The average horizontal well is more expensive and technically difficult to drill than the average vertical well. Yet, around the world, horizontal wells are being spudded in ever increasing numbers. Almost 80% of the wells being drilled in Oman, Qatar and Abu Dhabi are horizontal. Why should this be?

In simple terms, horizontal wells allow us to do things more efficiently than vertical wells. It would be short-sighted to ignore a technique which offers improved drainage in typical reservoirs and penetrates more of the discrete compartments in complex reservoirs, while helping to reduce gas and water coning.

In this article, Roy Nurmi brings together the experience of staff in the Middle East headquarters' interpretation, development and marketing team. Fikri Kuchuk (petroleum engineer), Bruce Cassell (geophysicist), Jean-Louis Chardac (log analyst) and Philippe Maguet (manager) examine new developments in horizontal well characterization for reservoirs of the Middle East region, spanning Egypt to India.

The article includes important published contributions to the Geo’94 Conference from A. F. Jubralla and P. Cosgrove (Qatar General Petroleum Corporation, Doha, Qatar), and S.J. Whyte (Petroleum Development Oman, Muscat, Sultanate of Oman).
Throughout the Middle East, horizontal wells are being used for field developments which, in the past, would have relied on vertical wells. While the basic geology of many Middle East fields is well known, details of reservoir structure, faulting, facies and pore system heterogeneity are not usually so well-defined.

The recent increase in horizontal drilling has helped reservoir engineers and geoscientists to understand the lateral variations, permeability barriers and compartments which occur between existing vertical wells. Using horizontal wells we can locate leached zones, find unconformities and probe pinchouts and other sites with bypassed oil potential.

Horizontal wells are usually drilled to enhance oil production. In some situations the improvement may be dramatic - enabling development of a reservoir which would otherwise have been considered marginal or uneconomic. However, in cases where the improvement is likely to be less spectacular, horizontal drilling costs and benefits must be assessed carefully.

There are many kinds of reservoir where the potential benefits of horizontal drilling are obvious.

- Thin reservoirs: a vertical well drilled into a thin reservoir will have a very small contact surface (effectively limited by reservoir thickness) with the oil-producing horizon. A horizontal well in the same reservoir layer can have a contact surface running the length of the reservoir.

- Reservoirs with natural vertical fractures: horizontal wells typically intersect thousands of small vertical fractures and, if the reservoir contains them, some very large ones. If the well trajectory has been planned carefully these large vertical fractures can be used to improve productivity, even when the overall fracture density is low. However, if a fault fracture system is misinterpreted the result may be early water or unwanted gas production. The damage which an inappropriate horizontal well can cause underlines the importance of having a good reservoir model before drilling begins or being able to assess the well accurately during or after drilling.

![Fig. 1.1: DON'T ADD WATER: The horizontal well produces more oil than its vertical counterpart, drains more of the reservoir and delays water production.](image1)

![Fig. 1.2: IN FULL FLOOD: The effectiveness of traditional waterflood methods, which rely on vertical injectors and producers, can be reduced by poor sweep efficiency and early water breakthrough (a). The alternative is injection and production through two horizontal wells. This has been shown to produce a more uniform and effective sweep (b).](image2)
Reservoirs where water (and gas) coning will develop: the flow geometry associated with a horizontal drain helps to reduce the amount of water or gas coning in any given reservoir (figure 1.1). This means that the total volume of oil recovered before water or gas breakthrough can be increased. The only potential obstacle to a significant increase in oil recovery rate is the presence of zones with high vertical permeability (e.g. the faults and fault-related fractures mentioned above). However, with advance planning, these can be dealt with using selective completion techniques.

Horizontal wells remove oil from a reservoir over a long producing zone at relatively slow rates. In contrast, vertical wells take oil very quickly through much shorter lengths of borehole. The flow geometry associated with horizontal wells tends to reduce the influence of heterogeneity along the long drain - so increasing total production.

- Thin layered reservoirs: oil recovery from water flooding can be improved dramatically by injecting and producing from horizontal wells, rather than using vertical wells in a traditional water flood (figure 1.2).
- Heterogeneous reservoirs: horizontal heterogeneity in reservoirs presents a problem for vertical wells - they can only access those reservoir compartments which lie immediately below the drilling rig. Horizontal wells can be used to search for isolated and by-passed oil and gas accumulations within a field.

From a logging viewpoint the benefits of horizontal wells in a heterogeneous reservoir are just as clear. Horizontal wells pass through the lateral heterogeneity, revealing much more about the internal reservoir structure than a vertical well could. This means that in a complex depositional environment (such as a channel sandstone) the well can find more of the oil- and gas-bearing zones or compartments (figure 1.3) and so increase total production (figure 1.4).

Fig. 1.3: HITTING THE TARGETS: In channel sandstone reservoirs comprising a number of discrete oil and gas accumulations a vertical well may only find one target, while a horizontal or deviated well could find several oil and gas zones. A similar application was used by QGPC for a heterogeneous Arab-C reservoir in Dukhan Field. From J. Bouvier and A. Heward of Petroleum Development Oman. Presented at the 1993 AAPG International Conference, The Hague, The Netherlands.

Fig. 1.4: OVERCOMING VARIATION: Reef reservoirs are often heterogeneous and vertical wells drilled in them suffer from low and rapidly diminishing production. Direct comparison of horizontal and vertical well performance in distal backreef facies indicates that the horizontal well is producing three times as much oil as its vertical counterpart during the three months since completion. After M. Kharusi, 1991 Archie Conference, Houston, Texas, USA.


