Finding fractures in deep and tight rocks has become a high priority among explorationists in the Middle East. Recent discoveries have shown that fractures can play an important role in the productivity of low permeability formations. This is because they form an interface with the rock matrix which is many times greater than that provided by the borehole.

In this article authors from different organizations discuss the origins of fractures, their importance within Middle East oil reservoirs, and outline the various fracture interpretation techniques currently being used.

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Fractures are 3D features - a fact that is often neglected in the early stages of reservoir development. While fractures seen in the wellbore will be analyzed to determine aperture and probable production rates, little effort is made to develop a detailed model of fracture distribution. This kind of study only takes place when the reservoir is formed almost entirely of fracture porosity (as in a fractured basement) or when some aspect of reservoir behaviour strongly contradicts the existing reservoir model - for example, in cases where there is sudden and unexpected water production.

In general, fractures are important because of their influence on tight reservoirs, not because of their actual oil storage capability. Although fracture volume may be negligible in comparison with the total reservoir volume, they provide an interface with the matrix which is much larger than the borehole. Consequently, very small primary permeability values are sufficient for production in a fractured reservoir.

Factors controlling the occurrence of natural, open, permeable fractures within Middle East reservoirs are the nature and degree of folding and/or faulting, in-situ stresses and changes in rock properties such as porosity, bedding and lithology, especially shaliness. Such geological factors are often mapped in reservoir studies. By accurately defining the relationship of these factors to the fracturing in a number of wells within a field, it should be possible to extrapolate the fracture data throughout the reservoir.

The major problem with large-scale fracture studies based on either borehole imagery or oriented cores is that the fractures in the borehole wall may not be representative of the large-scale fracture network which controls production. It is necessary, therefore, to relate geometrical information from borehole data to the reservoir’s geological characteristics (structure, stratigraphy, sedimentology, diagenesis and geostatistics). Simple cubic models used in reservoir studies are sometimes appropriate but often more complex geometric models are required.

Borehole-scale characterization and geological modelling must be fully integrated with dynamic testing and production data, not simply used for comparison as a type of quality control.

Using outcrop data to characterize the fracture pattern of a reservoir is frustrated by the stress release which occurs as rocks come to the surface. Uplift and erosion of overburden often result in tensile breaking of brittle beds due to deformation along ductile bedding planes (figure 3.1). As a result, fracture density in reservoirs is commonly lower than values recorded where the same formation outcrops. Consequently, outcrop data is unsuitable for modelling reservoir fractures.
Fracture orientations can vary considerably between reservoirs but the orientations are neither random nor chaotic. Early fracture studies, which were based on poor or insufficient data, provided very misleading information about fracture distribution in reservoirs.

Fractures are usually formed during folding or doming of a reservoir, with the most intense fracturing being concentrated in low-porosity rocks. In areas where the reservoirs have little matrix permeability fractures are critical to productivity. This is especially true of basement reservoirs where fracture porosity makes up most of the reservoir.

Borehole imagery and 3D seismic surveys have improved fault mapping and horizontal wells are providing a new insight into the fracturing associated with reservoir faulting.

Fracturing typically occurs in one of two ways - either parallel or perpendicular to normal or reverse faults. Oblique orientations are associated with wrench or shear movements.

Fracture density, or the ‘intensity’ of fracturing, is defined as the number of fractures per unit length inside an interval of a defined height. This value has to be corrected for the orientation bias created by changes in angle of the fracture planes and the borehole axis.

Anomalous increases in reservoir productivity are sometimes seen in wells. This is usually associated with faulting. Other variations in fracture density have been attributed to changes in lithology, porosity or shaliness. Low porosity and shale-free intervals generally contain more fractures, although these may or may not be mineralized.

Clearing up the chaos

In the past, wide variations in fracture orientations within anticlinal reservoirs, coupled with poor quality orientation data and fracture characterization, led to widespread pessimism about the usefulness of fracture data in reservoir models. However, improvements in fracture detection and analysis techniques have shown that there is order in the apparent chaos. Fracture orientations can be related to specific geological parameters and structural events.

The common fracture orientations found in Middle Eastern anticlinal reservoirs are shown in figure 3.3. Changes in orientations can be caused by later fault movement associated with variations in tectonic stress through time. In the carbonate reservoirs of Turkey and Iran, the orientation of karstic fractures associated with erosional unconformities, is much more variable. Low-angle, stress-relief, exfoliation fractures, which occur sub-parallel to the unconformity surface in these reservoirs, are particularly important features.

Variable orientations of open fractures in a reservoir are often associated with the rotation of principal stress in proximity to some of the observed faults. When the principal stress is perpendicular to the fault strike compressional forces are probably at work on the fault.

