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A Primer on the Geomechanics behind Fracturing Pressure Curves

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What Is This Article About?

In this article, I will break an idealized pressure curve (like what is recorded during hydraulic fracturing or pressurize fracturing tests) in different segments and explain the geomechanics behind each. I will try to answer questions such as:

- Why does pressure increase, decrease or remain constant in each segment?
- At what pressure a fracture initiates? At what stage it can be considered a mature fracture? what pressure is required for a fracture to grow?
- What are the important pressure values on this curve and how they are representing the mechanical state of the rock. How well-known pressure values such as *leak-off*, *initiation*, *breakdown*, *propagation*, *shut-in*, and *closure pressures* are defined and what is their geomechanical significance?

I will deliberately avoid getting deep in explaining mechanical models behind fracture initiation and propagation for the sake of simplicity.

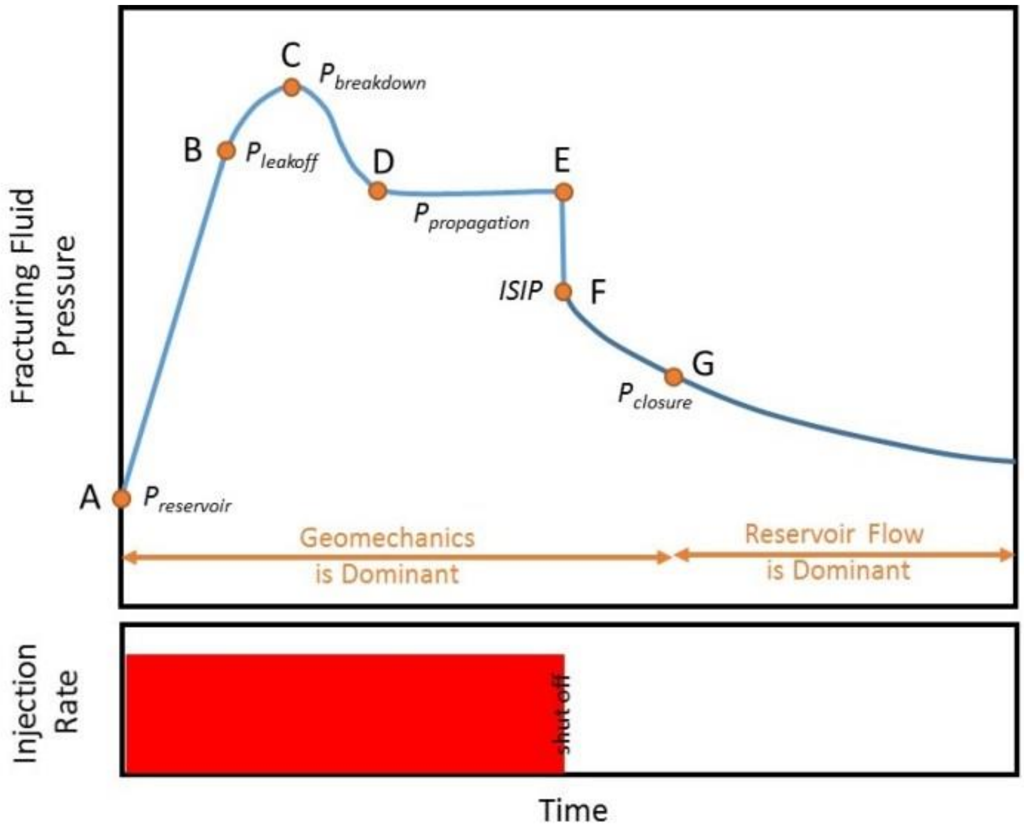

Figure 1. A pressure curve idealizing what is usually measured during hydraulic fracturing or pressurized fracturing tests. Remember that the graph is schematic and not-to-scale.