A technique for the '90s

Before 1990, horizontal drilling was not a popular technique. The oil industry only drilled horizontal wells in difficult situations as a 'last resort'. The global total for 1989 was just over 200 horizontal wells. In 1990, that total leapt to almost 1200 wells, with nearly 1000 of these drilled in the USA (figure 1.5).

In the USA, interest in horizontal drilling techniques has been concentrated in Texas, specifically on the Austin Chalk. Activity in this formation soared from just 10 horizontal wells in 1989 to more than 200 in 1990. The production results have more than justified some of the intense activity in this region. Success led some people to speculate that by the end of the century 50% of all new wells being drilled in the USA would be horizontal. Although this prediction seems unlikely to be fulfilled, there is no doubt that horizontal wells will form a major part of oilfield strategy in the USA and other mature oil provinces around the world as operators strive to produce oil and gas from low-permeability zones which have been missed by vertical wells.

The spectacular successes in the Austin Chalk Formation transformed horizontal drilling into a mainstream technique. Around the world, operators applied the lessons learned in Texas to boost production in their own reservoirs. Inevitably, this led to some failures where the horizontal drilling approach was inappropriate, but it also brought some outstanding achievements.

One of the leaders in horizontal drilling is the Canadian oil industry. The heavy, low-mobility oil which makes up a large proportion of total Canadian reserves was the initial reason for this interest in horizontal wells.

Gas and water are much more mobile than the thick, viscous oils found in Canada’s oil sands. As a result, vertical wells soon experience excessive water and/or gas production through coning effects. Using horizontal wells, oil can be produced at low pressures (without reducing production rates) to keep gas and water away from production wells for as long as possible. The maintenance of production rates is possible because the horizontal drainhole covers much more of the reservoir than a vertical equivalent.

A study based on the first 500 horizontal wells drilled in Canada predicted that in 1993 alone horizontal drilling would increase crude oil recovery by 2 billion barrels. Almost 20% of the 11,408 wells drilled in 1993 were horizontal.

Another Canadian development has been the use of re-entry wells to recover significant quantities of oil left behind by earlier production phases. These re-entry wells tend to be smaller in diameter (a factor controlled by the existing casing) and drilled with coiled tubing. Fig. 1.6: BALANCE SHEET: Horizontal wells produce higher volumes of oil (a) and smaller amounts of gas (b) than equivalent vertical wells. This sequence of wells is arranged in order of decreasing oil rate production for horizontal wells. This example is from Canada’s Devonian Rainbow Reef Reservoir, where lateral entry allowed the operator to produce oil without a high proportion of gas. Modified from F.J. McIntyre, et al. (1994).
In the Prudhoe Bay Field, Alaska, USA, British Petroleum has drilled more than 50 side-track wells from damaged or low-yield wells. These coiled-tubing workovers were a great success. It was discovered that some of the faults were water conduits. Review of the seismic profiles for the field showed that approximately 90% of the horizontal wells penetrated faults which were visible on the latest 3D seismic. It was concluded that between 10% and 20% of the faults were conductive.

**Why choose horizontal?**

Horizontal wells cost more than vertical wells - so what do they offer in return? In problematic wells, for example, where there is a thin oil column or a risk of early water or gas production, vertical wells are usually very inefficient. A comparison of horizontal and vertical well performance (figure 1.6) clearly illustrates the potential benefits. Every horizontal well in this example gives better results than its vertical counterpart. Higher oil rates, coupled with greatly reduced gas-oil ratios, have made horizontal wells the first choice for many reservoirs. In some countries, such as Qatar, Abu Dhabi and Oman, horizontal drilling has become standard practice, with the vertical drilling alternative being examined on a well-by-well basis.

In cases where the increase in production rate is not likely to be dramatic, there may still be implications for the long term development and total recovery rate for a given reservoir. Attic oil is a common feature of fields which have been developed using vertical wells (figure 1.7). Unless a vertical well intersects the highest point of a structural trap there will always be oil above it and, therefore, out of reach. A horizontal well can be placed precisely, passing through the top of the structure and so producing the oil which vertical and deviated wells have bypassed.

Drilling horizontal wells is expensive but, within any field, costs follow a clear downward trend with time. In Oman’s Nimr Field the ratio of drilling costs between vertical and horizontal wells decreased dramatically (figure 1.8) in the course of field development. This decrease reflects the driller’s greater familiarity with well conditions and the consequent improved advance planning.

![Diagram](image-url)
New horizons in Oman

The potential of horizontal wells has been recognized throughout the Middle East, but it is Oman that has seen the most radical changes in field development. In 1986, Petroleum Development Oman (PDO) drilled three short radius wells in a chalky Shuaiba limestone oil reservoir. This reservoir had a history of gas and/or water coning and low production rates. The results were not encouraging and horizontal activity was suspended.

The rapid improvements in horizontal drilling techniques over the following four years persuaded the company to try again and, in 1990, PDO embarked on a more ambitious trial of eight medium-radius wells in a number of reservoirs. The results of this second phase were so impressive that the trial was extended. Sustained success has led to almost continuous horizontal drilling activity, using up to four drilling rigs at any one time. By the end of 1994, PDO had drilled more than 200 horizontal wells in more than 20 fields and seven different reservoir horizons. These include carbonates and various sandstone facies (marine, fluvial, aeolian and periglacial) with thin and thick oil columns, heavy and light oils and high and low water cuts. Large numbers of reservoir heterogeneities have been encountered, resulting in productivities which were mediocre in one well and spectacular in another only 200 m away.

