



Geomechanics for Unconventionals Series, Vol VIII:

Who Redefined Frac Gradient: And Why?

By Dr. Neal B. Nagel

Having taught petroleum geomechanics for more than 25 years, I can attest that the term ‘**frac gradient**’ (fracture gradient) is both easily-defined and commonly confused. More importantly, a new definition of *frac gradient* has emerged from the completions community in the last several years based upon the **instantaneous shut-in pressure (ISIP)**. In this post, we’ll explore what *frac gradient* is and why it should not be derived from *ISIP* values.

First-things-first, ‘gradient’ needs to be defined. In petroleum applications, gradient mostly means a normalization of pressure or stress with respect to depth, so the common units might be psi/ft or kPa/m or ppg (where pounds per gallon is commonly used to express drilling mud density). One key to understand is that even if gradient is constant, the actual magnitude of pressure or stress is still changing with depth – so a constant gradient says there is no rate of change (of pressure or stress) with depth while a changing gradient means there is an increasing or decreasing rate of change with depth.

In the simple definition, *frac gradient* is the pressure (divided by the true vertical depth, TVD, where pressure is applied) at which a hydraulic fracture is opened, which means that it is equivalent to the least principal in-situ stress (S_{hmin} , in a normal faulting stress environment) and equivalent to the ‘**closure stress**’ normalized by depth. However, Schlumberger refers to it as ‘the pressure required to induce fractures’ and API actually has two definitions – *frac gradient* is ‘the pressure gradient at which the formation accepts whole fluid from the wellbore’ and *formation fracture gradient* is ‘the hydrostatic value...required to initiate a fracture in a subsurface formation’. Because the **opening/closure pressure** for a fracture is rarely equal to the **creation pressure (initiation or inducing pressure** in API or Schlumberger parlance) or the **propagation pressure**, confusion ensues.

The three most historically common methods to compute *frac gradient* (Hubbert and Willis, 1957; Matthew and Kelly, 1967; and Eaton, 1969) each essentially relate *frac gradient* to the (minimum) in-situ stress without considering conditions to create or propagate a fracture. We still use these and similar methods to, for example, generate a profile of S_{hmin} along a well path for well construction purposes or as input into a hydraulic fracture simulator for completion design. Confusion, however, arises when we consider what it takes to create (i.e., initiate or induce) and/or propagate a hydraulic fracture.

The consideration of the creation of a hydraulic fracture necessarily invokes consideration of geometry, but, again, note that none of Hubbert and Willis, Matthew and Kelly, or Eaton invoke geometry – as their computation of frac gradient is solely based upon the stress in the formation. As the common hydraulic fracture is generated in tension, geometry is important to fracture creation because to induce

tension in a formation, when we apply a pressure to the (largely) impermeable formation which typically generates compressive stresses, requires that we account for geometry. More simply, pressure can only push against something (compression) and not pull it (tension), and geometry is key to how (and where) tension is created when something is compressed.

For petroleum considerations, the common and obvious geometry is a circular wellbore and, in order to create a fracture from this wellbore, pressure must be exerted such that the wellbore expands and a tensile stress is developed in the formation. The computation of wellbore stresses and stress changes induced by a pressurized fluid within a wellbore is commonly solved through the application of what are called the Kirsch equations.

The Kirsch equations are based upon several assumptions including the assumptions that the formation is homogenous, the formation behaves elastically, and that the geometry is perfectly circular. If the geometry is not perfectly circular, the Kirsch equations should not be used and, should they be, the computed results would be incorrect. The term '**breakdown pressure**' is commonly used to describe the pressure at which a hydraulic fracture is created/initiated/induced. However, the computation of *breakdown pressure*, through, for example, the use of the Kirsch equations, is geometry dependent. This means that if the wellbore were circular, we would get one *breakdown pressure* (fracture creation pressure), if it was non-circular we would get a different *breakdown pressure*, and if the formation was non-homogenous (for example, with natural fractures present) we would get yet another *breakdown pressure*. The important take-aways then are that: 1) *breakdown pressure* is geometry dependent; and 2) because of this geometry dependence and associated stress changes, the *creation/initiation/inducement/breakdown pressure* (divided by TVD) is not equal to the *frac gradient*.

The fact that *breakdown pressure* is not equal to *frac gradient* (and often is much larger than the *frac gradient*) has caught up to more than one drilling engineer. The test methods for determining the pressure for opening or closing a fracture are time consuming and require that a fracture be first created. Commonly, to avoid these issues, a formation integrity test (FIT) or a leakoff test (LOT) will be conducted immediately upon drilling out a casing shoe at the start of a new well section. The challenge is that neither an FIT nor an LOT actually opens a fracture and the computed results are, rather, heavily influenced by the stresses around the wellbore and hence are geometry dependent and may be more similar in magnitude to the *breakdown pressure* than the *opening/closure pressure*. And when the well geometry changes (whether due to a non-circular wellbore, natural fractures, or the like), it is not uncommon to find that the well plan (based upon the FIT or LOT) is now seriously in error – with associated additional time or expense added to the well program.

