Fracture Conductivity and Cleanup in GOHFER®

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Introduction

There has been a lot of interest in, and requests for additional information and clarification, about the way fracture conductivity and cleanup are represented in GOHFER. My current understanding of the process is firmly rooted in the work conducted over the past 30 years by the Stim-Lab consortium, and by my own laboratory and field work. This document is my attempt to set out my current understanding of the process of generating useful fracture conductivity and effective length, more to document what I think I know more than to justify the formulation now used.

Fracture conductivity and cleanup are complex issues that relate to many aspects of the hydraulic fracturing process. In fact, the useful conductivity generated (along with possibly the total reservoir surface area exposed) are the only net results of the fracturing process that persist after the job is done. To describe the development of conductivity, it is necessary to consider multiple aspects of the process including fracture geometry, proppant transport and placement, leakoff and closure mechanisms, gel concentration and damage, stress on the proppant pack, interactions between the pack and the reservoir rock at the fracture walls, applied potential gradients during flowback and production, gravity and capillary effects (in the pack and at the fracture face), permeability as a function of velocity and saturation in the pack and surrounding reservoir, and the overall evolution of conductivity as related to the cleanup process.

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Fracture Geometry and Proppant Placement

The conductivity of the proppant pack, $k_{fw}$, is primarily related to the thickness of the continuous proppant layer connected to the wellbore. This pack width is therefore fundamentally determined by the width of the fracture created, and not by the injected slurry concentration. Pumping a high concentration slurry will not cause the fracture to be wider. Frac width depends on the geometry of the fracture (height, length, etc.), degree of anisotropy of the rock mass, stiffness of the system (fracture compliance) and net pressure during pumping. High mobility fluid systems, such as slick-water, tend to produce less net pressure, less fracture height, and less width, resulting in a lower maximum pack thickness. High viscosity gelled fluid systems give the opportunity to create more width, but carry the potential for more gel damage.

It must also be remembered that, contrary to their representation in almost all fracture simulators, the fracture walls are not smooth and regular. Rocks tend to break, in shear, along planes of weakness when subjected to imposed stress and strain. Rock masses provide many opportunities for shear along bedding planes, joints, natural fractures, inclusions, and wherever there are sudden changes in mechanical properties. During pumping, the fracture is more likely to resemble a series of fracture or joint segments with frequent offsets and possible pinch points, both in the lateral and vertical direction from the injection source. Whether because of settling or leakoff, and associated transverse particle migration, proppant will tend to accumulate on ledges or at pinch points and leakoff sites. This accumulation fairly quickly leads to the packing of the created fracture width at localized sites throughout the fracture. This mechanism has been demonstrated in hundreds of large-scale slot flow experiments conducted during the Stim-Lab fracturing fluid, rheology, and transport consortium. Some of these results have been published in SPE 67298.

There are multiple processes that cause holdup and accumulation of proppant during pumping. These processes tend to concentrate proppant near the injection point, and reduce transport into the far-field. The proppant pack therefore tends to accumulate until the created width of the fracture is filled, regardless of the input slurry concentration. Proppant holdup is expected to increase with low viscosity fluids and in conditions of high secondary leakoff through existing “natural” or induced fractures and fissures in the primary hydraulic fracture walls. Does this mean that the use of crosslinked fluids should minimize holdup? Not necessarily, as the fluid entering the fracture may not have the rheological properties expected or observed in surface tests.

Crosslinked fracturing fluids are shear thinning, and may require specific temperature and shear conditions to form a stable viscosity. The fluid entering the fracture is subjected to 3-5 minutes (typically) of high shear flow in the pipe, then a brief trip through the perforations and near-well fracture. This fluid is sheared so that a stable crosslink is highly unlikely. A crosslinked gel subjected to shear rates equivalent to thousands of reciprocal seconds for several minutes, will not immediately re-form a stable gel structure. A well formulated system may develop most of its structure (80-90% of peak viscosity) after a minute or so of stable low shear in the fracture. At typical fracture treatment velocity (1-2 fps) the fluid may be 100 feet from the injection site before it develops stable gel properties. In the near-well area the fluid more likely resembles a sheared linear gel.

Some fluid systems do not crosslink until a minimum target temperature is reached. In the past, many people have believed that the fracturing fluid reaches static reservoir temperature upon entry to the fracture. Distributed temperature sensing (DTS) measurements, via optical fibers, have become more common in recent years. These data consistently show that the wellbore temperature in cooled well below the formation temperature with the first wellbore volume of fluid pumped at frac rate. Well temperature can even approach surface temperature in high rate injection. The DTS data further show that the fracture fluid temperature remains relatively cold for days, weeks, and sometimes months, after completion of the treatment. If a crosslink system is
designed to work at an elevated temperature, and the fluid never reaches that temperature, the entire job may be placed with the equivalent of a linear gel.

**Gel Damage Effects**

The proppant holdup mechanism is not necessarily a bad thing, it just needs to be considered in understanding treatment design and production response. The net result of proppant holdup is that areas of the fracture near the injection point will be packed, from wall to wall of the fracture, with proppant. The first proppant in may accumulate near the well. This is often shown by the presence of the first injected radio-active tracer remaining within the radius of investigation of the tracer log, even at the end of the job. It may also be indicated by flowback, during cleanup or production, of the 100-mesh sand injected as “scour” at the start of the job.

Proppant holdup effectively concentrates proppant to fill the fracture to its maximum attainable concentration, regardless of the injected slurry concentration. This has a second benefit, in that the fracturing fluid in the pore space of that accumulated proppant pack will have a gel concentration that is close to the injected polymer load. Some filter-cake may be deposited during pad that will affect ultimate conductivity, but the bulk fluid in the pore space of the pack will be relatively un-concentrated. This is important because the polymers used in fracturing fluids cannot exit the fracture or enter the pore space of the reservoir. All polymer injected throughout the treatment, including all pad and sand-laden fluid, must remain in the created fracture volume. At closure, this effectively means that the polymer will be concentrated in the remaining pore volume of the proppant pack.

![Figure 1: Gel concentration factor during leakoff to closure, based on proppant pack pore volume.](image)

Figure 1 is a simple overall fracture material balance showing the concentration of polymer residue in the pack at closure. Open volume of unpropped fractures is not considered in this simplistic analysis. The x-axis is the total pounds of proppant pumped during the job, divided by the total gallons of pad and sand-laden fluid. Assuming a sand specific gravity for the proppant, and average pack porosity (from Stim-Lab tests), the total pore volume of the proppant pack can be estimated. The pore volume, at closure, divided by the total fluid volume represents a concentration factor. All the polymer that was dispersed in the injected fluid must end up residing in the remaining pack pore space. The y-axis shows the folds of increase in gel concentration resulting from different average proppant concentrations (APC). For example, at APC=1 (100,000 lbs of sand in 1000,000 gallons of fluid) the concentration factor is 38.2. Based on this, a 10 ppt linear gel would leave a residue of about 380 ppt in the proppant pack. Near the well, because of the proppant settling and holdup, the gel concentration factor will be (should be) close to one, neglecting filter-cake. That means that at the fracture extremities, near the tips and in the distal parts of the created fracture, the gel concentration could be 2-3 times the average.

It is not uncommon in horizontal well pad developments, to frac into or “bash” offset wells with frac fluid. This can sometimes cause damage to offset production. Almost instant pressure communication is often observed between the treatment well and the bashed well. Many operators have now reported that
observed pressure communication between wells is transient, and often disappears after the wells have been put on production for some time (30-60-90 days). It may take some time for the rock to creep and attain full closure on the gel residue left in the fractures. Closure on a 400-1000 ppt gel mass will ultimately result in a sealed fracture channel, causing loss of pressure communication. Because of proppant holdup, the fracture relatively near the injection source will maintain some conductivity and may participate in cleanup.

Work by Verne Constien, at Schlumberger Research, and later extended by Stim-Lab, has shown that the maximum regained permeability to cleanup by KCl brine, under high differential pressure flow conditions, is related to the gel residue concentration in the pack. Figure 2 shows the percent of absolute permeability regained by high pressure injection of brine, as a function of the gel residue, as the blue line. Note that gel-filled packs, in excess of 350 ppt gel concentration, only regain less than 0.001% of their absolute permeability.

![Figure 2: Regained permeability percent as a function of gel concentration in the pack, and the minimum pressure differential across the pack needed to initiate flow of 2% KCl brine.](image)

The pressure differential needed to initiate stable flow of brine, under laboratory conditions, for high concentration gel packs, approaches and exceeds 100 psi/ft. This magnitude of pressure gradient is not available during cleanup or producing conditions in real wells. Even gel concentrations as low as 50 ppt require initiation pressures of about 0.05 psi/ft. This may seem low, but further analysis of available viscous potential gradients, presented later, shows that this is difficult to achieve under producing conditions.