Pass the salt

Fracture orientations in salt dome reservoirs depend on the shape of the structure and the nature of the regional and doming stresses. As a result, reservoirs of the same age in different fields can have different fracture orientations if the fractures formed at separate times under different regional stress conditions (figure 3.4).

For the same reason, fracture orientations vary through geological time. In the same field it is possible to find fractures formed in the Permian with very different orientations to those formed in the Jurassic or in Cretaceous reservoirs. In addition, fracture orientations can differ between reservoirs of identical age in adjacent fields if doming and fracturing did not occur at the same time in the two reservoirs.

Early fracturing around The Gulf was affected by extension stresses during the Triassic which were later followed by compressional forces from the east due to thrusting associated with obduction (pushing of ocean crust onto continental crust) in Oman. In contrast, orientations of later fractures were determined by compressional forces of the Zagros Orogeny. These are generally oriented NNE.

Definition of reservoir fracturing in Mesozoic salt structures is important in The Gulf. These fractures rarely dominate productivity as their apertures and densities are usually much lower than those associated with tectonic fractures. (Pressure and flow tests indicate that intergranular pore systems in both shoal and reefal facies generally contribute more flow). However, it is clear that the fractures, which are often characterized by thin apertures, are connecting heterogeneously distributed porosity (Nurmi et al., 1990, WER Structural Geology Supplement).
Recognising faults

The presence of a fault is often indicated by rapid increases in fracture intensity or spacing. This means that once the relative intensity of fracturing has been determined for each reservoir zone any increase in permeability, especially in more porous intervals, can usually be attributed to faulting. In such situations, a focused search using borehole imagery can reveal the actual fault plane or zone affecting the fractures (figure 3.5).

Fault detection and analysis have only recently been recognized as a critical component in the characterization of fractured reservoirs. In early borehole images few faults were recognized because none of the available tools were specifically designed to find them. Fractures related to faults are much less abundant than fractures related to the folding or doming of a field, but the vertical continuity of faults often results in dramatic water movements through fault-associated fracture systems.

A major fault can be a single, high-angle plane cutting a reservoir horizon and may not be intersected by wells. However, there are associated smaller faults and fractures which formed at the same time and it is these zones which are more likely to be crossed by wells.

Indications of faulting can arise during drilling. These may take the form of missing rock sections in areas of normal faulting, repeated sections in areas of thrust or reverse faulting or loss circulation material in areas affected by wrench faulting or any other type of open fractures associated with faults.

Recognising faults depends on our ability to detect the bedding plane above and below the feature. However, even if the bedding is not recognised, the geometry of the fault plane can be measured where it intersects the well. This information can be used to project the fault plane away from the well and through any formation above or below. Unfortunately, this is not as simple as it may seem (figure 3.6).

Natural fractures

Natural fractures are usually assumed to have been created by tectonic stresses. They are more common in carbonate rocks than in sandstones and typically occur in specific directions which are dictated by the regional tectonic stresses. Induced fractures associated with natural

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**Fig. 3.5: FAMILY OF FAULTS:** The four major fault types (top row) can be distinguished using borehole imagery (bottom row).
Knowing the precise geometry of the fault plane where it intersects the well allows us to project the fault away from the well and so predict its effect in other locations.

**Fig. 3.6: THINGS ARE NOT ALWAYS AS SIMPLE AS THEY APPEAR:** These diagrams illustrate situations where normal faulting has developed on the hanging wall of a major reverse fault (a) and where small reverse faults have been created on a large, normal fault structure (b). The interpretation of either structure would depend primarily on the location of the well and its depth of penetration.
fractures might also be expected to have a preferred orientation, although this would not necessarily be parallel and could even be perpendicular to the natural fractures.

**Drilling-induced fractures**

Borehole electrical images, especially those which have been computer enhanced, provide useful information about the borehole wall and the reservoir rock.

Borehole enlargement is a common feature and often occurs in the same direction in a number of wells. The enlargement is related to stress release failure and is usually greatest parallel to the least principal horizontal stress direction. A complex mixture of induced fracturing with both shear and extension cracks is often present (figure 3.7).

Repeat logging of special process wells has shown that borehole failure and breakouts occur within days of drilling. Large fractures induced perpendicular to the direction of borehole enlargement are usually long straight cracks in an axial position lying on opposite sides of the borehole. These induced cracks are extensional fractures which form and are propagated in front of the bit during drilling. Cores taken from such zones often reveal these fractures.

Axial drilling-induced fractures have a modified appearance when the axis of the borehole is not parallel to any of the principal stress directions. This kind of crack has a jagged appearance, resembling a lightening bolt, in contrast to the long and straight cracks which are perfectly parallel to the axis of the borehole (figure 3.8). Such cracks are most common in horizontal or highly deviated wells where the orientation of the borehole with respect to the stress field was not accounted for in positioning the well.

