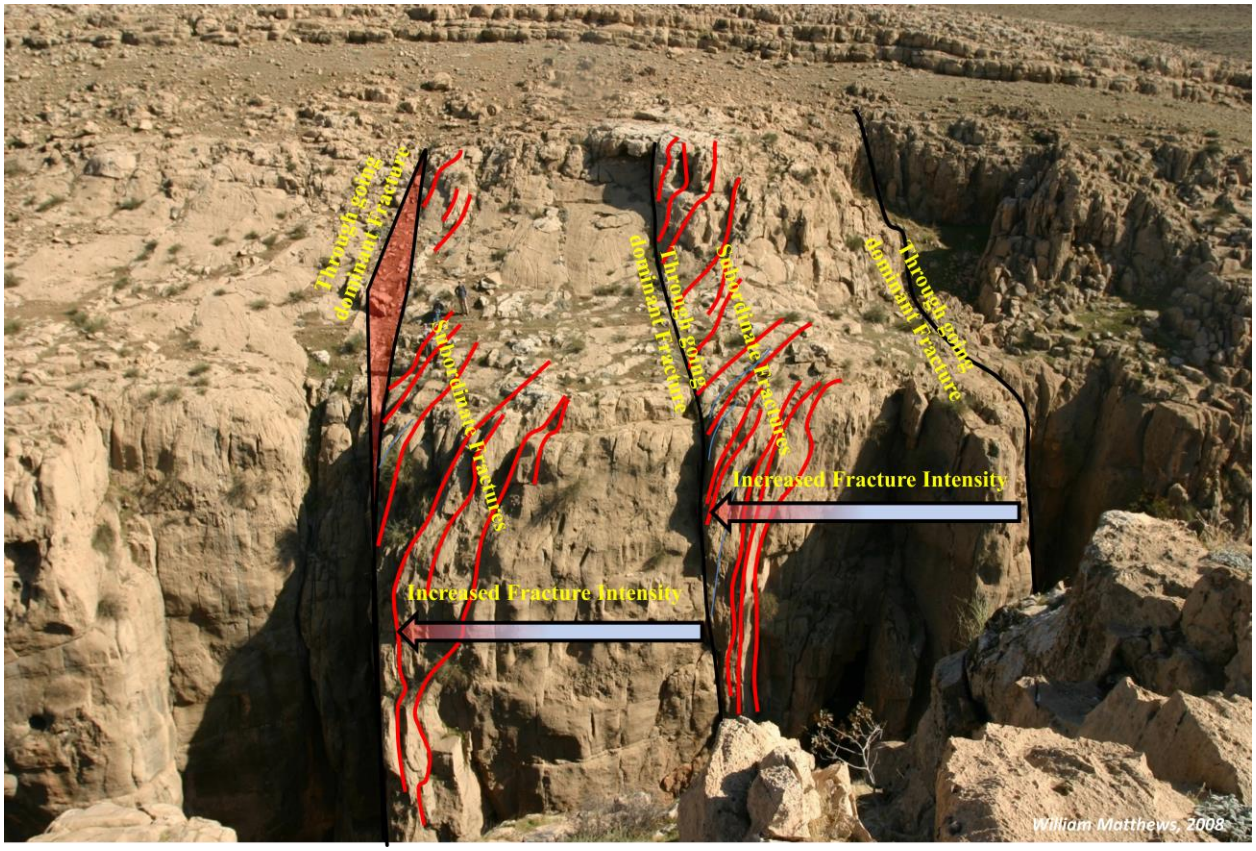
Chapter 1

The recognition and analysis of fractured reservoirs



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Introduction:

The study of fractures is a rapidly expanding field fueled largely by the surge in interest in petroleum resource plays. Initial studies in fractures were directed towards material strength issues. Essentially, at what point does the structural integrity of materials fail? Fractures were studied as a possible contribution to failure mechanism including slope stability problems, mine safety issues, well bore stability concerns to name a few. The field of study has rapidly changed and now fractures are viewed as the primary conduit through which fluids move through the crust. This has shifted the focus on the study of fractures from a material strength issue into a fluid conductivity issue. Some of the first recognition of fractures as a significant factor in fluid conductivity came with the search of looking for repositories for nuclear waste. Several underground sites within crystalline rock were investigated for the feasibility of storing waste fluids from nuclear reactors. It was consistently found that deep open fracture networks made potential sites an unsuitable option due to the inability of the rock to contain the injected waste.

Efforts into understanding fracture networks as a contribution to the reservoir permeability were initially investigated in the late 1950's and early 1960's as a means of explaining production from wells that did not fit the classic reservoir models. Experimental work into rock failure on core plugs carried out by Sterns and Friedman at Texas A&M helped develop the concept of conjugate fracture systems and the link between fracture patterns and the causal stress orientations. This model of fractures persists through much of the literature with little change from its inception.

A significant renewal in the interest in fractures as an enhancement to the reservoir permeability occurred in the 1980's and 90's as projects were drilled pursuing tight reservoirs in structurally complex geologic settings. These wells were dependent on open fracture systems to provide economic delivery of hydrocarbons. In this case the fracture development was recognized to be a combination of the classic models developed by Sterns and Friedman as well as fracture development created by the bending moment in the rock associated with folding.

As the role of fractures within the reservoir deliverability became more accepted a movement began to pursue zones that had hydrocarbon shows but did not have the characteristics of a conventional reservoir (matrix porosity and permeability). The rush to pursue Coalbed Methane projects and the recent interest in shale reservoirs has pushed the analysis of fracture systems to the forefront of exploration. Long reach horizontal drilling, image logs, microseismic, multi-stage fracs are all new technologies developed to help identify and exploit fracture systems.

Despite this strong effort to identify natural and induced fractures systems, the analysis remains largely qualitative (good vs. poor fractured zones) and effort to quantify the fracture systems has languished. As the need to quantify the resource and establish economic criteria to rank the quality of resource projects intensifies the science of fractures will be driven to greater exactitude. Fractures are a fabric within the rock that remains allusive to describe in anything

but general terms. The challenge of the future will be not only to describe the fracture systems with a reasonable degree of accuracy but to also accurately predict new fracture systems. As the demand for this information intensifies, new technologies and techniques will emerge. This is part of why fracture analysis is a fascinating and challenging field of study.

Rock Failure:

Before describing fractures it is worthwhile to investigate fracture generation. Fractures are failure surfaces in the rock volume. They are a response to stress conditions within the rock and as such record strain within the rock. Classical strain studies within rock deal with the concept of penetrative strain, a total rock volume response to stress conditions within the rock over some finite volume within the rock. However, fractures are discrete failure or strain surfaces in the rock. Fractures form, or stated more simply, rock breaks when the stress conditions within the rock exceed the strength characteristics of the rock.

Failure in rock is a function of the stresses acting on the rock and the mechanical strength of the rock. The stresses acting upon the rock are determined by the depth of burial (vertical stress) and the tectonic forces as a result of plate-to-plate interactions (horizontal stresses). The mechanical strength of the rock is determined by the physical rock properties. For failure to occur the effective stresses acting on the rock must exceed the physical strength of the rock. In a simple homogeneous isotropic medium, the stresses acting on any plane within the rock volume can be resolved into a normal stress (σ_n) and a shear stress (τ - Figure 1). With knowledge of the magnitude and orientation of the principal stresses (σ_1, σ_2, σ_3) it is possible to determine the normal and shear stresses acting on any plane within the rock volume.

The relationship of the shear stress acting along a surface and the normal stress acting across the same surface is easily described using a Mohr Diagram, which is simply the relationship of shear stress to normal stress in Cartesian co-ordinates (Figure 2). By convention if the normal stress is compressive it is considered positive whereas tensile stresses are considered negative. A shear stress with a dextral (right-hand) sense of motion is considered positive and sinistral (left-hand) shear stress is considered negative. The principal stresses acting on a rock volume are by definition acting on planes that have no associated shear stress acting along that plane. Thus the principal stresses lie on the horizontal axis of the Mohr Diagram.

In contractional systems it is convenient to assume that the system is behaving under the conditions of Plane Strain. This means that the intermediate stress (σ_2) is confining and that there is no motion in and out of the plane perpendicular to the intermediate stress (essentially all the deformation can be described simply with the maximum and minimum principal stresses (σ_1 and σ_3).

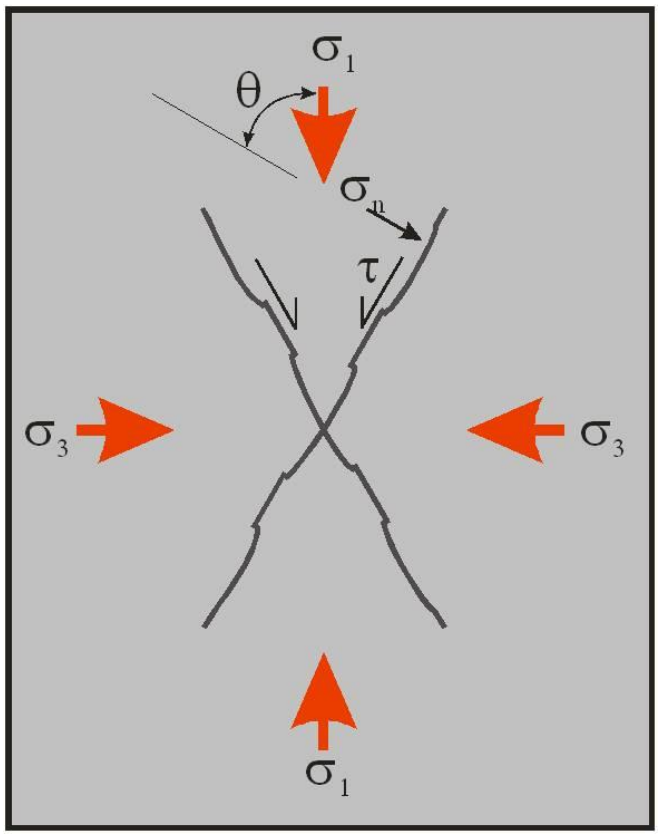

Figure 1: Stress distribution in an isotropic homogeneous system and how the normal and shear stresses relate to the principal stresses.

The difference in magnitude between the maximum and minimum stress is called the differential stress or the deviatoric stress. The stress conditions acting on any plane within the rock volume are described by a circle on the Mohr Diagram that is defined by the maximum and minimum principal stress. Thus the stress conditions acting on any plane in the rock volume lie on a circle defined by σ_1 and σ_3 whose diameter is the differential stress.

The strength conditions of the rock volume can also be described on the Mohr Diagram. A line separates the stress conditions that are stable from those that are unstable (failure) for a given material. The line approximates a straight line in the compressive field and is known as the Failure Envelope with the general form of $y = mx + b$. If the stress conditions exceed the strength conditions defined by the line then failure is anticipated. In this case, y is the shear stress τ and x is the normal stress σ_n. The slope of the line, m, is the rise over the run and is defined the tangent of the angle that the line makes with the horizontal axis (ϕ) and the *y-intercept* where failure occurs under no compressive stress is known as τ_o and defined as the cohesive strength of the rock (cohesion). Note that in the compressive field the strength conditions approximate a straight line but in the tensile field the strength conditions are not linear and the complexity of the relationship is greatly increased.

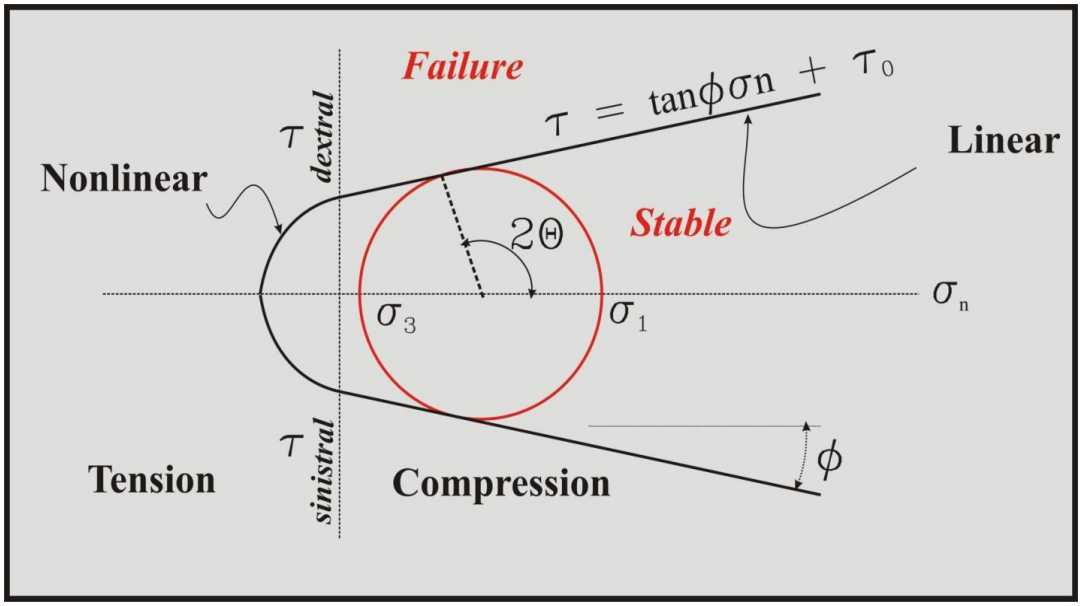

Figure 3: Mohr Diagram describing the stress and strength conditions of a rock volume.

