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Stress Shadowing and Fracture Interference in GOHFER® Software

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STRESS SHADOW OR INTERFERENCE

During hydraulic fracture treatment operations of horizontal wells, one important consideration is the subsequent spacing of multiple transverse fractures. In general, conventional fracture simulators analyze only a single fracture in infinite rock volume, and factors such as the induced stress and strain field away from the fracture are not examined. These factors become significant, however, when multiple fractures are created, as conditions surrounding each individual fracture impact the growth, geometry, and treating pressure of all interacting fractures. This effect of fracture stress interference, known as "stress shadowing," occurs between fractures and between fracture treatment stages.

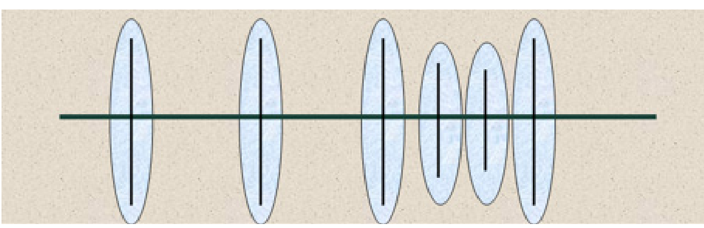


Figure 1 > Illustration of "stress shadowing" for multiple fractures. The heavy line represents the horizontal wellbore, the vertical lines represent the hydraulic fractures, and the blue ellipses represent the stress-shadowed regions.

Figure 1 shows the commonly accepted view of stress shadowing, or interference between adjacent fractures on a horizontal well. If vertical transverse fractures are initiated far apart, as they are on the left side of the wellbore, then the conventional assumption of a constant closure stress at some distance from the fracture may apply. However, if fractures are initiated closer together, as they are on the right side of the wellbore, then a plane of zero strain must develop between the parallel fractures. Rock can only be displaced on either side of the plane of symmetry, with no movement at the stagnation point. This reduces the amount of rock volume that can absorb the induced strain, and the interior fractures must sense the added stress from the outer fractures. Subsequently, the net pressure for the inside fractures is less than the outer fractures. The lower net pressure results in a smaller aperture and lowers the transmissibility, which causes less fluid to enter and slows the growth rate of the interior fractures. Eventually, these fractures will stop propagating and may be forced to at least partially close due to the increased external stress. All subsequent fractures at the end of the stage, regardless of the number of fractures, will behave as single fractures with no offset interference, as each fracture is surrounded by an effectively infinite rock mass at constant stress (at least on one side), which sets the minimum fracture extension pressure for the stage.

Subsequent stages along the horizontal well are affected by prior stages. Toeward fractures of the next stage will be induced under larger stress and strain field conditions created by the previous stage and will be forced to propagate in a high-stress environment. Heelward fractures may be far enough from the previous stage that they could be induced under original closure stress and propagate at normal treating pressures, potentially taking most of the stage volume. Accurate modeling of the fracture stress shadow must account for both conditions of interference between fractures within a stage (simultaneous propagation) and from one stage to the next.

LINEAR-ELASTIC THEORY

The linear-elastic solution for the deformation and stress in an infinite half-space, acted upon by an imposed external load, was derived by J. Boussinesq (1885). This solution is used in GOHFER® software for the fracture width at each grid cell, using a curtailed surface integration of the locally applied net pressure. The accompanying solution for the stress distribution within the linear-elastic half-space, as a function of distance from the displaced surface, is shown in Figure 2.

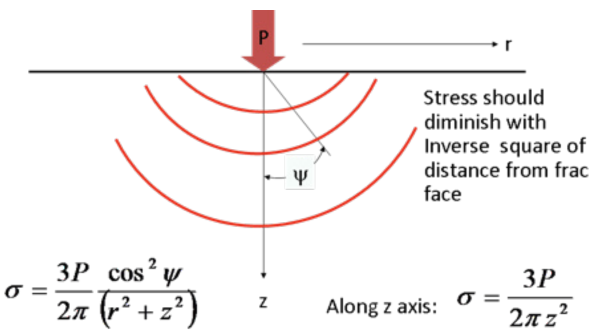


Figure 2 > Boussinesq (1885) solution for stress distribution in a linear-elastic half-space acted upon by an externally applied load.

If the surface of the half-space is taken as the face of the propagating hydraulic fracture, and the applied load is the net pressure (fluid pressure minus closure stress) at each point on the fracture surface, the stress profile away from the surface of the fracture can be computed. Considering only the stress along the perpendicular bisector of the fracture surface (*z*), the stress in the half-space resulting from the applied load decreases with the inverse square of the distance from the surface, and is proportional to the applied net pressure. This is consistent with a progressive compaction of the medium as long as stress and strain are linearly proportional, the material is linear and elastic, and there are no shear planes or poroelastic effects. However, this deformation pattern will not occur if the medium is broken into discontinuous segments by shear or intrinsic flaws (e.g., bedding planes and joints) or subjected to undrained compaction where the local pore pressure at the face of the fracture is increased by the imposed stress. All these deviations from the perfect linear-elastic solution are highly probable in unconventional reservoir stimulation.

