward. Mærsk Oil petrophysicists have noted that the Compensated Neutron (CNL™) log may be affected by fill on the bottom side of the drainhole. This suspicion cannot be tested, but it may explain log anomalies that appear like those known to occur from tool standoffs.

Accuracy of the density log depends on correct pad contact, which can be accomplished by the use of flex joints, a tool turner sleeve and the inclinometry tool, in combination or alone. Ensuring good pad contact of the density tool—or any pad tool, such as the Formation MicroScanner™ tool—in a horizontal borehole is not easy. The tortuous profile of horizontal wells often means that torque applied at the surface to orient the pads does not reach the tool—the driller may have to turn three times on surface to transmit a quarter turn downhole.

In its Rospo Mare horizontal wells, Elf solved this problem by using the azimuth indicator of the inclinometry tool to position the density pad on the floor of the hole. On the surface, the pad is oriented with the inclinometer. It is then run in to the casing shoe, the deepest point at which torque from the surface is satisfactorily transmitted. The tool is then reoriented with the pad down and run to total depth. On logging up, the driller occasionally corrects tool orientation by slightly reciprocating and rotating the pipe. Today, Elf sometimes uses the tool turner along with the inclinometry tool to determine pad orientation. Mærsk Oil obtains good density logs through a combination of flex joints and the tool turner sleeve. This configuration is so efficient that a viable density log is often acquired even on the down pass, when the caliper is closed.

A comparison of the neutron-density with the gamma ray reading can sometimes reveal whether a shale bed is approaching the borehole from the top or the bottom.² This capability takes advantage of the focused nature of the neutron-density measurement and the omnidirectional nature of the gamma ray. In a horizontal well in South America, it has been noted that when a shale bed approaches from the top, it is detected by the gamma ray before the neutron-density. When a shale bed approaches from the bottom, the neutron-density sees it immediately (above).


For an overview of Elf’s experience in Rospo Mare, see other entries in this 1988 seven-part series in Oil & Gas Journal issues of February 29, March 21, April 11, May 23 and June 13.

Variation in induction resistivity readings in a horizontal North Sea gas well (left, middle track), and in an offset deviated well penetrating the same interval (left, top track). Resistivity is thought to be higher in the horizontal well where low vertical permeability inhibits vertical invasion and permits the tool to read the unaltered gas zone (color schematic, bottom left). This is clear at formations II BC and II DE. Formations II DE and all of III are shaly sandstones; the rest are clean sandstones, with porosity of 5% to 24%. The schematics show that in the horizontal well (below), the deep induction averages over three layers, but may weight the uninvaded zone more heavily. In the vertical well (next page, bottom), the measurement reads only the invaded zone in one layer.
**Gamma Ray**

Although the gamma ray has no azimuthal focussing, it is slightly more sensitive to underlying than overlying formations because it lies on the floor of the hole. About 90 percent of the reading comes from within 8 inches (20 cm) of the borehole wall. Recently, Julian Singer developed a calculation to express gamma ray log response as a function of the distance from the tool to a sand-shale boundary in the horizontal environment.

In the Rospo Mare field, Elf Aquitaine used the Natural Gamma Ray Spectrometry (NGS) tool to distinguish cap rock shale from reservoir shale, and show where the cap rock had been dropped down by faulting. Integrating the gamma ray data with laterolog and small-grid, three-dimensional seismic data, Elf learned the geometry of the reservoir body. In drilling later horizontal wells, this knowledge helped keep the drainhole at the optimal distance below the cap rock.

**Sonic**

Sonic readings are prone to seeking the highest velocity bed near the wellbore, making the sonic porosity read too low compared with the neutron-density reading. Petroland observed this effect when its horizontal wells crossed or grazed thin siderite beds. Typically, the sonic starts reading a high velocity bed several meters along the borehole before it makes contact with the borehole and continues reading it several meters along the borehole after it departs from the borehole. Petroland discovered that this produced a discrepancy between the sonic and the shallow-reading neutron-density porosities crossing thin, siderite layers (above and right). Petroland attributes this to the continued reading of the siderite layer, even after the layer has left the borehole. Because of this effect, Petroland relies on the density to define the length of zones demarked by siderite layers.

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Formation MicroScanner

In all but one setting—oil-base mud (OBM)—the Formation MicroScanner tool has become the preferred wireline tool for fracture evaluation in horizontal wells. In OBM, bulk density and sonic logs can sometimes locate fractures, but not as confidently as microresistivity logs. The NGS tool, run at high sampling rate, is sometimes used to distinguish shale-filled from open fractures. (This was a standard procedure in Elf’s horizontal Rospo Mare wells, where reservoir and cap rock shales have distinctively different gamma ray signatures.) Other fracture detection methods include drilling breaks, variation in torque, lost circulation, mud log shows and resistivity reversals. None of them, however, is as sensitive as the Formation MicroScanner tool, especially at confirming the presence of fractures.

The chief functions of the Formation MicroScanner tool in the horizontal hole are to locate, count, orient, rate and classify natural fractures. Fractures are fairly straightforward to locate, since they appear the same as in vertical wells: open fractures are black sinuosoids, mineralized fractures are white or gray. Since most fractures are vertical, they appear as flat sinuosoids. Where fractures cluster (or “swarm”) in the well can tell whether they are likely to produce. It can also be used to predict production characteristics, since different fracture sets in one horizontal well can behave as if they tap different reservoirs, producing oil or water (or both) at dramatically different rates and pressures. Fracture count can equate with productivity (the more the merrier) but depending on which horizons they tap, can also equate with early water or gas breakthrough.

Determination of fracture orientation (mainly strike) is essential for finding the predominant fracture trend, so that wells can be drilled perpendicular to the trend to intersect as many productive fractures as possible. Dip angle can sometimes help distinguish fracture type. In the Austin chalk of south Texas, USA, where many horizontal wells are drilled to intersect fractures, faults tend to dip less steeply (30 to 60 degrees) than other fractures (≥70 degrees) and may have a different trend (above). Faults in horizontal wells of the Austin chalk can also be identified because they can separate reversals in fracture dip direction (next page). This reversal occurs when faulting changes the structural dip of the bedding.