Most of these terms are easily understood except for ϕ. ϕ is a function of the rock properties and is dependent on factors such as the strength modulii, density, anisotropy, lithology, depth of burial, cementation, etc. of the rock. These terms are grouped together under this single term ϕ and that angle is referred to as the Angle of Internal Friction. Fundamentally this is the rock's resistance to failure or its strength.

Once the strength-stress relationship of the system is understood, it is a straightforward process to understand how to create failure conditions and fracture a rock or propagate a fault through the rock volume. To create failure, the stress conditions must exceed the strength conditions as defined on the Mohr Diagram. One method of creating failure is to increase the maximum compressive stress while holding the minimum compressive stress constant. In this method the differential stress increases and the circle grows in diameter to place certain plane orientations into the failure field. Failure will occur on these planes and fractures or faults will propagate through the system. A second method of failure is to decrease the minimum compressive stress thereby increasing the differential stress and causing failure. Any combination of these two effects increases the differential stress and may lead to failure.

Another method to create failure is to increase fluid pressure. At a pore level, fluid pressure, P_f, is pushing out from the pore in all directions (pressure is not a vector and will have the same magnitude in all directions, unlike stress which is a vector and has directionality). Hence the fluid pressure works opposite to stress and the effective stress σ^* is defined as the absolute stress (σ) less the fluid pressure (P_f) -Figure 4.

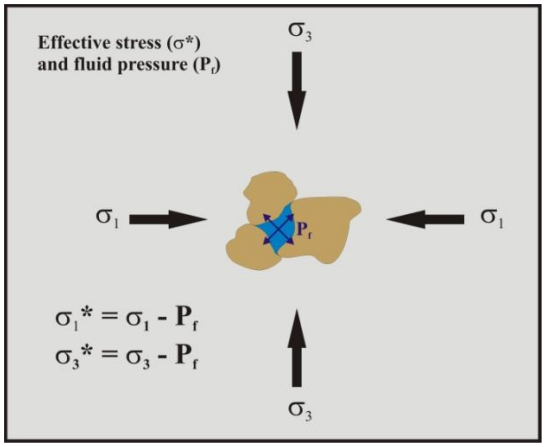

Figure 4: Fluid pressure works against the confining stress such that the effective stress is less than the confining stress.

The effective stress is less than the principal stresses by the amount of fluid pressure and will shift the circle on the Mohr Diagram to the left (Figure 5). This shift of the Mohr Circle will place certain orientations of the rock into the failure field and fracturing will occur.

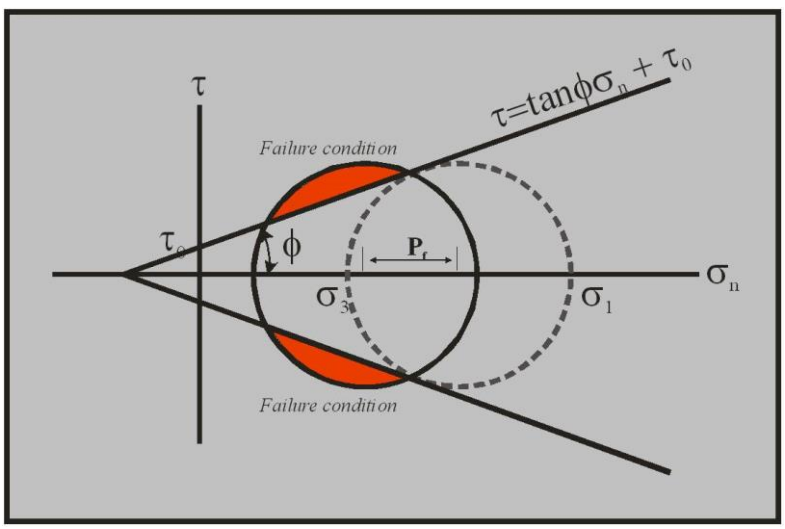

Figure 5: The role of increasing fluid pressure is to shift the Mohr circle to the left thereby creating failure conditions.

Since fluid pressure works in all directions σ1 and σ3 are affected equally such that the effective principal stresses can be defined as:

$\sigma_1^* = \sigma_1 - P_f$ and $\sigma_3^* = \sigma_3 - P_f$

The result of an increase in fluid pressure is to shift the stress conditions into failure mode.

In a contractional setting it is interesting to consider what happens as failure occurs. Consider an example where the system is at critical stress (Figure 6a). As fluid pressure increases the system shifts into failure conditions and the rock breaks (Figure 6b). The break creates a pathway that allows the fluid to escape and results in lower fluid pressure and a return to the stable stress conditions (Figure 6c). In this scenario, the stress conditions always remain critically stressed near failure. It is impossible to release the fluid pressure to such a state as to take the failure conditions deep into the stability field as the normal stresses acting on the failure plane will be allowed to work to close the fluid escape path to prevent excess bleeding of the fluid pressure. Over geologic time the system will eventually find itself in equilibrium with the overall surface or an overlying seal, but not until the horizontal stresses relax or the source of the elevated fluid pressure is exhausted.

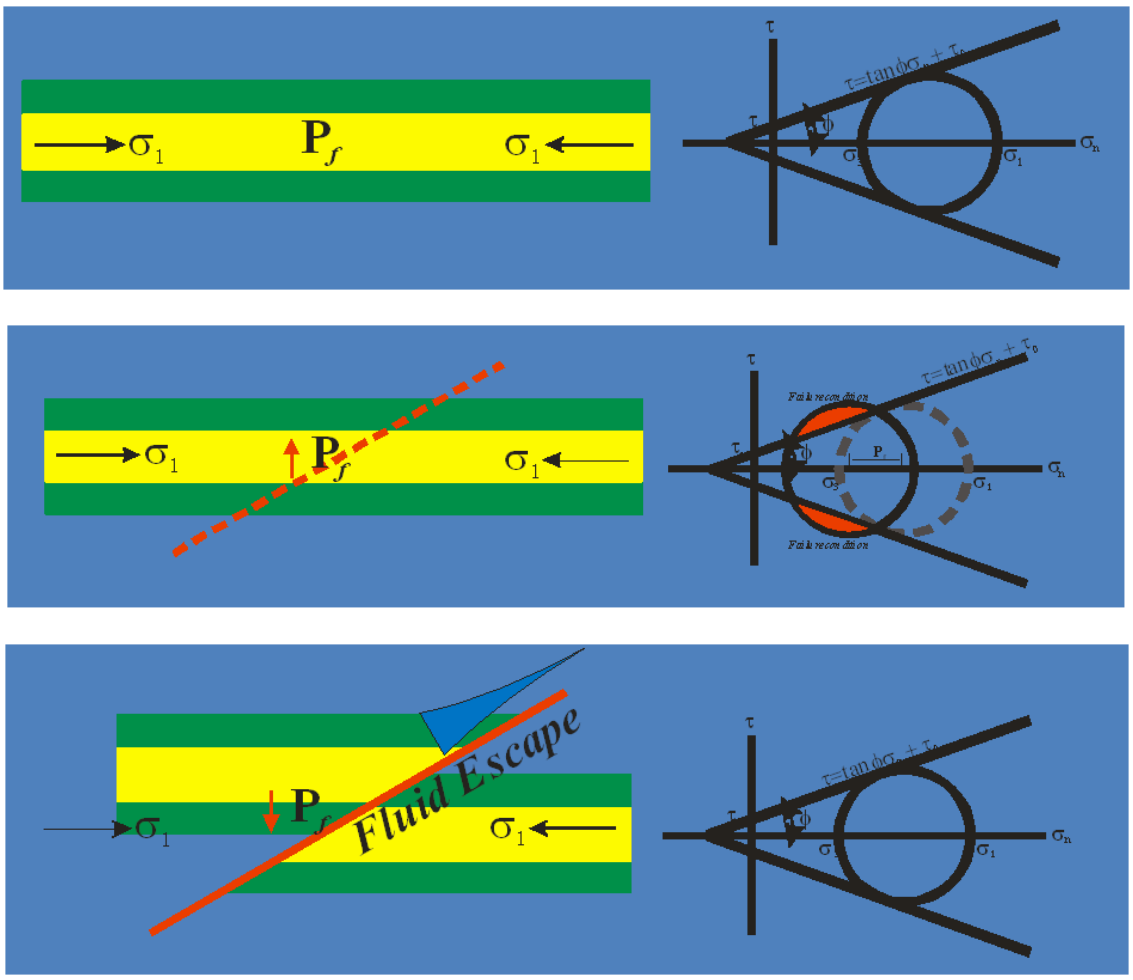

Figure 6: A critically stressed system near failure conditions (a). Increase in fluid pressure shifts the Mohr Circle to the right into failure conditions (b). The failure of the rock opens up fluid pathways that allow the fluid pressure to escape and the system returns to the critical stress conditions (c).

If fluid pressure plays such a critical role in the failure mechanism, what is the source of the additional fluid? In the sedimentary section the fluids available to the failure mechanism are either water or hydrocarbons. All other fluids that may be available are in such small quantities as to be insignificant. Water is an incompressible fluid and is an excellent source to create elevated fluid pressures, especially in systems that form in poorly lithified rock and systems that are undergoing compaction. In these systems, the compaction process results in elevated fluid pressures conducive to failure. In active deformations systems that are propagating through older strata or lithified rock, the use of water as the principal fluid source becomes problematic as the amount of water is limited and the system has compacted in a manner that does not favour the easy transfer of water from one horizon to another. In these cases the source of the fluid is more likely to be hydrocarbons that formed as the strata are buried and heated. The maturation process that converts organic material to hydrocarbons is generally a volume increase reaction although the degree and extent that this happens is variable and dependent on the chemical structure of the organic material.

The formation of the fracture has a range of implications to the rock/fluid system. The fracture forms as a response to the increase in fluid pressure and as such has the capacity to move fluids. Thus, all fractures are capable of moving fluids at some point in their inception. Essentially the fracture forms to relieve the growing fluid pressure in the rock. If the fracture does not move fluids, the fluid pressure would continue to build to impossible levels. This has another implication in that the fracture will have a preferential permeability to the fluid type that is present when the fluid pressure initially formed.

In a rock that has sufficient organic content to be considered a source rock, the generation of the type of hydrocarbon is essential to the relative permeability curves of the fluid system. Nature designs the fracture network to relieve the pressure in the most efficient manner. The fractures will open only as large as necessary to relieve the fluid pressure. If the nature of the fluid is a small molecule such as gas then the fracture that forms will likely be small aperture. Conversely, if the fluid creating the pressure has large molecules such as oil then the fractures will have larger aperture to be able to pass the larger molecule. In this manner the nature of the fluid that forms the pressure is of critical importance to the size of the aperture of the fracture and greatly affects the relative permeability curves of the system.

In the case of hydrocarbons as the fracturing fluid there is a slightly more complex attribute to consider. Different kerogen types tend to preferentially form different types of hydrocarbons. Type III kerogen favours the formation of gas such that the expectation in this setting would be a fracture systems that formed with a small molecule type of fluid. The fractures would have small aperture and have poor relative permeability to a liquid phase (oil or water) but would be permeable to gas. Organic material rich in Type I and II kerogen will tend to form oil, a larger molecule and as such will have fractures that have a larger aperture and will have greater permeability to the liquid phase (oil and water).

The thermal maturity of the organic material increases complexity of the fracture system in the cases where hydrocarbons are the dominant fracturing agent of the system (Figure 7). As the thermal maturity of a source rock increases the type of hydrocarbon that is generated changes. At relatively low thermal maturity liquid petroleum is generated. With an increase in the thermal maturity oil generation reaches a peak. With greater thermal maturity gas becomes the dominant constituent. Not only has the molecule size changed with the increase in thermal maturity but the relative compressibility of the generated fluid also changes. The early stage of the thermal maturation of hydrocarbons generates oil, an incompressible fluid. This will result in a large regional pressure front creating a regional interconnected fracture system with relatively large aperture and good permeability to oil.