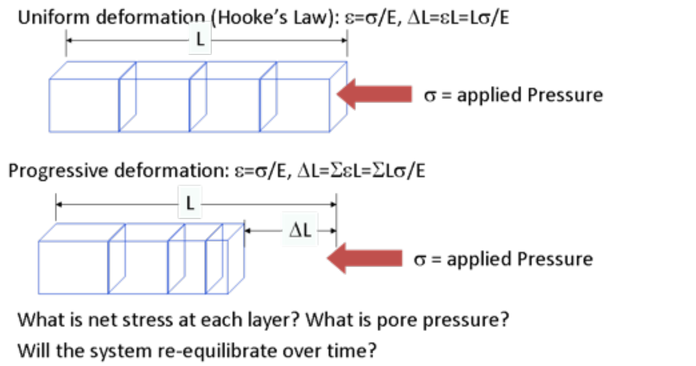


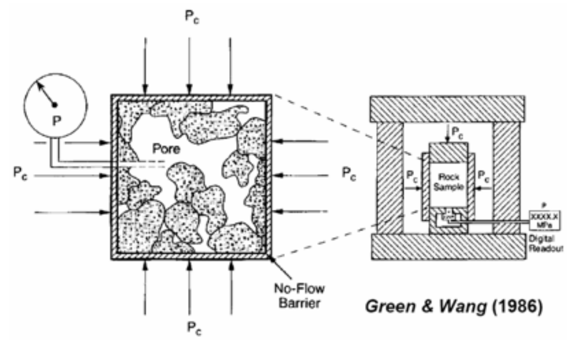
Figure 3 > Concept of progressive (lower figure) versus uniform (upper figure) deformation for unconventional reservoir stimulation.

Figure 3 illustrates two possible limits for elastic deformation, with different boundary conditions. Consider the rectangular surface of each column to be an element of the hydraulic fracture face, or a grid cell in the GOHFER model. The upper diagram represents a simple linear-elastic rectangular prism or rock column. This condition simulates a rock mass with frequent shear planes or weak bedding planes, or a rock mass with induced shear fractures resulting from the hydraulic fracturing process. If the outer surfaces of the rock prism are not bonded to the surrounding rock mass, the column is free to compress as an isolated element. If the material is a homogeneous elastic solid, a force applied to the end of the column causes a linear strain in proportion to the applied load and inverse to the modulus of elasticity. Under Hooke's law, the stress and strain are uniform throughout the column. In this case, the stress applied to the face of the column is transmitted through the column to the opposite end with essentially no loss. If the length of the column represents the distance between two adjacent fracture planes, then the stress interference between the fractures equals the net pressure applied to the face of each fracture. In any real system, some energy is lost due to friction along each shear surface; therefore, stress transmitted to the adjacent fracture planes is somewhat reduced. Since the fracture is hydraulically driven, any shear planes connected to the primary fracture are invaded by fluid, with a pressure nearly equal to the fracture extension pressure. This high internal fluid pressure reduces the net normal stress on each shear plane, thereby reducing the frictional losses to transmitted energy. In the extreme limit of this case, there is no decay to the stress field induced by a fracture, and stress shadowing is maximized.

If the element of rock is surrounded by other rock that is not uniformly loaded by the same net pressure, then the deformation may be concentrated near the surface acted on by the applied load, as predicted by the fully coupled linear-elastic Boussinesq solution. The displacement of the prism is resisted by the surrounding rock, which is assumed to be fully coupled to the element acted on by the applied load. As the element deforms, shear stresses are developed along each face of the prism that progressively reduce the displacement and accompanying strain with distance from the surface. In this case, the applied load is not transmitted through the column but dissipated into the surrounding rock mass. At some distance from the displaced fracture face, the imposed stress will no longer be sensed and there will be no stress interference.

The variation of stress and strain in the sample clearly depends on the boundary conditions assumed. Any model that assumes linear elastic rock behavior, with a coupled deformation solution (no shear), must predict a rapidly decaying stress field quadratic with distance from each fracture face. When dealing with porous media-containing pore fluids, the state of the fluid and possible change in pore pressure with deformation must also be taken into consideration. In the case of progressive deformation, or the linear-elastic assumption, most simulators ignore change in pore pressure within the deformed rock volume. For high-permeability formations (and slow deformation), this assumption is acceptable. For low-permeability formations (rapid deformation at the speed of a propagating hydraulic fracture), however, the assumption fails.