Fractures can be rated by their potential productivity. Until a fracture aperture algorithm becomes more widely available, a qualitative rating of fracture aperture has been used with some success in horizontal wells of the Austin chalk (See “Qualitative Rating of Fracture Aperture,” next page). Likewise, rules of thumb for fracture classification have helped distinguish types of fractures. Hydraulically induced fractures, for example, are often associated with fluid loss and tend to appear on all four pads. Stress release fractures often appear as V-shaped features normal to natural fractures. Hydraulically induced fractures and their attendant borehole washouts often parallel natural fractures and consequently appear on the same pads.

As with other pad measurements, borehole contact is a main concern in horizontal logging. To ensure pad contact, the Formation MicroScanner tool is often outfitted with stiffer springs. Actuating arms are also attached to the bottom of the pads, enabling the tool to log both down and up passes.


13. Two fracture aperture algorithms have been developed, one based on Stoneley reflections, and one based on electrical scans from the Formation MicroScanner tool. The respective commercial products are the STRAC and FRACVIEW computations. See:


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RFT Logs
The classic Repeat Formation Tester (RFT) pressure reading in a conventional well allows identification of gas, oil and water from their characteristic pressure gradients. In a horizontal well, these gradients are absent because measurements are not performed over an extensive vertical distance. However, the RFT tool can be used to determine lateral pressure distribution, which can aid in the depletion policy and reservoir management (next page).

Maersk Oil typically takes RFT pressure measurements through the entire reservoir section of a horizontal well, testing about every 200 feet [60 meters], perhaps at longer intervals in very thick beds (200 to 500 feet thick [60 to 150 meters]).

Based on openhole logs, the reservoir is divided into units. Within each unit, the RFT pressures show the amount of pressure depletion compared to the initial reservoir pressure. Lateral pressure gradients can also be determined, from which internal flow rates within the reservoir can be calculated. This, in conjunction with other data, is used to determine the reservoir drainage policy. Typically, Maersk Oil has found higher pressure in the flanks than in the center of producing fields.

Because all of Maersk Oil's horizontal wells are in low permeability chalks, supercharging of RFT pressures is a potential problem. This is avoided by the use of oil-base mud and a sale minimum overbalance, which limits the amount of invasion and avoids capillary effects in the oil leg. In water legs, where capillary effects come into play, tests are restricted to the most porous areas.

Maersk Oil has avoided long buildup times during RFT pressure testing by blanking off one of the tool's pretest chambers and by local modification to the probe to prevent plugging by soft chalk.

Production Log Interpretation
Production logging in horizontal wells is done for five main reasons:
- To assess gains in productivity associated with horizontal drainage
- To evaluate fluid flow in a horizontal configuration and to plan drainage from existing wells
- To detect oil, gas and water entries
- To detect gas and water coning
- To locate producing fractures.

Experience so far gives some tips on interpretation of spinner/temperature/holdup meter surveys (with the Production Logging [PLT] tool) and pulsed neutron logging.
PLT surveys
Assuming a minimal completion—a slotted liner—production log acquisition and interpretation face two problems: segregation of fluids in the wellbore by density, and channeling of fluids in the annulus between the slotted liner and formation.

In segregation, gas runs along the roof of the drainhole, oil in the middle and water at the bottom. Gas pockets tend to collect at drainhole crests and water in troughs. There are several ways to account for and minimize segregation effects:

• Compare spinner speeds with the well deviation plot (map of well trajectory angles). If the spinner speed suddenly drops then rises when logging on the down pass, for example, chances are the spinner just passed through to a different fluid or a water pocket. A sudden increase in speed might correspond to a gas pocket. Check the deviation plot to see if the velocity drop correspond to a trough and the velocity increase to a crest. Ørsk Oil minimizes this effect by making its spinner surveys at the highest possible flow rate that maintains stable flow—in Ørsk’s North Sea fields, 2500 to 3000 barrels of oil per day (BOPD). The hope is that this will reduce segregation by producing optimal mixing downhole.

• Oxygen activation can detect water entries where two phases are present. In the Rospo Mare field, where the two phases are oil and water, Elf uses oxygen activation, which can detect water entries spaced at least 33 feet [10 meters] apart, depending on production rate and relative cable speed versus flow rate. Entries spaced closer can be detected by adjusting logging speed, which can be time-consuming. This method locates only water entries; it does not give water volume.

• Compare openhole caliper and spinner data to assign a confidence level to

\[
\text{Formation Pressure at Datum Level, psia} \]

\[
\text{Initial pressure 4254 psia at 6500 ft true vertical subsea datum}
\]

\[
\text{RFT pressure at datum in horizontal hole} \quad \text{RFT pressure at datum in pilot hole Danian 1}
\]

\[
\text{Top Danian 1} \quad \text{Top Danian 2} \quad \text{Top Maestrichtian 1}
\]

\[
\text{Gas oil contact} \quad \text{Oil-water contact}
\]

\[
\text{Maersk Olie og Gas AS has found it most useful to jointly display openhole log interpretation (top), RFT data (middle) and well trajectory (bottom) for its horizontal North Sea chalk wells. The horizontal axis is the vertical section (horizontal displacement) of the well from its starting position along a given azimuth. Tick marks on the horizontal trajectory are perforations. The TEB-1 well in the Tyra gas field was drilled to be a horizontal, flank gas producer and to appraise the field’s oil rim. The well trajectory shows both the pilot hole and horizontal trajectory with respect to zone boundaries and fluid contacts. Log interpretation shows deterioration in reservoir quality from the center of the field toward the flank. High water saturations in the oil rim are due to a combination of poor reservoir and close proximity of the OWC. The RFT data from both the pilot and horizontal wells have been corrected to the reservoir datum level of 6500 feet (true vertical depth below sea level) to show pressures in the center of the field to be about 200 psi below initial reservoir pressure, but hardly depleted within the oil rim, because of the poor reservoir quality. A lateral pressure gradient of 0.06 psi/foot has been established within the gas zone and the high reading for setting 23 is attributed to supercharging.}
\]
Combining caliper and spinner data to find fluid entries in a North Sea horizontal well. As expected in a well completed with an unceded slotted liner, the flow and caliper measurements are inversely related—flow drops where the caliper increases; flow increases where the caliper decreases. But by examining flow rate only where the hole is in-gauge, production can be detected. Here, more flow is coming from the formation at X685 than at X850 meters, which suggests the higher depth is a producing interval. The ramps starting at X505 and X585 meters indicate annular flow shunted back into the casing.

• Caliper and spinner data are used to identify fluid entries.