Similar studies have not yet been done with polyacrylamide friction reducer (FR). In most jobs an FR concentration of 2 gpt is used. This represents about the same mass of polymer as a 10 ppt linear gel, but the structure of the polymer is very different. The same polymer has been used as a “pusher” in chemical EOR floods, so it is capable, at least at low concentrations, of entering the pores of a conventional reservoir. How it behaves, in terms of face plugging, in a shale or unconventional permeability system is not well described.

It is becoming more common to pump high concentration FR jobs, up to 6-8 gpt in some cases. This amount of polymer, if it remains in the fracture at closure, must cause a similar amount of damage to the pack conductivity. Whether FR can form any filtercake also remains a question. Field experience also shows that there are conditions in higher temperature formations, possibly due to interactions with iron, where FR can auto-polymerize or precipitate solid or semi-solid material that may be extremely damaging. At this time, it is clear that there is much to be done to understand FR damage, and little has been accomplished.

### Closure Stress on Proppant

Closure stress on the proppant decreases porosity and increases stress at grain contact points, until the grains begin to fail. The grain failure further reduces porosity and pack width, and generates fines that reduce conductivity. The function that is used in the Stim-Lab data to represent pack permeability as a function of stress in given as Eq. 1 below.

\[
k_s = k_m + \frac{(k_o - k_m)}{\left[1 + \left(\frac{\sigma}{S_c}\right)^p\right]^E}
\]

Eq. 1

The parameters in Eq. 1 are defined as:

- Permeability at given net stress (ks)
• Zero-stress perm (ko)
• Critical Transition Stress (Sc)
• Sharpness of failure (F)
• Perm-stress exponent (E)
• Minimum perm (km)

Each of these parameters is defined based on multivariate regression analysis of multiple laboratory conductivity tests, all conducted under standard consortium procedures. The data used for regression are based on stable conductivity after 50 hours of flow at each stress and temperature. A typical permeability reduction curve is shown in Figure 3. It has been assumed that permeability is not a function of concentration, once a stable packing and pore arrangement are attained. This generally occurs at about 2#/ft² concentration.

The width of the proppant pack at low stress is assumed to be a linear function of the proppant mass/area concentration. The slope of the pack width versus net stress is also taken to be linear, and is a function of concentration. Making adjustments for width and permeability at each stress gives a workable estimate of conductivity at any net closure stress, for any pack concentration (mass/area).

**Low Proppant Concentration and Wall Effects**

It has been recently noted that the assumption that permeability is not related to concentration does not hold at very low concentrations. When the wall-effect porosity represents a significant part of the flow capacity, the permeability of the pack increases for low concentrations. To offset this effect, it has also been noted that the apparent transition stress, Sc in Eq. 1, decreases with low concentration. The change in Sc is presumed, currently, to be related to failure of the rock surface and generation of fines that accumulate in, and fill, the wall porosity. This effect may be a strong function of reservoir rock mineralogy, grain size, and mechanical strength. Correlations for various rock types are not yet available, and are currently being studied.

The changes in the permeability with concentration, called the concentration factor (CF), and changes in the transition stress factor (TF), are shown in Figure 4. Both these concentration dependent correction factors are also a function of the median particle diameter in the proppant pack. Median diameter appears to control the depth of embedment, and amount of surface fines generated. When both correction factors are applied to the estimation of permeability, the original assumption that permeability is invariant with concentration yields acceptable results. The mechanical loss of conductivity due to closure stress is actually one of the more minor impacts on final fracture conductivity.

**Figure 3:** Typical permeability versus net closure stress for a proppant.

**Figure 4:** Concentration and particle diameter dependent correction factors for permeability and transition stress at concentrations below 2#/ft².
Core Laboratories Integrated Reservoir Solutions Team (IRS) on actual reservoir core samples. That mass of data has not yet been fully integrated into the conductivity model, but in general the results reported by IRS are consistent with the Stim-Lab observations of less than ½ grain diameter embedment at up to 12,000 psi closure stress.

Tests have been run at Stim-Lab on a limited range of rock substrates, including Ohio Sandstone, Bandera Sandstone, Niobrara Chalk, and stainless steel. Figure 5 shows a collection of data on all these substrates for 40/70 Brady brown sand. The modulus of these substrates varies from about 30 million psi to 0.6 million psi. The measured pack widths for all the tests, at all concentrations, and up to at least 10,000 psi are the same for all materials. Even the slope of the compaction trends cannot be differentiated between the hardest and softest materials.

In summary, the effects of stress, concentration, embedment, particle size, and strength appear to be well understood. At reasonable closure stress, these can account for about one order of magnitude loss in conductivity. This loss is taken into account in the baseline conductivity versus stress curves provided for each proppant in Predict-K, Proppant Manager, and in the GOHFER proppant library.

![Figure 5: Measured pack widths for 40/70 Brady sand on Ohio and Bandera sandstone, Niobrara chalk, and stainless steel, showing no measurable difference in pack width, hence embedment.](image)

### Change in Closure Stress with Production

There has been a lot of confusion, and many published misconceptions, about the effect of pore pressure depletion, through production, on the effective closure stress on the proppant pack. Some recent papers have suggested that depletion causes closure stress to decrease, so that weaker (and cheaper) proppants can be used. Most conventional frac models assume that pore pressure and closure stress remain constant somewhere out in the reservoir, “at infinity”. This is obviously not a well-defined boundary condition. As bottomhole flowing pressure (BHFP) or pore pressure near the fracture face decreases, the net vertical stress INCREASES. The assumption inherent in the uniaxial strain model for horizontal net stress (zero lateral strain under all conditions of compaction) therefore predicts that the net horizontal stress also increases. Note though, that if the pore pressure around the fracture decreases, and if the local pressure has more impact on stress felt at the fracture face, that the total closure stress drops as the net horizontal stress increases.
A common conservative assumption for proppant selection is that BHFP may be reduced to zero, while maintaining the original pore pressure, therefore applying the maximum total stress to the proppant pack. This is considered to offer a significant safety factor for proppant selection. If the pore pressure locally around the well and fracture decreases with production, the net stress transmitted mechanically to the pack, goes up but never as high as the conservative assumption of immediate drawdown to zero BHFP. While it is true, that the total stress decreases with production and depletion, the net stress goes up as the reservoir compacts. The assumptions in Predict-K are based on the far-field initial pressure and transient flowing BHFP to get a time dependent net stress on the prop pack.

Years ago we (at Stim-Lab) tested the impact of decreasing stress on the proppant pack, after it had been subjected to a high initial loading. The tests showed that there is essentially no rebound of conductivity from the pack conditions set by the maximum closure stress. This is illustrated in Figure 3 by the dashed red line, indicating the path of the conductivity versus stress function during unloading. Based on direct lab testing results, my opinion remains that using the initial total stress, representing horizontal net stress plus original pore pressure, minus the BHFP early in the life of the well, sets the maximum stress on the pack and therefore its conductivity. The only way net stress would go down is if BHFP increased. In this case the conductivity would not rebound. This hysteresis effect is included in Predict-K and GOHFER as they track the maximum stress the pack has been exposed to. Remember, the stress compressing the pack is the net intergranular stress transmitted to the grain contacts. At static shut-in conditions, with BHP equal to reservoir pressure the stress on the pack is the net stress normal to the fracture face. This is the lowest stress you can get. If the reservoir is depleted and the well shut in until BHP equals the new depleted pore pressure, the stress on the pack is still the net stress, which is now higher. Drilling new wells in a depleted reservoir will expose the proppant pack to lower total closure stress, but problems other than closure stress will likely dominate well performance.

**Multi-Phase and Non-Darcy Effects on Conductivity**

Among the largest losses to effective conductivity are those caused by the combination of multiphase flow and non-Darcy, or inertially limited flow. Under reasonable producing conditions, the proppant pack will always be in some multi-phase flow condition. Residual treating fluid will remain in the pack, and water saturation may be augmented by production from the reservoir. There is no case I know of where all the frac load, or even a majority of it, is ever produced from the fracture. With retrograde condensate reservoirs, any time the BHFP drops below the dew point some condensate will drop out, and will not re-vaporize when the pressure builds up. Even for low yield condensate systems, the small amount of condensate that drops out in the proppant pack cannot move until it reaches a mobile saturation. Condensate will continue to accumulate until the outflow mobility of the liquid phase reaches an equilibrium with the rate of condensate deposition.

Similarly, for a black or volatile oil system, the instant BHFP hits bubble point a free gas saturation will form. The presence of free gas, or trapped gas in the case of an imbibition cycle, is especially damaging. The gas, being strongly non-wetting, will seek to occupy the largest pores with the largest possible radius of curvature of the gas bubble, to attain the lowest possible energy state. This “Jamin effect” causes severe blockage of permeability by obstructing the largest pores, and the highest flow capacity channels. The small gas bubbles remain trapped, and act as if they are solid particles plugging the pack.

The impact of the presence of a second (or third) mobile or immobile phase on overall permeability is often described through the use of relative permeability functions. These functions attempt to ascribe a fraction of the total system flow capacity to each phase as a function of the phase saturation. It is commonplace, in the petroleum literature, to see the assumption that relative permeability curves for proppant packs can be approximated as straight lines, so that a 50% saturation of a given phase generates...
50% of the system flow capacity. These papers are written by folks with no understanding of relative permeability, and who have never seen or measured an actual relative permeability function. The truth is much more depressing than this simple-minded assumption.