If the first element of the rock column (in the lower part of Figure 3) is subjected to the largest volumetric strain, as predicted by the coupled linear-elastic solution, then the pore volume of the element must change as much as the bulk volume, assuming effectively incompressible grains under hydrostatic loading. If the pore volume changes more rapidly than the fluid in the pore space can move, there will be a change in pore pressure. This pore-pressure change caused by an applied external load is described by Skempton's coefficient B, illustrated in Figure 4. In a perfectly undrained condition, where pore fluid cannot be displaced during compaction, the mass of the rock and pore fluid remains constant. The value of B is close to 1 for shale and clay materials. In permeable sands, the B value approaches 1 when net stress is low and for short times after a step change in confining stress. Therefore, the apparent value of B is dependent on time, rate of strain, permeability, and other parameters. The impact of these factors is much more significant in over-pressured, low-permeability shale reservoirs.



Undrained Condition → $\Delta m = 0$

Skempton's Coefficient: $B = \left.\dfrac{dp}{dP_c}\right|_{\Delta m=0}$

Figure 4 > Definition of Skempton's coefficient B for undrained compaction.

Consider the effect of Skempton's undrained compaction on the decay rate of the induced stress field around a fracture. If the pore pressure in the element nearest the fracture face increases in proportion to the applied net pressure, then the actual net pressure acting on the fracture face is reduced (theoretically to zero). If the increased pore pressure equals the applied fracture fluid pressure, then there will be no deformation of the rock volume at the fracture face. Instead, the applied net pressure will be transmitted to the next cell. In a perfectly undrained state, with incompressible pore fluid, the system would approach the Hooke's law uniform compaction state, where none of the elements can effectively deform and stress is transmitted to each subsequent cell without loss. In all realistic scenarios, however, there will be some degree of pore-fluid compressibility, permeability, time-dependent decay of pore pressure, and other factors that allow deformation near the fracture face, as well as decay in the transmitted stress with distance from the fracture face.

IMPLEMENTATION IN GOHFER SOFTWARE

To simulate the combination of the shear boundary conditions and poroelastic effects in GOHFER software, the exponent in the Boussinesq solution for stress as a function of distance from the fracture surface is a variable called the Transverse Stress Exponent (t). The upper limit of this parameter is 2 in order to conform to the ideal linear-elastic, fully coupled deformation solution. The lower limit is effectively 1, which generates very strong interference between adjacent fractures. In extreme cases of rock volume shear and undrained compaction, the stress decay rate may approach zero, though this has not been observed in field cases. Most available fiber-optic (DTS/DAS) and other diagnostic measurements of injection into multiple closely spaced fractures suggest that an exponent of 1.2 is most appropriate. This value is much lower than the theoretical case for perfect isotropic, homogeneous, linear-elastic material, which indicates how significantly real rocks deviate from the ideal theoretical behavior.

One way to model the stress shadow between adjacent fracture planes is to consider the net pressure on the face of each fracture, as well as its decay with distance. Using the Boussinesq solution for a linear-elastic homogeneous and isotropic medium, the stress at any distance from a fracture face is given by by Eq. 1, where P is the net pressure acting on the fracture face, Z is the distance from the fracture face, and t is the variable transverse exponent.

$$\sigma = \frac{3 * 144 * P}{2\pi Z^t} \quad \text{EQ. 1}$$

This form of the equation is satisfactory as long as the fracture is actively propagating, but does not adequately represent the stress shadow remaining after pumping has ceased. If a propped fracture width successfully develops during a fracture treatment, there will be residual strain in the rock mass generated by the deformed rock volume related to the propped fracture width. This generates a sustained stress field in the surrounding rock that can persist for a long time and may only dissipate through plastic creep of the rock. To adequately model the residual stress associated with permanent strain, Eq. 2 is used in GOHFER software to represent the stress surrounding the fracture.

$$\sigma = \frac{wE}{12Z^t} \quad \text{EQ. 2}$$

In Eq. 2, w is the fracture width in inches, E is Young's modulus in psi, and Z and t are as previously defined. During pumping, there is a direct relationship between the net pressure, width, and modulus defined by the deformation solution. Using this relationship, the two methods yield nearly identical results while pumping, as shown in Figure 5. In this plot, the transverse exponent for the linear-elastic solution is 2. Note that, at a distance of 100 ft, the transmitted stress is less than 15 psi. Under these assumptions, there will be virtually no apparent interference between adjacent fractures unless they are very close together. However, this limiting solution is not very realistic for laminated, low-permeability rock masses that comprise most unconventional reservoirs.