• Be sure the spinner is well centralized.

• ARCO Alaska experimented with motorized centralizers to raise and lower the spinner within the diameter of the drainhole or high-angle hole. The company took spinner surveys at three points in the diameter of the well and found velocities that looked like they came from three wells—reverse flow on the bottom side of casing, mixed flow in the middle and highest flow rate along the top side of the casing. ARCO Alaska has had success holding the spinner in the middle of the hole diameter by using bow springs or other centralizers on the spinner end of the tool and letting the uphole end of the tool drag on the borehole floor. The best readings are obtained with the largest diameter spinner possible or a diverter flowmeter. Other operators find that the use of two-spinner flowmeters can help overcome poor tool centralization.

Flowmeter values and determine areas of production (above). Petroland found that large caves shown by Formation MicroScanner caliper, virtually doubling borehole diameter, correlated with areas where spinner speed went almost to zero. This is because in the typical completion, a slotted liner, flow fills the annulus as well as the borehole.

• Holdup meter (HUM) readings are most reliable where wellbore fluids have a better chance of being evenly distributed—in small diameter casing and at high flow rates. The HUM distinguishes hydrocarbons from water by electrical capacitance. In horizontal wells, it is used in place of the Gradiomanometer tool, which does not work in a horizontal well because it requires a pressure difference over height to give a fluid density. When the tool is on the floor of the well it tends to read water, and misses gas and oil entries along the roof of the well. In this case in gas wells, BP Alaska relies more on the temperature log for finding fluid entries. Maersk Oil has used the HUM to identify standing water at low points.

• In slotted liners, diverter and packer-type flowmeters are not recommended because they may cause a pressure drop that will divert flow to outside the liner. If a basket-type flowmeter is run, damage to the tool can be avoided or minimized by not running the tool through fill accumulated in the bottom of the liner (evidenced by no return signal from the down-looking windows of the Cement Evaluation [CET] tool). When running the fullbore spinner, using the largest spinner possible can help reduce the influence of water fallback—recirculation of water where the well swings up from the horizontal. Water fallback has been observed in Rospo Mare and Prudhoe Bay, Alaska, USA and can give the impression of a higher water cut than is produced at the surface. Water fallback can also appear on the spinner survey like fluid from one interval flowing into another (called crossflow)—a spinner reading lower than expected for what the well produces.
When significant flow is suspected to be channeling outside the slotted liner:

- Look for shale breaks on the gamma ray log and assign highest confidence to spinner readings taken at those points. Where shale collapses around a slotted liner, a greater portion of flow is probably shunted into the liner, making the reading more representative (below). Even with this assistance, however, many operators consider a spinner survey in unpacked slotted liner useful only for flow direction, not rate.
- Consider a radioactive tracer survey—but use an oil-soluble tracer to be sure that the tracer moves to the high side of the hole. Water-soluble tracers may pool and be unreliable in indicating flow. In Alaska, where many horizontal wells are completed with uncemented liners, tracer surveys are sometimes preferred to spinner surveys.
- The temperature log may give a rough estimate of fluid entry points. But in a horizontal well, the temperature log does not show a gradient as in a vertical well, but increases (from curing cement) and, sometimes, from oil influx and decreases (from gas and water entries). Cooling and warming effects occur over long intervals, so they are less pronounced than in a vertical well. Sometimes the temperature log in a horizontal well appears jagged. This phenomenon is poorly understood, and may indicate many oil and gas entries.

To obtain readings in an interval isolated with packers, the continuous flowmeter has to be used; readings can be obtained above and below the isolated interval with a fullbore spinner. Maersk Oil has used the continuous flowmeter to qualitatively evaluate flow contributions from different intervals. The results, however, have not been as reliable as those provided by the fullbore spinner.

Operators have developed two operational practices to help improve yield from horizontal production logging. First, Petroland has found that an extended, max-

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Shale breaks and variation in bottomhole flowing pressure on multiple production logging runs in a horizontal North Slope well. The shales at X570 and X760 may have sealed the liner and bypassed all flow through the spinus. The green area between the MWD and production log gamma ray measurements is due to a radioactive tracer pumped in during stimulation. The fullbore spinner rates indicate similar restrictions at X980 to X990 feet, X995 to X005 feet and X045 to X055 feet. Production varied markedly with downhole flowing pressure between the seven passes. Near the bottom of the interval, downhole flowing pressure was 1660 to 1890 psi, and the flow rate was 1000 to 200 BOPD as the well loaded and unloading.

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mum rate cleanup reduces skin. After this treatment, intervals come on line that did not contribute during initial production.

Second, experience in Alaska has shown that knowing flowing bottomhole pressure at the time of testing helps determine how the well is "loading up" and "unloading" between producing logging runs (previous page). In Prudhoe Bay, bottomhole flowing pressure between logging runs can vary by 100 psi, which can correspond to variation in surface production of up to 1,000 BOPD.

Under multiphase conditions, fluid flow is best approximated with a diverter flowmeter when there is interval isolation; the fullbore spinner flowmeter is preferred when there is no interval isolation. The influences of diphasic flow are at minimum where the phases will be mixed. This is sometimes the case at perforations and where tubular diameter narrows.

**TDT Logs**

Thermal Decay Time (TDT*) logging allows distinguishing gas and oil, gas and salt water, and oil and salt water through casing and cement. The current generation of tool also distinguishes formation neutron capture cross section, $\Sigma$, from wellbore $\Sigma$. This is particularly important when looking for cement channels in horizontal holes (above). Successful application of the pulsed neutron tool is limited, however, by porosity. In the karstic Rospo Mare field, which has a 2 percent effective porosity, Elf found that the count rate coming from the pore space was too low to discriminate between oil and water.

In Prudhoe Bay, ARCO Alaska has refined pulsed neutron logging in horizontal wells for detection of cement channels, particularly within the perforations. ARCO makes three pulsed neutron runs: the well flowing, shut-in (occasionally following loading the wellbore with crude) and after injection of a boron solution (boron is a strong thermal neutron absorber). The log made with the well flowing helps identify the type of fluid entering the wellbore and minimizes effects of crossflow (fluid from a high-pressure interval flowing into a low-pressure interval) on the log data. Overlaying the flowing and static passes further identifies fluid entries, especially gas. In wells with mixed gas/oil or water production, the shut-in pass further improves the formation readings by minimizing possible effects of changing wellbore fluids in a flowing well. In the postinjection mode, cement channels are inferred based on large changes in the formation $\Sigma$ as the boron is pumped through the perforations and channels and into the rock matrix. Cement channels are readily apparent because of the large magnitude of the change—on the order of 20 $\Sigma$ units.

