Factoring Anisotropy into Well Design

Christine Ehlig-Economides
Clamart, France

Don Ebbs
Mike Fetkovich
Philips Petroleum
Bartlesville, Oklahoma, USA

D. Nathan Meehan
Union Pacific Resources
Fort Worth, Texas, USA

Understanding directional variations in both earth stresses and permeability—using seismic surveys, core data, well testing, wellbore imaging and acoustic logging—can improve completion design, well location and selection of injectors and producers for enhanced oil recovery. Here is how information about anisotropy can be translated into greater efficiency in exploration, development and production.

What should be the completion strategy—which intervals should be opened? How many perforations per foot? What is the optimal stimulation strategy: acidizing or hydraulic fracturing? For horizontal wells, what bearing and deviation should the well be drilled?

Answers to these questions traditionally emerge after development is established and knowledge of a field matures. Today, demand for greater efficiency in exploration, development and production has rekindled interest in reservoir anisotropy—variation of essential vectorial parameters with direction. Recent work shows that large gains in productivity can be achieved by understanding the role of anisotropy in both permeability and earth stress (right).¹

Permeability anisotropy has direct impact on the decision to drill a horizontal or conventional well, the selection of a partial or full completion, well spacing and borehole direction and on the success of hydraulic fracturing. It often becomes visible only during enhanced oil recovery and waterflood projects. Stress anisotropy bears on hydraulic fracture direction and can affect permeability anisotropy in naturally frac-

¹ Permeability anisotropy represented by three values along the principal axes. Anisotropic properties are constant but of different magnitudes in at least two directions. Permeability of a formation is said to be anisotropic if its values in the vertical and two horizontal directions are unequal. Conversely, permeability is isotropic if its values are equal in all three directions—a rare occurrence. By convention, \( k_v \) is maximum horizontal value and \( k_h \) is the minimum. (Adapted from Reineck HE and Singh IB: Depositional Sedimentary Environments. New York, New York, USA: Springer-Verlag, 1986.)
Vertical Anisotropy

1. For stress and permeability in naturally fractured rock with randomly oriented fractures
   \[ v > H = h \]

2. Permeability in laminated beds
   \[ v < H = h \]

3. Cross-sectional view of a horizontal well passing through natural fractures oriented approximately normal to the wellbore in a thick formation. High vertical permeability in fractures permits drainage from the entire thickness of the reservoir.
   \[ v > H > h \]

4. Permeability for oriented natural fractures
   \[ v = H > h \]

5. Permeability controlled by depositional environment—streamed or crossbedding
   \[ v = h < H \]

6. Permeability controlled by depositional environment or layering
   \[ v < h < H \]

Some anisotropy conditions and structural and depositional environments where they may occur. In these examples, \( H \) denotes the direction of the maximum.

Vertical and Horizontal Anisotropy

Tered systems and matrix permeability in nonfractured, stress-sensitive systems.

Given nature’s complexity, almost any vectorial parameter is unequal in all three dimensions. In other words, not only is the value of permeability or stress in the vertical plane different from that in the horizontal plane, the value in the horizontal plane also varies by azimuth. This variation with direction in the horizontal plane is called horizontal anisotropy—the term subsumes anisotropy with respect to the vertical. But because sedimentary layers are deposited roughly horizontally, a fair degree of uniformity in the horizontal plane is often assumed—uniformity in, for example, mineralogy, grain size and sorting and in the properties they influence. The vectorial parameter’s horizontal component is then assumed constant irrespective of azimuth. This simplification, called vertical anisotropy, is tempting not only because of sedimentological uniformity but because horizontal anisotropy is difficult to measure. It is still unusual to know the details of a horizontally anisotropic formation (above, left).

Logging offers limited insight into horizontal anisotropy. In vertical wells, omnidirectional logging tools make a circumferentially averaged measurement, masking variation in properties along the horizontal azimuth. Pad-type tools do see in one direction, but there is no way to ensure sufficient azimuthal coverage, even with multiple passes of the tool. Recent advances in tool response simulation, however, may help determine horizontal anisotropy from logs made in deviated holes.

A formation’s vertical anisotropy can be determined and helps the reservoir engineer make important decisions about well design and completion, particularly in reservoirs producing mainly from matrix porosity. In these formations, anisotropy is caused, at many length scales, by compaction and variation in depositional environment, lithification and lithology. Usually a parameter of chief importance is permeability.