Two-Phase Relative Permeability in Proppant Packs

As part of the Stim-Lab effort to understand realistic proppant pack flow capacity, several years of laboratory effort were expended to measure two-phase relative permeability functions for proppant packs. All available materials, including sand, resin-coated proppants, and ceramics, were measured across a range of size from 100-mesh to 10/12 mesh. Because all proppants are well sorted and uncemented, the pore morphology for all materials is similar. If they are all assumed to be used in a water-wet state, then the relative permeability functions for all proppants are the same, within an acceptable error band.

The curves in Figure 6 show the relative permeability functions that describe two-phase flow in a proppant pack. The data were generated for a gas-water system, but have been verified for an oil-water system, as long as the pack remains strongly water-wet. Of course, the viscosity ratio and fractional flow at each saturation is very different for gas-water and water-oil system. The fractional flow of each phase is determined by multiplying the relative permeability ratio of the two phase by their viscosity ratio. For example, at roughly 40% gas saturation, for an oil/water viscosity ratio near 1, the two phases would each exhibit roughly 50% fractional flow, but each phase would have a permeability that is only 9% of the absolute permeability of the pack. For a gas water viscosity ratio of 50, at the same saturation, the gas fractional flow would be 98% of the flow stream, with only 2% water moving.

The wetting phase and non-wetting phase relative permeability functions can be approximated using Corey functions. Taking water saturation, Sw, as a fraction, the wetting phase relative permeability is approximately Sw^5.5. The non-wetting phase permeability is approximately (1-Sw)^2.7.

An additional caution is required regarding the use of these functions to model fracture flow and cleanup. For flow to be governed by relative permeability the flow conditions must be dominated by viscous forces. Capillary and gravity forces must be negligible, and saturation and flow capacity cannot be impacted “capillary end effects” or discontinuities in the porous medium. These conditions rarely occur in real fractures or in reservoirs, but the use of these functions in reservoir simulation persists. In order to correctly measure the proppant pack relative permeability curves, it was necessary to construct 20-foot long proppant packs so that the length of the pack dominated by the capillary outlet discontinuity did not affect the results. It was also necessary to flow at a high rate to get stable pressure differentials. The necessary rate was high enough to exceed the Darcy flow regime limits, so the observed laboratory relations between rate, pressure gradient, and saturation then had to be corrected for inertial effects.

Non-Darcy or Inertial Effects on Conductivity

Non-Darcy flow, or inertial effects, can be described for all proppants using a single dimensionless flow.
model that was developed at Stim-Lab after extensive testing on multiple proppant types and over a large range of stresses, including mechanically damaged or “crushed” proppant. The final function describing inertial flow is shown in Figure 7. The original publication of this work is SPE 89325.

The y-axis shows the fraction of the Darcy permeability remaining as flowing Reynolds number increases. Reynolds number is given by \((\rho*v)/(\mu*V)\), where \(V\) can be determined as the inverse of the correct \(\beta^*k\), the value of \((\rho*v)/\mu\) at which the observed permeability is half the Darcy permeability, or \(1/2D\), where \(D\) is the median particle size of the proppant sieve distribution, in centimeters. The two exponents, \(F\), and \(E\), have been found (by several doctoral candidates at various institutions) to both be slightly less than 1, and the minimum permeability \((k_{min})\) has been shown to exist, but may be impossible to reach under any realistic flow conditions. This function applies for single phase flow in a proppant pack. When more than one phase is present, the combined effects of multiphase flow and inertial effects are much more severe.

The presence of a second phase decreases the available pore channels open to flow of the non-wetting phase. This increases its velocity, and Reynolds number, and reduces flow capacity. The wetting and non-wetting phases move through different pore channels at different speeds, and each has its own effective Reynolds number and inertial resistance. The extension to multiphase non-Darcy flow is presented in SPE 109561. Some of the laboratory results, shown in Figure 8, show that the interchange of relative permeability and inertial effects are complex. Flow at constant fractional flow, as in the figure, leads to a different equilibrium saturation at each rate, because of the different Reynolds number for each phase. This interaction leads to an apparent plateau in the flow capacity at high Reynolds number, when both phases are mobile. The lines in the figure are predictions based on the model and the points are experimental observations.

The combined effects of multiphase and non-Darcy flow are the largest losses of conductivity in parts of the fracture subjected to high velocity. They can, under reasonable flowing conditions in a fractured completion in unconventional reservoirs, lead to about two orders of magnitude loss in fracture flow capacity. Considering no other damage mechanisms, these factors can result in an apparent fracture conductivity that is 1-2% of the baseline value.

**Gel Cleanup and Reservoir Energy**

There are several parts to the issue of gel damage cleanup or removal from the proppant pack. The first is filter-cake deposition and removal. In unconventional reservoirs, where “matrix” permeability is extremely small, there will be little or no filtercake deposition and most leakoff will be associated with fissures and induced shear fractures.
In very high permeability systems, above about 500 md, there will be almost no filtercake on the fracture wall, as polymer will invade the formation and generate leakoff control through invasion and pore obstruction. It is the intermediate range of conventional reservoir permeability where filtercake deposition has been studied, and causes the most concern. We envision a bell-shaped curve of filtercake deposition versus the logarithm of permeability, with a maximum at about 1 md.

**Filtercake Deposition and Erosion**

The concentration of polymer in a compressed filtercake is extremely high, and it cannot be dissolved or removed by breakers, or high velocity flow (erosion). Breakers tend to allow the cake to compress, de-water, and become denser and more immobile. Under high hydrostatic pressure the filtercake can compress, while the total mass of polymer it contains remains constant. Upon release of the pressure differential these cakes have been observed to re-imibe water and to swell to fill all available pore space in the proppant pack. In general, is a gel residue concentration of more than 400 ppt exists in any part of the fracture, that portion of the pack is assumed to be fully plugged (as in Figure 2).

Because the filtercake is deposited while the fracture is held open by hydraulic pressure, it will change thickness during closure. For example, a cake of 0.01 inches compressed on the wall during pumping will extrude into the pore space of the proppant pack at closure. Assuming, for simplicity, that the proppant pack porosity is 33%, the thickness of the cake will triple upon complete closure. The resulting extruded cake, with a thickness of about 0.03 inches, will “swallow” an entire 20/40 mesh proppant grain from each wall of the pack.

High flow rate tests, with brine flowing through the walls of the fracture and then through the pack, have shown that the filtercake cannot be removed. It is considered to be a loss of flowing fracture width rather than a reduction in permeability of the pack. The remaining gel residue distributed throughout the pore space of the pack generates the remaining permeability damage.

**Polymer Gel Residue and Damage**

Cleanup of the distributed gel residue in the pack has been related to the amount of energy that can be transmitted to the gel by the flowing fluid stream. The model, illustrated in Figure 9, shows the data for several fluids and the model curve for percent regained permeability, relative to the absolute permeability of the pack, as a function of pseudo-Reynolds number (pRe). The term \( \frac{\rho v L}{\mu} \) is not dimensionless as it is missing the effective diameter of the pore system.

![Figure 9: Current gel cleanup model, with regained permeability as a function of pseudo-Reynolds number established in the fracture.](image)

The fluid represented by the magenta line in Figure 9 has a maximum regained permeability of 90% of the absolute permeability of a clean pack. To achieve that degree of cleanup the reservoir must be capable of developing a pRe of more than 30. If the reservoir permeability is low, or pore pressure is low, or applied drawdown is too low, the reservoir may have insufficient energy to reach a high enough pRe to drive cleanup. For example, in Figure 9, a reservoir that can only develop enough flow to get to pRe=0.5 will generate less than 10% cleanup of a fluid that could be capable of 90% cleanup under ideal conditions.

In the case of a high gel residue concentration, approaching a gel plug, it is necessary to also consider the minimum pressure differential required to initiate
flow, as shown in Figure 2. A gel plug behaves as if it has a substantial yield point, like a Bingham plastic fluid. If a sufficient potential gradient is not available, the gel will not move. In either case, it is the reservoir that is responsible for cleanup and development of effective fracture length, not primarily the fracture itself.

An extreme example of this is a 2#/ft² propped fracture containing 20/40 mesh sintered bauxite, at only 2000 psi closure stress, with a propped length of 1000 feet, covering the entire reservoir thickness uniformly, placed with water and containing no gel residue or filtercake. Sounds great! What is the effective producing length? What if the imaginary reservoir has zero porosity and zero permeability? With no flow through the “perfect” fracture, what is its effective length?

**Velocity and Potential Gradients during Production and Cleanup**

So, cleanup and effective fracture length depend on the coupling between the fracture and the reservoir. The reservoir flow capacity provides the energy to drive cleanup and develop effective length. With insufficient energy there will be little conductivity development. At the end of the fracture treatment the proppant pack and surrounding fracture walls will be at essentially 100% water saturation, with no hydrocarbon flow capacity. Initial invasion of the water saturated pack, and penetration of the capillary blockage at the fracture wall will be discussed in the next section. But first we need to consider what velocity and potential gradient can be generated during typical producing conditions. Understanding of the relative magnitude of viscous, capillary, and gravity forces requires quantification of the various potential gradients.