**Agenda for the 1990s**

Operators have made progress in addressing the questions raised at the beginning of this article. The challenge lies in devising directionally focused measurements that can account for azimuthal asymmetry of formation properties and invasion in the horizontal well. There is also interest in the prospects for an ultra-long spaced sonic measurement to locate distant horizons, and in the potential for the Array-Sonic* tool to give more information on fracture aperture. More experience with real-time LWD and MWD measurements will help clarify how they can be combined with wireline measurements, particularly in equity negotiations. In production logging, multiphase flow remains a challenge to both theory and hardware in horizontal and conventional wells. And refinement of fluid density measurements will improve results in segregated and diphasic flow.

Drilling was the first horizontal well technology to mature and, in the past few years, advance fast enough to become routine. Lagging somewhat behind is completion technology; only recently have operators become confident that good horizontal completions can be achieved and can increase the value of the well. It seems only logical to presume that complete formation evaluation in horizontal wells is the next frontier.

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The Challenge of Completing and Stimulating Horizontal Wells

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Although drilling horizontal wells has become almost routine, completion and stimulation challenges still exist. These challenges include securing zonal isolation, taken for granted in a conventional well completion.

Vertical well technology took over half a century to progress from barefoot openhole completions to the range of cased-hole completions available today. Driven by the same need to selectively produce and treat individual zones, completion engineers are pushing horizontal well technology along the same road in less than a tenth the time.

At first sight, zonal isolation might not seem as important in a horizontal well as in a vertical well. The horizontal well should ideally tap one formation and produce from the entire horizontal interval. Experience drilling and producing horizontal wells, however, shows that reservoirs are often horizontally heterogeneous. With sufficient subsurface knowledge, oil companies can exploit heterogeneity by directing horizontal boreholes through natural fracture systems, or through facies and faults tapping several separate producing formations. This requires zonal isolation. Isolation may also be needed if the borehole drifts in and out of the target reservoir because of insufficient geological knowledge or poor directional control.

When horizontal boreholes are drilled to tie in to the natural fractures of a tight formation, such as in the Austin chalk fields of south Texas and the Rospo Mare field offshore Italy, zonal isolation is being seen as mandatory (left). Initial pressure in naturally fractured formations may vary from one fracture to the next, as may the hydrocarbon gravity and likelihood of coning. Allowing them to produce together permits crossflow between fractures and a single fracture with early water breakthrough, which jeopardizes the entire well's production.

Initially, horizontal wells were completed with uncemented slotted liner unless the formation was strong enough for an openhole completion. Both methods make it difficult to determine producing zones and, if problems develop, practically impossible to

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and stimulation techniques for the new environment are still in intensive development. The goals, and understanding the role of hydraulic fracturing.

selectively treat the right zone. Today, zonal isolation is achieved using either external casing packers (ECPs) on slotted or perforated liner or by conventional cementing and perforating (see “Which Completion?” page 58). In this fast-moving technological area, oil companies choose which method to use depending on their experience and the producing conditions. In the long run, conventional cementing and perforating offer the most reliable isolation. It is fast becoming the favored technique in most fields outside the USA and is mandatory if the well is to be hydraulically fractured.

ECPs are mostly used in naturally fractured formations such as the Austin Chalk and Roscoe Mam chalks. Attached to the outside of the liner, ECPs are reinforced, inflatable rubber diaphragms that are inflated with mud or cement to make a seal against the formation (right). Since ECPs inflate radially, they work less well in oval holes than in circular holes.

2. ECP is trademark of Baker Hughes Incorporated.
The Challenge of Completing and Stimulating Horizontal Wells

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Although drilling horizontal wells has become almost routine, completion and stimulation techniques for the new environment are still in intensive development. The goals include securing zonal isolation, taken for granted in a conventional well, and understanding the role of hydraulic fracturing.

Vertical well technology took over half a century to progress from barefoot openhole completions to the range of cased-hole completions available today. Driven by the same need to selectively produce and treat individual zones, completion engineers are pushing horizontal well technology along the same road in less than a tenth the time.

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Initially, horizontal wells were completed with un Cemented slotted liners unless the formation was strong enough for an open-hole completion. Both methods make it difficult to determine producing zones and, if problems develop, practically impossible to selectively treat the right zone. Today, zonal isolation is achieved using either external casing packers (ECPs) on slotted or perforated liners or by conventional cementing and perforating (see "Which Completion?" page 36). In this fast-moving technological area, oil companies choose which method to use depending on their experience and the producing conditions. In the long run, conventional cementing and perforating offer the most reliable isolation. It is fast becoming the favored technique in most fields outside the USA and is mandatory if the well is to be hydraulically fractured.

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External casing packer
Horizontal wells are frequently drilled to tap natural fracture systems in tight reservoirs. They generally cost no more than 1.5 times the cost of a normal well, but produce 8 to 10 times the quantity of oil.

For contribution to this article, thanks also to: Tony Griffl, Dowell Schlumberger, Houston, Texas, USA and David Vincent, Technip Norge A.S., Oslo, Norway. See also "An Introduction to Horizontal Well Technology" in an article in this issue, also.

Adapted from "Horizontal Drilling: From Art to Science." OMV, 1998. 4-32.
EPC is trademark of Baker Hughes Incorporated.
Cementing

The elements leading to a successful horizontal cementation are similar to those required for a conventional vertical job. It is the particulars that make the difference. As with every cement job, operators try to displace as much of the mud and solids from the annulus with cement as possible. The idea is to leave no continuous channels for fluid communication behind the liner. This is intrinsically harder to achieve in the horizontal environment than in the vertical. In the vertical well, channels may develop but they usually lack continuity. In the horizontal environment, gravity causes continuous channels to develop on the top side of the liner because of fluid separation in the cement and on the bottom side because of nondisplaced cuttings.

Centralizing the liner is the first step in a successful mud displacement. In horizontal wells, gravity pushes uncentralized pipe to the low side of the hole trapping undisplaceable mud there. Other causes of eccentricization can be the zigzag nature of horizontal wells from the natural resonance of drilling motors, which can create a corkscrew-shaped hole, and planned changes in hole direction during drilling. Two types of centralizer, rigid and bowspring, are used to counter eccentricization.

