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Pump-in and Flow-back Tests for Determination of Fracture Parameters and In-situ Stresses

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Abstract

Fracture parameters such as fracture initiation and propagation pressure and in-situ stresses such as minimum horizontal stress and overburden, are critical inputs for petroleum exploration design. They are important not only for wellbore scale issues, e.g. wellbore stability analysis, lost circulation prevention, well trajectory optimization and hydraulic fracture stimulation, but also for reservoir scale issues, e.g. basin modeling, reservoir compaction and subsidence studies and fault activity analysis. The pump-in and flow-back test is a promising and highly reliable method for determining fracture parameters and underground stress information. Moreover, such a test is extremely helpful for understanding the fracture growth mechanism from the wellbore wall to the far field region, which is particularly important for drilling and hydraulic fracturing design.

This paper first reviews the field tests used to evaluate minimum horizontal stress and fracture parameters, with a description of their advantages and limitations. Then, the effects of a number of factors (e.g. permeability, fluid leak-off and mud cake development) on the fracture parameters (fracture initiation and propagation pressures) of the test are discussed. Finally, due to their similarities, the importance of pump-in and flow-back tests for understanding the fundamentals of lost circulation and wellbore strengthening is highlighted.

Introduction

For drilling wells safely and efficiently, precise determination of minimum horizontal stress and fracture parameters (e.g. fracture initiation and propagation pressure) is critical for the drilling industry. These data are required for evaluating wellbore stability, determining fracture gradients and required drilling mud weights, predicting wellbore breathing and lost circulation, designing wellbore strengthening treatments, and selecting casing shoe depths.

Indirect methods from logs and geomechanical modeling[1] are often used to predict fracture gradient and minimum horizontal stress. However, where a high degree of precision is required, a direct field test measurement is usually needed to calibrate the predicted results. Field tests may include formation integrity tests (FITs), leak-off tests (LOTs), extended leak-off tests (XLOTs), and pump-in and flow-back tests. However, not all these tests can provide reliable stress information, either due to insufficient injection time/volume (resulting in insufficient fracture length for stress evaluation), or due to a number of factors distorting test signatures and leading to interpretation difficulties and uncertainties.

Misinterpretation of minimum horizontal stress and fracture parameters may cause a number of drilling problems, while increasing non-productive time and well costs[2]. If fracture pressure is overestimated, unexpected lost circulation and wellbore breathing can occur. Additional unplanned casing strings required to mitigate these problems, may in extreme cases jeopardize the success of the well. Conversely, if fracture pressure is underestimated, planned well costs will be unrealistically high. As a result, other projects may suffer from a lack of funding or the well may not even be drilled.

This paper first reviews the field tests used to evaluate minimum horizontal stress and fracture parameters, with a description of their advantages and limitations. Then, a variety of factors affecting pump-in and flow-back interpretation are discussed. Finally, the similarities between pump-in and flow-back tests and lost circulation are discussed, with the aim of understanding the fundamental physics of lost circulation and factors affecting fracture behavior.

Field Tests

Mud density and casing setting depths are strongly influenced by fracture pressure and in-situ stresses. Field injectivity tests, including FITs, LOTs, XLOTs, and flow-back tests, are designed to determine fracture pressure and minimum horizontal stress during the drilling process. These tests are typically performed after a casing string has been set, after drilling 10 to 20 feet[3] of new formation.

Formation integrity test (FIT)

An FIT is a test to confirm the cement and formation integrity near the casing shoe, and to ensure the fracture gradient at the shoe is sufficient to withstand any expected or potential loads while drilling the subsequent hole section. In an FIT, the bottom-hole pressure is gradually increased to a pre-determined value, which is lower than predicted fracture initiation pressure. Typically no fracturing occurs during an

FIT, and the wellbore remains intact. The pressure-time curve remains as a straight line during the test, while the slope of the line indicates the stiffness/compliance of the wellbore systems. Accurate fracture parameters or in-situ stress information cannot be obtained from an FIT.

Leak-off test (LOT)

An LOT, as schematically shown in Figure 1, provides an estimate of fracture gradient at the casing shoe. This information is used for mud weight design and lost circulation prevention in the subsequent hole section. It is often assumed that the lowest fracture gradient in a given wellbore will exist at the casing shoe, however for a variety of reasons this is not always the case. During the LOT, the well is shut-in and drilling fluid is gradually pumped into the wellbore at a constant (usually low) rate, until a noticeable inflection point is observed on the pressure-time curve. The wellbore pressure at the inflection point is known as leak-off pressure, indicating that a fracture has been created. Leak-off pressure is commonly assumed equal to fracture initiation pressure, which is used to determine the upper limit of wellbore fluid pressure.