**Convergent Skin Effects for Horizontal Wells**

Most wells in unconventional reservoirs are drilled horizontally and transverse to the expected fracture plane. Figure 10 shows a schematic representation of a possible, idealized, flow profile that may develop under these circumstances. Flow from the reservoir, through the face of the fracture, moves linearly down the length of the effectively flowing fracture, until it reaches a point where the flow must converge radially to the wellbore. This flow profile has been produced in large, proppant packed vertical slot models at Stim-Lab, where the flow lines have been delineated with tracer injection. Across the centerline of the fracture there is a no-flow boundary where flow from the opposing fracture wings converges. Near the well the flow rate, velocity, and corresponding pressure gradient are very high. In the linear part of the fracture, the velocity and flow rate are relatively low.

It is also important to consider the flow profile from the reservoir, through the fracture face. As distance from the well increases the available drawdown and potential gradient decrease. This has a feedback effect on fracture cleanup and conductivity, such that conductivity also decreases with distance from the well. An ideal model of flow into the fracture, that does not consider the coupling between potential gradient, or pRe, with conductivity, is a uniform-flux fracture. In this model the influx from the reservoir to the fracture is constant for each element of surface area. For a line source well, vertically across the center of the fracture, the velocity in the fracture would then be a linear function that is maximum at the well and zero at the fracture tips.

![Figure 10: Schematic diagram of convergent flow to a horizontal wellbore from a vertical, transverse fracture.](image)
face decreases along the length of the fracture. The impact of the convergent flow region, within a radius of the half-height of the fracture, is also considered. The approximate formation influx function used for the following examples is shown in Figure 11. The flowing fracture length is not fixed, but will be determined by the available potential gradients within the fracture. Calculations for flow velocity and pressure gradient are performed for non-Darcy corrected flow capacity of the fracture under various producing conditions for gas and liquid flow.

Using the model described here it is possible to evaluate the flowing conditions, including velocity profile and potential gradient, for various producing conditions. It is impossible to describe all conditions, but a few specific cases may suffice to get an idea of the range of values that may be encountered.

Effective Conductivity in Oil Wells

The first example represents an oil well flowing at initial, high rate, conditions while still above bubble point in single phase flow. The model was run to simulate a horizontal well with 30 active and contributing transverse fractures, each 50 feet tall. The produced fluid is assumed to have a viscosity of 1 cp. The initial rate from the well is 5400 bopd. That translates into 180 bopd per fracture (90 bopd per wing). Assuming an average proppant concentration of about 1 lb/ft², or pack width of 0.1 inches, and effective producing permeability (under Darcy conditions) of 10 darcies (83 md-ft effective conductivity), the velocity and Reynolds number can be computed over the length of the fracture. These results are used to adjust the permeability for inertial effects in the convergent flow region. The resulting velocity profile, and corresponding potential gradient, are shown in Figure 12.

The pressure gradient at the wellbore sandface is 4000 psi/ft, declining to 550 psi/ft only one foot from the well. This indicates that the well is probably physically limited to a lower initial rate by near-well tortuosity and convergent flow. At 100 feet from the well the pressure gradient is about 2 psi/ft. Towards the tip of the fracture, as reservoir flux decreases, the pressure gradient rapidly drops. At 240 feet the gradient is 0.18 psi/ft. Note that the average superficial flow velocity in the droops below 0.1 cm/sec to zero at less than 90 feet from the well. Beyond 300 feet of fracture half-length the potential gradient drops rapidly below 0.1 psi/ft, and enters the capillary dominated region.

Figure 13 shows the total pressure drop from the wellbore sandface, along the fracture length. At 70 feet from the well about 3000 psi of the available drawdown is consumed. The remaining 250 psi of total drawdown is consumed over the remaining fracture length. The gradient and velocity in the distal region of the fracture is so low that cleanup is problematic.
Figure 13: Total pressure drop from the wellbore face, as a function of fracture length, in a 50-ft tall fracture with 1 #/ft² proppant, 30 fractures, 83 md-ft conductivity, producing at 5400 bopd.

The same well and fracture conditions are shown in Figures 14 and 15 after the total well rate has declined to 190 bopd. At this rate each fracture produces 6.3 bopd or about 12 ounces per minute. Not an exciting rate, and certainly not enough to push water out of the fracture. The pressure gradient is less than 0.1 psi/ft from 100 feet to the tip of the fracture. At the wellbore, the gradient is about 40 psi/ft. Velocity drops below 0.03 cm/sec at only 10 feet from the well. At 100 feet, the velocity is 0.002 cm/sec. For mechanical cleanup to be achieved, it must occur early in the life of the well. Later accumulation of water in the extremities of the fracture will likely be impossible to move at these conditions.

Effective Conductivity in Gas Wells

Using the same fracture geometry and conductivity, a gas well producing a 4.4 MMSCF/D at a BHFP of 3000 psi was modeled, using a gas viscosity of 0.02 cp. Single phase flow was again assumed, but the Darcy conductivity was held at 83 md-ft. The potential gradient and velocity are shown in Figure 16 for the initial production rate.

The high gas mobility actually has a negative impact on cleanup potential, and a much higher non-Darcy flow effect. The pressure gradient at the well is about 3000 psi/ft, but drops to 4 psi/ft only 10 feet from the well. Over the bulk of the fracture length, from 50-100 feet, the pressure gradient is 0.4 to 0.06 psi/ft, or typically less than the gas-water gravity head. From
100 feet to the tip of the fracture the viscous gradient is far below the gravity head.

Velocity drops from 23 cm/sec at the sandface to 0.8 cm/sec ten feet from the well. Over the rest of the fracture the velocity drops from 0.2 cm/sec at 50 feet to less than half that at 100 feet, and approaches zero beyond 300 feet. Getting meaningful flow or indication of an “effective” fracture contribution from most of the fracture is hard to imagine.

The overall pressure drop for the high-rate gas well is shown in Figure 17. Note that almost the entire pressure drawdown is consumed within the first 10 feet of the well. Very little energy is left over the bulk of the fracture to aid in cleanup or water removal.

Once the gas well declines to about 150 MSCF/D (a comparable in-situ velocity to the oil case), the energy in the fracture is greatly diminished. Figures 18 and 19 show the conditions in the fracture for the depleted gas well case. Potential gradients are less than the gas-water gravity head at less than 5 feet from the well. Note that the potential gradient is less than 0.03 psi/ft at only 10 feet from the well. This value will have some significance during the discussion on capillary phenomena.

Superficial gas velocity in the fracture is less than 1 cm/sec at the well and below 0.1 cm/sec at less than 3 feet from the well. Beyond 10 feet the velocity is less than 0.03 cm/sec, and less than 0.01 cm/sec beyond 50 feet. The overall total pressure drop through the whole fracture, in Figure 19, is less than 3 psi over 300 feet, with 2 psi over the first 12 feet. If liquids accumulate in the proppant pack under these conditions, there is virtually no way to remove them by displacement.

Degradation of Proppant Conductivity Over Time

The Stim-Lab “Baseline” conductivity data are taken at 50 hours of flow at each stress. Analysis of data gathered during these tests has shown that the pack conductivity is not really stable at 50 hours, even under ideal laboratory conditions using mineral saturated, deoxygenated brine. Figure 20 shows data for a particular proppant, with observed conductivity...
versus time normalized to the conductivity observed after one hour at stress.

![Figure 20: Time dependent proppant pack conductivity under ideal laboratory conditions.](image)

At high stress (about 10,000 psi) the proppant shown has lost about 25% of the conductivity observed after one hour, for only 50 hours at stress. Additional testing has shown that there is no indication that conductivity ever stabilizes, regardless of the flow time. Reasons for this continued degradation are still debated, but probably include long-term creep, pressure solution and precipitation of silica, and degradation of the substrate rock surface. Figure 21, from the ASME Journal of Energy Resources, illustrates the effect of time, creep, pressure solution, and precipitation in a proppant pack. It can be expected that the rate of degradation in the field will be much more severe. These tests do not represent the cumulative effects of scale deposition, salt plugging, fines migration from the reservoir, deposition of waxes and asphaltenes, bacterial slime, and other probable progressive damage that occurs during production.

![Figure 21: Time dependent degradation of proppant pack due to solution and re-precipitation of minerals.](image)

Since the proppant pack is essentially a fixed sand-bed filter between the reservoir and the well, it is to be expected that plugging and damage will accumulate over time. The net result is that the fracture conductivity will have a finite life that can be measured in months. Extrapolation of early time production to 20 years or more, to justify stimulation costs, is probably not a justifiable practice since the fracture will probably have little or no useful conductivity at that time. Fortunately, because of the reservoir transient behavior, there will be so little fluid moving through the fracture in late time, that conductivity is no longer a limiting constraint on productivity of the well.