Rigid centralizers generally offer better results for in-gauge horizontal wells; certain types with plenty of space for circulation offer the additional benefit of increasing local turbulence, aiding mud displacement. Washedout sections of hole require bowspring centralizers. Some manufacturers fit centralizers with special bushings at each end to reduce torque when the liner is rotated to break down the mud's gel strength prior to pumping cement. To reduce drag when lowering liner into a horizontal hole, centralizers can be mounted over stop collars so they flatten as they are pushed through constrictions in the hole (above, left). Without stop collars, the centralizers would be pushed along by liner collars and expand.

Eccentricization in horizontal holes may also result from using heavy cement. When cement is pumped downhole, the liner becomes heavier and will sit low in the mud-filled hole, possibly compressing bowspring centralizers or causing rigid centralizers to sink into the formation. This creates a narrow channel on the low side of the annulus and impedes mud displacement there (top). As the cement moves along the annulus, however, casing buoyancy will increase and bowspring centralizers may recover, opening up the low side of the annulus. But then, it is generally too late to improve displacement.

A way to improve centralization is to use a smaller-diameter liner. This means less cement pushing the liner downward during displacement and more standoff from the borehole wall, a defined parameter that correlates with displacement efficiency (bottom). The completion design, however, may preclude using a smaller liner.

Bowspring centralizers mounted around stop collars on liner. This arrangement ensures the centralizers are pulled, not pushed, into the hole, flattening the centralizer during the descent and providing minimal drag.

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The completion design, however, may preclude using a smaller liner.

The design of the cement slurry must balance several conflicting requirements. The slurry should have low yield stress to promote turbulent flow, essential for maximizing displacement, and excellent fluid loss because it is exposed to possibly thousands of feet of permeable reservoir. But most important, the slurry must be stable, with no sedimentation or development of free water. Sedimentation, the separating out of the cement's solid components, leads to low strength, highly porous cement. Free water developing on the high side of the hole may create an open continuous channel. Tests by Elf Aquitaine and Institut Français du Pétrole (IFP) showed that a slurry with 0.2 percent free water would result in a channel up to 0.4 in [10 millimeters] high at the top of 7-inch liner/10-inch borehole annulus.3

The Elf and IFP researchers report three options to enhance slurry stability, depending on downhole temperature:

- Using dispersants to encourage the formation of ettringite, a mineral formed during setting that binds cement grains together (right).
- Viscosifying the interstitial water with latex emulsions.
- Mixing solid inert elements 10 to 100 times smaller than the cement grains to occupy interstitial gaps between grains and prevent water from separating.

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**Flow rate ratio**, the ratio of flow rate during mud displacement between the top and bottom sides of the liner, as a function of liner standoff. If the liner sits low in the hole, flow on the bottom side may drop to near zero. If the liner is perfectly centered, flow rate ratio is unity and displacement is optimum. The parameters \( w \), \( r_h \), and \( r_c \) are respectively the minimum separation of liner and hole, hole radius and liner radius.

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Spiky ettringite crystals growing from the surface of cement grains during setting.
Another ingredient for successful cementation in horizontal wells is easily displaceable mud, particularly with low gel strength. Pipe movement is the key to breaking down mud’s gel strength, and pipe rotation has proven more effective than reciprocation. Recently, special hangers equipped with bearings have been developed for simultaneous rotation and reciprocation (below). Reciprocation is typically with a stroke of around 10 to 20 feet [3 to 6 meters] every minute, rotation is between 10 and 20 rpm. Both are continued until the plug bumps on bottom. Rotation has the additional benefit of forcing cement around the casing and improving displacement on the narrow side of the annulus. In horizontal wells, hole torque and drag may preclude liner movement—theoretical drag models have been developed to predict when it may be impossible to move the liner.

The cement should be displaced at a rate that preserves a stable fluid interface between the slurry and mud, preferably in turbulence. This requires a rheologically stable slurry with low yield stress, low plastic viscosity and excellent fluid loss control, properties that can be ensured with latex-based additives such as used in the WELBOND® and GASBLOK® services.

Finally, special consideration must be given to the float equipment at the end of the liner that prevents cement flowback. Flowback can be a problem in horizontal wells because the hydrostatic pressures of the slurry and mud at the end of the hole may be similar. For near-balanced conditions, most operators prefer the spring-loaded flapper or poppet equipment, although specially designed ball-type float valves have been claimed to work satisfactorily in tests with a pressure difference as small as 5 psi between the fluids (top).

Perforation
Oil companies have been reluctant to cement and perforate the entire length of a horizontal well. With a well drilled up to 3000 feet [900 meters] through one producing sand, they see perforating as prohibitively expensive. Recently, it was shown that perforating the entire length of a horizontal well was unnecessary, particularly when tapping a thin reservoir—the same production can be obtained by perforating a fraction of the full length. Oil companies also recognize that most reservoirs are heterogeneous enough horizontally to warrant selective production. The trend is therefore toward perforating shorter intervals.

Other trends include a high shot density for hydraulic fracturing to reduce the pressure drop across casing; and for formation sand control, only downward perforation—experience in highly deviated wells shows it is difficult to gravel pack upper perforations.

Simultaneous rotation and reciprocation of liner during cementing. This helps break down the mud’s gel strength, facilitating mud displacement. Special liner hangers had to be developed that permit both movements.
The challenge in perforating horizontal wells is getting the guns along the borehole to the correct location, or "depth." Wireline-conveyed guns are limited to about a 75-degree deviation. Beyond that, perforating guns must be pushed down with tubing (tubing-conveyed perforating—TCP), coiled tubing (CT)\textsuperscript{7} or drillpipe. In reviewing the perforation of horizontal wells, Amoco Production Co. observed that while TCP is expensive, the system is robust and provides a wide selection of guns. On the other hand, the CT system's savings in cost and time may be more important than the smaller size of CT-conveyed guns (left).\textsuperscript{8}

Other issues in horizontal perforation are penetration depth and centralization. Generally in a horizontal completion, shots firing upward may traverse more hole and cement than downward shots. Centralizing the gun obviously helps to maximize penetration, but currently centralization is only possible with tubing- or drillpipe-conveyed guns. For TCP, Amoco uses the largest gun that can be fished, determined from the tubular dimensions of the well, and equips it with the best available centralization.