However, it is the authors' contention that leak-off pressure is not necessarily equal to fracture initiation pressure. It is usually somewhat higher than fracture initiation pressure, especially when "dirty" fluid (i.e. drilling mud with high solids content) is used for the test. This idea will be discussed latter in this paper.

It is worth noting that a leak-off test rarely provides far-field stress information, since the fracture created in a leak-off test remains very short (within several radii from the wellbore) due to minimal injection volume. This short fracture is still under the influence of the near wellbore stress concentration. Figure 2 shows the hoop stress concentration in the near wellbore region, for a vertical well in a formation with uniform far-field horizontal stresses. To correctly measure the far-field minimum horizontal stress, a fracture must extend through the near wellbore stress concentration region.

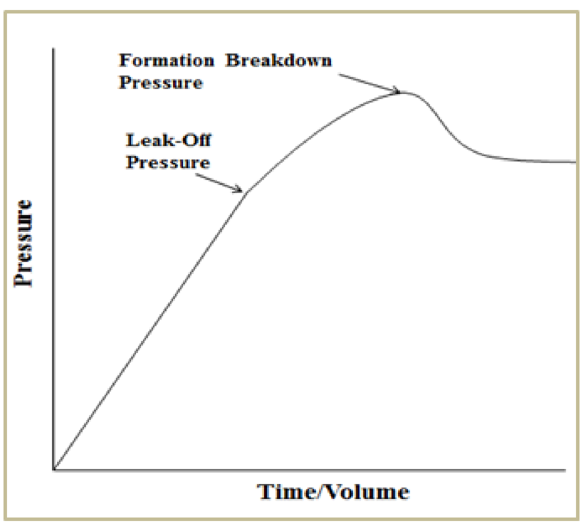

Figure 1. Schematic illustration of pressure-time/volume plot in a leak-off test.

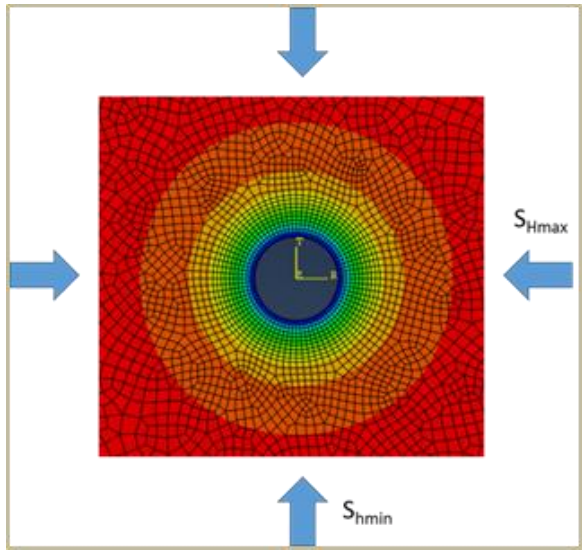

Figure 2. Near wellbore hoop stress concentration with uniform far-field stresses Shmin=SHmax (blue color = more compression, red color = less compression).

Extended leak-off test (XLOT)

A fracture generated during an XLOT will typically have sufficient length to pass through the near wellbore stress concentration region. Therefore, this test may provide sufficient data for estimating far-field stress and fracture information. In an XLOT, fluid injection continues until a relatively steady fracture propagation pressure is reached, followed by a shut-in phase as shown in Figure 3. In addition to leak-off pressure, several other fracture parameters can be estimated from an XLOT, including formation breakdown pressure, fracture propagation pressure, instantaneous shut-in pressure and fracture closure pressure.

Formation breakdown pressure is the divide separating the stable and unstable fracture propagation stages. During the time between leak-off and formation breakdown, the fracture experiences stable propagation. The fracture growth during this period is very slow, with a volume increase rate less than the pumping rate. Therefore, the wellbore pressure continues to rise prior to formation breakdown, which is the upper pressure limit for stable fracture growth. The volume increase during this stage is primarily due to the growth of fracture width rather than length.