PDO’s initial effort was centred on improving the viability of marginal reservoirs. However, using horizontal wells to replace vertical wells in the low permeability zones of good reservoirs, has proved very successful.

In the Natih Field, productivity depends on the number and orientation of fractures intersected by a well. A good well - one which penetrates many open fractures - will produce approximately 600 m³/day, but wells which intersect few fractures may reach only 85 m³/day. Unfortunately, fracture distribution is not uniform across the field and, consequently, a lot of effort has gone into predicting fracture location and density.

Fractures are relatively small features, typically accounting for less than 0.1% of total rock volume and are, therefore, not visible on seismic. However, their presence can sometimes be inferred indirectly. By manipulating high-quality 3D datasets on CHARISMA and SPIRIT it was possible to map flexures and faults with throws as small as 3 m. By overlaying the fracture orientation data from core and FMI* (Fullbore Formation MicroImager) on a seismic dip map (figure 1.9a) a link can be established between fractures and faults. A revised well-targeting strategy based on this information has allowed the placement of wells near small faults and flexures with an average improvement of 30% in gross productivity, indicating that the wells are intersecting more open fractures than before (figure 1.9b).

The close association between fracturing and faulting was also observed in FMI images from horizontal wells in Idd El Shargi Field, offshore Qatar (figure 1.10). Borehole imagery was combined with the poor 3D seismic to ensure optimal field development using horizontal wells. The increased production from the first and second horizontal wells drilled in this field was 10 times greater than production from the earlier vertical wells.

Apart from the economic benefits which a well-planned horizontal drilling campaign can provide, there are other factors to be considered. Horizontal drilling reveals a great deal about a reservoir, information which is simply not available from vertical wells. Detailed logging of a horizontal well allows us to measure and model the lateral variations of permeability and porosity which influence reservoir development (figure 1.11).

As more information is gathered, the full complexity of many reservoirs has become apparent. By improving our picture of the reservoir we can recognize and avoid potential problems or deal with them before production is affected.
Since 1989 more than 50 horizontal wells (46 producers and a handful of injectors) have been drilled in several Offshore Abu Dhabi reservoirs - Zakuk, Umm Shaif, Um Al Dalkh and Satalah. Successful efforts to reduce the time and cost of operations while increasing productivity have recently been described at the ADIPEC meeting in Abu Dhabi. Major advances were possible, thanks to the steerable drilling techniques which were introduced in 1991. These have provided smooth well profiles, and minimized fishing and side-tracking. ZADCO reported that almost three weeks of drilling time could be saved on dual completion horizontal wells when comparisons were made with the standard dual-completed deviated wells being drilled three years ago.

ADNOC has used a horizontal drilling in the development of the Jarn Yaphour Field which is situated close to the suburbs of Abu Dhabi. Horizontal drilling was seen as the best way to minimize environmental impact and guarantee the highest safety levels for the city.

**Side-tracking in Saudi Arabia**

The reservoir characteristics of many Middle East oil and gas accumulations suggest that horizontal infill drilling could bring about major improvements in semi-depleted reservoirs in fields which may have been producing for 40 years or more.

One such reservoir is the Ratawi reservoir of Wafra Field in the Saudi Arabia-Kuwait Neutral Zone. A review of selected well performance and reservoir data showed that drilling moderate to long horizontal wells in the more permeable layers would improve recovery efficiency and field productivity.

A study indicated that over a five-year period a 2000 ft horizontal well, completed in the upper layers of the reservoir, would produce almost seven times more oil than a vertical well in the same location.

When the length of the horizontal section is extended to 3000 ft, the five-year cumulative oil production increases by 15%. More importantly, the cumulative water production for the well is only one quarter of that estimated for the 2000 ft example.

H. Menouar (King Fahd University of Petroleum and Minerals) and W.S. Huang (Texaco E&P Technology) Horizontal Well Design in Wafra Field, Ratawi Oolite Reservoir. 1993 SPE Middle East Oil Show.

Fig. 1.10: Unexpected faulting made it difficult for two horizontal wells to remain within the target (Kharaib reservoir layer) in Qatar’s Idd El Shargi Field. FMS images from both wells revealed that the fractures were closely related to the faults. Exact dip and strike values for the faults were also obtained using the FMS. The use of borehole imagery indicated which faults were open and were responsible for the loss of drilling fluids in the second well. This figure is modified from the GEO 94 paper presented by P. Cosgrove and A.F. Jubralla of QGPC.

Fig. 1.11: Borehole imaging tools were designed for vertical wells and analysts have become accustomed to interpreting vertical well images. When run in a horizontal well the geometry of faults, fractures and bedding features are very different.
**Horizontal - always best?**

Amid the upsurge of horizontal drilling and the predictions of its future dominance around the world, we face a fundamental question - are horizontal wells always better than vertical wells?

Numerical modelling carried out by researchers at the University of Waterloo, Canada, investigated the general case. They found that in isotropic reservoirs horizontal wells out-perform their vertical counterparts for two main reasons:

- borehole inclination; and
- the longer contact length between borehole and reservoir.

In cases where vertical permeability is significantly lower than horizontal permeability (figure 1.12), production can be reduced to the point where vertical wells are better. For a fixed length well, horizontal wells are less effective than vertical wells only where $k_v/k_h$ (vertical permeability/horizontal permeability) is less than 0.5.

**Record makers and breakers**

Drillers claim world records more regularly than sportsmen and women. The long reach wells of 1990 are dwarfed by wells drilled in 1994 (figure 1.13).