Idealization

To avoid complexities that are out of the scope of this primer article, I will use an ideal case of hydraulic fracturing similar to pressurized fracturing tests such as mini-frac, extended leak-off, or DFIT tests (Figure 1). The curve in Figure 1 simply shows how fracturing fluid pressure (on the vertical axis) varies with time (on the horizontal axis). The rate of injection is assumed to remain constant before the pumps are turned off. Note that this is an ideal curve and similar to many other idealization in engineering, the real curves may not look as smooth as this one. Also, the graph has not been drawn to scale on any of its axes to ensure all the major details and variations could be demonstrated. In addition, it was assumed that no natural or induced fractures exist in the zone of interest prior to fracturing.

Setup

The operation is performed on an isolated zone of a wellbore that can be either cased or open. In a simple pressurized fracturing test, the fracturing fluid is injected at a specific and constant rate for a period of time (that is to be known by the response of the rock to injection during the test) and then pumping is stopped although the pressure measurement is continued. In massive hydraulic fracturing, the injection rate varies by time and varying volumes of proppants are also injected along with the fracturing fluid.

Fluid pressure is measured throughout the entire test most likely at the wellhead and occasionally downhole. If pressure is measured at the wellhead, it needs to be converted to downhole pressure by accounting for the hydrostatic column of the fluid and all the dynamic pressure losses caused by friction and other effects during injection. This conversion becomes more cumbersome in massive fracturing jobs performed with high injection rates, special fluids (viscose, energized, foam, nitrogen, etc.) and proppants.

Ascending Straight Up (A-B)

After injection is started, the low-permeability target interval is usually intact with no fractures to let the injected fluid escape. At this condition, by continuing injection in the isolated volume of the borehole, the fluid will be compressed and, as a result, pressure has to increase. The rate of pressure increase (e.i., the slope of the line A-B) depends on different parameters mainly the compressibility of fracturing fluid (e.g., you can inject a larger volume of a less compressible fluid with less increase in pressure) and the rigidity of your container (the well). The rigidity of the container varies based on whether the well is cased or not and, also, dependent on how packers used for zone isolation and other tools will deform in response to pressurization. This straight line might be affected by high permeability of the formation, pre-existing fractures, or fluid pathways related to the cement job.

A Little Bit Extra!

If injection is stopped at a desired pressure along this period , the test is called Formation Integrity Test (or FIT). This test is used to ensure the target formation is competent enough to stand the maximum pressure needed for drilling or enhanced recovery. Nowadays, however, conducting full-cycle tests is more favored as it provides much more useful information.

When It Bends (B) – Leakoff Pressure

The discussed straight line does not continue forever and there comes a so called 'leak-off' point where this line bends. This is the time when induced fractures are starting to form. Initiating fractures means there will be more room for the injected fluid to occupy. Having this extra room, fluid will not get as much pressurized as before and the slope of the line is reduced and it will appear as a bending point.

Although fractures are already initiated at this bending point, they should not be considered as maturely extended fractures. These initiated fractures are small in both length and width and they are not likely to propagate far without being exposed to greater pressures. Note that Leakoff pressure is usually greater than minimum in-situ stress and the reason is speculated to be the stress concentration around the borehole.

The Uphill (B-C)

By keeping on injection, the initiated fractures will open wider and extend farther from the well and, as a result, more room will be created for the injected fluid. This extra room means less pressure increase and more bending (the curve slope will reduce) in response to more fluid injection. This segment of the curve might be quite short for the highly brittle rocks. Fluid injection type, rate and viscosity along with the complexity of the fracture also play roles in forming this uphill segment.

An important point to remember here is that, at this stage, the fracture is 'stable' in contrast to what we will see soon in the next segment of the curve. A stable fracture needs higher pressure to overcome the rock's resistance against propagation and if the pressure does not increase, the fracture will not grow anymore. At this stage, more injection and pressure is required to extend the fractures meaning that the operator is in full control of the fracture's destiny. However, as soon as the climax of the curve is passed, we are going to lose control as will be discussed in the following.