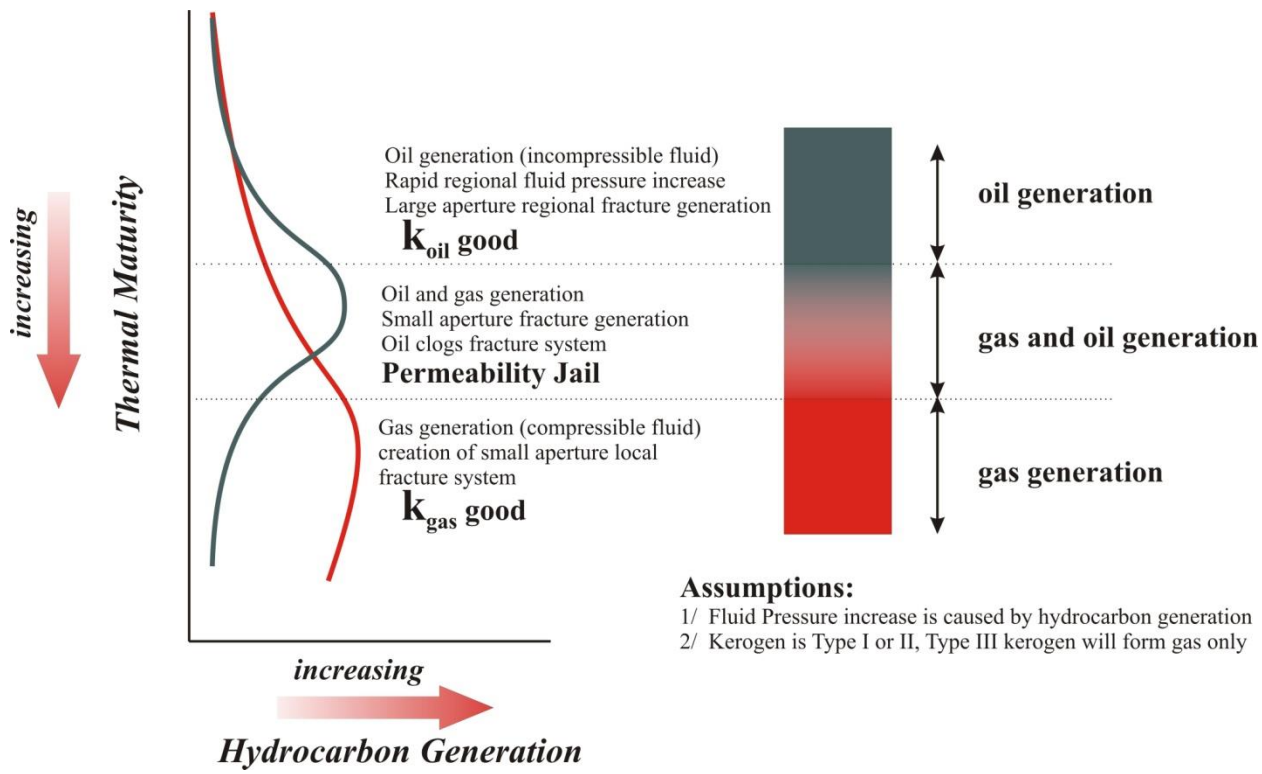

Figure 7: Thermal maturation of organic material affects the fluid type in terms of molecule size and compressibility (influences the areal extent of the pressure event)

In situations of high thermal maturity the generating fluid is gas, a compressible fluid. In this case the fluid pressure is not transmitted significant distances and the fracture system is likely to be more local with poor permeability to liquids. These systems will transmit gas but if fluids are introduced into the system (such as drilling mud) then the fractures may become blocked and the permeability of the system to gas is compromised.

In the intermediate stage of the maturation levels there are two phases of fluid that form. Liquid petroleum is still being generated but a gas phase also begins to form. The pressure release created by the fracturing of the rock will preferentially release gas as it is the smaller molecule.

Oil is in the system but the fracture network is partially designed to pass gas and the liquid phase is less mobile. In part, the liquid phase will move but the fracture aperture is smaller and the relative permeability for oil is reduced. The clogging of the fracture system with the liquid phase has the effect of reducing the relative permeability of gas and a partial permeability trap forms that has compromised the fracture systems ability to move either gas or oil. This stage of the maturation pathway has been referred to as the "Permeability Jail", where neither oil nor gas is easily transmitted.

Permeability:

As previously discussed, fractures are of critical importance with respect to the transmission of fluids within a rock. Given this importance it is necessary to discuss the term permeability and to grasp the influence that fractures have on this term. Permeability is defined as the ability of a material to transmit fluids. It is defined by Darcy's law, which relates fluid flow through a material as a function of the pressure gradient (dP/dl), the distance (Δl), the cross sectional area (A), the viscocity (ν) of the fluid and the permeability (k) of the system.

$$Q = k\,(dP/dl)\,A / \Delta l\,\nu$$

Some of the concepts about permeability flow from this law. One is that permeability has directionality. Flow has directionality and as such so must permeability. This means that the permeability will differ within a reservoir not only in spatial terms but also in directional terms, vertical permeability is different from horizontal permeability, the permeability across bedding is different from the permeability parallel to bedding. Another concept is that permeability is really a frictional term as it is on the opposite side of the equation to flow. In other words it really is representing the resistance to flow. This is an important concept when discussing fractures. When discussing permeability as friction it is necessary to describe the source of the friction. The friction comes at the edge of the permeability pathway at the rock/fluid interface (Figure 8). At this boundary the flow is essentially zero, much like the flow at the base of a river channel is zero at the channel/water interface.

Darcy's law was based on observations of fluid through sand where the pore-to-pore connections are approximated by tubes, which are circular in cross-section. Fracture systems are planar in nature and as such have a significantly different circumference to area ratio in cross-section as compared to pipelines. The effects of friction are not only felt by the shape of the cross-sectional area but also by the roughness of the surface. Fractures tend to have a smoother surface than a typical pore found within a rock. As such the friction is further diminished by the smoothness of the fracture as well.

Finally the type of material also plays a role in the friction between the fluid and the rock. Soil scientists have recognized this phenomenon and as such don't discuss the permeability of a

system but rather hydraulic conductivity of a system. This field of study has developed a series of empirical curves that take into account the soil lithologies as well as the conduit shapes.

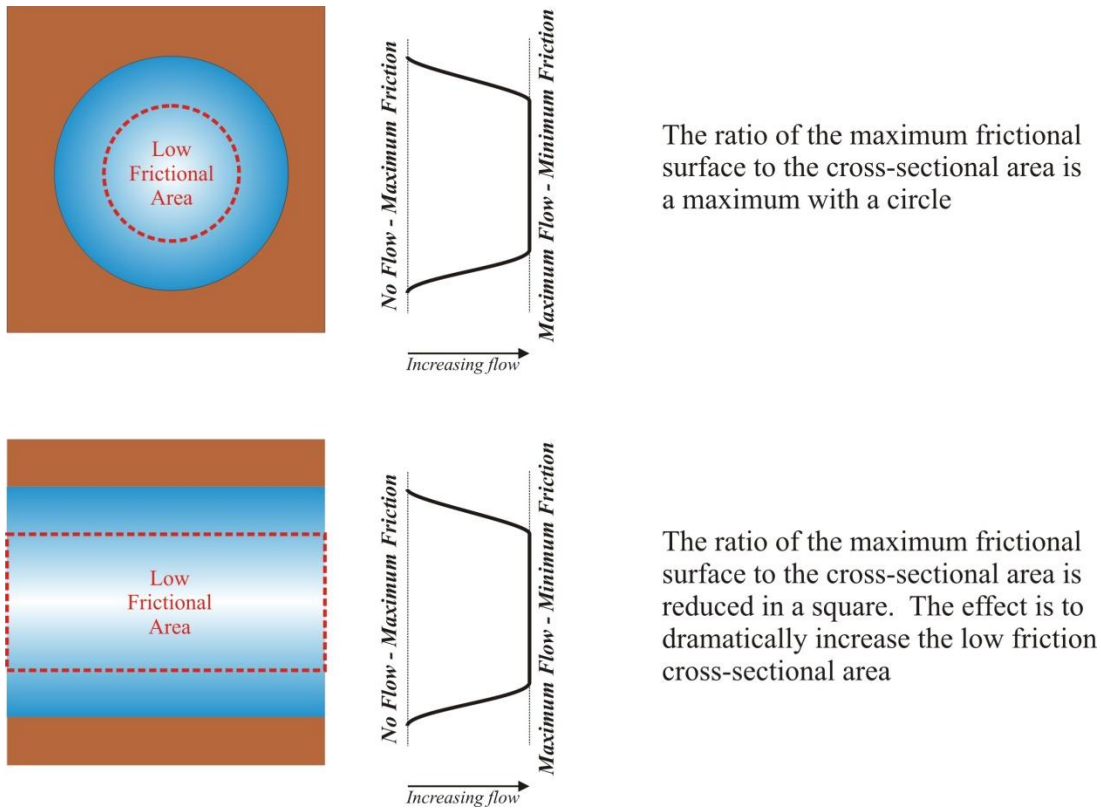

Figure 8: Schematic diagram to compare friction effects of a tube of set diameter compared to a plane of surface of equal diameter

Fracture Analysis:

As the pursuit of fractured reservoirs develops and intensifies the boundary between reservoir geology and reservoir engineering becomes blurry. The challenge for geoscientists is to discuss fractures in quantitative terms rather than in qualitative terms. The challenge for reservoir engineering is to move away from the simplistic view of linear flow within a reservoir and to develop tools that can simulate the complexity of fractured reservoir.

There are many components to fracture analysis. To fully describe the fracture network it is necessary to describe the orientations of the fractures, the connectivity of the fractures, the extent and aperture of the fractures and their ability to conduct fluid (both quantity and type). The intensity or density of the fracture system is also important both in terms of fluid conductivity but also in terms of fluid storage. Ultimately, what is of greatest use to the reservoir analyst is how the fractures hydraulically connect the reservoir to the well bore.

Fracture Orientation:

Fractures are the primary conduit that connects the reservoir to the well bore. As such it becomes important to know which fractures are open and the orientation of these fractures. The determination of open fracture networks is difficult. Boundaries in reservoirs determined from pressure response are based on the assumption of linear flow, which is likely to be a crude approximation; however they do give some insight into the reservoir. More reliable tools are image logs that directly observed the fracture planes. The assumption in image log analysis is that the fractures are planar, as a first order approximation this is likely acceptable. Another assumption is that the resistivity contrast required to observe the fracture is the result of drilling fluid invasion into the fracture plane. This would suggest that only open fractures will appear on the resistivity image log. In reality there are a range of resistivity responses on image logs, which can be interpreted as variations fracture aperture. Outcrop studies are unreliable analogues for aperture analysis due to the stress relaxation at surface and the general opening of most fracture surfaces. Image logs are currently the only reliable tool to estimate fracture aperture.

A more significant problem in fracture orientation analysis lies with the sampling technique. Fractures tend to form perpendicular to bedding. In areas with little structural dip most fractures will be sub-vertical. This makes it exceptionally difficult to intersect vertical fractures with a vertical well bore. The petroleum industry has adjusted to this issue by drilling horizontal wells. The concept is to drill perpendicular to the dominant fracture orientation with the expectation that this will be the direction of the well bore that is likely to best connect to the reservoir. The issue with this approach is the supposition that fractures are predictable away from the well bore and that there are remote sensing methods to observe undrilled fracture systems. To date this is not possible although there is promise with some of the newer seismic techniques under development.

The most common method for predicting fracture orientation ahead of the drill bit are model based predictions that take into account the structural setting and the existing stress conditions. Most model based predictions are based on the concept of conjugate fracture sets. A conjugate system (Figure 9) is a combination of two shear fracture orientations and one extensional fracture orientation. The shear fractures have opposite senses of motion such that shortening in the maximum compressive direction can be accommodated if both shears are simultaneously active (the definition of conjugate). The maximum compressive stress direction bisects the angle between the two shears; hence the conjugate model ties the stress direction to the fracture pattern. This is a useful concept as it is possible to predict stress direction hence the model will tie the predicted stress direction to the fracture orientation. It is the extensional fracture that is of the greatest interest to the connection to the reservoir. Extensional fractures form as a result of the two shear surfaces. The shear surfaces form a wedge that pries the rock apart to form the extensional fracture. Much like an axe splitting wood, the extensional crack propagates some distance in front of the shear formed wedge. The extensional fractures are most likely to be

open, form perpendicular to the least compressive stress and will likely pass fluid along its surface. It is these cracks that allow the well bore to connect to the reservoir so drill orientations are determined to intersect the maximum number of these fractures.

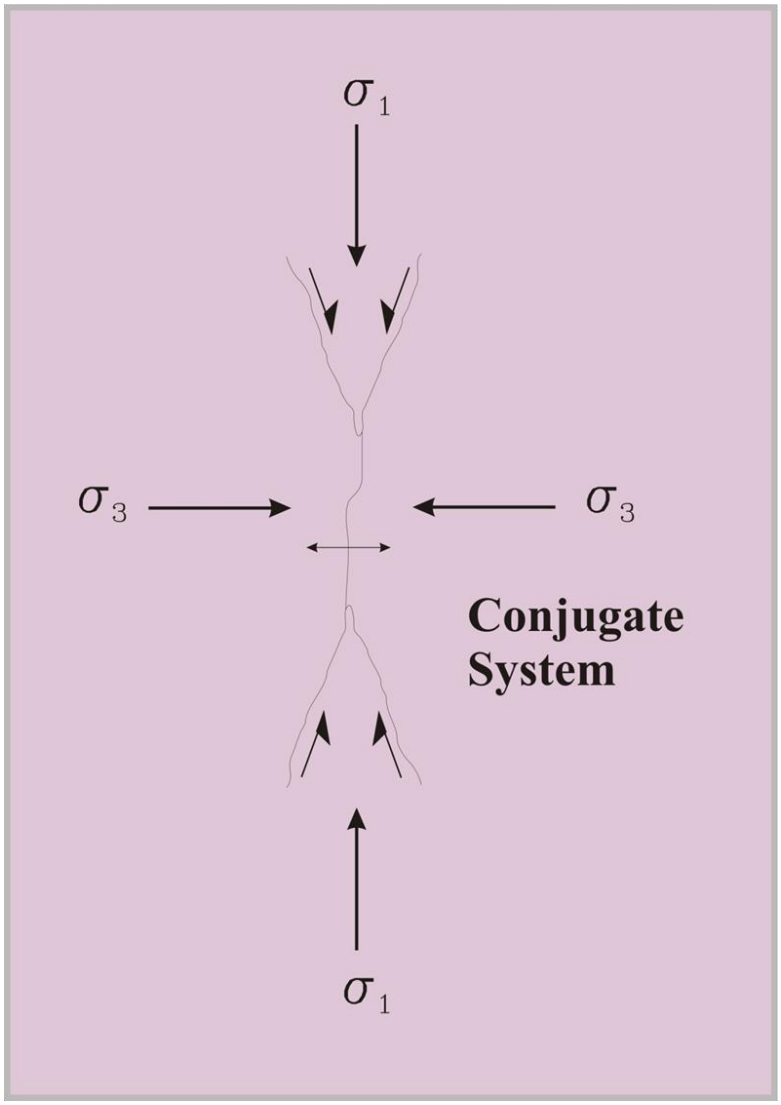

Figure 8: Conjugate fracture systems consist of two shear fracture surfaces acting with opposite senses of motion and a single extensional fracture oriented perpendicular to the minimum stress direction.