Depth control, crucial for perforating vertical wells, may be less critical in the horizontal environment. The accuracy required depends on reservoir heterogeneity—the more heterogeneous the producing formation, the more accurate the depth control.

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* Mark of Schlumberger
† Mark of Dowell Schlumberger

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*Perforating in horizontal hole with coiled tubing-conveyed guns. Depth control, so vital in vertical wells, may be less crucial in the horizontal environment. However, it is more difficult. The conventional gamma ray correlation method is compromised because most formations display only small lithology variation in the horizontal direction. The surest depth control comes from identifying a short pup joint inserted in the liner just above the producing zone with a casing collar locator (CCL) or a radioactively tagged liner section with a gamma ray tool. Both techniques are performed with wireline equipped coiled tubing.
Which Completion?

Open hole
How most horizontal wells were initially completed, but now used only in the homogeneous reservoir with enough geomechanical strength to support itself. No zonal isolation is possible with this type of completion.

Open hole, cemented off-bottom
Similar to an openhole completion except that the top zone is filled with cement, to isolate a gas cap perhaps, and then drilled out. The technique requires the isolation of the lower horizontal portion of the wellbore from the section being cemented using a highly viscous, crosslinked polymer plug up to 200 feet (60 meters) long.¹

Slotted liner in open hole
The easiest completion after open hole. Slotted liner can support weaker formations, but should not be used where sand production occurs. The sand will plug the slots or be produced through them. No zonal isolation.

Prepacked liner in open hole
The easiest solution for sand control. A resin-impregnated sand is trapped between two concentric screens. Prepacked liners prevent collapsed sand from entering the well but do not discourage the sand from collapsing. The sand may form a zone of reduced permeability around the outer screen and impede production.

Gravel packing
The ideal completion for weak formations, but hard to achieve in a horizontal well. The easiest method is to leave the well openhole and pack gravel around a slotted liner or, for insurance, around a prepacked liner. For details, see “Sand Control” on this page.

Sand Control
The most widespread technique for sand control in horizontal wells utilizes prepacked liners, comprising two concentric screens packed with resin-coated particles. They are usually set in open hole, though Elf recommends installing a slotted liner first to facilitate workover. Prepared liners prevent sand from entering the wellbore, but they do not halt formation collapse. Thus, produced sand accumulates around the liner and may block production.

A conventional gravel pack, in which gravel completely fills the annulus, prevents sand collapse, but is hard to achieve in highly deviated wells. Chevron reports considerable success in the Gulf of Mexico for 70- to 80-degree wells. Most gravel packing in horizontal holes is done open hole and, for insurance, around prepacked liners.

Best results are to be expected by pumping the gravel and carrier fluid down the annulus and up the liner. This allows the gravel to accumulate starting from the end of the well minimizing the chances of bridging. The carrier fluid should have excellent suspension properties to carry the gravel, and high leakoff to encourage gravel placement. The gravel should preferably be light and close in density to the fluid as possible, again to increase suspension. Dowell Schlumberger’s nondamaging PERM PAC® carrier fluid and low-density ISO PAC® gravel substitute were designed to satisfy these requirements and are expected to eliminate the need to perforate only downward for gravel packs in horizontal cased hole. Upward perforations in deviated cased wells are considered risky, too likely to go unpacked and later produce sand.

Matrix Stimulation
Intersection of the wellbore with natural fractures is often a goal of horizontal drilling. But just as these channels are potential conduits for oil or gas production, they are also possible thief zones during drilling, causing deeply penetrating damage to the formation. Oil companies suspect that matrix damage may be exacerbated in horizontal wells because the drilling tends to produce liner cuttings that plug formation more easily. A cleanup program reconditions these fractures, as well as secondary fractures connected with them, and restores the original matrix permeability through injection of acid or other solvents at below fracturing pressure.

Because horizontal wells intersect long intervals of producing formations, cleanup treatments can require huge volumes of chemicals—in excess of 100 gallons per foot for thousands of feet! Chemical costs become prohibitively expensive if the stimulation fluids disappear down a few permeable channels and open communication to unwanted gas or water zones. This is avoided by using diverting agents such as benzoic acid, wax beads, foam or micro-

scopic oil-soluble fibers. These block permeability during the treatment but dissolve once production begins. Nondestructible diverting agents such as ball sealers are not recommended because they may remain in the horizontal section after the treatment and even after the well is put on production, compromising future workover.

In cased and perforated completions, acid can be injected at precise depths through coiled tubing with the Formation Selective Treatment (FSTS) System, which comprises an injection port between two inflatable packers (left). In openhole or slotted liner completions offering no zonal isolation, the recommended procedure is to pump acid through coiled tubing that is initially pushed to the end of the hole. During pumping, the coiled tubing is slowly withdrawn and diverting agents are released every 50 to 100 feet to seal off the already cleaned section of the hole. The rate of coiled-tubing withdrawal depends on pumping rate, reservoir permeability and skin damage, and the required cleanup radius. Successful matrix cleanup has been performed this way at rates less than 25 gallons per foot.

Matrix acidizing with the Formation Selective Treatment (FSTS) system on coiled tubing. The FSTS tool comprises an injection port between two inflatable packers. A circulating valve just above the tool obviates the need to push large volumes of well fluid into the formation before the acid. For less efficient spotting of acid, coiled tubing can be pushed to the end of the hole and slowly withdrawn while acid and diverting agents are pumped.
Hydraulic Fracturing

Hydraulic fracturing, using either acid or sand, improves production by creating fractures through high-pressure pumping. How successfully induced fractures drain a reservoir depends on their orientation, reach and fluid conductivity.

Near the well, fracture orientation is dictated by the complex near-wellbore stresses. As the fracture develops away from the wellbore, however, it will align itself perpendicular to the earth's minimum stress (right). At depths more than about 2000 feet, this is in a horizontal direction, so the fracture plane will be vertical.

A key factor in determining the productivity gain from induced fractures is their relative orientation to the wellbore. If the well runs perpendicular to the minimum stress direction, fractures will develop along the well. The entry point into any fracture will be through an extended length of perforation (below).