The Climax (C) – Breakdown Pressure

This is a climax necessary for creation of a trustworthy fracture. For a long time, definition of breakdown pressure and its difference with fracture initiation pressure has been a source of debate mainly due to the complex physics behind the problem. There are some less popular theories that speculate that the time of breakdown is when a fracture actually initiates (e.g., Boone and Ingraffea, 1989). However, the commonly accepted theories in fracture mechanics believe in existence of fracture prior to this time. These theories, however, differentiate the status of the fracture before and after breakdown. According to these theories, breakdown is a point where the fracture moves from a 'stable' to an 'unstable' condition (Guo et al., 1993, is a great read on this if you are interested). They also sensibly argue that even the fluid entrance into the fracture and pressure distribution within the fracture are different in these two distinct states.

Breakdown pressure has been observed to be dependent on fracturing fluid type and viscosity, injection rate and borehole size. Efforts to simply calculate breakdown pressure from elastic models (commonly used in borehole stability and drilling models) have not been very successful. Also, there have been some efforts in the industry to use the recorded breakdown pressure in these models to estimate magnitudes of in-situ stresses using elastic models, mostly showing less success.

A Little Bit Extra!

The similarity between fluid pressure-time graphs recorded during fracturing (Figure 1) and stress-strain curves measured during compressive failure of rock (Figure 2) is interesting. It might have been the reason that, in earlier times, some experts (e.g., Morgenstern, 1962) theorized that breakdown of the rock might be the result of shear failure. Some experiments have also shown that geometry complexities of the curved or parallel fractures have major influences on the magnitude of breakdown pressure (see Figure 3 for an example).

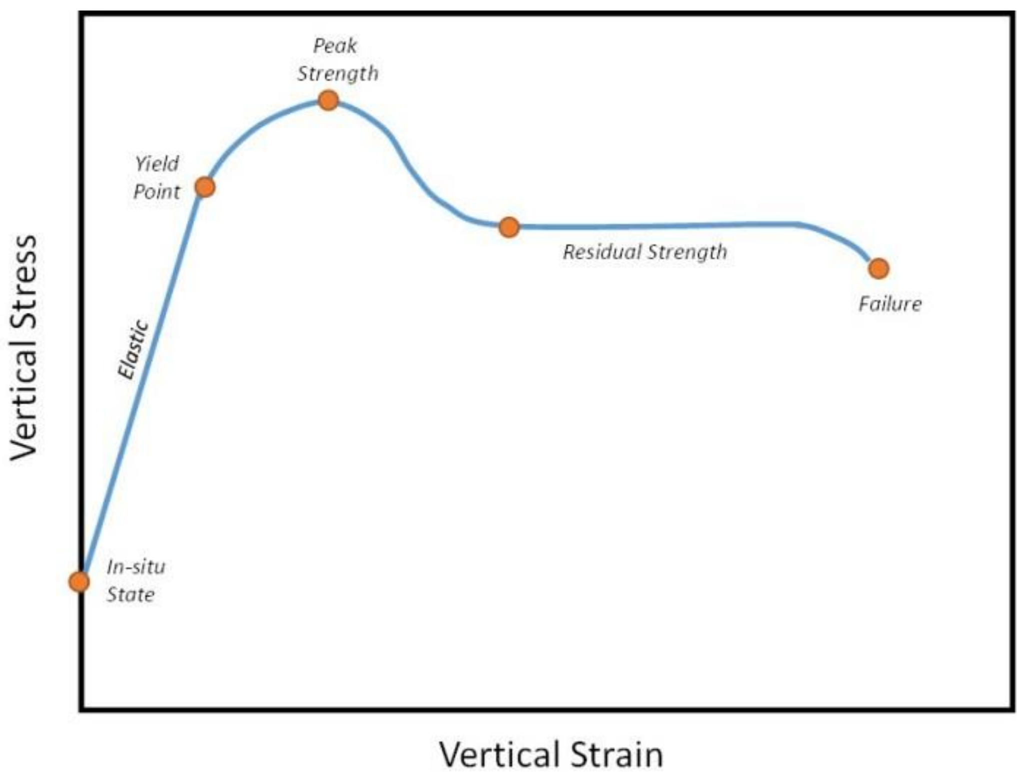

Figure 2. A schematic of stress-strain curve as recorded during compressive triaxial test. In this test, the rock is believed to mostly fail in shear. Although the general appearance of this curve looks similar to the fluid pressure-time curve recorded during hydraulic fracturing, the modes of fracturing in these two cases are known to be very different.