How does information about vertical permeability anisotropy influence completion design? It helps with determination of coning, perforation productivity and sweep orientation. Recently, it has come to bear on the decision to drill vertically or horizontally (below). When vertical permeability is low compared with horizontal—typically the case in laminated formations—the increased productivity afforded by a horizontal well

2. Horizontal and vertical anisotropies may go by different names. In a previous article, vertical anisotropy was “transverse isotropy,” meaning that properties were uniform normal to the vertical, but different from the vertical value. Horizontal anisotropy was “azimuthal anisotropy,” indicating nonuniformity of properties in a plane intersecting the wellbore. See “Formation Anisotropy: Reckoning With Its Effects,” Oilfield Review 2, no.1 (January 1990): 16-23.
Horizontal to vertical productivity index (PI) ratio versus wellbore length. In a horizontal well, PI increases with greater wellbore length, with a greater vertical to horizontal permeability ratio ($k_v/k_h$) and with a decrease in reservoir thickness.

Compared with a conventional one depends entirely on bed thickness, drainage length, $L$, and vertical permeability anisotropy, $\alpha = k_v/k_h$. There is less advantage in a horizontal well for thick beds than for thin. And obviously, the more drainage length the better, although there will be limits to drainage length in a vertical completion. But the key is vertical permeability anisotropy. If vertical permeability is high compared with horizontal, then more hydrocarbons reach the well and the advantages of a horizontal completion prove overwhelming.

If there is a nearby gas cap or aquifer, a low vertical permeability compared with horizontal may be advantageous in alleviating coning (right). In vertical wells, for example, low $k_v/k_h$ means a longer interval can be perforated, whereas a high ratio means only a short interval should be perforated. In horizontal wells, the value of $k_v/k_h$ determines how close the drainhole can be placed to a coning source. The higher the value of $k_v/k_h$, the farther the drain should be from the source.

Knowing vertical permeability anisotropy can also be crucial in interpreting well tests. In a formation with low $k_v/k_h$, a well that is partially completed appears to have positive skin. Skin relates to pressure drop at the wellbore face that is usually indicative of formation damage. Positive skin indicates an increase in pressure drop, negative skin a decrease. Knowing that positive skin can be caused by vertical permeability anisotropy may prevent unnecessary remedial treatment. Computing a match for the measured pressure transient test data may quantify the treatable causes of skin, such as perforation damage (right).

Injection in a reservoir with high $k_v/k_h$, for example, may aggravate vertical migration of water or steam due to the natural tendency for water to descend and for steam to rise. On the other hand, if low $k_v/k_h$ is a result of layering, when there is high contrast between bed permeabilities, and if the beds are continuous from well to well, the injected fluid will tend to break through in the high permeability beds. Uneven breakthrough results in poor vertical coverage for the flood project. It is important to correctly diagnose the reason for early breakthrough. Tracer tests and measurement of vertical flow profiles in injection and production wells help determine where the fluids are flowing and can help characterize flow conditions between wells.

Skin damage as shown on a production rate profile (above) and a transient well test interpretation (right). The production log shows that about half the perforations (dark bars) in this well are plugged. Openhole log data suggest that perforated beds are in vertical communication. Well test interpretation permits quantification of $k_v$ and $k_h$, and shows that skin opposite the open perforations is negligible, although the total skin factor computed from a Horner plot was significant. (From Joseph S. Ehlig-Economides CA and Kuchuk F: "The Role of Downhole Flow and Pressure Measurements in Reservoir Testing," paper SPE 18379, presented at the SPE European Petroleum Conference, London, England, October 16-19, 1998.)

How permeability anisotropy affects perforating strategies. The low $k_v/k_h$ value in the top shaly sandstone means that perforating the base of the interval will delay coning from the gas cap. But in the fractured sandstone, water coning will be difficult to prevent because of the high $k_v/k_h$ value, due to natural fractures. The low $k_v/k_h$ in the middle zone will go undetected if the entire interval is perforated.
Since vertical permeability anisotropy is so important, how is it measured? Currently, the most common technique is the vertical interference test (right). In this procedure, a packer is placed in the borehole to limit the flowing interval and induce vertical fluid flow in the formation. Transient pressure measurements are then made in the wellbore opposite the productive bed, above and/or below the packer. The success of this measurement relies on the absence of leaks in the packer and cement. Also, the test is not routine because standard completions often do not allow testing for vertical communication between perforations.

Vertical permeability anisotropy can also be quantified with an openhole drillstem test (DST), which avoids the problem of leaks. A DST is conducted when only a por-

![Diagram](https://via.placeholder.com/150)

---

3. In a transient well test, bottomhole wellbore pressures and flow rates are measured over time in response to a change in the surface flow rate.