**Capillary and Gravity Forces**

In these example cases a formation influx factor was assumed, with decreasing influx away from the well. While overall results are not strongly sensitive to the shape of this function, details may change. It is reasonable to assume, based on all the available laboratory data, that cleanup and conductivity will suffer significantly at very low potential gradients and low values of pRe. In these examples it is hard to justify much flow beyond a few hundred feet of fracture length. The gross created fracture length could be 1000 feet or more, but beyond a couple hundred feet there is simply insufficient energy to
overcome gravity and capillary forces in the proppant pack. This limits the total flowing length of the fracture, based on reservoir energy.

With no gel damage, or filtercake, there are still damage mechanisms that can stop hydrocarbon movement in the proppant pack. These are related to the capillary forces at the filtrate invaded fracture wall and in the proppant pack itself. At the end of the fracture treatment, the proppant pack is 100% water saturated and the fracture wall has been invaded with fluid filtrate, forced in under (typically) more than 1000 psi pressure differential. Capillary forces in both these regions may block or limit movement of a non-wetting hydrocarbon phase.

### Derivation of Capillary Entry Pressure

We will first consider the capillary blockage, or end-effect, that occurs at the interface between the formation fracture face and proppant pack. The pore size within the proppant pack is so large, compared to the pore size of the formation, that a capillary pressure discontinuity will exist at every fracture surface. The source of the capillary discontinuity is the phase pressure differential caused by the radius of curvature of the interface between two immiscible fluids. The common definition of the phase pressure differential across a distended interface, or capillary pressure, is derived in Figure 22.

In the equations given in Figure 22, \( \sigma \) is the interfacial tension (IFT) between the two phases (dynes/cm). The wetting phase contact angle with the solid surface is given by \( \theta \). The radius of the capillary, in our consideration this is the radius of the reservoir or proppant pack pore throat, is \( r \). A typical water-oil system will have an interfacial tension of 20-30 dynes/cm, while a gas-water system will typically be in the range of 50-70 dynes/cm. Use of effective surfactants may drop interfacial tension to about 5 dynes/cm. A purely water-wet system will have a contact angle approaching zero, with \( \cos(\theta) = 1 \). Intermediate or neutrally wet systems may have contact angles of 60-90 degrees. If a contact angle of 90 degrees were possible, there would be no capillary phase pressure difference between the phases.

\[
\text{At equilibrium Force Up} = \text{Force Down}
\]
\[
\text{ForceUp} = 2\pi r a \cos \theta
\]
\[
\text{ForceDown} = \pi r^2 \Delta p g h
\]
\[
P_c = \frac{2\pi r a \cos \theta}{\pi r^3} = \frac{2 \cos \theta}{r} \text{ and}
\]
\[
P_c = \frac{\pi r^2 \Delta p h g}{\pi r^2} = \Delta p h \frac{g}{g_c}
\]

Figure 22: Explanation and derivation of the conventional capillary pressure equation.

### Capillary Entry Pressure for Shale and Tight-Sand Reservoirs

The pore size of typical reservoir rocks, \( r \), has been given in Figure 23 (Nelson, AAPG Bulletin 93, No. 3, March 2009). Note that unconventional systems, typically shale, have a pore diameter in the range of 0.01-0.1 microns. “Tight” gas sands are typically in the range of 0.05-1 micron pore diameter.

These values can be used to estimate the capillary threshold pressure for a range of contact angles and pore sizes that may be encountered along the face of a fracture. Figure 23 shows the results of these calculations for a contact angle of zero and IFT of 70 dynes/cm (gas-water), zero contact angle and IFT=30
(gas-oil), contact angle of zero and surfactant-reduced IFT-5 dynes/com (surf), and a contact angle increased to 85 degrees to represent a strongly oil-wet system such as an organic rich shale source-rock.

Figure 24: Capillary threshold, or entry pressure, for a non-wetting fluid invading a pore filled with a wetting fluid, for various pore sizes, interfacial tensions, and contact angles.

Note that for water-wet shales, pore sizes of 0.005-0.05 micron diameters, the threshold entry pressure is more than 1000 psi. This means that the invaded face of the fracture forms a capillary wall that must be breached to move non-wetting (hydrocarbon) phase from the reservoir to the proppant pack. Even if the invaded zone is only a few pore diameters in thickness, this capillary blockage will exist. This capillary threshold pressure, or caprock seal capacity, can (and has been) measured in the laboratory for water saturated shale samples. More than 1000 psi pressure differential is required, in some shale systems, to inject a single bubble or droplet of gas or oil into the shale. If the shale is oil-wet, and the produced phase is oil, then the threshold pressure may be much lower, as shown by the light blue curve (ca, in Figure 24).

Since shale formations are composed of a range of pore sizes with variable wettability, depending on local saturation and grain coatings, it is probable that breakthrough occurs in individual pores, distributed over the face of the fracture. The production mechanism from the formation face to the proppant pack may look more like a condensation phenomenon, as in Figure 25, if we could visualize it. Each individual bubble of oil or gas entering the proppant pack has to overcome the capillary forces of the proppant, and have a large enough potential gradient across it, in order to move. Locally sourced droplets may coalesce until a large enough droplets forms, so that it can begin to migrate through the pack. This migration may form preferential channels for later flow. This mechanism suggests that production is not uniform over the entire created surface of the fracture system, but may be derived from a small fraction of the total surface area. As long as the proppant pack remains water filled, as will be the case when there is standing water in the wellbore, oil and gas production will always be dominated by this percolation mechanism. Flow will never be fast enough to be fully viscous dominated, except very near the well. That means that conventional relative permeability predictions of flow capacity do not apply to fracture flow or cleanup, over most of the created length of the fracture network.

Figure 25: Condensation and mobilization of water droplets.

Oil and Gas Migration Through the Proppant Pack

Once oil or gas droplets coalesce sufficiently to accumulate in the proppant pack, they still need to migrate through the water-wet pack itself. This process was examined by Hill (AAPG Bulletin V 43, 1959) in his study of secondary migration of oil through aquifers. His experiment, summarized in Figure 26, was conducted in a water saturated 30/50 white sand pack.
Figure 26: Oil migration by buoyancy through a water saturated 30/50 sand pack.

In panel A of Figure 26, there are three disconnected droplets of oil, each about 4 inches in diameter, injected by syringe into the water saturated sand pack. The buoyancy force created by the height of each droplet, fluid density difference, and gravitational acceleration, is insufficient to overcome the threshold pressure of the sand pack. The oil cannot move under a potential gradient of about 0.09 psi/ft (assuming oil-water density difference of 0.2 g/cm³). Water permeability through the pack is in the range of hundreds of Darcies, and may add some hydrodynamic gradient to the oil droplets at high water flow rate.

In panel B of the figure, the oil droplets are gradually increased in size, through additional oil injection, until the total continuous height of the oil is about 36 inches. At this point the buoyant force at the top, leading edge of the oil drop, reaches the threshold pressure of the water-filled pores in the pack. This is an approximate phase pressure difference of 0.26 psi at the limiting pore throats. Once the threshold pressure is breached, the entire oil blob (or ganglion) migrates upward through the pack. Water displaced by the moving oil falls around the oil and fills in the pore space. Net “load recovery” is effectively zero during this migration, or percolation of the oil. The area vacated by the oil now contains residual trapped oil droplets that may act to block pores, reduce pack permeability, and be hard to contact and mobilize by later produced oil ganglia.

This experiment may elegantly describe the producing process that occurs over much of the fracture system. In typical well operations, the pump or tubing tail is set high enough above the lateral, that the horizontal section of the well maintains a water layer. Any fractures that have a continuous source of water, aided by gravity drainage, will tend to remain water filled, with local percolation of gas and oil droplets moving through the proppant pack.

### Capillary Entry Pressure of Proppant Packs for Various Sieves

As a result of these observations, Stim-Lab measured the capillary threshold pressure of typical water-wet proppant packs of various sizes. The data were compared with theoretical calculations of entry pressure, based on expected pore size derived from sieve distributions. The results of these measurements are summarized in Figure 27. The oval, centered at 40-mesh, shows an entry pressure of about 0.26 psi, corresponding to the conditions of the Hill experiment. For this sand pack, an oil droplet of roughly 36 inches in height is needed to achieve mobility through buoyancy. A gas bubble about 8 inches in height could achieve mobility in the same pack.

Figure 27, capillary entry, or threshold pressure, for water-wet proppant packs, based on mean sieve size of the particles in the pack.

Referring back to Figures 12 through 19, the estimated potential gradient at various flow...
conditions can be compared to the gravity head for gas-oil and oil-water systems. At very high flow rate, usually early in the life of the well, the viscous gradient may equal or exceed the gravity potential gradient out to more than 100 feet from the well. Unfortunately, at this time the water saturation in the pack is at a maximum, and oil and gas mobility may be limited. In the low-rate case, after the initial hyperbolic decline period, the gravity head dominated the viscous gradient in the range of feet to tens of feet from the well. Over much of the producing life of the well, and over most of the fracture length, gravity and capillary forces control oil and gas migration, not viscous forces, and therefore not relative permeability functions.