On the other hand, if the minimum stress parallels the well, the fractures will develop transversely, potentially increasing the drainage area of the reservoir. The disadvantage is that the limited contact of each fracture with the wellbore acts like a choke, impeding injection of fracturing fluid and proppant and then afterward the flow of hydrocarbon. A partial solution is to multiply perforate the point of intersection or completely cut the cemented liner with radial perforating jets or a radial blast of fluid-conveyed sand, as provided by the ABRASIJET service, for example.

If the earth's stress is known, the well can be directed to take advantage of either scenario—transverse or longitudinal induced fractures. Borehole direction can be accurately kept on target with directional drilling techniques (see "Horizontal Drilling Comes of Age," page 22). The earth's stress can be determined from minifrac tests, wellbore ovalization (observed with a four-arm caliper logging tool in nearby vertical wells), or by observing the orientation of natural fractures with imaging tools such as the Formation MicroScanner tool.

But it must be ensured that the planned horizontal well will better the performance of an equivalently stimulated vertical well and pay back the extra cost it takes to drill and stimulate horizontally. Recent theoretical work permits such a comparison (top, right). The results depend on whether the horizontal fractures are longitudinal or transverse to the well, their number and size, their fluid conductivity, formation permeability and, for transverse fractures, the skin that develops at the intersection point between fracture and well (above, right).

Having established that fracturing the horizontal well is economically desirable, the operator must choose among a variety of methods to selectively isolate each zone during the fracturing operation. This used to be done with permanent bridge plugs that were later drilled out. But this technique takes time and creates debris that can


Three methods for stimulating horizontal wells selectively. The traditional method (left) uses a retrievable packer to seal the top of the zone and millable bridge plugs to seal the bottom. Debris from drilling the plugs out may obstruct the formation. A second method uses straddle packers set by reciprocating the tubing. Setting must be done after the tool has been moved opposite the zone just perforated. A third method uses a retrievable bridge plug on the bottom. Other more exotic ways to isolate a zone for stimulation include multiple completion packers with tubing equipped with sliding sleeves, liners equipped with polished bore receptacles (PBRs), sliding sleeves, or aluminum disks that can be dissolved with acid.

- Multiple polished bore receptacles (PBRs) in the liner used with a retrievable seal assembly that close the well at PBR depth: This simple concept requires only reciprocation of the tool assembly to open and seal the well. Problems arise, however, when the casing cannot be set at the correct depth—the PBRs will automatically be off too. The PBRs can also be damaged by the trip downhole or during operation if proppant remains in the wellbore.
- Sliding sleeve collars or aluminum disks built into the casing: The sleeves can be difficult to open and close, and this problem can also prevent the running of packers. Aluminum disks dissolve in acid, making a perforating tool string to go in the hole unnecessary. However, difficulty has been experienced dissolving the disks and fracturing through the cement.
- Perhaps the most successful fracturing program in horizontal wells has been in the Dan field, a low-porosity chalk reservoir in the Danish sector of the North Sea operated by Mærsk Oil and Gas AS (see “Exploiting Reservoirs with Horizontal Wells: the Mærsk Experience, page 11”). In a 1987 study, the productivity of a nonstimulated horizontal well was shown to be no better than a conventional, fractured deviated well, yet cost more. Even a matrix-acidized horizontal well hardly offered better production. The study concluded that horizontal wells in the area could compete economically only if they were fully stimulated by fracturing. There were additional risks to such a procedure in the low-permeability chalk, but Mærsk Oil decided they were worth taking.

Three horizontal wells were fractured with up to seven fractures per well (next page, middle). Mærsk Oil reports that once on stream these three multistimulated horizontal wells accounted for 25 percent of the field’s production. At the time, the field had 41 producing wells.

In 1989, more than 100 horizontal medium- and long-radius wells were drilled and the number seems to be doubling every year. With the exception of a few major field developments, these wells have been paid for from R&D budgets or by special funding.

Proponents of horizontal well technology foresee its dramatic proliferation in the future with perhaps up to 50 percent of all wells being drilled horizontally. The advocates predict that combinations of vertical, directional and horizontal wells, whether fractured or unfractured, will be used to create an “underground architecture.”

For this dream to be realized, experience completing and evaluating horizontal wells will be needed in a far greater range of reservoirs, not just in ones with special needs or problems. Operators will require conclusive proof that horizontal wells are the most economic producers. Once the proof is there, the technology will move into the mainstream.

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Seven fractures, shown schematically, induced in a horizontal well in the Dan field in the Danish North Sea by Maersk Oil & Gas AS. Just three such wells provide 25 percent of the field’s production from a total of 41 producing wells. A pilot hole was drilled first to locate the dip of the producing Maastrichtian formation, the overlying low-permeability Danian formation and the 50 percent water saturation level. Adapted from reference 14.
**Horizontal Well Testing in India**

The continued success of horizontal drilling has emphasized the need for test interpretation models tailored to horizontal wells. Schlumberger researchers have developed an analytical model for the pressure response and flow regimes during testing of the horizontal well in nonfractured formation. The model has been incorporated into the Schlumberger Transient Analysis and Report (STAR) program, part of a computer-based reservoir analysis system. Using the STAR program, reservoir engineers recently interpreted pressure transient tests for the Oil and Natural Gas Commission (ONGC) in the Bombay High field, offshore India.

**Horizontal Flow Regimes**

In a horizontal well allowed to produce after shut-in, three flow regimes will normally occur. Flow is first radial (normally elliptical because of permeability anisotropy) around the wellbore in the z-y plane, hence the term early-time pseudo-radial flow (left). This is the only regime in which the true skin can be measured. Wellbore storage effects, which are increased by surface shut-in and can only be accounted for by measuring downhole flow rates, can obscure this regime.

Next, if the well is long compared to the reservoir thickness, intermediate-time linear flow parallel to the y-axis develops as the pressure transient reaches the reservoir.

*Mark of Schlumberger*
Diagnosis of flow regimes during a horizontal well test from a log-log plot of the normalized pressure and pressure derivative versus elapsed time. Wellbore storage is more prominent in horizontal than vertical well testing because more fluid exists in the wellbore below the tool. It can mask the early-time pseudo-radial flow, particularly if downhole flow rates are not available to account for it.

boundaries. Intermediate-time linear flow will not develop in wells with pressure maintained by a gas cap or an aquifer. The third regime—late-time pseudo-radial flow—also involves radial flow around the well, but in the bedding (x-y) plane. This period may not develop if the horizontal width of the reservoir is not much greater than the well length or if reservoir pressure is maintained by a gas cap or aquifer.