As stated previously, fractures tend to form perpendicular to bedding. In the case of most resource plays the beds are near horizontal so the maximum horizontal stress (S_{Hmax}) needs to be determined so that the extensional fracture system orientation may be predicted. Note that the maximum compressive stress (σ_1) orientation is not essential at this stage. Most sedimentary rocks are well bedded, which creates a strong anisotropic fabric in the rock with respect to material strength (rock properties). This anisotropy steers the fracture orientation to vertical

hence the need to determine the S_{Hmax} rather than σ_1. There are several techniques to determine S_{Hmax}. Well bore breakout patterns, induced fractures from drilling, microseismic analysis are some of the tools that can be used to resolve S_{Hmax} (Figure 10).

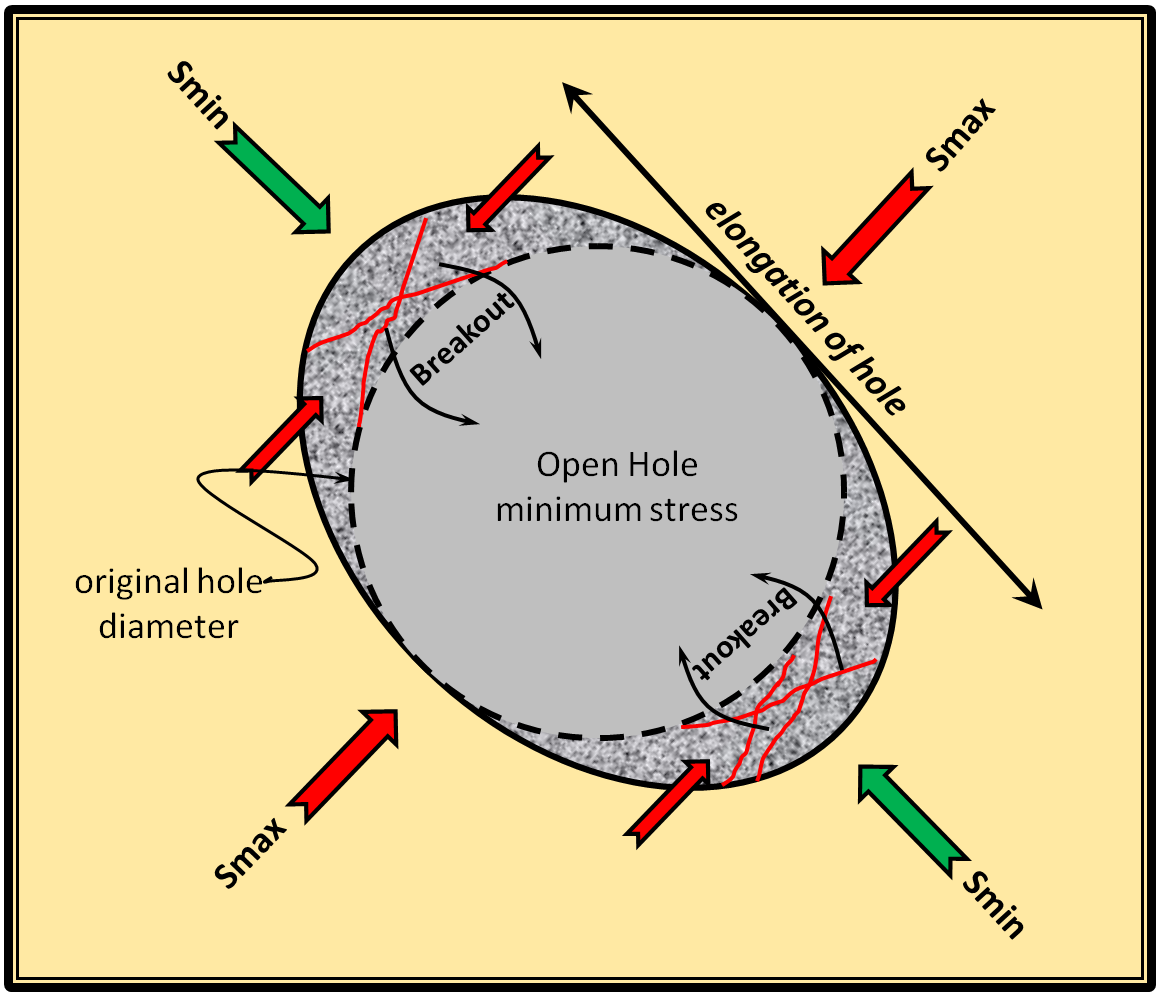

Figure 9: Determination of S_{Hmax} from well bore breakout patterns

Another aspect of fracture orientation that should be considered is the connectivity of the fractured system. If all fractures were rigorously parallel then the connectivity in the reservoir would be poor. Similarly, if all the fracture orientations were random the connectivity in the reservoir would be good and in concept the random fracture distribution with large fracture intensity would emulate a conventional linear flow reservoir. It is possible to estimate the connectivity of the fracture system within the reservoir using a stereonet. Plotting the poles of the fractures on a stereonet will give insight into the connectivity of the fracture system (Figure 11). If the poles form a tight cluster then the fractures are sub-parallel to each other and the fractures have poor connectivity. If the poles have a broad cluster then the fractures are at angle to each other and are likely to have better connectivity.

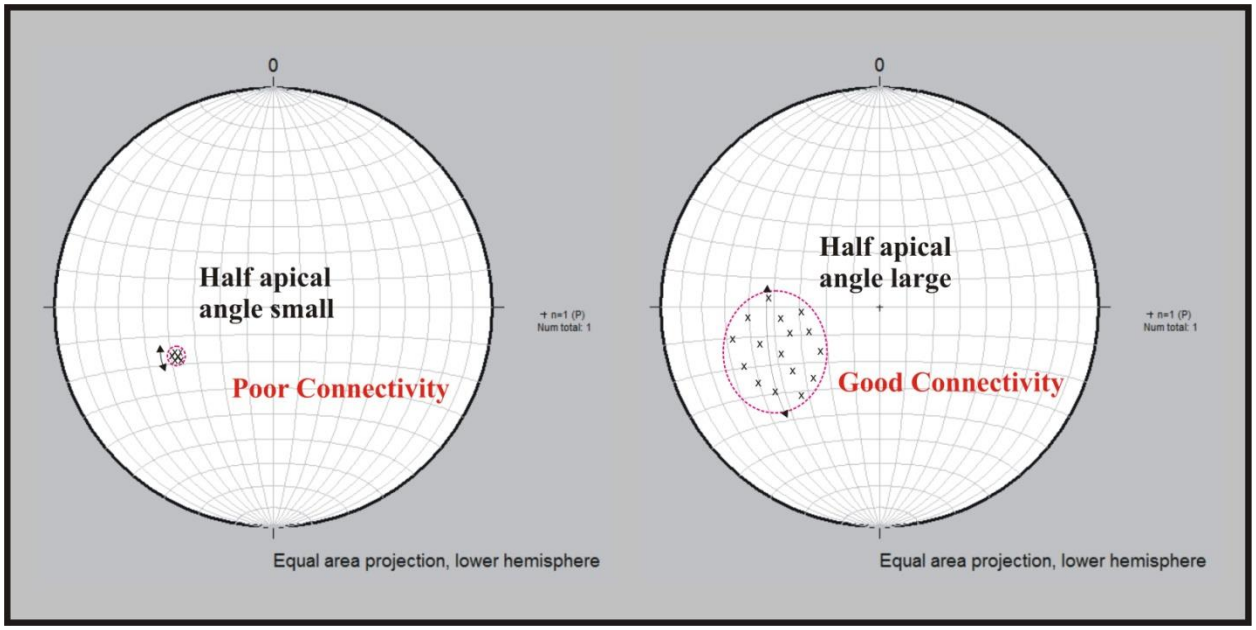

Figure 10: A stereonet is an effective tool for fracture analysis. In this case the tightness of the cluster gives insight into the connectivity

Most fractured reservoirs have one or more dominant fracture orientations. Multiple sets of open fractures create good conductivity in the reservoir. Figure 11 are fracture data taken from an image log and plotted on a Rose Diagram and stereonet respectively. Note that on the Rose Diagram the data looks like a single population of fractures trending northwest – southeast. On the stereonet there is a great scatter of fractures but in some areas on the stereonet there appears to be a concentration of poles. Creating a density plot of the fracture data is an effective means of identifying population peaks within the data. The density plot reveals two dominant orientations of fractures within the data, which was not reflected in the Rose Diagram. The Rose Diagram can only reveal the strike of the fracture but not the dip.

Fracture connectivity also affects the permeability in a reservoir. Fracture connections form a line (the intersection of two planes). Along this line permeability is greatly increased due to the significant decrease in friction. The result is that the fracture connections become preferred fluid conduits and many fracture intersections will greatly increase the fluid flow within a reservoir. In a typical flat lying reservoir where the fractures are dominantly vertical, the fracture intersections will be dominantly vertical. As the dip on the fractures varies from vertical the fracture intersections become increasingly more horizontal. The result is that for a given fracture system with a set aperture, the permeability of the system is affected by the connectivity. This permeability enhancement created by connectivity can greatly affect the drainage area of a well.

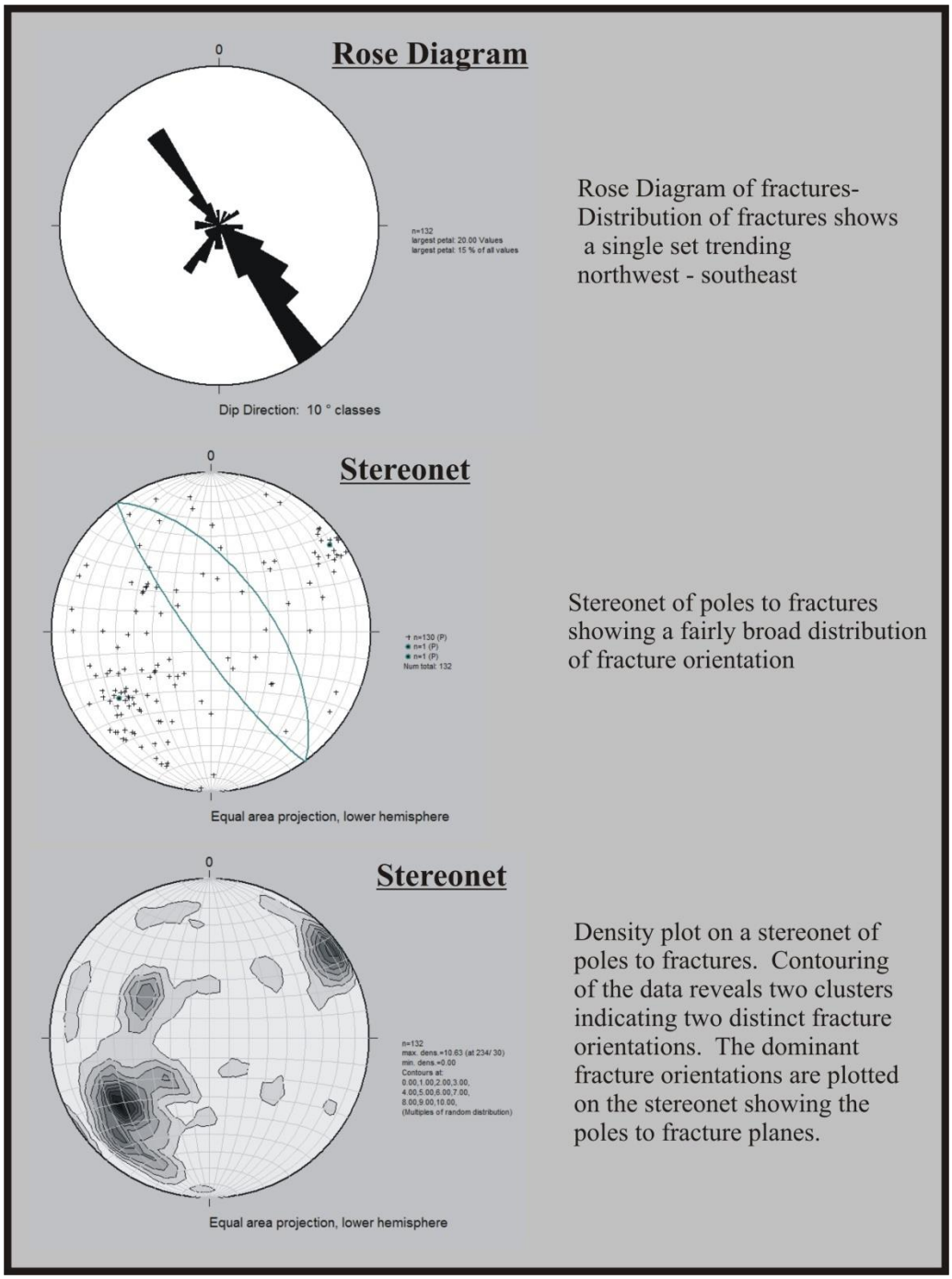

Figure 11: Fracture data from a well shows different display techniques. All plots are using the same data. The rose diagram shows the dominant strike of the fractures but gives no insight into the dip of the fracture plane. The stereonet is good to observe the scatter of the data but can be difficult to group populations. A density plot of the data shows two dominant groups of fractures and helps with analysis.