Subsequently, during the time between formation breakdown and fracture propagation, the fracture extends unstably with a rapid increase in fracture length. The wellbore experiences a sudden pressure drop immediately after formation breakdown, since the fracture volume expands at a rate much greater than the pumping rate. With continued injection, the pressure ultimately levels off to fracture propagation pressure, indicating the fracture growth rate is roughly equal to the pumping rate. However, with continued pumping and an increase in fracture length, the fracture propagation pressure will gradually decrease in a wave-like pattern. This pressure change signature will be discussed later in this paper.

Instantaneous shut-in pressure (ISIP) is the pressure observed immediately after pumping is stopped. Once pumping ceases, the additional pressure required to overcome flowing friction along the fracture and tubing (if pressure is recorded at the surface) and the fracture tip resistance, immediately drop to zero. Therefore, instantaneous shut-in pressure is always somewhat lower than fracture propagation pressure.

Fracture closure pressure is frequently estimated from shut-in data using interpretation methods developed for mini-fracturing tests. Fracture closure pressure is commonly taken as the best estimate of minimum horizontal stress, based on the assumption that the wellbore pressure is equal to minimum horizontal stress as the mechanical fracture starts to close. It is worth noting that mini-fracturing test interpretation methods were initially developed for diagnostic fracture injection tests in permeable reservoirs with clean fluids. However, XLOTs are usually performed in tight shale with mud. Therefore, direct use of these methods for XLOT interpretation may give inaccurate results. In addition, fracture closure during the shut-in phase is the result of fluid leak-off into the formation, which is highly dependent on permeability and threshold capillary entry pressure. In low-permeability formations like tight shale, leak-off may be too slow for the fracture to close within a reasonable amount of time. In this case, minimum horizontal stress cannot be properly evaluated using the aforementioned methods. Alternatively, an extended leak-off test with a flow-back phase may provide a better solution. This test is referred to as pump-in and flow-back test in this article.

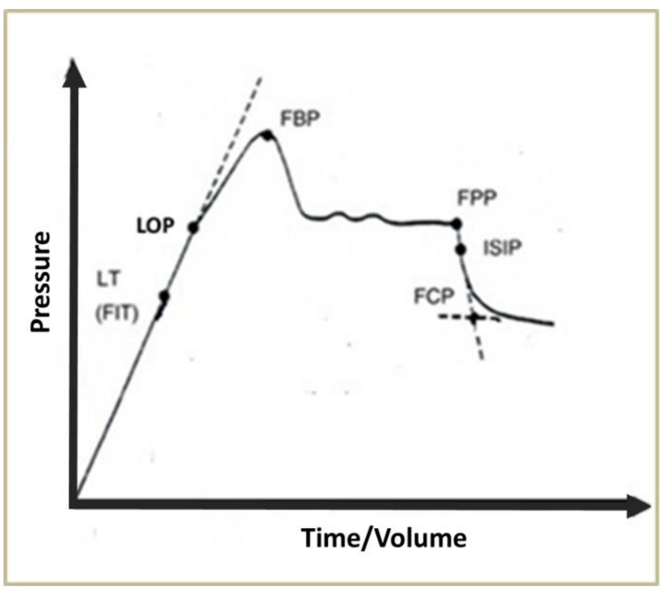

Figure 3. Typical XLOT plot (Modified after Gaarenstroom et al.[4]).

Pump-in and flow-back test

A pump-in and flow-back test is a standard XLOT followed by a flow-back phase with either a constant choke or constant flow-back rate at the surface. Both XLOTs and pump-in and flow-back tests can include multiple cycles for confirming test results. Since fluids flow back directly to the surface, fracture closure in a pump-in and flow-back test is almost always assured and not dependent on fluid leak-off into the formation. These tests provide a superior method of measuring fracture closure pressure in low permeability formations, especially when mud is used as the injection fluid. In a pump-in and flow-back test, wellbore pressure and flow-back time/volume are recorded. A plot of pressure versus flow-back time/volume will show an inflection point, which indicates a change in system stiffness/compliance (Figure 4). This inflection point is commonly interpreted as fracture closure pressure, equal to minimum horizontal stress.