Recognizing and analyzing induced fractures is valuable in determining the orientation of the principal horizontal stress which may vary within a reservoir. The orientation of ‘mini-frac’ jobs has also been ascertained and confirmed by logging before and after ‘fracing’.

**Enhanced fractures**

In addition to natural and induced fractures, there are pre-existing fractures which are extended or opened in the borehole by drilling. These have been called ‘enhanced fractures’ (Standen, 1991). It has also been observed and reported that even totally mineralized fractures can be re-opened during the course of drilling.

The enhanced fractures are usually oriented sub-parallel to the principal horizontal stress as are drilling-induced fractures. Generally, drilling-enhanced fractures do not seem to affect the productivity of an interval as they usually have very small apertures in the undisturbed state.
**Understanding India's fractures**

*Borholla-Changpang*

In the mid-1960s, a basement high was mapped near Borholla, Assam in India. The first well, drilled on the highest part of the antiform feature was dry. However, a second well, drilled several years later, located oil in a Palaeocene sandstone overlying the granitic basement.

Further ‘wildcat’ drilling in the plains around Borholla was unsuccessful but a last ditch attempt was made to drill a test hole in the nearby Naga Hills. This Naga Hills ‘guess’ was rewarded when the first well, drilled close to Changpang, in Nagaland, struck oil in fractured granite rock (*Middle East Well Evaluation Review* Number 7 1989, *India - 100 Years of Oil*). This discovery proved that commercial accumulations of oil could be found in fractured basement rocks and had a radical effect on exploration in India.

Conventional seismic investigations carried out around Borholla in the 1960s were followed by six-fold CDP (Common Depth Point) surveys in the early 1970s and 12- and 24-fold CDP surveys about five years later. These studies helped to clarify regional tectonics, but the low quality of seismic images did not throw light on structures within the fractured basement.

The inadequacy of seismic data meant that the only way to decide on the location for a delineation well was to analyze data from previous wells. As more wells were drilled a structural model emerged.

This approach allowed the basement structure to be described as a single dome near Borholla. However, as clearer information was gathered, the model was refined to show two separate culminations in the basement, one at Borholla and another at Changpang. The contour maps for the fields became increasingly detailed and eventually contained faults with throws of less than 25 m. At this stage the structure began to be redefined as a mosaic of several fault blocks and sub-blocks (figure 3.10).

**Geology - the first analysis**

The explorationists began detailed correlation of micro-features on electrologs, in order to improve their understanding of the faults. By analyzing well data for sand thicknesses in the Sylhet and Kopili formations, it was possible to infer the location of faults by their effect on the sediment. This approach provided an indication of the underlying basement structure, but not a detailed image.
3D seismic data was gathered between 1987 and 1988. Difficult terrain, poor logistics and subsurface complexity combined to produce lower quality data than had been anticipated. However, the high density of 3D data enabled interpreters to produce a much better image than would have been possible using 2D techniques.

Unfortunately, the reservoir map produced from the 3D survey was viewed with reservations because it contained no reflection event corresponding to the basement’s top surface. This deficiency was explained as absorption and dissipation of seismic energy by the fractured basement.

More importantly, the fault pattern from the 3D survey did not match the pattern which had been inferred from well data and the 2D survey.

Mechanical contouring performed using GEOPIC failed to provide a logical structure over one producing field. The 3D seismic showed the structure to be much steeper than had been previously believed, which meant that there would be a marked reduction in closed area.

As a result of these apparent inconsistencies, the 3D survey was treated with scepticism and the earlier map was used for delineation purposes.

However, the 3D seismic data indicated a fault wherever the sand isopachs showed reduced thicknesses or missing stratigraphic units. Subsequent wells confirmed the pattern revealed by the 3D survey (figure 3.11) and prompted its use for fault and structure delineation. It was concluded that, in the absence of a strong reflection from the top of the basement, a good reflection of the overlying Sylhet Limestone would be sufficient to deduce the basement fault pattern as well as depth.

This model proved to be highly successful. Instead of two distinct culminations seen at the basement level, the structure now appears to consist of a large number of discrete antiformal cumulations separated by basement lows. These lows are the sites of major normal faults typically trending NNE-SSW which generally avoid the antiformal highs.

Fig. 3.10: BASE MODEL. This structure contour map represents the top of the basement in the Borhollo-Changpang area. This model is based on data gathered from 2D seismic surveys and numerous delineation wells. At this stage the structure appears to be a mosaic of a few major fault blocks, each comprising many sub-blocks.