If *frac gradient* is not equal to the *creation/initiation/inducement/breakdown pressure*, how does it compare to fracture propagation? Is fracture propagation equivalent to *frac gradient*?

Anyone who has had the occasion to buy an ice cream milkshake (or malt, if that suites your taste) knows that you need a straw with a good size diameter. Trying to drink a milkshake through a narrow straw is often fruitless as the fluid is too thick to move through the straw. The primary reason for this is that the flow resistance of the milkshake is related to its viscosity. As viscosity increases, so does the

flow resistance (as a function of flow area; in our case the straw diameter). A similar effect occurs with frac fluid inside a hydraulic fracture.

As the viscosity of the fluid in the hydraulic fracture increases, the resistance to flow increases, but in order for a hydraulic fracture to propagate, fluid (fluid pressure) must get to the tip of the fracture and fail the formation. If the flow resistance is high (due to high viscosity and/or a long or narrow hydraulic fracture) more pressure is required to propagate the fracture. In addition, if the formation is more difficult to break, more pressure is needed to propagate the fracture. This means that: 1) the *propagation pressure* is higher than the *frac gradient*; and 2) the *propagation pressure* varies with the fluid viscosity and the ability to break the formation (grow the fracture). So not only is the *propagation pressure* not equal to the *frac gradient* but, like *breakdown pressure*, the *propagation pressure* is not solely a function of formation stress (in the case of *breakdown pressure*, it is a function of geometry; in the case of *propagation pressure*, it is a function of fluid viscosity and the pressure required to physically break the formation and grow the fracture).

During the injection process, pressurized fluid moves through surface equipment, then the wellhead, the casing/tubing of the well, and into a hydraulic fracture. Owing to a combination of the fluid properties and injection rates, there are often considerable friction pressure losses (i.e., pressure that does not get to the fracture tip due to the energy lost to friction). When the pumps are quickly stopped, and the fluids stop moving, these friction pressures disappear and the resulting pressure – called the *instantaneous shut-in pressure, ISIP* – serves as an indication of the excess pressure in the hydraulic fracture above the *opening/closing pressure* due to the effect of fluid viscosity and the pressure required to break the formation at the fracture tip. The *ISIP* value will be close to or at the *propagation pressure* and will (again, divided by TVD) be greater than the *frac gradient*. The difference between the *ISIP* value and the *opening/closing pressure* is called the **net pressure**. *Net pressure* is the key to hydraulic fracturing since *net pressure* essentially represents the work being done to the formation. Again, when the injection pumps are stopped and an *ISIP* value is obtained, the hydraulic fracture is still open (due to the net pressure). This excess (net) pressure must dissipate (leakoff into the formation) before the fracture can close.

A common meaning to each word in a language (the concept behind the word) is important since this facilitates communication. ‘Green’ only means green because we have agreed it means that particular color (and does not mean blue or red or yellow). If we all agreed that ‘frac gradient’ meant the *ISIP* value divided by TVD, at some level this could be acceptable. However, that is not the case and using *ISIP* to define *frac gradient* adds confusion within the oil and gas industry rather than reducing it.

More importantly, recall that the *ISIP* value is a function not only of the true underlying *frac gradient* but is also a function of the frac fluid, hydraulic fracture dimensions, and the ability to grow a fracture. These can and do change even if depth is constant (as is possible in a horizontal lateral). As a result, the *ISIP-based frac gradient*, rather than being an indicator of the rate of change of pressure or stress with depth, is now a complex, and largely unpredictable, variable of depth, frac fluid properties, hydraulic fracture dimensions, and the ability to break formation and grow a fracture. This, in-turn, makes it very

difficult, for example, to interpret the physical significance of changing *ISIP-based frac gradient* from toe to heel in a horizontal lateral.

So, in the end, does this matter or is this simply a time-consuming academic exercise? Twenty years ago, in the age when we believed in equal-length, bi-planar hydraulic fracture creation, we predicted that *net pressure* was on the order of a few 100s of psi for most hydraulic fractures. For a 10,000-ft wellbore with a true *frac gradient* of 0.7 psi/ft, a common *ISIP-based frac gradient* would be in error by +/- 5%. However, we now see *net pressures* reported to be 1000 psi or more, which may represent an error of 15% to 30% or more. Is this error level still academic?

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