This strain solution, based on residual fracture width, maintains the stress shadow after pumping and during production. During periods when the fracture is in the process of relaxation due to leakoff (i.e., fracture closure and in the time between stages), the strain solution provides an acceptable estimate of the stress shadow as long as the correct transverse exponent is used. This value will be affected by the degree of heterogeneity in the rock mass, pore pressure, pore-fluid compressibility, permeability, and rate of deformation (pump rate during the fracture treatment). Currently, there have been no field cases where a value greater than 1.5 appeared to apply.

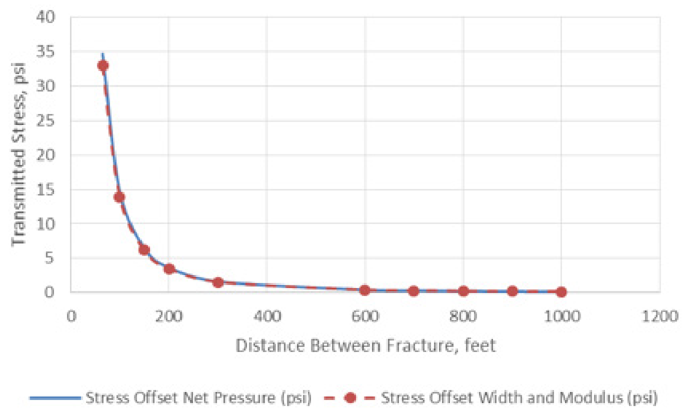


Figure 5 > Comparison of the stress shadow for Eq. 1 and Eq. 2 with t = 2.

To demonstrate the impact of the transverse exponent, Figure 6 shows the computed stress shadow versus distance for a transverse exponent of 1.2, which matches available field observations. In this case, the transmitted stress to an adjacent fracture 100 ft away from the primary fracture is approximately 600 psi. This suggests that an interior fracture flanked by two dominant fractures will sense a closure stress that is 600 psi higher than the flanking fractures. Given that all fractures are connected to a common pressure source at the well, assuming all are propagated simultaneously in a single stage, the net pressure in the interior fracture is 600 psi less than the outer flanking fractures. This results in a substantially smaller fracture width, transmissibility, and lower injectivity from the well. The net result is that the interior fracture(s) will grow much more slowly and will eventually stop accepting fluid from the wellbore. Excess fluid is diverted to the fractures in the lower stress regime, either at the outer edge of the stage or at one end of the stage that is most remote from the previous stage's stress shadow.

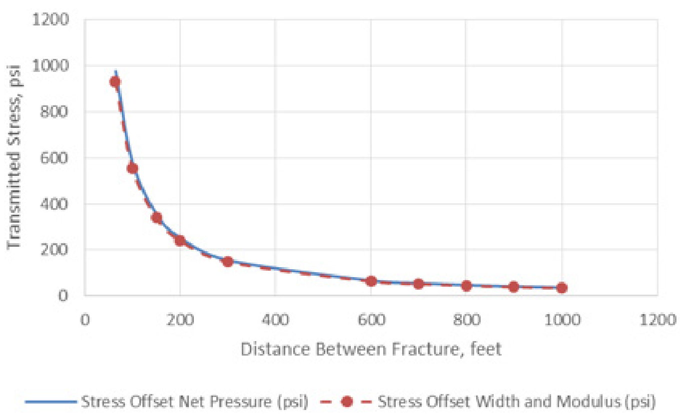


Figure 6 > Comparison of the stress shadow for Eq. 1 and Eq. 2 with t *= 1.2.*

GOHFER software is a grid-oriented simulator – each rectangular cell on the fracture surface is assigned different reservoir, mechanical, and stress properties. Subsequently, the stress shadow and net pressure are different at each cell. Figure 7 illustrates the GOHFER method for computingthe stress shadow propagated from each fracture cell to any number of offset fracture planes at various distances.

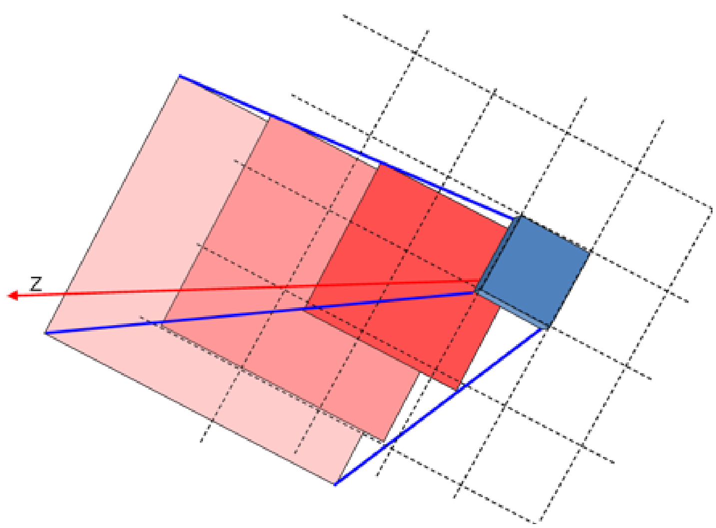


Figure 7 > Illustration of the stress shadow from a single fracture face cell to offset planes.