Flow Regimes in Vertical Transverse Fractures

If gravity drainage is an important part of fracture cleanup and conductivity, the geometry of a transverse fracture on a horizontal well must be considered more carefully. Figure 28 is a hypothetical illustration of a vertical transverse fracture on a horizontal well intersecting the center of the fracture height. There are three different flow regimes represented in this figure. Each will have a different potential for developing conductivity and contributing to production.

In the upper part of the fracture, the proppant pack will drain effectively by gravity. The water saturation left behind by the fracturing fluid will drop to approximately the capillary residual saturation (10-15%), and the high gas and oil saturation will enable substantial flow capacity to those phases. The water saturation at the face of the fracture will continue to decrease over time through production, gravity drainage, and spontaneous imbibition into the reservoir. This section of the fracture, if allowed to drain, will provide the most efficient stimulation and effective flow area.

The section of the fracture below the lateral is in a disadvantaged state, where water saturation will be constantly replenished by any water flowing down the wellbore and gravity-draining into the fracture. As long as there is any water production from the well, these fracture segments will probably remain waterlogged. Oil and gas can only migrate through the water saturated proppant pack by percolation, and the fracture faces will remain at a high water saturation, with severe capillary blockage. It is possible that the flow rates in these lower fracture limbs will be so small that they will not affect the transient production of the well, and may not contribute to producing net pay thickness.

The third flow regime is the convergent area around the well, where potential gradients and velocities are high. This are will be dominated by inertial losses, viscous forces, and will likely be in a constant multiphase flow condition. The calculations presented in Figures 12-19 show the impact of this region clearly.

Effective Fracture Length and Dimensionless Conductivity

Integration of all the potential damage mechanisms discussed so far is a complex and dynamic process, that changes continuously during the producing history of the well. Gel and filtercake damage removal, that may occur early in the well life while high pRe flow conditions are possible, is assumed to persist through the life of the well. Long-term
progressive conductivity damage will continue to increase throughout the well life. Saturation effects are transient, and may come and go rapidly, in response to changes in well operating conditions, such as pump efficiency, tubing setting depth, applied drawdown, reservoir pressure depletion, and reservoir transient response. These effects, also related to well loading and cyclic shut-in or killing operations, including well bashing from offset well fracs, offer the greatest potential for damage and loss of effective fracture conductivity.

**Re-Saturation and Hysteresis Effects**

Water imbibition, from shut-ins, well killing, or bashing, is one more damage mechanism that is worth of some discussion. The proppant pack conductivity will be impacted by successive drainage and imbibition cycles, causing a change in direction from decreasing to increasing wetting phase saturation. This is illustrated in Figure 29, which shows both primary drainage and imbibition cycles for a gas-water system in a reservoir core sample.

![Figure 29: Drainage and imbibition cycle relative permeability curves for a reservoir core sample.](image)

The same trend is present in proppant packs. On primary drainage (initial cleanup) the wetting phase (frac load) saturation decreases and gas or oil permeability increases. If water is re-introduced into the pack as a result of a shut-in, secondary injection, or influx from an offset fracture treatment, the water saturation increases rapidly due to the favorable mobility ratio of water displacing oil or gas. The water influx leaves a trapped non-wetting phase saturation in the pore space of the lack that is discontinuous, and effectively impossible to move by later drainage cycles. This cuts the maximum attainable permeability of the system, even at 100% fractional flow of a single phase, by up to 80% in many cases. Later drainage and imbibition cycles operate within a reduced hysteresis loop on the saturation-relative permeability plot. If the waterflood occurs late in the life of the well, when there is little energy left in the system, the fractures affected may never recover useful flow capacity.

**Dimensionless Fracture Conductivity**

Accounting for all the potential damage mechanisms, at any time during the producing life of the well, makes it possible to estimate an effective proppant pack conductivity (k_fwf), usually expressed in units of md-ft. This damaged effective dynamic conductivity is often used to compute a dimensionless fracture conductivity, F_{CD}. The equation for F_{CD} is shown as Eq. 2.

\[ F_{CD} = \frac{k_f w_f}{k_r X_{flow}} \]  

Eq. 2

The effective producing permeability of the reservoir is \( k_r \) in Eq. 2. The problem with use of this dimensionless conductivity is that the flowing length of the fracture is not well defined, and is practically independent of the fracture conductivity alone. As has been asserted throughout this discussion, the length of fracture that can sustain flow depends heavily of the available flow capacity and energy of the reservoir. A high conductivity fracture in an impermeable reservoir will have a high \( F_{CD} \), but will have virtually no effective length. A model has been developed, through the Stim-Lab consortium, and
implemented in the Predict-K and GOHFER software, to estimate the flowing length based on the energy balance, pRe, and transient production from a given reservoir. That transient flowing length can then be used to derive a dimensionless conductivity that changes constantly, along with flowing length, through the life of the well.

The flowing length and dimensionless conductivity are then entered into the modified Pratts relation, as shown in Figure 30, to derive an infinite conductivity effective length of the fracture. This approach avoids ambiguities associated with finite conductivity fracture descriptions, where length and conductivity can be exchanged over an almost infinite range of values, to describe the fracture flow capacity. The single-valued infinite conductivity effective length is a reliable description of the effective stimulation derived from the fracture. It has virtually no relation to the actual physical dimensions of the fracture, only to how the fracture affects the transient production of the well.

As in conventional transient test theory, any value of $F_{CD}$ greater than 30 gives an effective infinite conductivity length equal to the flowing length. That means that any fracture producing with an $F_{CD}$ of 30 or more has a negligible pressure drop or resistance to flow down the flowing length of the fracture. For this case, consider the low-rate oil and gas well cases in Figures 15 and 19. The total pressure drop through the fractures in both cases is insignificant compared to total drawdown.

When people look at Eq. 2, and compute a value of $F_{CD}$ for an unconventional reservoir, assuming the reservoir permeability to be very low, all fractures appear to have infinite conductivity, regardless of their length, if baseline proppant pack conductivity is assumed. The foregoing discussion, hopefully, makes it clear that the actual effective conductivity is a very small fraction of the baseline conductivity (2% is a good working hypothesis), but that can still yield a high $F_{CD}$ if the reservoir permeability is small. The missing link in most transient analyses, and in many reservoir numerical simulation studies, is the actual flowing length. In too many cases the created or propped length is used, or (worst case) the microseismic length of the fracture is used along with a damaged conductivity estimate.

**Problems with Dimensionless Conductivity and the McGuire-Sikora Curves**

The main problem with relative, or dimensionless, conductivity is illustrated by the McGuire-Sikora “folds of increase” curves, shown in Figure 31. In these curves, the productivity increase is plotted along the ordinate with a correction for well drainage area, $A$. In this case the stimulation ratio is $J/J_0$, or the expected folds-of-increase in productivity index resulting from the fracture.

The abscissa is a measure of the relative conductivity of the fracture to the surrounding formation, corrected for well spacing. Note that the fracture conductivity is used in units of md-inches, rather than the usual md-ft, and that reservoir permeability is in md. Well drainage area ($A$) is in acres. Fracture length is shown by the various curves as a function of fracture half-length relative to the well drainage radius.

These curves indicate that for fractures with a low dimensionless conductivity (left end of the plot), a significant increase in fracture length does not improve productivity. For higher conductivity fractures, relative to the producing capacity of the formation (right side of the plot), this model predicts that increasing length can greatly improve the well.
productivity. For unconventional reservoirs, when using the often measured crushed-core permeability, all fractures plot far to the right-end on this plot. This leads to the conclusion that conductivity is unimportant, and longer created fractures will always improve production.

The case modeled is a 1000-ft propped fracture. Each curve on the plot represents a damaged fracture conductivity, shown by the legend as “C”, where the values are in md-ft. The x-axis is the producing reservoir effective permeability. The y-axis is the infinite conductivity fracture length, including cleanup response and dimensionless conductivity.

There are several fallacies in this conclusion. The model assumes that the entire created fracture length represents the effective flowing length of the fracture. The model was derived for single-phase flow, using an electrical analog model. Capillary forces and cleanup are not recognized. In reality, it is impossible to clean-up an extremely long fracture in a very low energy or flow-capacity reservoir. In unconventional reservoir the upper-right quadrant of the plot in Figure 31 effectively does not exist.

Effective Flowing Length

When the low energy state generated by production from an unconventional reservoir is considered, the flowing length can become severely limited, not by lack of conductivity, but by lack of reservoir energy. Combining the energy available to drive cleanup with the dynamic conductivity of the overall fracture system, it is possible to estimate the effective infinite conductivity fracture length that can result. This length can be used to predict the production and decline profile of a well, and help to optimize fracture treatment design. Figure 321 shows an example of this process, as described in SPE 84306 and 84491.