A well drilled recently by the Norwegian State Oil Company, Statoil, in their offshore Statfjord Field, had a horizontal displacement of 7288 m with a true vertical depth (tvd) of 2788 m, giving a total length of 8788 m.

In Louisiana, USA, a very deep horizontal well has been drilled by Clift’s Oil and Gas. The well, Martin A-1, has a true vertical depth of 4675 m and a total displacement of 5212 m.

One of the longest short-radius horizontal wells was drilled by PDO in Oman, while the longest medium-radius well, Maersk Oil Qatar’s Al Shaheen No.2, reached 3899 m.

The greatest horizontal/vertical depth ratio is found in a well drilled by UNOCAL in June 1992. This well, drilled offshore California, USA, has a 1489 m horizontal displacement and a tvd of just 293 m. This means a length:depth ratio of 5:1.

As drilling distances and depths grow larger, the importance of accurate and reliable directional methods becomes ever more important.
**REACH AND RADIUS**

Getting long tool strings into horizontal wells can be a problem (figure 1.14). The tool length is effectively controlled by the radius of curvature in the well: long tool strings cannot be pushed around tight bends. Short radius wells cost less to drill, but cannot be logged - so we have no explanation for their success or failure.

**The options**

- **Long radius:** the long radius well has a relatively low curvature and a final horizontal section which runs along the top of a reservoir (figure 1.15). It makes use of conventional directional drilling and completion techniques.
- **Medium radius laterals:** the medium radius lateral was developed to allow conventional directional drilling, logging techniques and completion hardware in horizontal lateral drainage wells. Build rates of 8°-20°/100 ft are used to drill from a vertical bore into a conventionally sized lateral. Control over build rate is achieved by varying motor size and borehole size.
- **Short radius laterals:** the entry sections from a vertical well to short radius lateral are drilled at build rates of 1.5°-3°/ft. They are normally drilled in competent (non-friable) formations with an open hole completion. The high curvature prevents logging using the MWD system and directional control in the horizontal section is difficult.
- **Extended reach wells:** these have long horizontal sections to ‘reach’ their target.

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<thead>
<tr>
<th>Build rate (MWD)</th>
<th>Direction control</th>
<th>Drilling method</th>
<th>Completion</th>
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<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Medium radius</td>
<td>8°-20°/100ft</td>
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<tr>
<td>Short radius</td>
<td>1.5°-3°/ft</td>
<td>No</td>
<td>Difficult</td>
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**Fig. 1.14: ROUND THE BEND** Short radius wells cannot be logged. The tool strings are too long to negotiate the tight wellbore curve.

**Fig. 1.15: REACHING THE RIGHT LEVEL** Horizontal and extended reach wells perform a variety of functions. The radius of curvature for each type determines the logging and completion techniques which can be applied in each case.
Follow the pilot

Some pilot holes are vertical but others are inclined holes which are drilled through the zones of interest before beginning the horizontal portion of a well. A pilot hole is usually situated close to an existing development well when there is uncertainty in the structural dip across the field. Good dip data is essential for horizontal wells: a minor measurement error, such as 0.5°, will result in a vertical displacement of 44 ft over a horizontal distance of 5000 ft. Images recorded in a pilot well provide the most thorough dip determination available because the geologist can select the dip directly, even in cases where wavy or discontinuous bedding would reduce the quality of data from a dipmeter survey.

Pilot wells were initially vertical boreholes drilled to test the sequence (figure 1.16a). Inclined pilots are best drilled at angles up to 45° in the direction of the planned horizontal well trajectory (figure 1.16b) to complete half the build and move the control point closer to the drainhole.

In reservoirs where the structure or stratigraphy remain uncertain, pilotless horizontal wells are now being drilled with geosteering methods (figure 1.16c) which rely on the flexibility of the technology rather than detailed planning along a fixed trajectory.

This pilotless drilling relies on new systems such as MWD (Measurements While Drilling), LWD (Logging While Drilling) and geosteering techniques. In areas where the geology is relatively simple and well-known, horizontal wells can now be drilled without a pilot. In complex fields, however, we rely on pilot holes to identify the tops of formation precisely.

Steering clear

Directional drilling (or geometrical steering) aims to keep the well on a preplanned trajectory, while ‘geosteering’ is the use of geological information to guide a well to its target, especially when the geology turns out to be different from that expected. Sophisticated measurements, now available during drilling (from MWD and LWD methods), make this geosteering task considerably easier.

The latest techniques can identify changes in resistivity and allow directional adjustments to be made before the drill bit strays deep into overlying shales or an underlying water layer.

Geosteering methods can keep a well in a very thin reservoir zone and can react quickly to abrupt lateral changes such as those encountered when a borehole crosses a fault plane.

Keeping the well on course is obviously very important, but there are other reasons for using LWD and MWD techniques. They permit:

• accurate selection of 1st and 2nd build points and, especially, the target entry point (horizontal section or reservoir section);
• recognition of changing reservoir qualities such as porosity or fluid content;
• measurements of resistivity with minimum invasion;
• revealing faults early enough to react to potential problems;

• detection of fluid boundaries;
• earlier identification of casing and coring points; and
• replacement of pilot holes.

The GeoSteering tool is the petroleum industry’s first fully instrumented, steerable, positive displacement motor (PDM). It provides long to medium radius directional drilling capability plus azimuthal resistivity and azimuthal gamma ray to aid steering, motor RPM and inclination measurements at the bit.