The blue box represents an active fracture cell (or node) with a width, net pressure, modulus, and other properties to describe the surrounding rock volume. The displacement at this point is projected, using Eq. 2, to compute the transmitted stress at each fracture plane in the stage as a function of its distance. It is assumed that the stress field will disperse to cover a larger area with increased distance. Stress shadows from adjacent nodes that overlap at offset fracture planes are superimposed, though the stresses are not additive. If an adjacent fracture plane contains one face exposed to an infinite rock volume (i.e., by being at the edge of the active or previous set of fractures), the fluid pressure in that fracture will always act against the original, undisturbed closure stress and deformation will not be restricted by any interference.

The same method is used for stage-to-stage stress shadow calculations. If a previous fracture stage has been modeled, the simulator finds the final fracture width at each cell of each fracture plane of the previous stage. The simulator then computes the residual stress shadow thrown by that stage on the current stage, along with any interference resulting from induced deformation during the current stage treatment. As illustrated in Figure 8, this can result in asymmetric fracture growth when the fractures are not orthogonal to the well, or when the geologic structure is not symmetric about the well axis. The stress shadow from some cells, shown by the red arrows, may not impinge on any offset fracture planes that do not overlap the affected stress/strain field. Some stress shadows will bypass one fracture plane but affect a further offset plane, as indicated by the double-headed blue arrow.

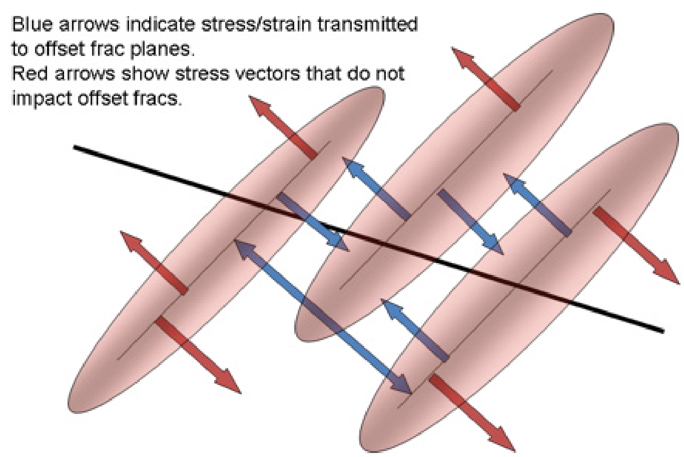


Figure 8 > Illustration of stress shadow propagation for non-orthogonal and asymmetric fractures.

Figure 9 displays an actual GOHFER output for the first and second stages on a horizontal well with perforation entry cluster spacing of 45 ft, and five clusters per stage with limited-entry perforating. The fractures are not orthogonal to the well, and the fracture direction is controlled by the prevailing stress field.

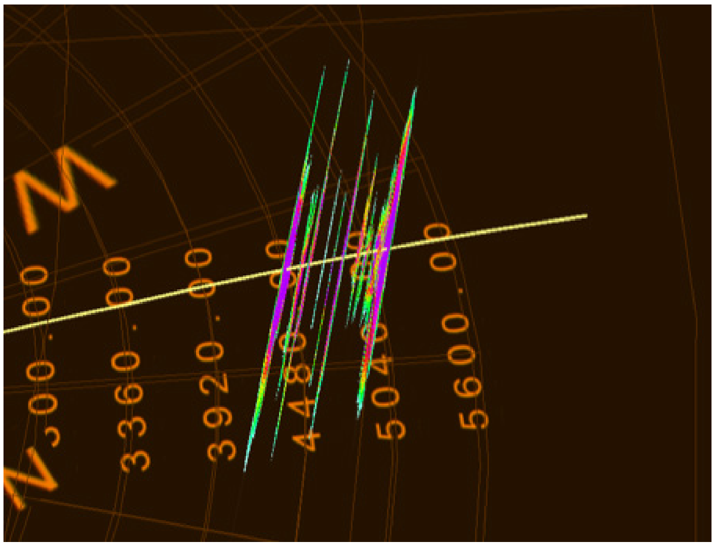


Figure 9 > GOHFER output for non-orthogonal interfering fractures. Plan view looking down on the two stages (10 total clusters).