In very high permeability systems, the fracture conductivity is not sufficient to carry fluid from the reservoir to the well without a significant pressure drop. This is similar to the high-rate oil case of Figures 12-13. Non-Darcy inertial effects and the high velocity in the fracture diminish effective conductivity so that the \( F_{CD} \) limit reduces the effective length. At the far right edge of the plot (1000 md reservoir permeability), with a 5000 md-ft proppant pack conductivity and 1000-ft propped length, \( F_{CD} \) is 0.005. According to the data in Figure 30, the effective frac length will be about 2 feet. This condition is commonly observed in offshore frac-pack completions.

At the left edge of the plot, a different condition exists. Reservoir permeability is less than 0.001 md, so \( F_{CD} \) for the fracture is greater than 30 and all fracture behave as infinite conductivity. The limit is the cleanup of the fracture due to lack of reservoir energy. A sub-microdarcy reservoir will produce little flow rate, velocity, or potential gradient in the fracture. It will be difficult to achieve significant cleanup, so conductivity will be impaired. The low
energy, and low cleanup, result in a short flowing length but the entire available flowing length has a negligible pressure drop, hence infinite conductivity. The lack of the pressure gradient is, itself, responsible for the poor effective frac length.

The concept of FCD alone does not effectively describe fracture flow behavior, without the additional constraint that extremely low permeability reservoirs are not capable of cleaning up long fractures. Capillary and gravity forces dominate the fluid movement to such an extent that viscous gradients are negligible. This is equivalent, in the Hill experiment, of trying to flow oil through the water saturated 30/50 sandpack at with an imposed differential pressure of 0.1 psi. Since the entry pressure is approximately 0.26 psi, it is possible to have a proppant pack at 100% water saturation, with an absolute permeability to water of hundreds of darcies, exhibit zero flow when oil is exposed to the inlet face of the pack with a pressure differential below the threshold.

In the middle range of Figure 32, the flow capacity of the reservoir and possible conductivity of the proppant pack are balanced for optimum performance. Long infinite-conductivity effective length fractures can be produced in this range of reservoir properties. Since the curves shown in the figure represent one drawdown condition, it should be remembered that high reservoir pressure and/or high drawdown can shift the curves to better performance at lower permeability. The converse is also true. Low pressure reservoirs will not clean up as well, so the family of curves will shift to the right.

As usual, there are other factors affecting well performance than those directly impacting fracture conductivity. For example, highly over-pressured reservoirs may seem to offer the opportunity for high cleanup and high initial rate, by pulling the well as hard as possible early in its life. However, a high pore pressure implies a low net-effective stress in the reservoir, and the strong possibility of irreversible stress-dependent reservoir permeability. High drawdown for initial production may collapse the reservoir in the low pore pressure field around the well, causing closure of microfractures and loss of reservoir flow capacity that will adversely affect all future production. In most cases this stress-sensitive permeability collapse is not reversible if the well is later constrained to allow BHFP to rise.

Similarly, water coning, dropping below phase transition pressure (dew point or bubble point) early in the well life can have irreversible and catastrophic impact of fracture conductivity. The entire well, fracture, and reservoir system must be taken as a tightly coupled system to determine the most effective stimulation design, and well operating procedures. In most horizontal well developments in unconventional reservoirs, I remain convinced that the primary problem is not fracture geometry, proppant placement, proppant crush or embedment. The primary problems are related to well operations. Current practices do not favor unloading of the well and fractures, removal of water, gravity assisted drainage, and do not provide sufficient potential gradient to allow adequate cleanup of the existing fractures that we are capable of emplacing with current technology.

Proppant Cutoff Length, Flowing Length, and Effective Length in GOHFER:

GOHFER attempts to incorporate all the preceding discussion to determine a realistic effective fracture length, modeling as an infinite conductivity fracture, to be able to effectively compare different designs. The use of multiple fracture length descriptions often confuses users, when the “proppant cutoff length”, “flowing length”, and “effective length” are all presented. Based on the previous discussion, this section attempts to clarify these different fracture lengths, so that the appropriate length is used in reports to managers and co-workers. The following discussion refers to Figure 33, which is an output file generated by GOHFER for every run made. The name of the “Design” level in the GOHFER project is used, with a “.csv” extension, to contain the data shown. The file resides in the top level of the design folder, under the appropriate Geologic Section.
Figure 33: Output of various predicted fracture lengths: Cutoff, Flowing, and Effective, from the GOHFER simulator.

For a given fracture treatment design, GOHFER outputs a grid of the vertical and lateral proppant concentration distribution. The mass/area concentration of the proppant in the fracture is used to compute the fracture width at closure. Local variations in total closure stress, formation modulus, filtercake residue, compression of the proppant pack, and other factors are included in the estimate of flowing fracture width. The width and compressed pack conductivity, under the appropriate stress, are used to estimate a conductivity, in md-ft, for each column of nodes (vertically) across the net pay covered by the fracture. The average proppant concentration with distance along the fracture, is plotted in figure 33 as the line with blue diamonds, referring to the right ordinate axis.

At this time, at the end of the fracture simulation, details about producing GOR, GLR, and water-cut are not available to the simulator, so an estimate of multiphase flow effects is applied to the estimated proppant conductivity. The approximate conductivity as a function of length is plotted as the solid orange line. As fracture length increases, and average concentration decreases, the average conductivity over the entire fracture declines.

The average conductivity, producing length, and average permeability from the model grid are used to estimate a flowing length of the fracture, using the cleanup algorithm presented previously. The estimated length of fracture that can clean-up and contribute flow is called the “flowing length”, and is plotted as the solid red line, relative to the left ordinate axis. The flowing length and conductivity are used to compute the dimensionless conductivity (FCD, as a function of fracture length, which is plotted as the solid yellow line. Finally, the FCD and flowing length are used to compute an approximate infinite conductivity effective length of the fracture, which is plotted as the solid blue line.

All these estimates are made before the production analysis or forecast is run in the simulator. The results are output in the design level summary table in the GOHFER output, along with the gross created fracture length, which is the maximum length of the fracture, propped or not, that is also the largest value on the abscissa of the plot in Figure 33. Note that for a proppant cutoff length of less than 200 feet, to more than 1900 feet, the predicted effective fracture length varies by less than 3 feet, and averages 50 feet. The actual proppant cutoff length is an input to the production analysis, and has no real value in describing the fracture. It can be used as an estimate of the effectively propped length, but the gross length of the fracture, which controls pressure hits on offset wells, is closer to the gross length. The length of fracture between the cutoff length and gross length is expected to close and seal sometime after the well is put on production.

When the production module in GOHFER is run, the flowing pressure constraints on the well are applied, along with the producing water-cut, and GOR or condensate yield (as appropriate). The production is run with whatever proppant cutoff length the user selects. The default cutoff length is chosen based on the derivative of the estimated infinite conductivity length versus distance plot, and is picked to give an optimum estimate of the final infinite conductivity length. All the intermediate calculations are performed under the specified producing conditions, for conductivity (including multiphase and non-Darcy effects), flowing length, FCD, and infinite conductivity effective length. These values are plotted in Figure 33 as the round points, with colors matched to the preliminary values for the same run.
In this case the default proppant cutoff length was 420 feet. Note that the longest infinite conductivity length, at about 44 feet, occurs at this value of cutoff length. The final results, after the production analysis, are slightly less than the estimated values, but the trend of each curve, along with its maximum, is similar. It is also worth noting that very small assumed fracture lengths generate infinite conductivity fractures of very small length. This again illustrates that $F_{CD}$ is not a good indication of fracture effectiveness, and flowing length (maximum cleanup length) must be considered.

### Multi-Cluster Stages in Horizontal Well Fracturing

In the case of multiple transverse fractures on a horizontal well, the same procedure is applied to each fracture in the stage. Production from each fracture is different, so the energy available for cleanup of each fracture is different. Because most of the cleanup and effective length is developed near the well, where potential gradients are large, even relatively poor fractures that are shut-down by stress interference, can contribute useful effective fracture lengths of tens of feet, and can sometimes compete with much larger fractures. Interference of the production transients generated by closely spaced transverse fractures, draining a shared reservoir volume, can accelerate the production decline. These effects are accounted for in the GOHFER transverse fracture production module.

For example, Table 1 shows the estimated fracture properties for six transverse fractures placed simultaneously in a single stage on a horizontal well. The estimates are conducted base on the grid reservoir and proppant concentration properties from the fracture placement model. The fracture labeled “Transverse 1” is at the toe of the stage, and the presence of a previous stage, with its stress shadow, are accounted for. The proppant cutoff length for this fracture is only 40 feet, with an estimated flowing length of 25.4 feet. Most of the created length is effective, so the infinite conductivity effective length is estimated to be 22.4 feet. This cluster took only 3.5% of the stage volume. Transverse 6, at the heel of the stage, and furthest removed from the previous stage stress shadow, takes 24.4% of the stage volume, and has a cutoff length of 1100 feet, but an estimated flowing length of only 47.4 feet, with an estimated effective length of 41.7 feet.