Losing Control (C-D) – Relief-In Pressure

At the breakdown point, the energy provided by pressurization helps the fracture to become mature enough and grow unstably. This unstable fracture is not in control anymore and employs the previously stored energy along with the currently injected one to grow wider and farther. As a result of this extensive fracture propagation, the fracturing fluid has a lot of room to occupy and so, it relaxes some of its high pressure and the fluid pressure drops substantially. There is another reason for pressure drop: the unevenly distributed pressure in the previous immature fracture is now re-distributed much more uniformly in the current wide and long fracture.

As we will see in the next section, like any instability with a limited amount of energy, this one has to come to a stable state if given enough time.

The Flat Ride (D-E) – Propagation Pressure

Ultimately, with no change in the rate of injection, fluid, fracture and rock will all come to a stable and balanced condition where, first, the existing pressure at the tip of the fracture is exactly what is required to extend the fracture and, second, the volume of the injected fluid is exactly in balance with the fracture volume generated by fracture extension.

Having everything in balance, pressure does not need to vary significantly if injection rate does not change. This equilibrium pressure is called fracture propagation pressure or fracture extension pressure or simply fracturing pressure. Fracturing pressure is higher than minimum in-situ stress and it is usually used to determine the allowable upperbound pressure during drilling or injection to avoid fluid loss or leakage.

Enough Pumping! (E)

So far, many things have been revealed throughout a course of injection of a fluid in an isolated interval of a well. Things such as how the wellbore as a container reacts to injection, how much pressure is required to initiate the first fractures in the rock, at what pressure we can create a 'mature' fracture, and finally, the balanced pressure at which the fracture keeps propagating. In case of hydraulic fracturing jobs, the operator has a desired fracture geometry in mind so s/he keeps injecting until s/he is convinced that the desired fracture geometry is achieved based on the designs (I leave it to him/her to tell us how much s/he trusts the results). In the case of formation tests, keeping on injecting for long is not going to reveal much more. In contrast, there is still so much valuable knowledge to be learned by stopping injection and simply observing the pressure response of the system.

A Little Bit Extra!

Based on several lab simulations of hydraulic fracturing for wells with different orientations , Abass et al. (1996) showed that the pressure loss during the unstable growth period (so called 'relief-in pressure') is related to fracture geometry complexities such as curving.