Fig. 3.11: BASEMENT JIGSAW. A 3D survey revealed that the basement structure did not contain two large oil-bearing structures, but many small antiformal ‘highs’ separated by basement ‘lows’. These lows correspond to major normal faults which trend NNE-SSW.
More than one way to image a reservoir

From a detailed examination of all the new data which emerged from the 3D survey it became apparent that the maximum fracture intensity would be encountered on the flanks of the antiformal culminations. Production tests of wells located on the flanks confirmed this model and showed that these are the most prolific oil producers in the field. These wells have very low initial gas-oil ratios and a negligible decline in pressure during production. Some wells had the capacity to sustain self-flow with more than 60% water cut - proof that they operate under active bottom-water drive conditions.

In contrast, wells drilled in the synformal lows often registered good daily flow rates but produced only moderate amounts of oil. Recent wells in the lows have either ceased production as a result of water loading or produced water containing only traces of oil. These observations support the idea that oil accumulation in the basement is controlled not only by fractures but also by structural constraints. Below a certain level virtually all fractures are water-bearing and the aquifer has generally flooded the troughs in the vicinity of good producers. This is the reason why peripheral wells have short production lives and wells in the lows surrounding the main field produce little or no oil.

Reservoir models evolve as the techniques used to investigate them change. A major obstacle, in this case, was the uncertainty about replacing or modifying an older model with the contradictory information derived from a 3D survey. Perhaps the most important benefit of the 3D survey has been in development drilling. In situations where previously there had been uncertainty, the model provides clear targets in the quest to extend the field.

In the Borholla-Changpang area, a continuous compressive regime has resulted in extensive basement fracturing. In an attempt to define the tectonic framework of the region, 3D seismic surveys were planned and carried out in 1987 and 1988.

A recent reservoir study highlighted the possibility of using horizontal wells to exploit this fractured basement reservoir (figure 3.11). But before any decision could be made on developing the field a number of parameters had to be determined - fracture orientation, dip, spacing and fracture density.

The replacement ratio Fr can be calculated by taking into account the differences in drainage areas of horizontal and vertical wells. This ratio represents the number of vertical wells which would be required to produce at the same rate as a single horizontal well. In this case, the Fr value increased with length of horizontal section and the computed value was never more than 4.8.

Production performance is a function of the number of intercepted fractures. Since the major fracture trends are oriented NW-SE and E-W (figure 3.13), the horizontal section of each well had to be drilled in NNE-SSW orientations to maximize production. Environmental factors such as land acquisition and logistics also contributed to the argument that horizontal, rather than vertical wells were more suitable for developing this field.

Oil from Bombay High

Drilling in the giant Bombay High Field, offshore India, has revealed large volumes of oil and gas in basement rocks composed of basaltic and granitic gneiss. The field, discovered in 1974, is situated approximately 150 km off India’s western coast. Most of the oil and gas is contained in Miocene limestone reservoirs and a smaller proportion in the basal clastic sandstone reservoirs which overlie the fractured metamorphic rocks.

The main limestone reservoir is encountered at a depth of approximately 1300 m but the basement hydrocarbons occur at 1900 m, on the crest of the structure.
Away from the wellbore, characterization may also be divided into static and dynamic approaches. The static method consists of projecting fracture systems laterally, away from the wellbore, guided by input from high-resolution seismic data or offset VSPs. Dynamic characterization beyond the wellbore requires well test data to determine fracture length, boundary conditions, vertical communication and extended flow capacity for reserve calculations.

Core studies, borehole images and Stoneley acoustic permeability logs all show the presence of a high-angle (75°) open fracture set and a low-angle (20°) healed fractures in the study wells. The high-angle fractures strike NNW, parallel to the adjacent faults.

The low-angle fractures, which are generally filled with either calcite or quartz, have apertures between 5 mm and 10 mm. These fractures may have resulted from a ‘rebounding effect’ and expansion in the basement with subsequent fluid movement.

**Fracture characterization techniques**

Fracture characterization at the wellbore is a two-step process, requiring static and dynamic approaches. The static characterization involves determining in-situ fracture location, density and orientation using a range of wellbore imaging tools, petrophysical anomalies, core and drilling information. The dynamic approach makes use of acoustic data (SDT- and LSS-derived Stoneley) for relative fracture conductivity at the wellbore. This can be verified with production logs from flow and injection tests.
Egypt’s basement bonus