Fig. 1.16: PILOTS FOR PREDICTION: A pilot well allows the driller to predict what will be encountered along the line of the horizontal well. Pilot wells have evolved from simple vertical wells (a) to deviated pilots (b) with angles of 45° in the direction of the planned trajectory. Pilotless horizontal wells (c) are being drilled thanks to geosteering techniques which react to reservoir variations rather than following a planned geometric trajectory.
The sensor package is located in the motor housing, which reduces bit-to-measurement lag to a few feet. Data is transmitted to the PowerPulse MWD tool by electromagnetic telemetry with no wiring through motor sections or drill-string components.

Guiding a drillstring directionally through the earth’s crust has been a less than perfect science. Reaching the target quickly and safely depends on careful planning, the expertise of the directional driller, and the performance of the hardware and navigation instrumentation. The directional driller formulates a drilling plan prior to spudding the well, but as the bit is guided towards the target formation, the driller must be prepared to modify that plan in response to unforeseen changes in bed and fluid boundaries between offset wells.

Until now, the directional driller has had to manipulate the drillstring based on MWD measurements made from less-than-ideal positions, as far as 100 ft from the bit. When geological changes are noted, the bit may already have penetrated unwanted formations because of the time lag in information acquisition. Now the IDEAL* (Integrated Drilling Evaluation and Logging) system changes all this. The system puts the sensors where they belong - at the bit - and turns the drillstring into a reliable source of real-time drilling and petrophysical information that leads to dramatically improved drilling performance and productivity.

As horizontal drilling becomes standard practice in oil provinces around the world, the technique which allows driller and geologist to ‘see’ the rocks during drilling will probably become more popular. This method is likely to reduce the number of pilot wells drilled in the future.

Horizontal wells are not a new idea. The earliest horizontal wells were drilled more than 2000 years ago (figure 1.17). The first written records concern the use of horizontal groundwater wells in the central plateau of Iran. According to the Greek historian Polybius, they were used to increase water production.

Many thousands of such wells, and the air shafts that allow access for servicing, are still being used in central Iran. These horizontal, tunnel-like wells are known as ghanats (or qanats) in Farsi, kharis in Turkish and loggara (or phalaj) in Arabic. Similar wells were used in Egypt’s Western Desert more than 2500 years ago to increase the water flow from fractured Nubian sandstone. The use of horizontal tunnel-wells as water producers soon spread across the globe to places as far apart as India and Spain.

As the technique spread through Europe, a better understanding of the process emerged. In south-eastern England, for example, long (up to 7500 ft) horizontal tunnels were constructed in the low permeability chalk. The higher flow rates associated with the presence of fractures proved to the early horizontal drillers that placing their wells perpendicular to the main fracture orientation increased the number of fractures encountered and boosted production.

The application of horizontal wells in oilfield technology has a shorter, but equally intriguing history. By the mid-1930s, patents for hardware and specialized techniques began to appear in the USA, and by the 1950s many short horizontal drainage wells were being drilled. In the countries which comprise the Commonwealth of Independent States (CIS), horizontal drilling dates back to the 1950s.

Reaching the parts other wells cannot reach

The horizontal approach in oilfield technology has generally been reserved for problematic fields or reservoirs. This ‘last resort’ status for horizontal drilling meant that technical advances were slow and applied only to local problems. Horizontal drilling has gone through several ‘false starts’ where the technique has been applied to solve a particular problem until new, cheaper or more efficient alternatives have been developed. So why, after all this time and the technical development of vertical methods, is there still so much interest in horizontal drilling? The answer is simple: horizontal wells can succeed in places where vertical wells would fail.
FAULTS, FRACTALS AND FLUIDS

Fractures and faults can behave as barriers or baffles to reservoir flow, but very little research has been published on these effects. Generally we should expect to encounter more open fractures and permeable faults in a horizontal well than previously mapped for the reservoir - unless the well is drilled specifically to avoid these features. Good reservoir characterization is critical for optimal well placement (figure 1.18), for design of appropriate well tests and for selecting the correct completion methods. Multidisciplinary studies and new technologies in 3D seismic surveys and 3D borehole imagery have been combined to reveal faulting which would not have been detected by standard development methods. However, in carbonate reservoirs many faults are invisible to dipmeter and seismic techniques. Deformation occurs by brittle failure, rather than plastic deformation so there is no characteristic ‘drag zone’.

In some reservoirs it may be possible to use fractal methods or other statistical analysis of fracture distribution (figure 1.19). This method may help to explain the size distribution of sub-seismic faults encountered in horizontal wells. Reservoir faults have been identified as water sources in many of the massive carbonate sequences in and around the Gulf and in some sandstone reservoirs from Syria to Yemen. As the volume of borehole imagery data from horizontal wells continues to grow, it becomes apparent that shear faulting plays a major role in water production for many fields. How can we identify these faults and deal with them before they affect production?

Typical shear faults dip at high angles and are very rarely intersected by vertical wells. In addition, their movement is predominantly strike-slip (lateral) which makes them invisible on 2D seismic sections. Moreover, their brittle deformation and the absence of drag zones along the fault plane make them equally invisible to dipmeters.

Careful examination of electrical images can reveal shear faulting. Apertures which are larger than those of associated fractures and differences in bedding or textural characteristics on either side of these high-angle, conductive features (faults) are subtle yet definite clues to their presence (figure 1.11).