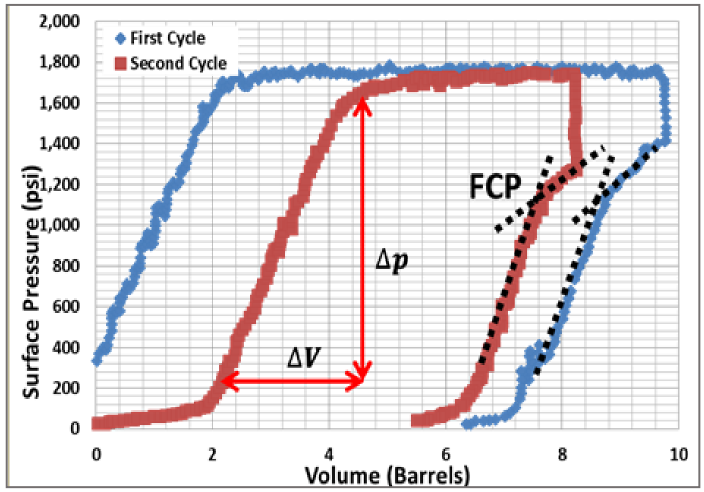

Figure 4. An example of pressure-volume plot in a pump-in and flow-back test (Modified after Gederaas and Raaen[5]).

In addition to minimum horizontal stress, pump-in and flow-back tests also provide leak-off pressure (fracture initiation pressure), formation breakdown pressure, fracture propagation pressure, instantaneous shut-in pressure, and fracture reopening pressure. These values (especially fracture initiation and propagation pressure) are important considerations for mud density selection, casing program design and lost circulation prevention, particularly in wells with narrow drilling margins.

With clean injection fluid, fracture initiation and propagation pressures are primarily dominated by in-situ stresses and rock strength. Conversely, when drilling mud is used as the injection fluid, these parameters are also highly dependent on mud properties (e.g., mud type and solid particle size and concentration), petro-physical properties of the rock other than strength (e.g., lithology, permeability, and wettability), and interactions between the drilling mud and formation rock (e.g., fluid leak-off and filter cake development on the wellbore wall and fracture faces, and capillary pressure effects). A detailed understanding of these and other factors is required for a proper interpretation of pump-in and flow-back tests, and understanding fracture growth behavior and lost circulation fundamentals. The remainder of this paper will focus on the influence of these factors.

Fracture Initiation Pressure and Leak-off Pressure

Fracture initiation theory

In theory, fracture initiation takes place when the effective circumferential stress (sometimes called tangential or hoop stress) at the wellbore wall reaches the tensile strength of the rock[5]. In addition, poroelastic theory predicts that fracture initiation pressure at the wellbore wall, can vary significantly, depending on whether or not there is fluid penetration into the formation.

For impermeable formations (or perfect mud cake) without fluid penetration, fracture initiation pressure can be estimated by the Hubbert-Willis model (Equation 1)[6, 7]. For permeable formations with fluid penetration, the Haimson-Fairhurst model (Equation 2) is more applicable[6, 7].

$$p_{ini} = 3S_{h\min} - S_{H\max} - p_p + T \tag{1}$$

$$p_{ini} = \frac{3S_{h\min} - S_{H\max} - \eta p_p + T}{2-\eta} \tag{2}$$

In these equations, P_{ini} is the fracture initiation pressure; S_{hmin} and S_{Hmax} are minimum and maximum horizontal stress, respectively; P_p is pore pressure; T is tensile strength of the formation rock; and η is a poroelastic parameter of the rock with a range [0, 1], which determines the magnitude of the stress induced by fluid penetration.

Factors that affect fracture initiation pressure

Fluid penetration leads to an increase in pore pressure in the vicinity of wellbore wall. This elevated pore pressure can further cause an increase in the local tensile stress. As a result, fracture initiation pressure can be much lower with fluid penetration than without fluid penetration. This means, any factors which influence fluid penetration through the wellbore wall, may alter fracture initiation pressure. Several of the most influential of these factors are discussed below.

Permeability: If all other conditions are identical (including in-situ stresses) a formation with low permeability will have a higher fracture initiation pressure than a formation with high permeability. This is because, in less permeable rock, fluid penetration through the wellbore wall and any related pore pressure increase around the wellbore, is largely restricted. Conversely, fluid penetration into a permeable formation can increase the near wellbore pore pressure, resulting in decreased compression or increased tension in the vicinity of wellbore wall. Therefore, a lower fracture initiation pressure is expected in permeable rock, compared to impermeable rock (or perfect mud cake) provided the in-situ stress state is equivalent. However, due to differences in material properties, the minimum horizontal stress in low permeability, clean shale is typically higher than the minimum horizontal stress in high permeability sand, under identical load conditions (overburden). Furthermore, mud cake development in high permeability formations can also significantly inhibit fluid penetration. Cleary, there are multiple factors besides permeability, which influence fracture initiation pressure, particularly with high solids content drilling mud.