* Mark of Schlumberger
the well (right and below). The tool has a sink, or sample, probe and two other pressure probes called the horizontal and vertical probes. The sink probe is opened and the resulting pressure disturbance is measured at the vertical and horizontal probes. This permits an interpretation of vertical permeability and average horizontal permeability, thus vertical permeability anisotropy. One or more MDT probes may land in non-representative reservoir rock, perhaps of limited areal or vertical extent, skewing evaluation of anisotropy. This error can be minimized if numerous measurements are made and considered in the context of other related data.

**Horizontal Anisotropy**

Horizontal permeability anisotropy results from a variety of geologic conditions concerning mode of deposition and fracturing. Full-scale horizontal anisotropy becomes important in certain depositional environments such as river channel deposits and crossbedded sands. In river channel deposits, the arrangement of bedding can produce a higher permeability either normal to, or aligned with, the channel (next page, top left). In crossbedded sands, permeability is nearly always higher parallel to bedding than normal to it (next page, middle). But understanding horizontal anisotropy becomes crucial in naturally fractured formations and can be a factor in hydraulically fractured wells.

In fractured formations, horizontal permeability varies dramatically with azimuth, becoming high when the azimuth coincides with the fracture plane and low when it doesn't. By convention, \( k_h \) denotes the maximum horizontal permeability, and \( k_v \) the minimum. Often in fractured rock, \( k_v \) and \( k_h \) are close in value, while \( k_h \) is much greater than \( k_v \).

In fractured rock, though, permeability is intimately related to another anisotropic property of subsurface rock, earth stress. Stress anisotropies are important in fractured reservoirs because they influence fracture orientation, density and aperture, which greatly affect well productivity. Stress anisotropies are caused by variations in earth stresses on all scales, from local alterations in the stress field around a microcrack, to the scale of the borehole, to that of a field and a geologic province. Fractures generally develop in a vertical plane and open normal to the least horizontal stress, \( \sigma_h \). They therefore strike parallel to the maximum horizontal stress, \( \sigma_h \). Determination of stress anisotropy opens a window on permeability anisotropy.

In naturally fractured rock, \( k_h \) and \( \sigma_h \) are related. If the direction of \( \sigma_h \) has remained relatively constant over geologic time, fractures will likely be aligned with each other and strike roughly parallel to \( \sigma_h \) (next page, bottom). But if the \( \sigma_h \) direction has varied over geologic history, fractures of varying strike will have formed. Today's \( \sigma_h \) will tend to close fractures normal to it, so fractures parallel to the modern \( \sigma_h \) will open wider and, in the absence of mineralization, have greater permeability than those normal to \( \sigma_h \). This produces a horizontal permeability ratio, \( k_h/k_v \), that is related to the stress ratio, \( \sigma_h/\sigma_v \).

Another case of interest is naturally fractured rock with fractures that are mineralized, closed or healed. Such fractures may...

---

**The MDT tool and its data, used for determination of horizontal and vertical permeability.** The sink probe is opened and the resulting pressure disturbance is measured as a change in pressure at the vertical and horizontal probes. This example shows the typical response—the horizontal probe pressure dropping faster and farther than the vertical. In this example, the horizontal permeability is about twice the vertical permeability. The pressure disturbance is therefore propagating as an ellipsoid, with the long axis in the horizontal plane, which is not sensed as much by the vertical probe.
Varying stress direction over geologic history

Near constant stress direction over geologic history

Cross-sectional view of trough crossbedded sand with preferential permeability directions. (Adapted from Reineck HE and Singh IB: Depositional Sedimentary Environments. New York, New York, USA: Springer-Verlag, 1986.)


5. See reference 4, Sytle et al.

October 1990
Measuring horizontal anisotropy is even more difficult than measuring vertical anisotropy. Horizontal permeability anisotropy is generally obtained from extensive multiwell interference tests. They provide the best possible measure of reservoir-scale horizontal anisotropy.

Sometimes horizontal permeability anisotropy can be assessed by integrating seismic data and conventional well test data from a single well. For example, if the tested well is located near a sealing fault that has been located by seismic interpretation, the circumferentially averaged horizontal permeability and the apparent distance to the fault can be determined from a well test. If well test and seismic interpretations suggest different distances between the well and the fault, a permeability anisotropy may be present. If the direction of the maximum permeability is known or assumed, then both $k_h$ and $k_v$ can be computed.

Horizontal minimum and maximum permeabilities can also be quantified by transient tests in horizontal wells and in vertical wells that have been hydraulically fractured. In both cases, a transient test may be sensitive to flow that is initially unidirectional and later radial. Unidirectional flow moves normal to the fracture face or horizontal well, whereas radial flow comes from all directions.