Further evidence of shear faulting can be gathered by looking at horizontal slices, or slices parallel to the formation boundaries, in high-quality 3D seismics. Seismic and electrical imaging techniques should be combined to assess the large-scale distribution of shear faults, while well testing can be relied on to determine their effect on fluid flow. Fault identification methods used in vertical wells (e.g. missing sections to indicate normal faults or repeated sections for reverse faults) are not generally applicable in horizontal boreholes. Extensional faults can be recognized by the fact that the dip of the deformation or drag along these faults is in the same direction as the fault plane, but dipping in the opposite direction to the fault plane. For listric growth faults and reverse faults, the deformation along the downthrown block dips in a direction opposite to the fault plane.

Fig. 1.18: DRAINING AGAIN: This South American example, from Lake Maracaibo in Venezuela, illustrates the flexibility of the horizontal well technique. Having identified the location and orientation of the major fault, the operator chose to position the horizontal drainhole along the crest of this plunging anticline to maximize oil recovery. Similar techniques are being used by GUPCO in the fault-block reservoirs which occur in Egypt’s Gulf of Suez.

Fig. 1.19: Fractures often display a fractal, or power law, distribution. In simple terms, this means that there are relatively few large faults and a huge number of small faults. Bill Belfield and Jerry Sovich of ARCO recently revealed a fractal, or power, relationship for fracture spacing from horizontal well data. Modified from W. Belfield and J. Sovich (ARCO). This study is based on analysis of more than 13,000 fractures defined by electrical imagery in six horizontal wellbores.

W. Belfield and J Sovich, Fracture Statistics from Horizontal Wellbores. Canadian SPE/CIM/CANMET International Conference on Recent Advances in Horizontal Well Applications.
Logging along the horizon

The long period when horizontal wells were considered a ‘last resort’ is underlined by the under-development of logging systems and interpretation for horizontal wells. The methods which are available have lagged behind the advanced interpretative techniques developed for vertical wells, but this situation is changing. Established research and development programmes are currently yielding new approaches to log analysis in horizontal wells.

Acoustic measurements in horizontal wells

Seismic and sonic techniques can be applied in horizontal wells, although processing and interpretation of the data can be more complicated than in vertical wells.

Vertical Seismic Profiles (VSPs) and Walkaways work by measuring the difference between downgoing and reflected wavefields. In horizontal wells, where the receivers are arranged horizontally, there is no moveout difference between the two wavefields. This problem is easily overcome by comparing the responses of geophones (velocity sensitive devices which record directional information) and hydrophones (pressure-sensitive devices which produce an identical pressure response for both downgoing and reflected fields). By subtracting one seismogram from the other we can eliminate the effect of the downgoing wavefield, allowing geophysicists to image reflectors below the seismic receivers.

Sonic measurements in horizontal wells

Sonic waveform acquisition using the Dipole Shear Sonic Imager, for example, can be applied to estimation of mechanical properties (e.g. compressional and shear bulk moduli, rock strength and failure conditions etc.), or to gather information on fractures and permeability.

The permeability measurements are derived from Stoneley wave measurements. There are two techniques, one based on Stoneley slowness and the other on amplitude attenuation. Depths of investigation using these techniques range from 0.5 to 5.0 ft, depending on the formation’s shear velocity and transmitter frequency. However, in a horizontal well the shear wave may be affected by layers lying near the borehole. In this situation the shear wave can no longer be relied on to estimate Stoneley slowness and permeability predictions can become highly dubious.

The effects are shown in figure 1.20, where a horizontal well showed abnormally high Stoneley slowness-derived permeability wherever the overlying shale was penetrated. In this particular example the wellbore trajectory penetrated the shale layer on two occasions. In both cases the shear measurement appears to read the limestone slowness and is, therefore, unsuitable for permeability determination. Track four of figure 1.20 shows an abnormally high fluid mobility predicted in the shale. The energy-based approach involves only energy loss due to actual fluid movement between the borehole and the formation, so the technique works even as the borehole crosses from one formation to another. The result is displayed in track five, where the Stoneley anelastic attenuation curve shows zero fluid mobility wherever the borehole is completely surrounded by shale. The relatively high fluid mobility seen in various places coincides with fracture systems which are also evident in the waveforms and confirmed by Stoneley fracture detection as well as by FMI images. Fractures can only be detected by Stoneley reflection when they are sub-orthogonal to the borehole trajectory. However, since horizontal wells are usually drilled orthogonal to the fracture orientation, this technique is ideally suited to horizontal holes.
**How big is this measurement problem?**

Formation logging tools were developed for vertical holes where they make lateral measurements on the surrounding formations. During the development process it was assumed that the tool would encounter similar sediments on either side of the wellbore.

These tools provide information on horizontal wells, but the data they record can be distorted and must be interpreted with care.

When the zone influencing the tool’s reading is not uniform, the data reflects the mixed properties from the various layers (figure 1.21). Devices which contact the borehole wall may give apparently irreconcilable readings over large distances, while those tools which have been designed to compensate for borehole or invasion effects may be distorted beyond recognition.

There is, however, some good news: tools such as the FMI* (Fullbore Formation MicroImager) and the Formation MicroScanner* (FMS) were easily adapted to the new conditions, and have proved particularly useful for defining barriers and heterogeneities in horizontal wells.

As horizontal drilling becomes increasingly popular (for certain operators in some regions it is already standard drilling practice) it is certain that new logging tools and techniques will emerge. An example of this is the new Resistivity-at-the-Bit measurement which is available using the IDEAL GeoSteering system (figure 1.22). At present, most interpretation is carried out on data which has been collected using traditional logging techniques. The emphasis now is on changing interpretation techniques - not tool configuration.