<table>
<thead>
<tr>
<th>Fracture</th>
<th>Gross Frac Length ft</th>
<th>Proppant Cutoff Length ft</th>
<th>Est Flowing Frac Length ft</th>
<th>Est Inf Conductivity Fracture Height ft</th>
<th>Average Proppant Conc./ft²</th>
<th>Average Fracture Width In</th>
<th>Max Fracture Width In</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transverse 6</td>
<td>2000.00</td>
<td>1100.00</td>
<td>47.4197</td>
<td>41.7468</td>
<td>0.30735</td>
<td>0.16375</td>
<td>0.255</td>
</tr>
<tr>
<td>Transverse 5</td>
<td>1980.00</td>
<td>760.00</td>
<td>45.426</td>
<td>34.0233</td>
<td>0.221321</td>
<td>0.094094</td>
<td>0.252</td>
</tr>
<tr>
<td>Transverse 4</td>
<td>2800.00</td>
<td>300.00</td>
<td>42.0125</td>
<td>35.465</td>
<td>0.369114</td>
<td>0.107063</td>
<td>0.262</td>
</tr>
<tr>
<td>Transverse 3</td>
<td>1980.00</td>
<td>1200.00</td>
<td>46.9357</td>
<td>37.9318</td>
<td>0.277261</td>
<td>0.114565</td>
<td>0.257</td>
</tr>
<tr>
<td>Transverse 2</td>
<td>1980.00</td>
<td>820.00</td>
<td>44.98</td>
<td>38.3515</td>
<td>0.399348</td>
<td>0.138818</td>
<td>0.256</td>
</tr>
<tr>
<td>Transverse 1</td>
<td>60.00</td>
<td>40.00</td>
<td>25.4453</td>
<td>22.3806</td>
<td>0.238247</td>
<td>0.028177</td>
<td>0.0489</td>
</tr>
</tbody>
</table>

Table 1: Estimated fracture properties for a multiple-cluster horizontal well frac, before production forecasting.

After running the production model, and accounting for drawdown, multiphase flow, and interference of production, the results of Table 2 are generated. The Table 1 results are inputs to this analysis, and the production results are considered to be a more accurate representation of expected fracture performance. These results show that Transverse 1 is expected to generate and infinite conductivity effective length of about 25 feet, while Transverse 6 generates 26 feet of effective length. The fracture all perform similarly because they are so closely spaced (only 38 feet) that they interfere with each other.
within days of the start of production. The “short” fracture at the toe of the stage also has higher average proppant conductivity because it is more effectively packed.

Table 2: Final fracture effective and flowing lengths after production forecasting.

<table>
<thead>
<tr>
<th>Transverse Fracture Result</th>
<th>Effective Length (ft)</th>
<th>Flowing Fract Length (ft)</th>
<th>PCD</th>
<th>KRW (in²/psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>26.1800</td>
<td>36.9998</td>
<td>3.205</td>
<td>3.22139</td>
</tr>
<tr>
<td>5</td>
<td>26.9775</td>
<td>38.1057</td>
<td>3.7067</td>
<td>3.66539</td>
</tr>
<tr>
<td>4</td>
<td>22.0096</td>
<td>31.2175</td>
<td>4.0571</td>
<td>3.18436</td>
</tr>
<tr>
<td>3</td>
<td>28.8244</td>
<td>44.3284</td>
<td>3.48176</td>
<td>3.86627</td>
</tr>
<tr>
<td>2</td>
<td>28.3745</td>
<td>40.8011</td>
<td>3.85</td>
<td>3.94123</td>
</tr>
<tr>
<td>1</td>
<td>25.0779</td>
<td>27.9754</td>
<td>4.14123</td>
<td>10.1149</td>
</tr>
</tbody>
</table>

The downside of the small toe fracture is that the volume of rock around it that has been deformed, and possibly exhibits enhanced permeability, will be very small. In this case, with close fracture spacing, the offsetting fractures will develop the needed drainage volume to support an economic EUR. The biggest loss of efficiency is that the heel fractures in the stage are taking more of the stage volume than necessary or desired.

Final Thoughts on Drainage Area and EUR

In discussing this topic with people, I have often gotten the response “Why don’t we just design really small treatments then?” There are several reasons why fracture treatments, especially in unconventional reservoirs, must be larger than indicated by their eventual effective-length performance. First is the issue of wellbore volume, near-well breakdown conditions, tortuosity, and other things that make sand placement problematic. These are discussed elsewhere and will not be dealt with in detail here. It’s enough to say that we can’t usually start pumping 2-5 psa slurry and get away with it. Pad and scour are required to clean up entry conditions and determine what maximum slurry concentration the system will accept. This takes multiple wellbore volumes of fluid.

The bigger problem is that a small volume treatment will generate little deformation in the reservoir rock mass. If an altered pore pressure state, volumetric strain, and significant created fracture length are required to generate a stimulated reservoir volume or enhanced permeability region around the well, or fracture, then we must pump sufficient volume at sufficient rate, to create a large deformed volume. It may not need to be propped. It may not need very high conductivity. It seems, based on extensive field evidence, that is does take a relatively large volume of fluid to generate a sufficient drainage area for economic recovery. There is a fairly large body of evidence that fluid volume is more important than proppant mass, and there is an equally large body of evidence that very large treatments do little to improve effective fracture length. Drainage volume and effective length are therefore almost independent variables, and must be designed for separately.

What constitutes the enhanced permeability volume? To me, this is a volume of rock containing hydrocarbons that is deformed sufficiently to generate a system of fissures and microfractures fairly extensively throughout. Some people like to tie this to the microseismic noise field, but microseism are generated by shear. Shear fractures may have no aperture, and may produce gouged surfaces with little conductivity. The shear planes can be activated by a strain field passing through the rock mass, and may not be connected, or fluid invaded. Some subset (several authors suggest 10-15%) of the microseismic volume may relate to an interconnected network of fissures that are at least partially connected to the well and primary hydraulic fracture system. In a sub-microdarcy rock matrix, these small fractures, while having practically no storage volume, can greatly enhance the system flow capacity.
Figure 34: Uplift of system flow capacity, or permeability, as a function of induced micro-fracture porosity.

Figure 34 shows the increase in system permeability over the “matrix” permeability of a rock mass for different base matrix permeability values and different fracture porosities. The average fracture aperture is assumed to be 0.001 inches for this analysis. Note that in high permeability systems, such as the 1 md line (green), the presence of fractures makes little difference to flow capacity until the fracture porosity reaches about 1e-04. These are conventional reservoirs where the flow capacity is dominated by matrix properties. Considering the 0.001 md line (orange), the permeability of the system increased 100-1000 fold for fracture porosities of 1e-05 to 1e-6. These are the enhanced permeability effects of a large deformed rock volume that contribute to an economic drainage volume and EUR. This is not tied to the volume of the fracture system, but to the volume of the rock that can be drained by the fracture system. Within this system, the flow of gas and oil are controlled by capillary and gravity percolation, as discussed here. This very-low-energy flow eventually feeds into the dominant hydraulic fracture, and proceeds to the well. This system does not show up on any reservoir or well rate-transient analysis, and is not related to what we perceive as an effective fracture length.

So what is the effective fracture length? As I choose to define it, the effective fracture length is the fracture that affects the rate-transient decline of the well by developing a linear flow regime. In this linear flow regime, the flow into the exposed surface of the fracture, then down the length of the fracture, dominates the production and generates an increase in flow rate from the reservoir. In time, the reservoir pressure transient will expand away from the fracture face, eventually developing either a pseudo-radial or boundary influenced transient flow regime. At this time the fracture is no longer controlling production. Instead, the reservoir flow capacity (enhanced permeability region) controls the movement of fluid from the reservoir to the fracture and well. The good news here, is that damage to fracture conductivity after this time has little impact on well productivity. The degree of permeability enhancement controls the rate at which production can be sustained during the pseudo-radial flow period. The size of the enhanced permeability region, or spacing of wells (interference) determines the size of the ultimate drainage volume and EUR.

Figure 35 is an Agarwal-Gardner type curve model for a fractured well. The early time, dimensionless time (Tda) less than 0.001, is the flow period dominated by the fracture. Once the pressure transient moves into the pseudo-radial flow regime, around Tda=0.01, the fracture has minimal impact on production. Boundary effects show up, in this example, at about Tda=0.1. Further production beyond this time is controlled by depletion of a fixed drainage volume.

Figure 35: Type-curve model for a fractured well in a rectangular bounded drainage area.

Improving fracture effective length and conductivity have a definite impact on initial production rate (IP), and can extend the linear flow period. The size and extent of the enhanced permeability area control the production and duration of the pseudo-radial flow period. The onset of boundary effects is controlled, in part, by the size of the enhanced perm region, but
more likely by well spacing and induced transient pressure interference between wells. Judicious planning of fracture treatment design, fracture spacing, and well spacing, taking into account expected commodity pricing and service costs, should allow for an economically optimum development plan (see SPE 168612). This apocryphal optimum plan does not mean the biggest frac you can pump, or the highest possible rate, sand mass, or concentration. It does not mean the highest IP ever reported in the area. It means the development plan that maximizes the value of the asset and resource base.