The fractured granite reservoirs of the Gulf of Suez, Egypt, are flanked by porous and permeable reservoir sands and carbonates. The permeability of the granite horst blocks and the fact that they are in hydraulic communication with these flanking sands and carbonates makes them ideal drainage systems. The Precambrian-age granites were probably first fractured in Paleozoic times as the Suez and Aqaba shear zones were developing (figure 3.16). Porosity system studies of these granite reservoirs indicate the development of secondary porosity along fractures and a pervasive leaching of feldspars. The basement complex was later covered by the Nubia sand sequence and a thick succession of Cretaceous sediments, prior to the start of rifting in the Gulf of Suez (figure 3.17).
Fractal fractures

Statistical analysis of fracture data in the Gulf of Suez indicates a fractal or frequency relationship between the computed fracture apertures. Figure 3.18 shows mean aperture of fractures in a section of basement granite reservoir. The increase in aperture towards the top of the granite and the variation of aperture at all vertical scales are particularly important features.

Fracture spacing data also shows variations which are useful in predicting expected ranges of values throughout the reservoir. However, this kind of data does not give absolute values at any location. Data sets from the fractured granite reservoirs of the Gulf of Suez show a particularly interesting variation of fracture aperture with depth.

The fracture data revealed up to 4000 fractures in each 1000 ft. Fractures were selected by hand and a computer program was then used to calculate mean aperture and mean hydraulic aperture for each one. Fracture density and porosity were then calculated using an averaging technique with a fixed sample rate.

Several wells were analyzed in this manner, with the results showing a similar range of porosity values but different fracture densities and average aperture values for each well. This variation in average aperture was further corroborated by production results which showed that density of fracturing and width of fracture aperture were the main criteria for initial production (Taleb et al EGPC 1990).

Fracture orientation

A consistent relationship could not be found between orientation and aperture for the granite reservoirs. In certain cases, where a strong, principal, far-field stress is present in the rocks, the fractures seemed to open parallel to the principal stress. This was usually accompanied by drilling-induced fractures in the section. In one granite reservoir, flowmeter data recorded in the barefoot completed section of the well, correlated with a pseudo-flow profile from the cumulative fracture porosity results. This, however, was only after the drilling-induced fracture porosity data was added, indicating a contribution to the flow by the drilling-induced fractures (Taleb et al EGPC 1990).

Production changes (coning of water and gas) with respect to fracture orientation have also been noted in the granite reservoirs. In general, there is a higher vertical permeability when a single set of high-angle fractures is encountered. Oil production is better with a mixed orientation of fractures such as at the margins of the granite blocks (El Wazeer et al EGPC 1990).
Middle East Well Evaluation Review

Only the Stoneley

Analysis of acoustic Stoneley waves offers a way of assessing the permeability of fractures and porous beds. The dispersive Stoneley waves move along the interface between the borehole and the formation. While travelling along the borehole wall, the wave propagates without much energy loss. However, the wave decays when it encounters a permeability change or a break in the wall.

In a cylindrical plane, such as a borehole, the detailed borehole geometry becomes a very significant factor in wave propagation. At very short wavelengths, the borehole’s influence on the wave is similar to that of a flat surface. However, at an operating frequency of approximately 10 kHz, the Stoneley wavelength is approximately 6 inches, roughly comparable to the diameter of a borehole. In these circumstances the wave decays only slightly as it crosses the borehole and is referred to as the Tube Wave. The low-frequency Stoneley mode of the Dipole Sonic Imager® (DSI) tool operates under these conditions.

At low frequencies, the tube wave may be considered as a simple pressure pulse propagating in a cylindrical borehole. When it intersects a permeable fracture crossing the borehole, pressure is released into the fracture. This pressure drop causes an attenuation of the direct arrival and produces a secondary (or reflected) Stoneley wave. The reflected Stoneley wave may be regarded as being generated by a secondary source located where the fracture crosses the borehole. The strength of this secondary source (reflection) is dependent on the amount of energy lost by fluid displacement inside the fracture and, therefore, the permeability of the fracture (figure 3.19).

The Stoneley waves generated by the DSI tool have frequencies which have been selected for maximum sensitivity to fluid motion. In fast formations the Stoneley wave propagates faster than the fluid slowness. In slow formations the wave is more strongly coupled to the formation and propagates at slownesses greater than that of the shear slowness.

Stoneley attenuation and permeability

At low frequencies, propagation of the Stoneley wave actually causes fluid flow. This makes it an ideal technique for estimating permeability (figure 3.20). The Stoneley wave can be thought of as a ‘dynamic micro-drill stem test’. Acoustic pressure in the borehole forces fluid into the formation. The volume of fluid flow, and the size of the Stoneley wave attenuation which it causes, is directly controlled by permeability.