Fracture Intensity:

The term fracture intensity refers to the sum of the area of all fracture planes in a given volume of rock (Figure 12). This term caries with it units of number of fractures per unit distance, the sum of the area (length^2) divided by volume (length^3). In practice it is difficult to measure the area of every fracture in a given volume of rock. A means of approximating this value would be to measure a rock surface and measure the line length of every fracture intersection on that surface. Although possible in outcrop studies, this can be a tedious process. Note that the units remain the same (number of fractures per unit distance) with this approximation as the measurement is now intersection length divided by area (length^2). The more common approach is to take a scan line through a rock volume and count the number of fracture intersections per unit distance. Again, the units for this approach remain the same (number of fractures per unit distance) This method is used in both outcrop studies and in subsurface studies but it should be noted that it has an inherent bias based on the scan direction.

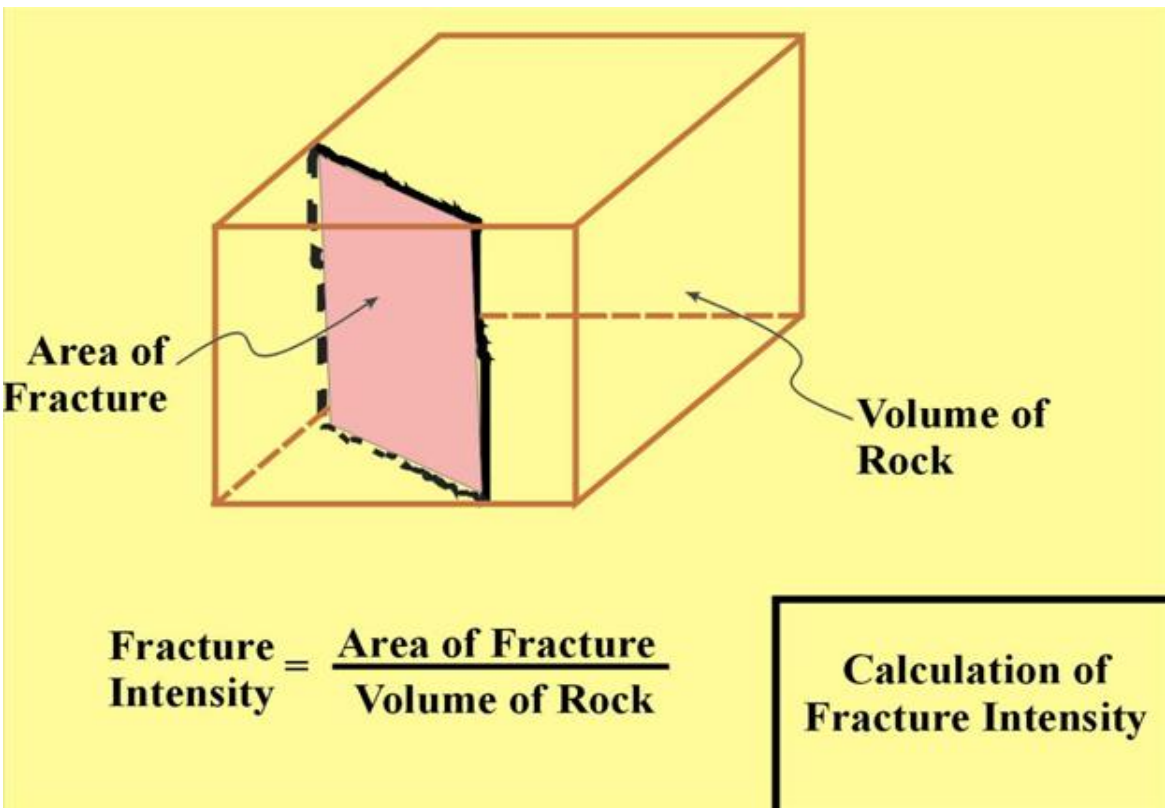

Figure 12: The calculation of fracture intensity

The result of the scan line approach is to develop a comb function marking each fracture at its position along the scan line. An attribute of the fracture can be assigned at each fracture position and from this shaped functions can be created. For instance, in wells with image logs the

amplitude of the resistivity response may be assigned giving some inference into fracture aperture. In outcrop studies the length of each fracture may be assigned. Whatever attribute is assigned; the effect is to create a comb function, which can be analyzed.

Blue Draw is an outcrop (Figure 13) in the Wind River Basin of Wyoming containing excellent exposures of mid-Cretaceous aged sandstones of the Frontier Formation. The outcrop is analogous to a producing fractured reservoir in the Frontier Formation, part of the Madden Field also in the Wind River Basin. A scan line was laid out along this outcrop approximately 1.5 kilometres long and fracture measurements were taken along the scan line noting the strike, dip, fracture height and position on the scan line for each fracture. From this a function was developed comparing fracture height against the *x*-position along the scan line.

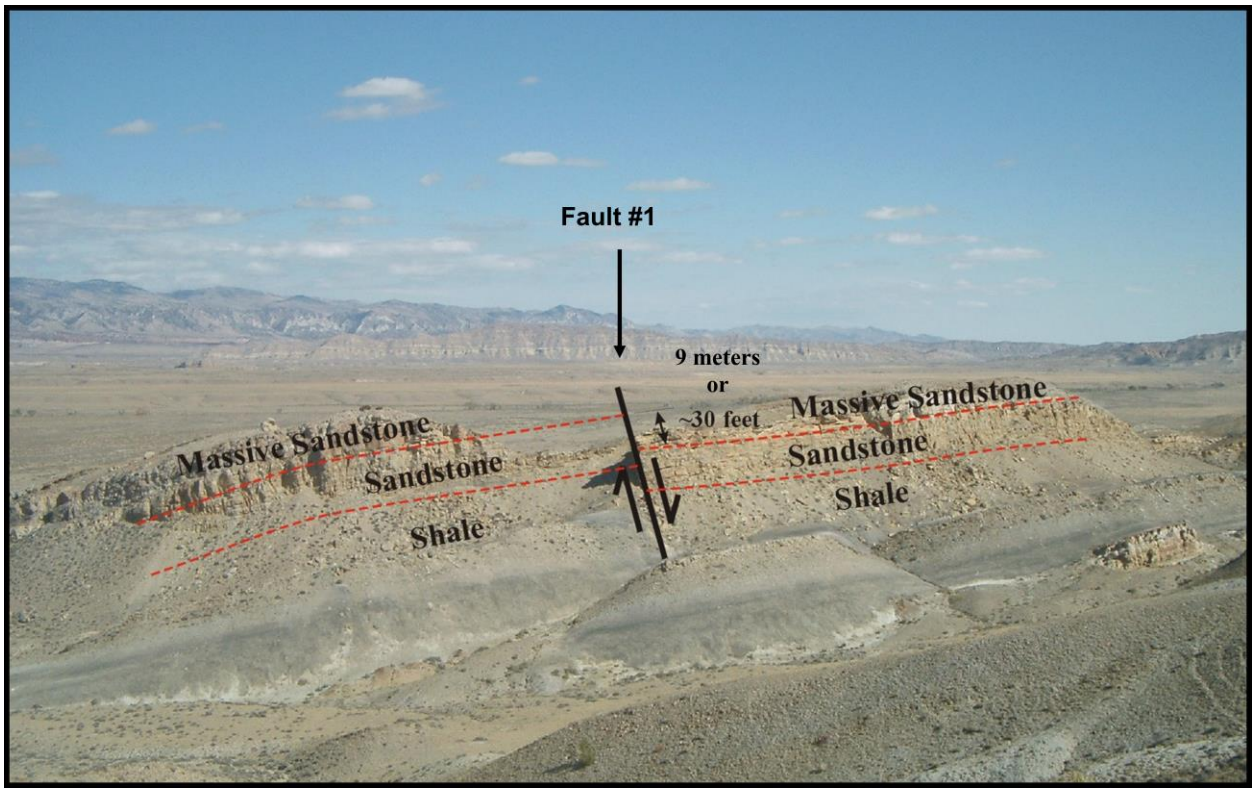

Figure 13: Outcrop of mid-Cretaceous Frontier Fm. at Blue Draw, Wind River Basin, Wyoming. A scan line was laid at the base of the sandstone and every fracture was measured (strike, dip, and height) at the intersection point with the fracture.

Analysis of the data began by running a series of summing curves along the scan line. The concept behind this was to treat fractures in close proximity to each other as contributory but keep isolated fractures isolated. The summing curve was created by taking a window in the data of set length and adding the lengths of all fractures in that window and assigning that value to the mid-point of the window. The window is then moved forward one sample (in this case one centimetre) and repeating the calculation. The summing window is moved along the scan line in

incremental steps until the entire scan line has been processed. Windows of different lengths can be run through the data to see at what window length the fracture swarms along the scan line begin to mesh with each other (Figure 14). The resultant curve is essentially a profile of the potential fluid flow from the reservoir.

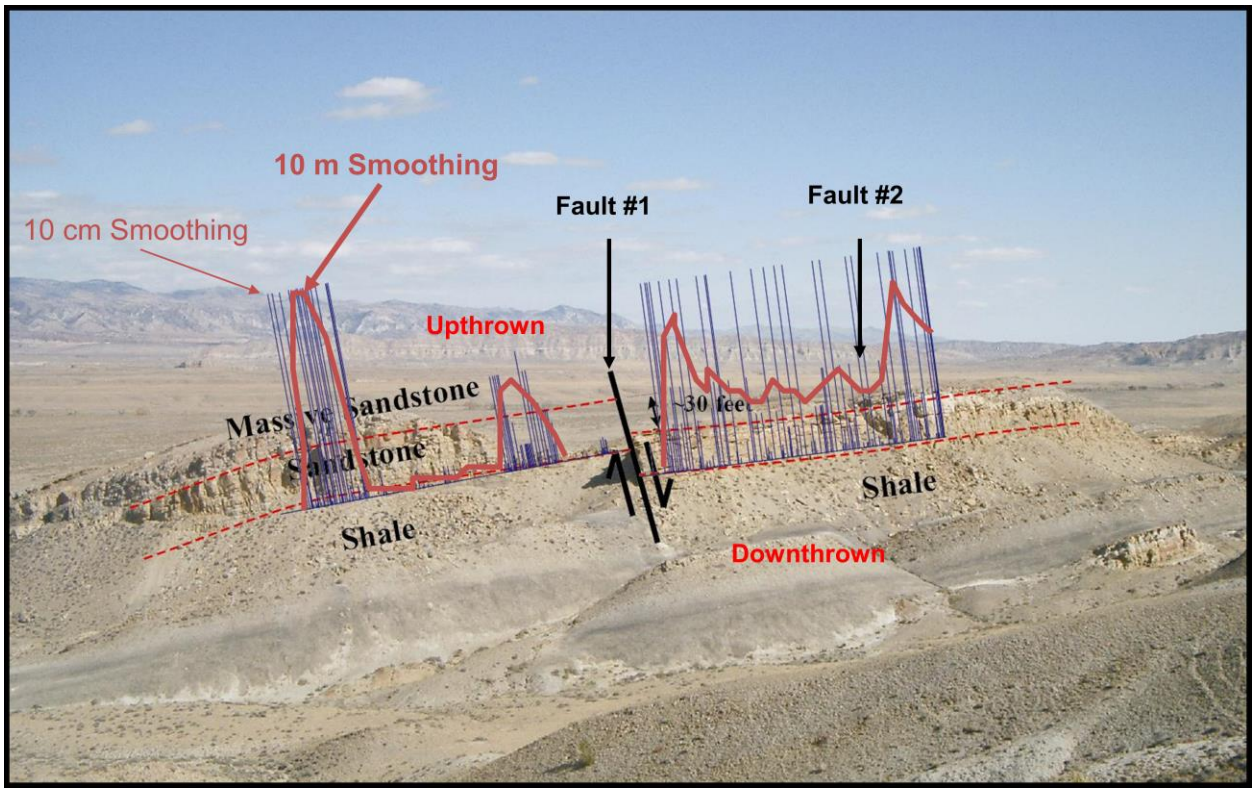

Figure 14: Comparison of different smoothing curves (amplitudes standardized) along the fracture distribution at Blue Draw, Wind River Basin, Wyoming.