**Horizontal thinking - turn your ideas around**

The main adjustment involves the analysts themselves. Accustomed to working in a vertical frame of reference, the log analyst must overcome months or years of practice interpreting vertical logs to ‘think in the horizontal’. However, once the interpretive adjustments have been made, an astonishing variety of reservoir data becomes available and a range of new opportunities can be visualized.
Given the rapid variations which are possible in rock sequences, there is no reason to suppose that at any given position the sediments immediately above a horizontal hole are identical or even similar to those immediately below it. This has posed a problem for log analysts. In fact it has literally turned the world of logging on its side.

For example, a tool which makes eight measurements around the borehole will give mixed readings even in the simplest geological sequences. However, if we can select data from one or two sensors at a time, we can characterize the beds which lie above, below and around the tool.

**The IDEAL solution?**

Recent developments such as the new IDEAL system have revolutionized horizontal drilling. IDEAL can transmit vital drilling and geological data from the bit to the surface in real time. This transfer is accomplished in two stages. The tools at the bit communicate, via a wireless telemetry link, with a high data rate MWD tool located further back along the string. This device then pulses data through the mud column to the surface. This arrangement means that the MWD tool can be placed anywhere in the string and still make measurements at the bit.

The data transmission rate, recording frequency and the information which is transmitted in real time can be selected to meet the requirements of each particular job.

The resistivity and gamma ray measurements which the system makes are azimuthal, and so can be used to 'look' up or down into the surrounding rock. This means that the driller and the geologist have advance warning when the bit is about to pass up through the roof of a reservoir or drop into the water layer below.

This geosteering technique is a significant improvement on the geometrical steering methods which had become standard practice (figure 1.23). In geometric steering a plan is drawn and the well drilled according to agreed spatial coordinates. Then, after drilling, the well is logged to determine whether it is in pay or not.

In geological steering, measurements from Logging While Drilling tools, typically 50-90ft behind the bit, are used to check if the hole is in the target zone.

The geosteering technique uses measurements taken at the bit. This allows geologists and drillers to work together - keeping the drill bit where it should be. The usual result is a higher percentage of drainhole pay with associated increase in hydrocarbon production and reduced water cut.

**Taking the test**

Wells are tested to gather information about a reservoir from downhole pressure and/or flowrate measurements. In vertical wells, the process is familiar and relatively straightforward. For horizontal wells, the situation is a little more complex: extra parameters have to be derived from the pressure transient test data.

Horizontal wells pose two special problems for the reservoir engineer. The most obvious is the large wellbore storage effect associated with horizontal sections which may be thousands of feet in length. Wellbore storage effects are pressure effects caused by the volume of fluids in the wellbore before the test begins. This potential problem can be overcome by downhole shut-in or downhole flow measurements and logarithmic convolution.
The second problem is the more complex nature of the transient. Once the wellbore storage has stabilized in a horizontal well, four types of flow regimes may develop (three of which are radial).

**First flow regime - (first radial flow period)**

When a horizontal well first starts to flow, an elliptic-cylindrical flow regime develops as the pressure disturbance propagates through the near-well rock in anisotropic systems. In most reservoirs, except those in which the anisotropy ratio $k_h/k_v$ is large, this flow regime eventually changes to pseudo-radial (figure 1.24a) and this radial flow pattern continues until the effect of the nearest boundary is felt at the wellbore. The behaviour of this first regime is similar to the early-time behaviour of partially penetrating vertical wells.

It is possible to obtain the geometric mean permeability and damage skin from the first flow regime provided the wellbore pressure is not affected by wellbore storage and/or boundaries. The vertical permeability can be computed from the time of onset of the pressure or pressure-derivative from this flow regime (in oilfield units).

**Second flow regime - (second radial flow period)**

Once the pressure disturbance reaches a no-flow boundary (either above or below the well) a second flow regime takes over. Hemi-radial flow develops as shown in figure 1.24b. This type of flow regime occurs when the well is not equidistant from the top and bottom no-flow boundaries. Occasionally, a well may be located so close to a boundary that the first flow regime does not have time to develop. The slope of the second flow regime, which is twice that of the first, can also be used to obtain the geometric mean permeability and damage skin.

**Third flow regime - (intermediate time-linear flow)**

If the length of the horizontal well is much greater than the formation thickness, a linear flow regime may develop for a short period after the effects of the top and bottom no-flow boundaries have been felt. The well length can be obtained from this flow regime.

**Fourth flow regime - (third radial flow)**

As the pressure disturbance continues to propagate into the reservoir, the influence of the length of the well on the overall flow regime diminishes to the point where the well can be assumed to be a single drainage point. A third period of radial flow pattern then starts.

The upsurge in horizontal drilling activity has made the use of transient well testing common practice in determining the productivity of horizontal wells. In the past, horizontal wells were analyzed using the techniques which had been developed for vertical wells. Over the last 10 years, however, new solutions have been presented for horizontal wells. We now have interpretation techniques for estimating horizontal and vertical permeabilities, skin and reservoir pressure.

Testing hardware has also undergone a rapid change to meet the horizontal challenge and coiled tubing technology has been developed to allow the use of production logging tools.
**Layered reservoirs**

Most oil and gas reservoirs are layered. This layering reflects the sedimentary processes which produced the rock sequence. Geological characterization of layered reservoirs and their evaluation has become much easier in recent years, thanks to the availability of 3D seismic surveys and high-resolution wireline logs.

Transient behaviour in layered reservoirs is important because the layering influences productivity in horizontal wells. Single-layer models are frequently used to interpret data from layered reservoirs, but this produces results which are clearly less than perfect. Research into multi-layer models has not been rapid but recent results have been encouraging.