Combining the low-frequency monopole Stoneley with dipole shear from the DSI has greatly enhanced acoustic waveform logging. Low-frequency Stoneley wave data can now be analyzed in terms of the formation’s dynamic permeability response. An additional benefit is that the high-quality shear data obtained with the dipole measurement offers a way to account for non-permeability effects recorded in the Stoneley wave velocity. This is possible even in very slow formations and allows accuracy far beyond that achieved by standard sonic tools.

Fractures derived from the DSI analysis can then be compared and combined with images from the FMS tool to improve our understanding of the reservoir.

Fig. 3.19: Stoneley wave data gives clear indications of fractures. This example is taken from a fractured basement in the Ashrafi Field, Gulf of Suez, Egypt.
**Stoneley slowness and permeability**

Stoneley slowness can also be used to derive permeability measurements. Although less sensitive to changes in permeability than attenuation data, slowness can be measured more precisely and is less sensitive to mudcake and lithology. Data gathered using this technique compares well with information taken from cores and RFT/MDT tool data.

When using Stoneley wave reflections to detect fractures it is important to first identify thin shales in the sequence, as these can create reflections and attenuations similar to those from fractures.

**Integrated fracture interpretation**

One way of improving reservoir models involves combining FMI/FMS images with Stoneley permeability profiles and comparing the estimates from both techniques:

1. Where the fracture aperture estimates from both techniques are in close agreement the fractures are likely to be isolated planar features of large extent (ie greater than Stoneley wave penetration away from the borehole).

2. When fracture aperture measured on electrical images is larger than fracture aperture from reflected Stoneley waves then the borehole fractures are probably connected to a network of fractures which extend far enough from the borehole to be beyond the scope of the FMS.

Marked lithology changes, which cause significant variations in formation shear modulus (eg the interbedding of calcite with soft shale) can give measurable reflected Stoneley wave responses but will have little effect on FMS tool response. The common occurrence of thin, washed shales below the resolution limits of most logging calipers, often causes false increases in recorded Stoneley permeability. However, their bedding geometry, seen with borehole imaging techniques, indicates that they are not permeable fractures.

From this it should be clear that no single technique should be employed for fracture evaluation. Borehole imaging, high-resolution calipers, lithology indicators and Stoneley wave data should be used in conjunction in order to discriminate against environmental effects and to arrive at a reliable interpretation of fracture properties.

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**Sounding out Bombay High**

An Array Sonic (SDT*) tool was evaluated on well BH-19 in the Bombay High Field. The SDT has a single, low-frequency transmitter with an array of eight receivers spread 6 inches apart. This configuration allows a better determination of the Stoneley event than data gathered using the Long Spaced Sonic (LSS*) tool.

This technique was used at two vertical resolutions. The first, based on the stacked Stoneley energies over the transmitter-receiver spacings offers resolution of approximately 10 ft and can be used to evaluate gross fractured intervals. Resolution of approximately 2 ft can be achieved by examining differential Stoneley energies between selected adjacent receivers.

Since most of the wells logged in the basement have only LSS data, the SDT Stoneley technique was adapted for LSS waveform processing. Further work resulted in the development of a Stoneley Permeability Index from different energies. Results on BH-36 compared well with the actual flow entries in the production logs.

The Stoneley signal from the LSS waveforms has less energy than the SDT waveforms and contains broad-spectrum pseudo-Rayleigh guided waves. At first, these effects appeared to completely mask the permeability variations. However, the introduction of a select band-pass filter allowed the Stoneley waves to be isolated and interpreted.
Appraising apertures

Computer modelling has shown that the width of a fracture is proportional to the fracture conductivity on an electrical borehole image (Luthi and Souhaité, 1990). Fracture character depends primarily on the drilling fluid which invades the crack.

The resistivity of the drilling mud within the borehole should be measured directly and accurately. Miscalculations can occur due to changes in the conductivity of the fracture-filling fluid or because of conductive material along the fracture plane. Overall, the data calculated in the modelling tests suggest that reasonable fracture aperture values are obtained from water-filled fractures in a wide range of lithologies.

Fracture apertures often increase in size along paleo-unconformities within Middle East reservoirs in Turkey, Iran and the United Arab Emirates. In Iran the karstic fractures in Asmari carbonate reservoir sequences were detected using both imagery and core. Core examination showed that most of these carbonate fractures were filled with porous red sandstone.

Fig. 3.21: OPEN OR SHUT?: The apparent reduction in aperture at the top of this section (left) is due to the reduced volume of water in the oil zone. The plot on the right shows the same apertures after correction.