The relationships between well productivity and stress/permeability anisotropy are complex. When a hydraulic fracture propagates parallel to oriented natural fractures, well productivity increases only slightly. In reservoirs with randomly oriented natural fractures and alignment of the minimum horizontal stress direction with the direction of maximum horizontal permeability, hydraulic fracture simulation can be particularly attractive. When the maximum horizontal permeability and stress directions are aligned, a horizontal well can provide better productivity than a hydraulic fracture.
9. see reference 1, Branagan et al.
See reference 5, Thomas et al.
See reference 6, Slichter et al.
See reference 7, Chen et al.
See reference 9, Chen and Lescarboun.

---

Structural map of the Ekofisk field, Norwegian sector of the North Sea. Green dots are producing wells, purple dots are injectors and arrows indicate fracture orientation. The formation is composed of highly porous, low-permeability chalk that is naturally fractured. Fracture planes are nearly vertical and strike directions vary, as shown by the arrows. Injectors have been positioned to avoid early water breakthrough. Courtesy of Phillips Petroleum Company, Norway. This presentation does not necessarily represent the view of the operator/partners.
around the wellbore. When the angle between the direction of maximum horizontal permeability and the wellbore or vertical fracture is known, both $k_h$ and $k_v$ can be computed from transient data that exhibit both unidirectional and radial flow responses. In horizontal wells, early-time radial flow allows computation of the treatable skin and can provide $k_v$ when the geometric average of $k_h$ and $k_v$ is known.

Detailed characterization of natural fractures, including their aperture and therefore permeability, is possible by integration of Formation MicroScanner* and Array-Sonic* measurements with core analysis. If fracture apertures intersecting the wellbore appear to vary with fracture strike, this may offer a way to estimate horizontal permeability anisotropy. For example, if wellbore imaging implies that fluid-filled fracture apertures vary with azimuth, then the modern maximum horizontal stress direction may be surmised as parallel to fractures with largest apertures. Fracture aperture, however, is not controlled entirely by stress. It also varies with lithology and fracture surface morphology, which are related. All other things being equal, fractures in sandstone tend to be more permeable than fractures in shale or carbonates because the larger grain size of sandstone produces a rough fracture surface that resists closing more than the smooth fracture surface in shales and carbonates.

Fracture surface morphology also describes whether the fracture shoots through the rock in a straight line or takes a jagged path. Fractures tend to trace a jagged path when there is a low contrast in horizontal stresses, and a straight path when the stress contrast is high. Jagged fractures tend to be more permeable than straight ones, again, assuming all other variables constant and assuming no change in the stress field since fracture inception.

Union Pacific Resources Company has developed a technique for estimating well productivity and permeability anisotropy from the FracView* presentation of Formation MicroScanner images. The technique involves dividing fractures into groups by apparent aperture (poor, fair, good or large), counting the number in each group and assigning weight factors. This yields a "fracture index" for a well corresponding to its productivity index. The method requires several Formation MicroScanner logs in each reservoir to provide a sufficiently large sample.

Stress anisotropy is as difficult to determine as permeability anisotropy, particularly in the absence of natural fractures. Fractures can indicate stress directions only when
their azimuth relates to modern stresses. Wellbore ellipticity may be used (with caution) to determine the maximum stress direction. Whether the long axis of the ellipse aligns parallel or normal to the maximum horizontal stress depends on the mechanical properties of formations crossed by the borehole and the mode of failure.

The most common mode of failure is shear fracturing, in which elongation is parallel to the minimum horizontal stress (previous page). Shear fracturing is virtually always symmetric in the borehole and on imaging logs appears to cover a broad arc. Partially developed elongation resulting from shear failure may be recognized on imaging logs as short segments that are inclined to the borehole wall. Less often the wellbore fails because it intersects natural fractures. In this case, the failure will be parallel to the existing fractures. Natural fractures are not necessarily symmetric about the borehole axis. They appear on imaging logs as long, linear features that parallel the long axis of the borehole and occupy a narrow arc of the borehole. In a rock that deforms elastically, the long axis of the ellipse aligns normal to the maximum stress direction. The borehole wall may also fail from being struck during drilling by the rotating or sliding drillpipe. Many horizontal wells are thought to be elliptical, with the long axis vertical, strictly from mechanical erosion during drilling.

To quantify the minimum horizontal stress magnitude, microfract tests are frequently performed in wells that are candidates for hydraulic fracturing. These fractures may be visible on imaging logs. Today, characterization of vertical permeability anisotropy in a vertical well is fairly straightforward. A better understanding of horizontal permeability anisotropy may evolve with the development of downhole measurements that can quantify azimuthal variation in petrophysical properties.

—CE, JMK