Conventional well tests (figure 1.25a) allow the modeller to characterize a homogeneous reservoir. Since sedimentary rocks are generally deposited at relatively low angles (typically <30°) a vertical well is usually perpendicular to the depositional environment and flow can be considered to be radially symmetrical around the wellbore.

In horizontal wells, however, (figure 1.25b) the vertical variations of formation properties and irregular shale distribution mean that the system must be considered heterogeneous in relation to a horizontal well. As in the case of a vertical well we can estimate average permeabilities, skin and reservoir pressure if the contrast between the layer properties is not high. However, other factors, particularly those which are affected by faults, fractures and other discontinuities, are more difficult to characterize in a horizontal well.

**Layer variations**

The subtle, and not so subtle, variations which occur within the layers of a multi-layer reservoir must be considered for modelling. Engineers who take average permeability values for each layer and plug these into a single-layer model can only expect poor estimates of actual reservoir behaviour.

A recent study focused on a nine-layer system comprising horizontal layers of different thickness, with high and low permeabilities distributed randomly through the layers (figure 1.26).

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**Fig. 1.25:** In vertical wells (a) reservoir tests can be carried out and interpreted quickly on a routine basis. Horizontal wells (b) encounter lateral heterogeneities which are difficult to predict and greatly complicate the testing process.

**Fig. 1.26:** This example, showing the contrast between horizontal and vertical permeability within individual layers, underlines the problems which reservoir modellers must overcome in apparently simple reservoirs.
In this study, single-layer and multi-layer approaches to modelling were applied to the data and the results are presented in figure 1.27. For the single-layer models, the thickness-weighted average horizontal permeability and either the harmonic average of vertical permeabilities or the harmonic average of $k_h k_v$, are used to compute system behaviour. The derivatives for each of the three cases clearly indicate the first radial flow regime before the effects of the top and bottom no-flow boundaries are detected.

After a transition period, all of the curves flatten, indicating that infinite acting radial flow conditions have been reached. The behaviour of the nine-layer reservoir model is clearly very different from either of the two equivalent single-layer models, although the curves converge after 100 hours.

This example demonstrates that multi-layer systems cannot be treated as an equivalent single-layer system.

**Pressure in profile**

A pressure profile along a horizontal well can reveal a lot of new information about a reservoir and can open up new hydrocarbon accumulations which have been by-passed in the early stages of field development. Figure 1.28 shows an example where production from the original vertical well has depleted reservoir pressure in a single fault compartment. By continuing along the reservoir zone, the horizontal well can cross sealing faults or other permeability barriers to locate and produce separate oil accumulations. Analysis of pressure along the length of the well informs us about reservoir connectivity.

**Contemplating completion**

At present, horizontal wells are usually completed in open hole or with slotted liner. However, as the technology becomes more widespread and drain-holes grow longer, there will be a greater need for more sophisticated completion techniques.

Mechanical limitations mean that medium and short radius horizontal wells are normally completed barefoot (figure 1.29a). This type of completion can cause major problems. The long producing length of horizontal wells means that they are likely to cross zones of contrasting vertical permeability, a situation which inevitably leads to premature water or gas production. Barefoot and slotted liner completions offer no prospect of repair: once the well has started to produce water the situation can only get worse.

Only long-radius horizontal wells can be completed with cemented/perforated liners. However, as a result of gravity segregation during cementing, mud displacement is often incomplete. This can make it difficult to achieve a consistently high quality of cementation.

A popular completion method in long-radius wells is a slotted liner set in a bare hole which may have a sand pack (figure 1.29b). However, in the long term, when well repair is necessary, this technique is no better than barefoot completion.
The introduction of slotted liners with inflatable packers mounted externally (figure 1.29c) offers the ideal answer for the selective completion of wells with potential water producing zones, such as major faults or heavily fractured intervals. The external packer arrangement allows each section of the horizontal well to be shut off or flow-metered independently.

**Turn and fire**

The heterogeneity encountered along the length of a horizontal drain will call for greater flexibility and improved methods for selective completion. The selective completion approach will, in turn, increase the amount of perforation carried out in a well. Oriented perforating techniques have proved very useful in many horizontal wells. A method which allows charges to be fired upwards, perforating the well on the side away from the water layer, or firing down and perforating away from a gas layer, are two obvious applications.

Other aspects of completion currently under investigation include looking at gravel fluid properties during mud displacement (as completion fluid is inserted into the well), and stability problems (borehole stability, cleaning of perforations etc.) which are typical of horizontal wells.

**The future**

A 1991 forecast of the market share of logging techniques which would be applied in 1995 (figure 1.30), correctly predicted that the near monopoly for traditional wireline techniques which existed then would be replaced by fast-growing shares for LWD (Logging While Drilling) and coiled tubing methods. The main reason for this shift was the anticipated increase in horizontal drilling.

However, some of the predictions about horizontal drilling made in the mid-1980s were over-enthusiastic. While these forecasts now seem unlikely to be fulfilled (vertical techniques have not been completely abandoned) there is no doubt that horizontal wells can out-perform vertical wells in a variety of settings.

Future articles will outline the innovative use of laterals in reservoir development. One example is the multilateral (four holes in one well) dual horizontal completion which Zakum Development Company (Zadco) are using to produce from three separate reservoir zones in the Upper Zakum Field, UAE.

If the evolutionary process continues and horizontal wells claim a larger share of drilling expenditure in the world’s major oilfields, further changes in drilling, logging and completion practices are sure to follow.