Fig. 3.22: High fracture densities are often associated with faults but can be caused by a number of geological features. Basement reservoirs are frequently cut by smaller igneous bodies such as this dyke which is characterized by a higher density of fracturing than the surrounding granite.
The variation of the apertures of basement fractures in Egypt's Gulf of Suez shows an unusual cyclic nature. Each sequence of downward increasing aperture widths is followed by another cycle with a similar range of aperture variation. Even more surprising is the fact that these cycles have a fractal nature. Each cycle is composed of smaller cycles of downward increasing apertures which are in turn composed of still smaller cyclic variations of aperture.

The presence of hydrocarbons within reservoir fractures can lower apparent fracture apertures in some wells (figure 3.21). This shift is due to a reduction in the volume of water within the fracture which is not taken into account by computer software during the initial aperture calculation. However, the location of the shift in apparent aperture seems to occur at the oil-water contact within the fracture network even in cases where there is little to no oil within the surrounding rock matrix. In these cases, reservoir fracture porosity can be corrected empirically. Careful analysis of aperture variation indicates whether oil or water will be tested or produced.

The correction to the data is found by dividing the input mud resistivity ($R_m$) by the average calculated water saturation ($S_w$) from standard log interpretation. This gives an estimate of the correct input apparent mud resistivity ($R_{ma}$) which can be used in the workstation fracture analysis program (figure 3.23).

**Production information**

Massive mud losses are generally caused by open fractures being encountered or created during drilling. Some reservoirs in the Middle East have even been discovered as a result of severe mud losses. In the Ain Zalah Field in Iraq, the mud losses typically correlated with the productive potential of development wells. Since mud losses can result from either induced or natural fractures, it is recommended that borehole imagery be used to analyze the nature of fracturing and the geometry of the fracture system. Careful monitoring of mud losses may reveal intervals which ought to be logged that might not otherwise be scheduled for logging. However, during normal monitoring conditions only the largest fractures will be detected, and mud losses are not necessarily related to fracturing.
High hopes in the horizontal

The growing use of highly deviated wells has thrown new light on the distribution of fracture planes in reservoirs. There are obvious limitations in using a vertical wellbore as a method for sampling the density of vertical or sub-vertical fractures and fracture spacing. A well’s orientation to the major fracture sets can be controlled to avoid or to intersect the maximum number of fractures, depending on the well’s intended role in any given field. (Middle East Well Evaluation Review Number 8, 1990 Putting a bit aside.)

The productivity of horizontal wells can be optimized by drilling the well in the most effective orientation - parallel to the major fractures. Horizontal drilling appears to be most beneficial when there is little communication between fracture systems, for example when there is a single fracture orientation and/or when the fractures are not highly interconnected.

Borehole imagery in horizontal wells (figures 3.25 and 3.26) has provided direct evidence of variations in fracture orientations because of the greater number of fractures encountered in highly deviated wells. This has shown that while fracture spacing may be fairly consistent in some fields it is highly variable in others, with the greatest single cause of variation being faulting.

Fracture spacing

Fracture spacing has been one of the most elusive parameters for reservoir modellers. This is mainly because of the small number of fractures intersected by vertical wells. As petroleum companies come to appreciate the improvement in fracture detection and accept that fracture systems can be modelled, it is certain that highly deviated development wells will be used to increase the statistical sampling of fracture spacing.

The information will also improve our understanding of fracture-related production effects (figure 3.27). In 1987 Nolan-Hoeksema and Howard (AAPG Bulletin) suggested a method for computing optimal drilling direction in reservoirs where there are a number of fracture sets or populations.

Numerous outcrop studies have revealed a statistical relationship between fracture spacing and thin beds. This has led many people to expect a similar relationship in the subsurface but examination of imagery and core suggests that such a relationship is not as common as occurs in outcrops. This may be because uplift and overburden erosion cause stress relief and tensional breaking of brittle beds which deform along ductile bedding planes.
Improved interconnectivity - hydraulic fracturing

The interconnectivity of a fracture system can be further increased hydraulically by creating deeply penetrating frac. Research by Schlumberger Dowell has led to the development of techniques designed to obtain minimum leak-off and deeper penetrating acid frac (>200 ft).

The intervals most suitable for ‘fracing’ and the best methods for fracture propagation within a reservoir have been discovered by modelling the fracture process. Tests of a new fluid-loss-controlled acid fracturing system indicate that it is possible to connect more natural fractures to the borehole.

Information concerning the vertical distribution of natural fractures is important when planning a hydraulic fracture job. Even the recognition of induced fractures and their orientation from imagery is valuable for frac planning. In some cases, it is not possible to generate frac from perforations that are not parallel or subparallel to the principal horizontal stress. Moreover, fractures induced from perforations which are not parallel to the principal horizontal stress have a tendency to lose frac effectiveness as a result of later closure.