COMMON 'RULES OF THUMB'

Many simulators use common rules of thumb based on closed-form analytical fracture geometry models and hidden assumptions. The most common models are illustrated in Figure 10. One common rule is that, if adjacent fractures are at least one fracture height distant, there will be no apparent stress interference. This rule applies to an assumed Perkins-Kern-Nordgren (PKN) fracture geometry. This model assumes that fractures are elliptical in cross-section, with the maximum width controlled by net pressure, modulus, and height of the fracture. Coupling this with the assumed quadratic stress dissipation function, and with the maximum strain controlled by fracture height, a distance of one fracture height effectively eliminates the stress shadow effect.

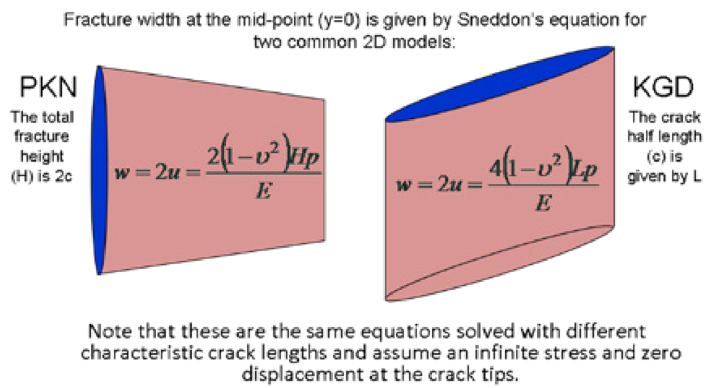


Figure 10 > Common analytical fracture model solutions for PKN and KGD geometries.

When the Khristianovich-Geertsma-DeKlerk (KGD) model geometry is assumed, which relates maximum width to the fracture length, the fractures must be at least a fracture length (or half-length) apart to avoid stress-shadowing effects. However, both models and their associated rules are not accurate or even applicable in complex geological settings where rock fabric and pore pressure may affect fracture growth and the resulting stress and strain fields. Furthermore, if any stress decay function other than quadratic form (t = 2) is applied, these rules cannot adequately describe the stress field.

DO FRACTURES CURVE?

The final and most controversial part of modeling stress shadowing and interference relates to the concept of non-planar fractures, or curving fractures in a complex stress field. Some models predict that fractures will curve in plan view, based on the alteration of the stress field caused by stress shadowing. These models invariably assume a linear-elastic, fully coupled deformation solution in an isotropic medium. They also rely on the assumed elliptical shape of the hydraulic fracture given by the PKN and KGD type models. In this highly idealized view, it is possible to generate a curved stress field around the tip of a propagating fracture.

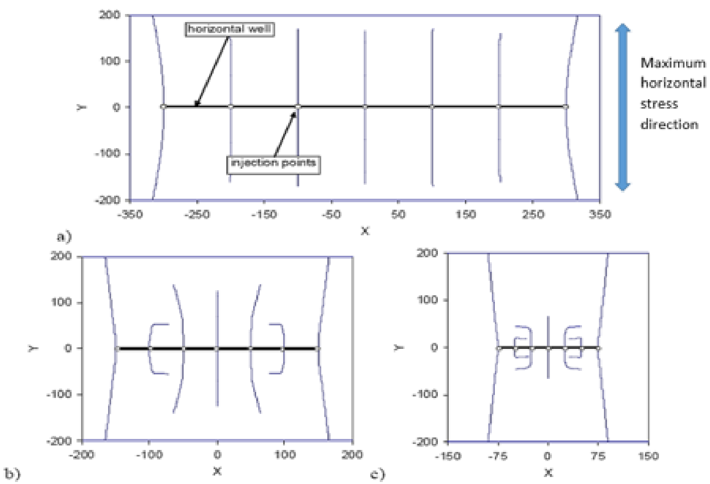


Figure 11 > Illustration of curving fractures in an isotropic linear-elastic 2D model (Olson, 2008).

An example of a curving fracture is provided in Figure 11, taken from ARMA 08-327 by J. E. Olson. The figure shows a map (i.e., plan) view of hydraulic fracture propagation patterns from seven simultaneously pressurized injection points for initial fracture spacing of 100 m (a), 50 m (b), and 25 m (c). All fractures are vertical and have the same height of 100 m. The velocity exponent for propagation was n = 1, and the remote horizontal stress was isotropic. As fracture spacing decreases, mechanical fracture interaction becomes stronger, as evidenced by the non-planar propagation paths of the interior fractures of the arrays.

In this model, the injection into all fractures is specified and not controlled by a common wellbore pressure, as it would be in reality. Consider, if all seven injection points were connected to the well and fed by a common pressure source, what would happen as the interior fractures begin to sense the imposed stress of the offset outer fractures? Rather than turning and growing into a high-stress area near the bounding fractures, the extension pressure required to drive these inside fractures would rise. This necessitates less fluid entry from the well, with more diversion of fluid to the outer fractures. Instead of turning and being forced into a high-stress field, the interior fractures would simply stop growing and would begin to collapse, as predicted in GOHFER software.