The length of the window that is required to show the meshing of the fracture swarms gives some insight into the reservoir flow characteristics. In a rock with no matrix permeability and only fracture permeability it would be expected that a shorter summing curve would be more reflective of the potential fluid flow. A rock with a reasonable amount of matrix permeability would be reflective of a longer summing window. This would suggest that although matrix permeability is not a significant contributor to initial flow from the well it is likely important to effective drainage and dictating which fracture swarm will have the greatest long term effect on the productivity of the well.

The summing curves may also reflect the connectivity of the fracture system. Fracture systems with good connectivity will behave more like the long window analysis whereas wells with poor connectivity would be more likely reflected in the shorter window summations.

Determination of the window length requires manipulation of the data and comparison to production data. In the case of Blue Draw windows of 10 cm, 100 cm, and 1000 cm were run on

the data. Comparison of the curves showed that the data was very spiky at the shorter lengths but at the longer window length of 1000 cm a waveform developed in the data. The shape of the waveform can be of great value in the analysis of the fracture distribution and the production of the reservoir.

A waveform is the sum of a series mono-frequency waves of different amplitude and phase. Any given waveform can be transformed into the amplitude and phase for each given frequency within a reasonable spectrum of frequencies. This transformation is done using a Fourier Transform. The result is to take the waveform plotted in amplitude vs. distance and create two new plots of amplitude vs. frequency and phase vs. frequency. The frequency in this case is spatial and is designated as k (not to be confused with permeability) with units of cycles/metre. Analysis of the amplitude for each frequency shows the dominant frequency (Figure 16). This is a significant number in that it is a statistical analysis indicating the dominant period for fracture development within the rock. This is the period (1/frequency) at which it would be expected that fractures would occur.

Using the Fourier Transform it is possible to statistically predict the dominant period of fracture swarms within the reservoir and begin to estimate the distances well must be drilled to intersect a set number of fractures. For example, if it was determined that the dominant frequency in the Fourier Transform was 0.004 m^{-1}, the period would be 250 metres. The prediction would be that approximately every 250 metres there should be a fracture swarm within the reservoir. If it was deemed that a minimum of 4 fracture swarms were needed to make a successful well then the well length would need to be at least 1000 metres.

The phase component of the transform is a more difficult concept to deal with and is probably of little use at this stage of sophistication of the approach. Phase is related to the position of the trigger mechanism that created the waveform. Previously the concept of fractures as strain within the rock has been addressed. Strain is a response to energy imparted into the system and as such the fractures will have some memory of the failure event that created the crack. A nearby fault, a bending moment in a beam or some other event has released energy into the rock that has formed fractures. The position of this event relative to the fracture will have some effect on the phase analysis. Since fractures are the product of many such events over geologic time, the phase information is a series of imprints that become impossibly difficult to deconstruct. Information is locked in the phase component of the curve but at this stage it remains a mystery.

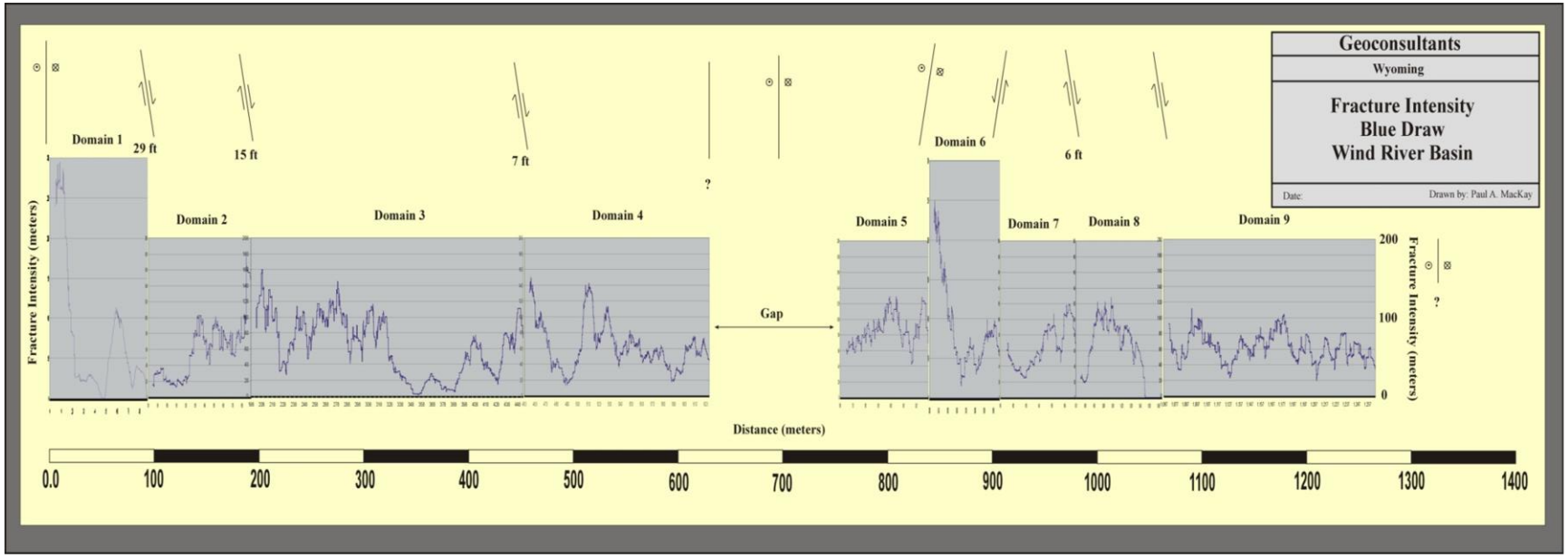

Figure 15: Profile of the Fracture Distribution of the Frontier Fm. at Blue Draw with the 1000 cm summing window applied.

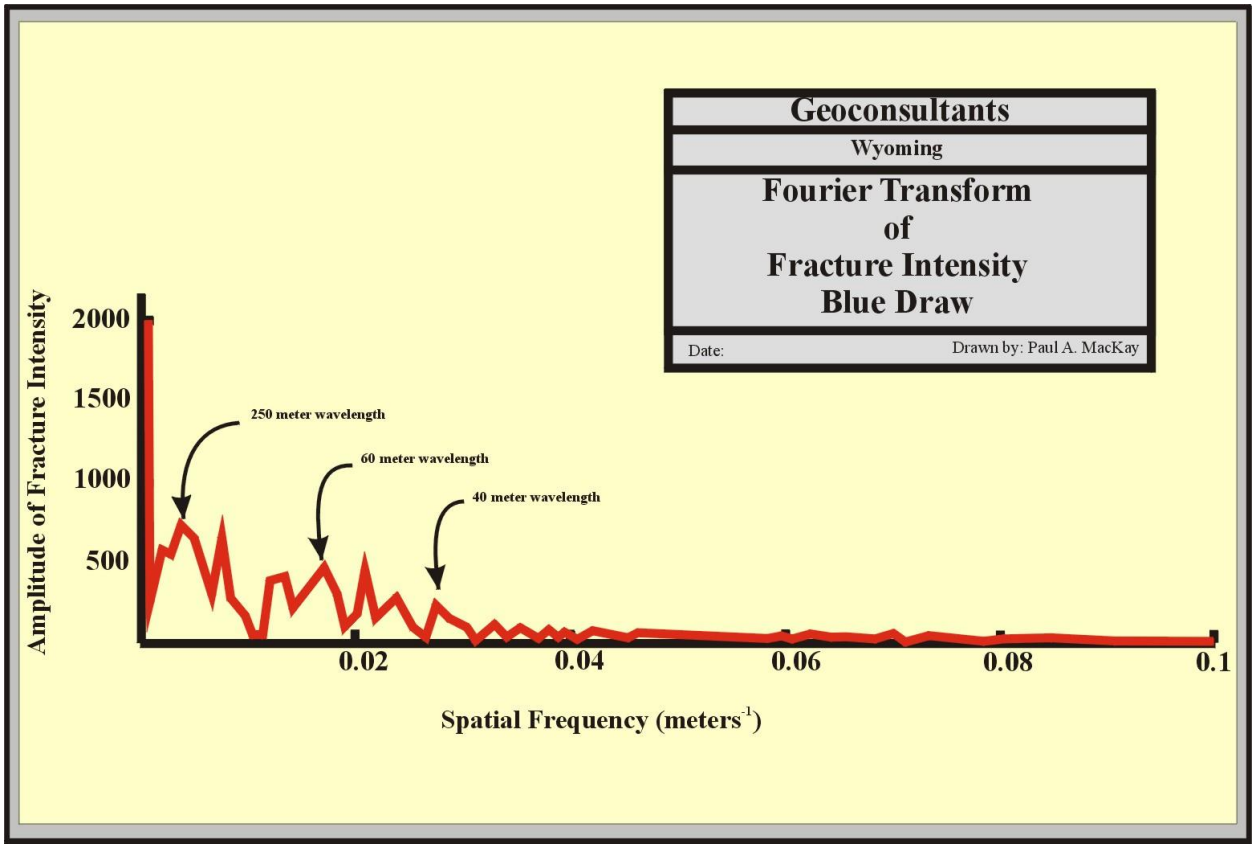

Figure 16: Fourier Analysis of the fracture distribution at Blue Draw based on a summing window of 10 metres.

The Fourier Analysis does not give one single dominant frequency but has several spikes in the data showing that other dominant frequencies exist suggestive of a much more complex process. Fracture patterns are not simply a product of stress. The observed pattern is a complex relationship of several different variables over time and as such it should not be a surprise to find many different dominant frequencies within the data.

There is more information that can be mined from the frequency analysis. If the transform represents the amplitudes for the range of frequencies then the integral of the curve (the area under the curve) is the summation of all of those amplitudes or, phrased differently, is the total fracture energy within the rock volume. This means that the total fracture intensity for the scan line (or a portion of the scan line) may be calculated. In this way a quantitative value may be assigned to the scan line for the potential of the fractures. This allows comparison of scan line values from one area to another.

At Blue Draw the outcrop is segmented by a series of low displacement near vertical normal faults. These faults divide the outcrop into a series of different domains. Individual Fourier Transforms were made for each domain and the total fracture intensity was calculated for each domain (Figure 16). Plotting the total fracture intensity shows a decrease in fracture intensity

away from the left boundary of Domain 1. At this boundary there is a larger displacement strike slip fault. The exception to this pattern is between Domains 5 and 6 where there is another relatively large strike-slip fault. The fracture intensity analysis is giving quantitative value for how fracture intensity decreases away from faults.

Figure 17 is a cross-section across a fold in the Zagros Mountains of Kurdistan. A series of scan lines measured fractures on both the forelimb and the backlimb. Analysis of these scan lines using Fourier Transforms shows that the fracture intensity on the front of the limb is 2.5 times greater than the backlimb. Where previously the fracture intensity was related to qualitatively (intensely fractured, saturated, moderately fractured poorly fractured, etc.) using this method qualitative values can be assigned with the recognition that these values are relative.