Recent developments in fracture detection

New tools have been developed to complement the FMI. Recently, two new imaging devices have been introduced. The Azimuthal Resistivity Imager* (ARI) tool appeared in 1992, and the Ultrasonic Borehole Imager* (UBI) tool entered service in 1993.

The main area of overlap between these tools occurs in fracture and thin-bed analysis. The techniques they employ to detect fractures or bed boundaries are different and the images produced by each tool may or may not be similar. Clearly, the interpreter must know when and why the images will be similar and the reasons for any discrepancies when they occur (figure 3.28).

ARI: A second opinion

The ARI tool is a standard dual laterolog modified by the addition of 12 azimuthal electrodes. This electrode array provides a 360º, quantitative and calibrated resistivity image of the formation. In common with other resistivity tools, the ARI tool response is strongly affected by fractures filled with conductive fluids. The ARI tool provides the best indication of fracture porosity in partially mineralized fractures and is capable of distinguishing shallow, drilling-induced fractures from tectonic fractures.

The ARI tool also provides a link between geological data and traditional formation evaluation of fractures and thin beds. Numerical models have been constructed to show that fracture aperture can be determined from tool response. Individual fractures, which are more than 8 inches apart, can be distinguished using the ARI tool. In cases where fracture separation is less than 8 inches, the computed aperture value will be the sum of the individual fracture apertures. Providing estimates of fracture and structural dip data will be valuable in wells or zones where FMI/FMS logs will not be run.

UBI: A third opinion

The UBI tool was developed from the Ultra Sonic Imager* (USI) tool and is suitable for open hole use. The UBI tool has a revolving transducer which emits ultrasonic pulses and receives returning echoes from the borehole wall. Two-way transit time and echo amplitude can be obtained and, with a high sampling rate, borehole images can be rendered using either time or amplitude.

If the velocity of ultrasound in the borehole fluid is measured, the transit
time can be converted to borehole radius. Either transit time or radius measurements give a high-resolution, quantitative and continuous scan of borehole shape. If the borehole wall is disrupted, by fractures or features which are large compared to the spot size for the tool (about 0.25 inches for the 250 kHz transducer), they can be seen in the transit time values. The main limitation is that the UBI tool cannot provide quantitative aperture information. The amplitude measurement facility available with UBI offers a more detailed image than transit time, but is difficult to analyze quantitatively.

Under normal logging conditions there are many factors which influence amplitude. These include the angle of incidence, scattering by irregularities on the borehole wall and the acoustic impedance contrast and loss between mud and formation.

However, fractures and vugs should be visible in the amplitude image provided that losses in mud and those from high angles of incidence do not eliminate a particular echo. UBI data is analyzed using the FracView utilities developed for the FMI/FMS image analysis techniques. Dip and strike are easily defined in FracView. However, it should be recognized that accurate measurements of borehole radii are necessary for good fracture orientation analysis and identification of bed boundaries.

Field tests using the UBI tool have shown a dramatic improvement in borehole acoustic imaging. The introduction of advanced tools has helped to remove most of the low-quality images and broad black bands that have frustrated geological interpreters over the years.

Pictures in oils

The UBI tool’s acoustic technology provides high-quality borehole imaging in oil-base muds. While this represents a significant step forward, there are a few limitations. For example, the very small fractures which can be resolved using electrical imagery cannot be detected by the UBI tool or any other acoustic imagery tools. This presents a problem because small fractures are important for statistical analyses of fracture geometry. Acoustic images contain less bedding information than their electrical counterparts. This bedding data is critical for differentiating fault types. Therefore, in wells with oil-base mud the Oil-Base Dipmeter* (OBDT) tool is sometimes run along with the UBI tool to ensure that fractures and their associated structures can be defined.

Fig. 3.28: A SECOND (AND THIRD) OPINION. In addition to the FMI and ARI tools, the fracture-seeking geologist or engineer can now call upon the UBI tool for locating fractures. The UBI tool has been developed for wells with oil-base muds where the FMI tool is not suitable. The ARI tool is being used to help identify deep open fractures and the fluid they fractures contain.
Slip sliding away

Cross-sectional plots of wellbore shapes (figure 3.29) show the detailed geometry of various types of borehole damage; including stress release, borehole breakouts and key seat wear by drill pipe. A careful examination of borehole shapes by Schlumberger Etudes et Production in Paris has revealed slippage or shear displacement along fault and/or fracture planes in response to drilling (figure 3.30). This slippage, which is often imaged on UBI tool surveys, may result from reduced friction along the fault planes, with drilling fluids acting as a lubricant.

In a few cases, the slippage may be so large that production tubing or casing will be damaged. Vincent Maury of Elf suggests that some wells in southeastern France may have been completely lost as a result of this movement. This fault slippage data may prove to be an important source of tectonic information.

References