Horizontal well test interpretation is more complex than its vertical counterpart. In a vertical well, radial flow is easier to identify because it occurs after wellbore storage effects become negligible and before boundary effects are seen. Pseudo-radial flow free from these effects does not last as long in horizontal wells because they exhibit spherical flow at the ends of the well. Furthermore, in a horizontal well, fluid flow near the wellbore is influenced by permeabilities perpendicular as well as parallel to the depositional structure. Consequently, vertical variations in permeability and shale distribution affect the pressure and flow rate responses. One benefit of a horizontal well is that a properly designed test with downhole flow rate measurements can yield anisotropic permeability components, \( k_x \), \( k_y \), and \( k_z \).

As with a vertical well test, initial estimates of the major formation properties from a horizontal well test—permeability, skin and pressure—may be determined from radial (and sometimes linear) flow regimes identified on log-log plots of normalized pressure and its derivative with respect to the superposition time function (above). If downhole flow rates are measured, then the normalized pressure and its derivative with respect to the sandface rate convolved time function are plotted instead. Pseudo-radial flow yields a zero slope on the pressure derivative plot. Effective permeability measured in early-time pseudo-radial flow is \( k_e \), and in late-time pseudo-radial flow is \( k_e' \). Intermediate-time linear flow yields a slope of \( 1/2 \) on the pressure derivative and gives an effective permeability of \( k_e' \).

The key to a successful horizontal well test interpretation is identifying the early-time pseudo-radial flow. Skin caused by wellbore damage can be more accurately obtained from this regime than from the late-time pseudo-radial regime. At late-time, the apparent skin has two contributions: one from wellbore damage and an additional pressure drop, called the geometrical skin, because the flow pattern near the well differs from the radial one far away in the horizontal plane. This geometrical skin, which usually dominates, depends on the anisotropic permeabilities that are not known precisely. Also, only the early-time pseudo-radial flow regime is affected by the vertical permeability, \( k_z \). If the early-time period is missed, \( k_z \) cannot be determined.

Testing the Bombay High

In testing NR-1H, one of two ONGC experimental Bombay High wells, ONGC was especially interested in the permeability anisotropy ratio (see “Reservoir Parameters of Horizontal Well NR-1H,” below). The

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<th>Reservoir Parameters of Horizontal Well NR-1H</th>
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<tr>
<td>Length of perforated interval, ft</td>
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well was completed with cemented casing and tubing-conveyed perforation. It then underwent a matrix acid job, standard practice for wells in this limestone formation. Next, a series of alternating drawdown and buildup tests was performed using a Production Logging (PLT*) tool equipped with flowmeter and temperature and pressure gauges (left). Downhole flow measurements were crucial for identifying the early-time pseudo-radial flow regime.

Of the post-acid pressure transients, drawdowns 5, 6, and 7 and buildup 6 lasted long enough to yield significant information. STAR-generated log-log plots of the pressure and its derivative for these tests revealed strong cleanup effects from acidizing on drawdowns 5 and 6, eliminating them from further analysis. The remaining transients were replotted on log-log plots of the pressure and its derivative with respect to the superposition time function and the pressure derivative with respect to the sandface rate convolution time function. The combined plot for buildup 6 and drawdown 7 illustrates the consistency of the data from one transient to the next (left). Two plateaus in the derivative curves appear, indicating pseudo-radial flow but at different times. The early-time pseudo-radial flow shows up more clearly in the drawdown 7 data while the late-time pseudo-radial flow regime appears only during buildup 6, which lasted longer. Derivative curves for both transients show the slope of 1/3, characteristic of intermediate-time linear flow. The effective permeabilities $\sqrt{\kappa_x k_y}$ and $\sqrt{\kappa_z k_y}$ for the early and late-time pseudo-radial flows, and $\kappa_d$ for the intermediate-time linear flow permeability, respectively—were calculated from the slopes of the sandface rate convolution plots (see “Buildup 6 and Drawdown 7 Estimates,” below left).

So far, only particular flow regimes had been used to provide initial estimates of reservoir parameters. To refine these estimates, reservoir engineers use a full-scale simulation combining all data for one test or several tests. The initial estimates of permeability and skin were put into the analytical model, which then simulated (or history matched) the measured flow rates from the well tests with the measured pressures as input and vice versa. Reservoir engineers used the STAR system to determine the set of reservoir parameters that optimized the match between measured and simulated data (see “Parameters of the STAR System,” next page, below left). Flow rate simulations based on pressure measurements may be preferred if there are periods of unmeasured flow rate during a test sequence. These

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**Buildup 6 and Drawdown 7 Estimates**

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occur when the flow rate falls below the spinner threshold or debris jams the spinner. Pressure measurements, however, are usually available for the entire test period.

Buildup 6 and drawdown 7 were each history matched using a model of the reservoir with horizontal permeability anisotropy (see “Estimates of Simulation from Anisotropic Permeability Model,” below, right). Excellent reproductions of observed transient behavior can be seen on the history matches based on measured flow rates for drawdown 7 and based on measured pressure and its derivative for buildup 6 (right).

In general, good agreement exists between the reservoir parameters obtained from the history match of the two transients. The estimates of $k_v$ differ significantly. The higher $k_v$ value obtained from the drawdown is considered more reliable because the flow rate measurements during the intermediate-time of buildup were noisy. This was due to flow rates approaching and then falling below the spinner threshold.

The ability to successfully interpret horizontal well tests has played an important role in ONGC’s ongoing development of the Bombay High field. Two additional horizontal wells have been drilled since this initial testing and plans for an expanded drilling program are underway. 

—TAL

### Parameters of the STAR System

The STAR module for horizontal wells allows reservoir engineers to estimate any combination of the following parameters:

- horizontal permeabilities, assuming either horizontal isotropy ($k_h = k_v$) or horizontal anisotropy.
- vertical permeability, $k_v$.
- skin: this refers to a pressure drop at the wellbore face caused by a change in flow at the well. Early-time pseudo-radial flow is more indicative of formation damage than skin from late-time pseudo-radial flow.
- wellbore storage coefficient: this accounts for pressure loss and expansion effects of the fluid volume existing in the wellbore below the flowmeter.
- distance of wellbore from layer boundary: this parameter is sometimes not known a priori, since horizontal wells snake up and down in the formation.

### Estimates of Simulation from Anisotropic Permeability Model

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