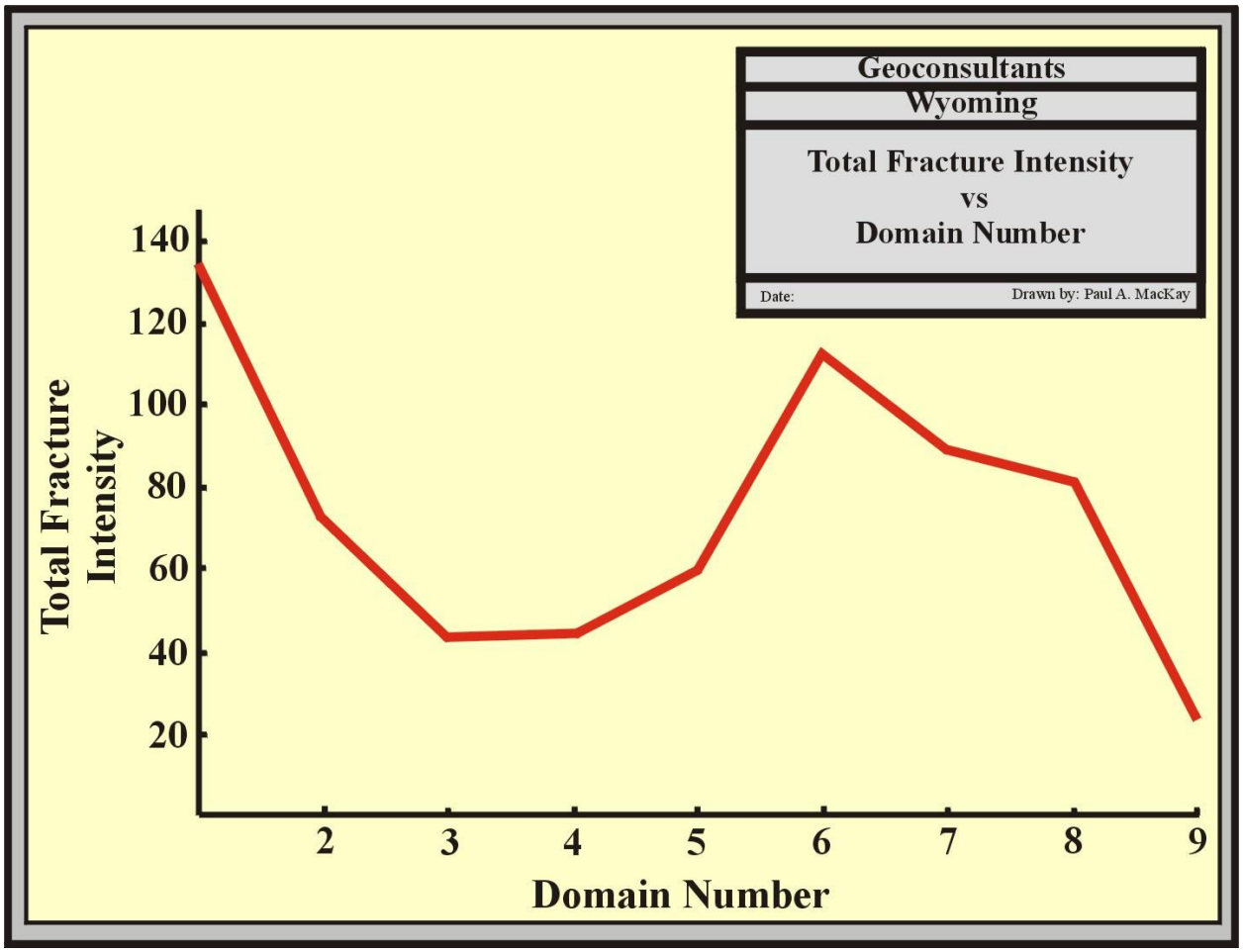

Figure 17: Calculation of total fracture intensity for each individual domain at Blue Draw

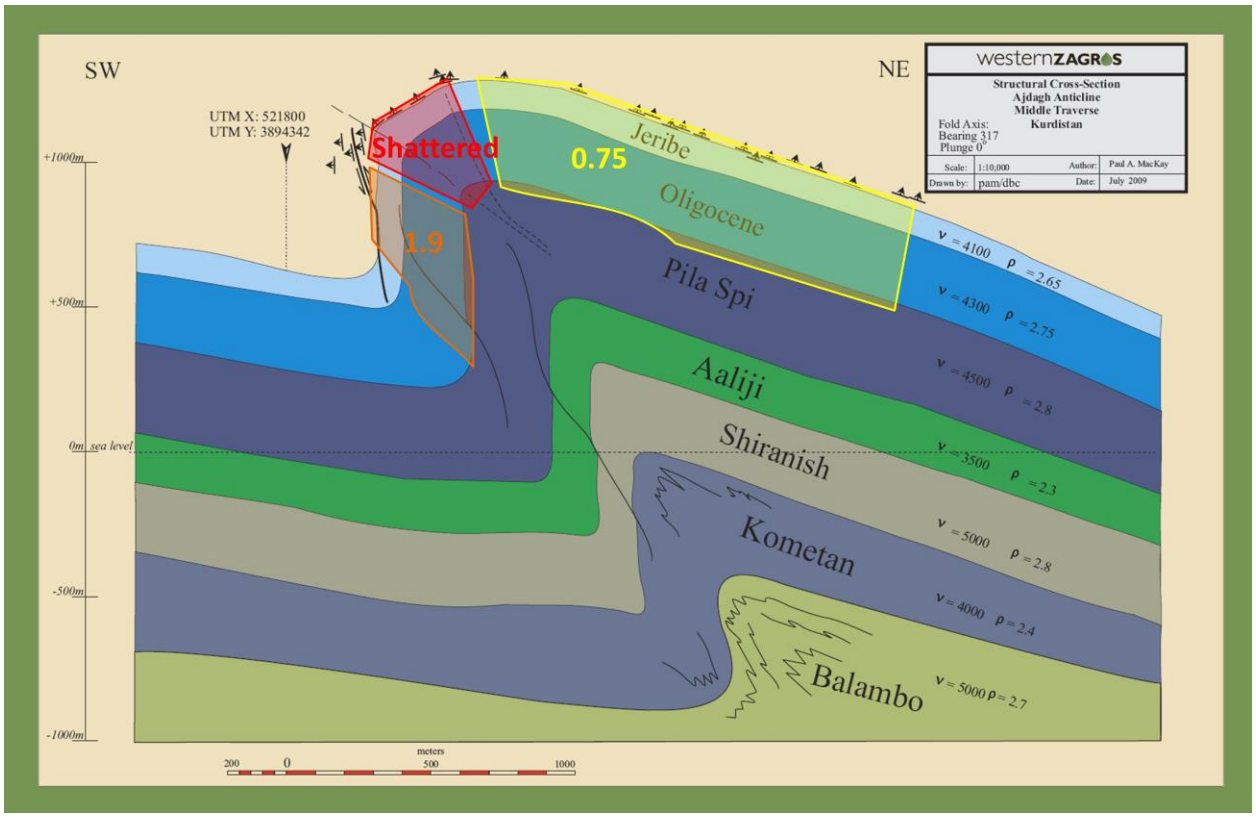

Figure 18: A cross-section across the Ajdagh Anticline in southern Kurdistan with fracture intensity overlayed onto the fold. Note that the front limb has approximately 2.5 times more fractures than the backlimb based on outcrop analysis.

k_x vs. k_y transform:

A k_x vs. k_y transform is a means at analyzing surfaces for linear events such as the trace of a fracture on an outcrop surface. Much like the analysis of scan lines are greatly improved with a Fourier Transform, the k_x vs. k_y transform aids in the analysis of surfaces. The concept is based on FK Transforms used to analyze seismic records (Figure 19). In this case the seismic record is in time vs. distance. The transform converts the data from time vs. distance into temporal frequency (F) vs. spatial frequency (K). The slope of the line on an FK transform has units of time vs. distance and represents velocity. In the case of a k_x vs. k_y transform the surface is spatial frequency in the *x* – direction vs. the spatial frequency in the *y* – direction.

An example of this technique can be seen in Figure 20. In this case the surface is a curvature surface from a 3D seismic survey. The high contrast lines are assumed to be minor faults which approximate fracture trends. The surface could be analyzed by measuring each event but the k_x vs. k_y transform is a more elegant solution and gives more insight into the system due to the statistical approach.

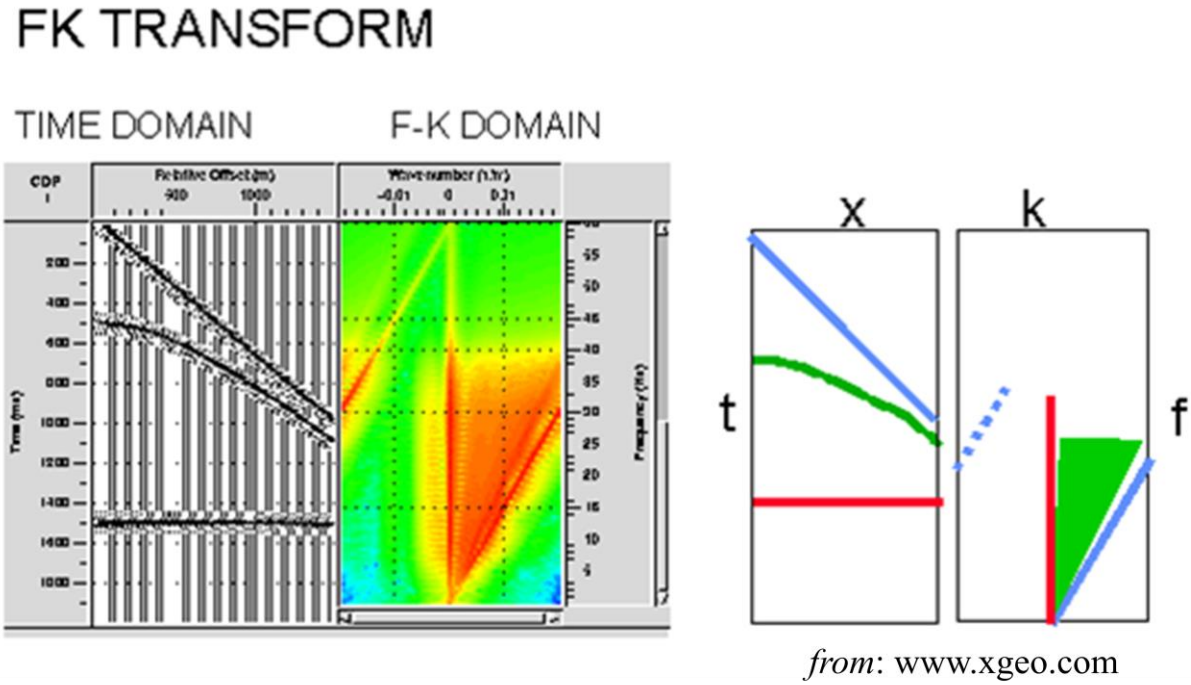

Figure 19: FK Transform of a seismic record from time vs. distance into temporal frequency vs. spatial frequency

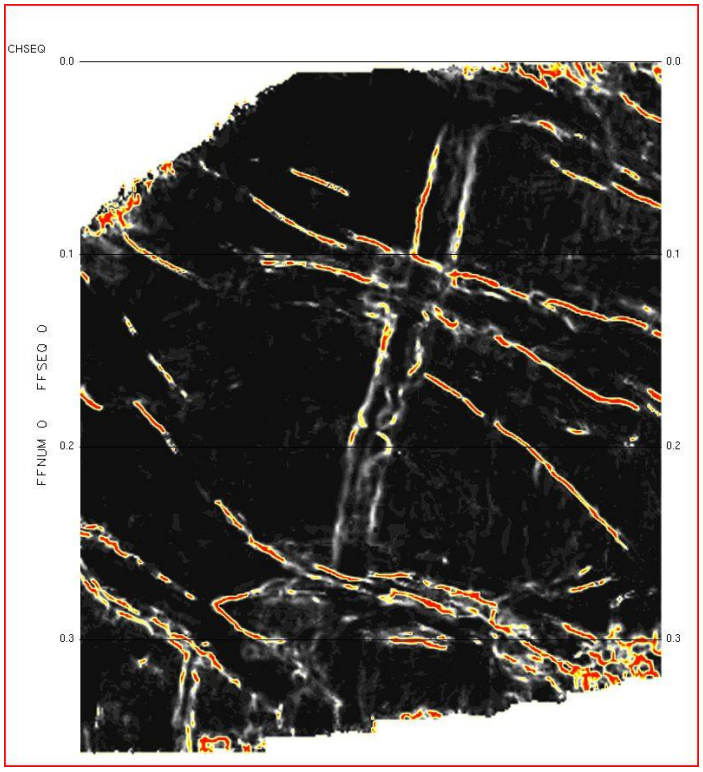

Figure 20: A surface from a curvature volume of a 3D seismic data set.

The k_x vs. k_y transform may be analyzed by looking at the amplitude of the events (Figure 21). The most dominant fracture system will have the largest amplitude on the transform. The spread on the linear events on the transform is a direct indication of the range in orientations of the lines. The actual dominant trend of the event may also be determined. The units of the trend lines are dimensionless but are pointing in the bearing direction of the fracture trend. Note that this is a method of looking at a surface that intersects fractures; it is not a direct method of measuring the fracture surface. The technique is made especially useful with seismic data as it can be used to compare one part of a surface to another, or one slice of the data to another or finally one area of one data set to another slice from another data set. Using this method it is possible to build a series of volumes with information on the fracture system. Such as a volume of dominant fracture orientations, spread on the orientation and highlight areas that have more than one fracture orientation.