In GOHFER software, the rock is assumed to contain frequent discontinuities, both parallel to bedding and in high-angle (near-vertical) planes. These may be existing joints, natural fractures, or induced shear planes associated with observed microseismic events, and all cause the deformation behavior to deviate from the classical analytical linear-elastic solution. Including variable and sometimes complex rock fabric as a control of fracture growth, rather than simply the idealized stress field, will eliminate the tendency for smoothly curving fractures.

In nature, fractures always follow the path of least resistance, whether controlled predominantly by stress or by weaknesses within the rock fabric. Models that ignore the actual rock fabric risk predicting unrealistic outcomes.

The question of fracture curving may be a function of the relative rate at which each fracture in the system propagates, as well as the spacing of those fractures. It is commonly accepted that, in the absence of existing fractures, a hydraulically driven fracture will open against the minimum stress in the 3D tensor. Given an initial horizontal stress anisotropy, the fractures will initially grow in the direction of the maximum horizontal stress. As stress interference from adjacent fractures increases, the minimum stress (orthogonal to the fracture face) increases. As long as this normal stress is less than the maximum stress, however, the fracture may continue to grow in the same direction. Curving the fracture requires a change in the direction of the far-field maximum stress, which can be executed in an isotropic elastic model, but may be more difficult in nature.

Most field evidence, including tracer and temperature observations of fractures intersecting offset horizontal wells in a pattern, show either fractures propagating in a straight line between wells (along the original maximum stress orientation) or fractures following geologic discontinuities or planes of weakness, such as fracture swarms or flexure zones. Although the fractures in GOHFER software are drawn as if they are planar, the numerical grid is mapped into the plane normal to the minimum stress in the tensor. The actual plane of the dominant fracture is not required to be flat, but can curve in space if the stress field appears to curve. Slurry-transport experiments in physical slots, conducted as part of the Stim-Lab rheology and transport consortium, have shown that non-planar fracture slots, or even discrete offsets and severe wall roughness, do not substantially affect the flow in the fracture or the pressure distribution along the fracture face.

Until compelling field data and observations become available to confirm that a stress field of sufficient curvature can be developed by interference to affect fracture geometry, GOHFER software will continue to display the fractures as if they are effectively planar. The decision to draw fractures as curving planes is a largely cosmetic addition based on user input of an assumed stress field or rock fabric. At this time, no such field evidence for strongly curving fracture planes, caused by interference of closely spaced hydraulically driven fractures, exists.

When there is sufficient stress shadowing and interference to reorient the stress field, the largest stress change occurs at the wellbore itself, where the aperture of the induced fractures and their net pressure is largest. There is also a massive tangential stress concentration around the borehole that favors longitudinal fracture initiation over transverse fractures. In cases of high stress shadow, if there is a tendency for the fracture direction to change, it is almost certain that the fracture will reorient at the borehole itself, where the energy level is maximized, rather than in the far field where fluid pressure and stress concentration are much lower. The concept of longitudinal fractures, and their probable dominance in horizontal well stimulation, is further discussed in SPE 173356.

INDICATION OF STRESS SHADOW IN TREATING PRESSURES

Another common misconception is that each successive stage in a horizontal well will show an increasing treating pressure, or instantaneous shut-in pressure (ISIP), if stress shadowing is occurring. Conversely, it is also believed that a constant treating pressure from stage to stage indicates that stress shadowing does not exist. Both interpretations are fundamentally false. Another common industry belief is that multiple interacting fractures drive up the net treating pressure for the entire stage. This idea persists despite having been disproven many times, as in the work by Germanovich presented at the North American Rock Mechanics Symposium in Seattle (2001).

Figure 12 shows the results of Germanovich's linear-elastic coupled finite-element flow and deformation model for five parallel fractures. The fractures are initialized at the same constant aperture, and the model simulates injection at a constant rate into all five parallel fractures. The final equilibrium fracture aperture distribution is shown. The outer fractures open, and the inner fractures are compressed to effectively zero width, as expected based on the previous discussion of stress shadowing. In the model, the rock is linearly elastic and homogeneous, and the fractures are assumed to follow the PKN geometry solution.