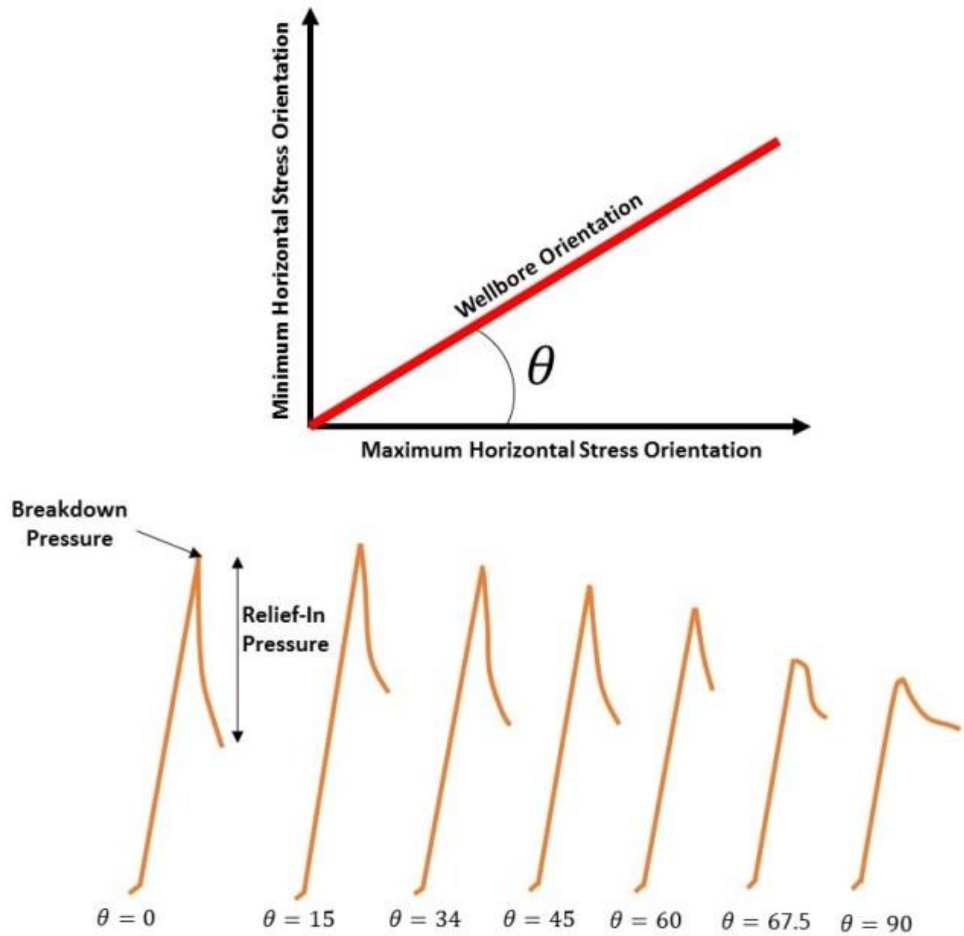

Figure 3. Results of experimental hydraulic fracturing tests performed by Abass et al. (1996) showing variation of *breakdown pressure* and *relief-in pressure* versus change in horizontal wellbore orientation with respect to the in-situ horizontal stresses.

Free Fall (E-F) – Instantaneous Shut-In Pressure (ISIP)

As soon as the pumps are off, a sudden drop will happen in the pressure curve and pressure will fall to a value called Instantaneous Shut-in Pressure (ISIP). This drop happens because the pressure caused by flow turbulence and friction during injection instantly disappears after pumping is stopped. With no influences from the dynamic flow, the mechanical characters of rock and fracture are probably less masked in ISIP in comparison to the previously recorded parameters. This is the reason that ISIP has gained so much popularity in the industry.

Some may argue that ISIP is the 'real' fracture propagation pressure as it does not include the dynamic effects of the flow. This reasoning might not be very convincing as fracture propagation pressure cannot be really considered valid if fracture does not propagate. In other words, existence of flow and its characteristics can hardly be separated from fracture propagation.

Curtains Closing (F and Beyond) – Closure Pressure

After shut-in, the fracture will stop propagating and instead, in absence of the required pressure for its propagation, it will start closing. Fracture closure is the consequence of pressure drop in the fracture as fluid flows back into the well and penetrates into the rock, simultaneously. This period is probably the most favorite part of the operation for geomechanics as it provides a great opportunity to find closure pressure, which is a great proxy for minimum in-situ stress. Let me emphasize here that closure pressure is not exactly minimum in-situ stress (i.e., a parameter that we might never be able to measure it exactly) but it can be very close to this stress component. One other thing to keep in mind is that the exact location of closure pressure on the curve is not always easily identifiable and industry has come up with several different approaches to estimate it.

After closure, pressure will still decline due to the permeable behaviour of the fracture and rock but contribution of geomechanics to the process becomes trivial. The rest of the curve is highly favored by the engineers who want to find out more about fluid efficiency, formation leakoff capacity, permeability, and reservoir pressure.

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