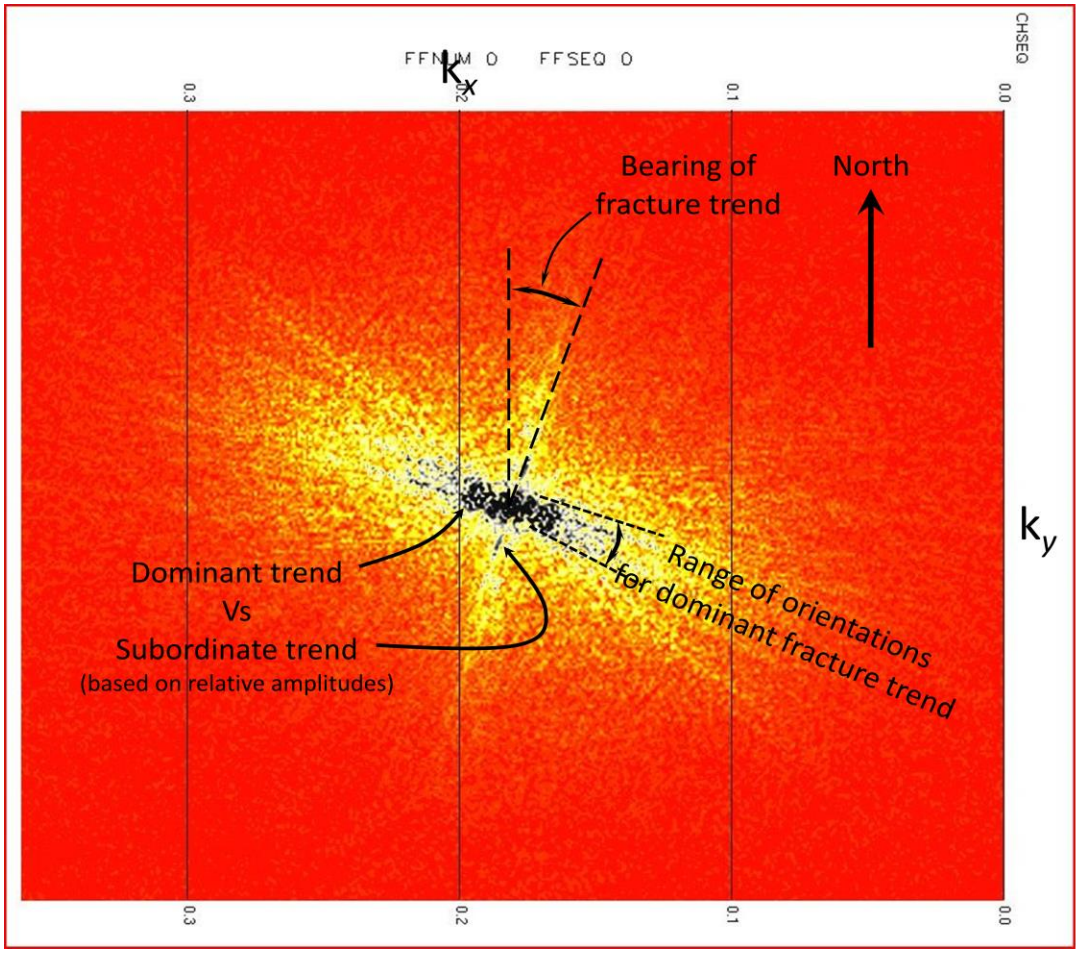

Figure 21: k_x vs. k_y transform of the surface from Figure 20.

Modeling:

The advantage to this approach lies in the development of reservoir models that can take into account the fracture development within the model and the variation in fracture development throughout the model. Three-dimensional models are an important process in the analysis of reservoirs. The building of a model is a complicated process that requires the input from a range of different disciplines. A critical step in the modeling is the scaling of the data into discrete cells and assigning values to these cells. Values such as porosity, thickness, water saturation, structural position can be assigned to each cell. The scaling requires averaging of some types of data and upscaling for other types of data. The scaling of the model is difficult for a number of reasons but some of these reasons are inherent problems with the data collection.

Geologic data is biased. The data is collected in discrete areas that are controlled by biasing processes such as outcrop data where the position and distribution of the outcrop (and resultant sampling) is controlled by erosion. In the subsurface the sampling is also biased such as mines that are excavated along specific seams or wells that are drilled to target specific "anomalies". The model generation is plagued by this bias sampling and as such carries the error that comes from poorly sampled (biased) data.

Another issue with the data in the inconsistent sampling in terms of sample interval. Some aspects of the sampling are handled at very small intervals such as well data where well logs may sample at a rate of every decimeter. In other cases the sampling is made at very large intervals such as seismic data (tens of metres) or potential field data. The result is that the three-dimensional model contains significant flaws.

One of the most significant steps in the reservoir model is the assignment of permeability as a characteristic of each cell. This is a difficult process when dealing with conventional reservoirs and the reliance on laboratory measurements of core plugs to assign a permeability value. With the advent of fracture recognition and significance to fluid transmission within the reservoir the task of assigning a permeability value to each cell is fraught with assumptions and potential significant error.

Discrete Fracture Networks (DFN) models have been developed to help deal with the issue of fracture systems within a reservoir. Different software is available to build the model but essentially a predictive algorithm is used to populate a given volume with fracture surfaces. The size of the fractures, orientation and distribution of the fractures, aperture of the fractures, and density of the fractures are determined by sophisticated probabilistic curves determined by the geologist and used to predict the fracture model of a given reservoir.

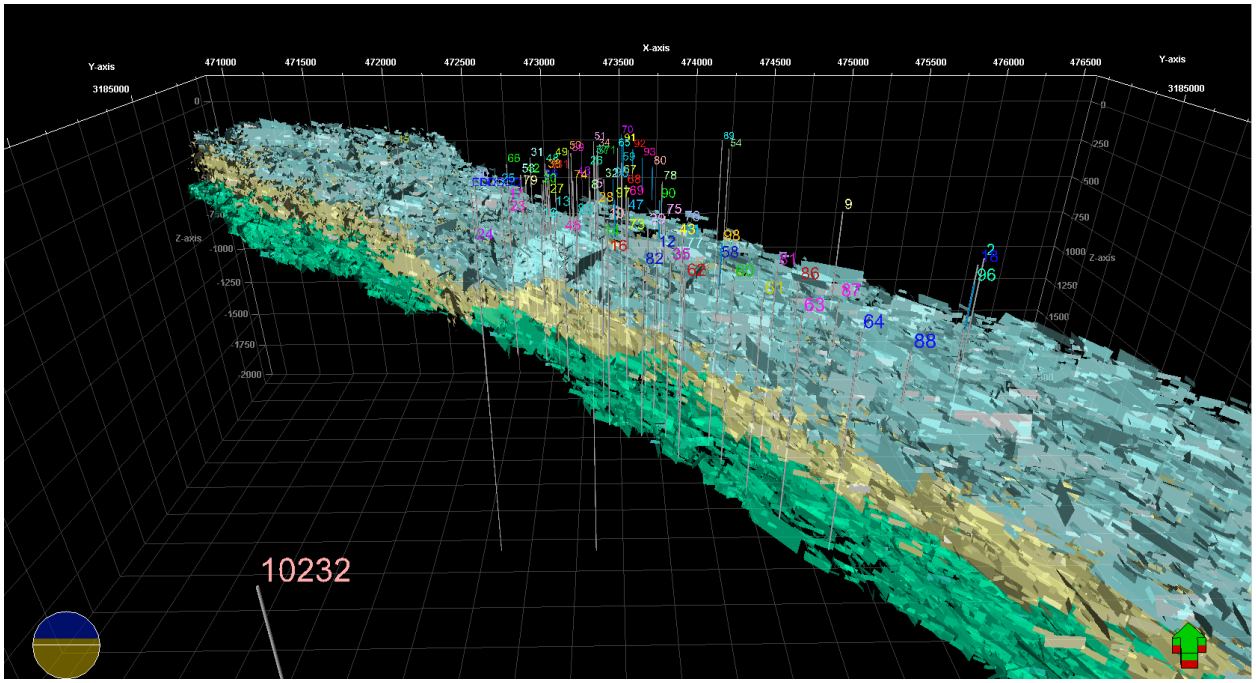

Figure 22: DFN model developed for Issaran Oil Field based on fracture data from image logs.

Figure 22 is one such model developed for a Miocene aged carbonate heavy oil reservoir in Egypt along the west flank of the Gulf of Suez. In this case there were numerous vertical wells with image logs acquired so that the fracture model could be built. The resultant DFN model is difficult to interpret visually in that there appears to be a mass of plates within the model with little appearance to fracture systems observed in nature. In essence the model does not look like nature and so the logic in the model is suspect. Rather than throw away the model and try again further modeling on the model can be applied in an effort to bring the model closer to what is observed.

In this case the fracture data was further analyzed and was determined that all horizontal or sub-horizontal fractures would not be used as: (i) they were likely over-represented in the data due to the sampling of vertical wells (vertical wells will over-sample horizontal surfaces and under-sample vertical surfaces) and (ii) any horizontal fractures were more likely to be partially or completely closed due to the vertical overburden stress acting on the surface. Another aspect of the filter discarded all closed fractures or partially closed fractures based on the strength and continuity of the resistivity response on the image logs.

Another significant filter process was based on the faults. In the model several normal faults were defined using well data and a 3D seismic volume acquired over the area. An assumption was made that the fracture system was controlled by the faults and the fracture response would

be a function of proximity to the faults. The logic behind this statement is that the faults are the trigger mechanism for the fractures and that the fractures are part of the strain response of the faults. Given this assumption and recognizing that strain is a form of stored energy in the rock volume a filter is designed for the fracture intensity. The predicted fracture response in the DFN model is filtered by $1/r^2$, where r is the distance of the cell from the fault. This function is equivalent to an energy spreading loss where the fault is the release point of the energy and a distance from the fault as exponentially decreasing energy. The results of the filter can be seen in Figure 23. In this case the fracture distribution is a superior reflection of the actual geology.

In wells drilled into the field it is observed that the fracture intensity in the downthrown block is greater. The model also shows an elevated fracture intensity response where a fault was not observed on in the seismic data volume but the fault was predicted based on production data. These correlation between the predictive model and the well results gives greater confidence in the model and should result in more reliable information with respect to the reservoir simulation.

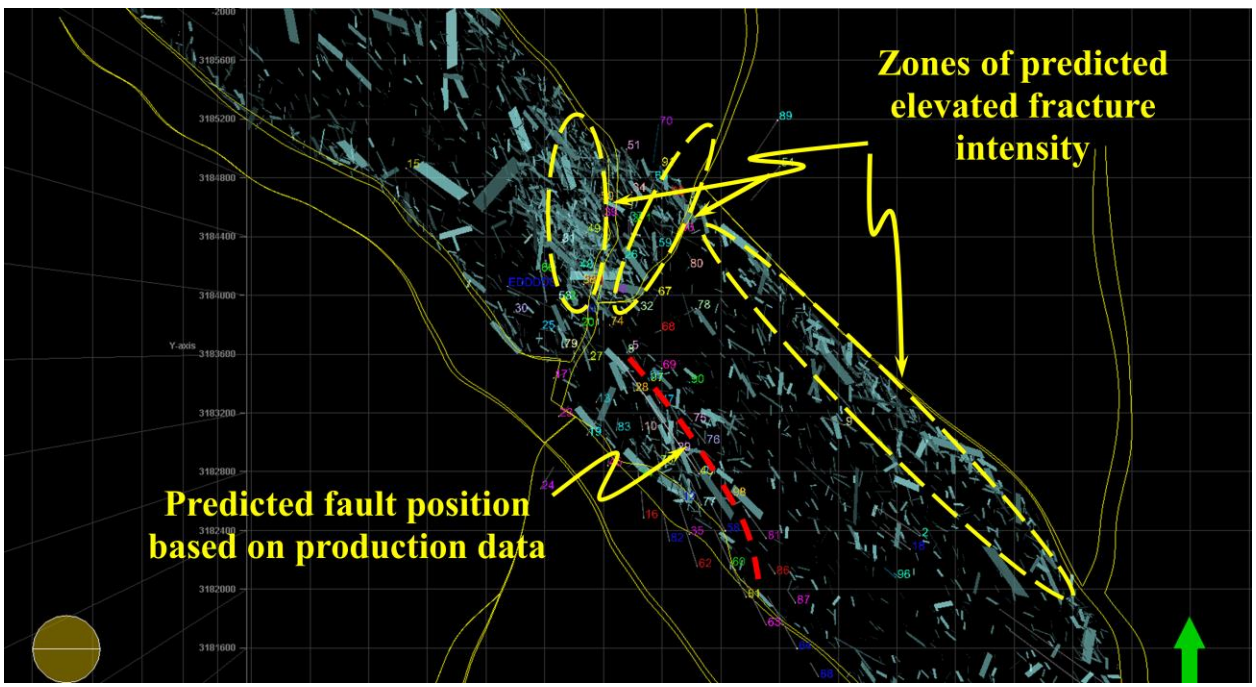

Figure 23: DFN model after spatial filter applied based on assumption that fractures are related to the faults

Conclusions:

Fractures are a key component to the understanding of how fluid moves through the earth's crust. Techniques have been developed that allows the reservoir technician to quantitatively analyze fracture systems. Orientation and intensity are key characteristics of fracture systems and these attributes of the fracture network can now be described by quantitative means. However, fracture analysis is in its infancy. As the importance of fractures continues to grow to the

understanding of fluid flow through the crust new techniques will develop to quantify fracture systems. The merits of these techniques will be tested by how closely they reflect the natural systems and how effectively models may be built to predict other fracture zones and estimate the resource potential within the rock volume.

Acknowledgements:

This discussion is the results of years of contemplation of fracture systems and their analysis. Numerous colleagues have been involved in discussions of fractured systems and the implications that these systems have on hydrocarbon recovery, ground water transport, nuclear waste disposal, metamorphic reactions, heat flow, geodynamics, rock properties, etc. These conversations were critical to the development of the ideas within this manuscript. Any errors are specifically from the author and most good ideas were hatched with the gracious help of a colleague. Specific contributions were made by Satindar Chopra, Malcolm Lamb, Dennis Quinn, William Matthews, Hutch Jobe, and Randy Herr. The author received support from numerous corporations as this work progressed, specifically from Burlington Resources, Rally Energy, Tanganyika Resources, Western Zagros Exploration, General Reef Corp., and Triangle Resources.