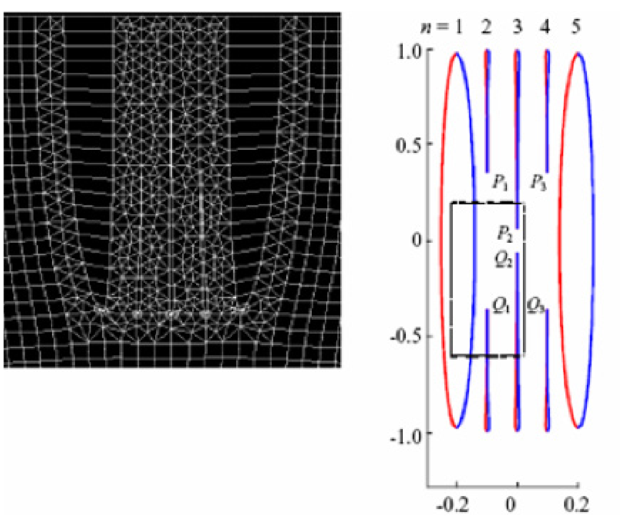


Figure 12 > Stabilized fracture profiles for five parallel interacting fractures.

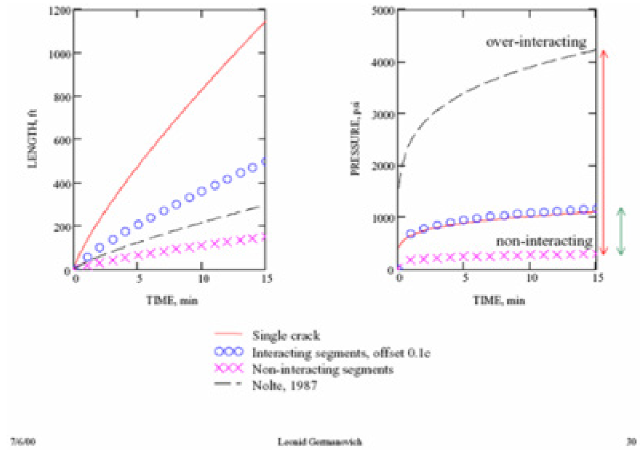


Figure 13 > Fracture length and treating pressures for 29 interacting parallel fractures.

As shown in Figure 13, a similar model was run for 29 parallel interacting fractures. The solid red line represents the length of a created single fracture (left panel) and the predicted treating pressure for a PKN single planar fracture (right panel). The blue circles depict the longest fracture length for the 29 parallel fractures (left) and the model predicted treating pressure for the composite of 29 fractures (right). Note that the treating pressure is the same for single or all 29 fractures because the outer fractures respond to the original closure stress of the system, setting the lowest energy state for fracture propagation. The aperture of the fractures changes in response to the injection rate to balance the frictional pressure drop through the system. The length of the created fracture system is approximately half the length of a single fracture because only the two outer fractures of the 29 have significant volume.

In real wells, as long as any one perforation cluster or entry point from the well can encounter rock outside the previous stress-altered zone, that fracture will propagate at the original treating pressure. As long as this path of least resistance remains viable, fluid injected from the wellbore will follow the fracture at the expense of any fracture entry points in higher-stress environments. Similarly, the same treating pressure may be observed if there are one, three, five, or more fractures propagating simultaneously. The only difference in treating pressure noted at surface may be due to the number of open perforations or severity of near-well tortuosity. These parameters are not affected by stress shadowing or the number of fractures in the stage.

CONCLUSIONS

While many simulators compute stress shadowing by using an overall elastic deformation solution for an assumed fracture geometry, GOHFER software employs a far more discrete formulation that differentiates the stress shadow caused by each element of the surface of each fracture, and the interaction between all existing fracture planes, while pumping, during leakoff, and after closure. Each cell on the surface of each fracture has a different net pressure and fracture width, as well as different surrounding rock mechanical and reservoir properties. Therefore, the stress shadow extending from each fracture surface element is different. All fractures propagated within a stage are coupled at the wellbore to a common injection pressure. Rate into each fracture is redistributed at each timestep (generally less than one second) as the treating pressure and transmissibility of each fracture evolves.

The perpendicular distance between each fracture plane is used to determine the attenuation of the induced stress and strain field. Rate of decay, or attenuation, of the stress field is a user variable that can be calibrated to individual reservoirs based on field observations. Available data from field measurements suggests that the induced stress shadow decays much more gradually than the classical linear-elastic theory.

Although fractures displayed in the GOHFER graphical interface appear to be planar, this is not a functional requirement. When multiple fracture stages on a well are simulated, the close spacing of the fractures relative to their created length does not allow much room for fracture curving or turning. The stress state between the fractures clearly defines a minimum and maximum stress orientation and, therefore, the orientation of the fracture planes.

The same formulation allows modeling of induced stress diversion fracturing, from one stage to the next, in both vertical and horizontal wells. Most importantly, the GOHFER results have been validated by direct and accurate field measurements of fluid entry into multiple perforation clusters during limited-entry treatments.