Capillary entry pressure: Threshold capillary entry pressure is the pressure at which the non-wetting phase begins to displace the wetting phase in the largest pore throat size in a formation. When the wellbore fluid and pore fluid are immiscible, the capillary entry pressure can significantly inhibit fluid penetration and local pore pressure increase at the wellbore wall. Therefore high capillary entry pressure may help maintain high fracture initiation pressure.

Capillary entry pressure depends significantly on pore throat size, rock wettability, and miscibility/immiscibility of the injection and formation fluids. Assuming all other factors are identical, and the injection and pore fluids are immiscible, smaller pore throat sizes, mean higher capillary entry pressures and less fluid penetration at the wellbore wall. Shale normally has a much smaller pore throat size distribution than sandstone, and threshold capillary entry pressures for hydrocarbons in water-wet shale are typically in the range of 200 to 800 psi, compared to 10 to 100 psi for water-wet sandstone[1]. Therefore, fluid penetration (even with immiscible fluids) is more likely to occur in sandstone, facilitating fracture initiation. Capillary entry pressure, hence fluid penetration, is also controlled by rock wettability and fluid immiscibility. In brine saturated water-wet rock with small pore throats, if the injection fluid is non-wetting phase (e.g. oil based mud or synthetic based mud), the capillary entry pressure can significantly inhibit fluid penetration. In contrast, if the injection fluid is wetting phase (e.g. water based mud), there is no capillary entry pressure preventing fluid penetration. Thus, fracture initiation is more likely to occur in the latter case under otherwise identical conditions.

Mud cake: Due to its extremely low permeability, mud cake can effectively isolate wellbore fluid from formation fluid, inhibit pore pressure increase, and maintain high fracture initiation pressures. Additionally, the high plasticity of the mud cake may also make fracture initiation more difficult.

Two prerequisites for quality mud cake development are high solids content in the injection fluid and initially high fluid penetration rate through the wellbore wall. Thus, mud cake development is highly related to rock permeability, as well as capillary entry pressure of the injection fluid. In turn, a well-developed mud cake will prevent additional fluid penetration. As discussed above, sand and sandstone usually have a higher penetration rate than shale, due to their high permeability and low capillary entry pressure. Therefore, when mud is used, sand and sandstone can exhibit a relatively high fracture initiation pressure due to mud cake development, despite some temporary pore pressure increase around the wellbore. Any elevated pore pressure from filtrate invasion, should quickly bleed off to the far-field.

The effect of a quality mud cake on fracture initiation is very important for lost circulation prevention. In a preventive wellbore strengthening operation, lost circulation material

(LCM) is added to the drilling mud before lost circulation or hydraulic fracturing occurs. LCM can assist the creation of a tight mud cake on the wellbore wall, which greatly inhibits fracture initiation.

Leak-off pressure

Leak-off pressure, as shown in Figure 1, can be read directly from an injectivity test. Often, leak-off pressure and fracture initiation pressure are assumed to be the same. However, this assumption only stands when clean injection fluid (without solids) is used. When a fluid with a high solids content (i.e. drilling mud) is used, leak-off pressure and fracture initiation pressure may not be equivalent.

Leak-off pressure is the point where the pressure vs. injection time/volume plot begins to deviate from linearity, indicating a significant change in the stiffness or compliance of the system. Fracture initiation pressure is better defined as the point at which a micro-fracture starts to form at the wellbore wall. With clean fluid, a micro-fracture can usually grow at a high enough rate to generate a noticeable inflection point. Clean fluid can readily enter the newly generated micro-fracture, leading to an increase in compliance or a decrease in stiffness of the system. Conversely, with drilling mud as the injection fluid, mud solids can immediately seal the newly created micro-fracture, or form a filter cake across the fracture mouth. This mud barrier effectively isolates the fracture from the wellbore, and arrests fluid flow into the fracture. Injectivity tests[8] show that micro-fracturing and mud-sealing events are usually not detectable in the pressure build-up curve, even in laboratory tests using precise gauges. Laboratory tests[8] have also shown that fractures can grow to a significant size without any deviation in the pressure build-up curve. This means the fluid pressure does not breakdown the mud barrier, and no fluid enters the fracture. However, fracture initiation has already been achieved, and the fracture grows mechanically without fluid driven pressure inside it. For a detectable pressure change to occur, wellbore pressure must build up to a high enough level to breakdown the mud barrier and cause rapid fluid loss into the fracture. The leak-off pressure observed in an injectivity test, using a high solids content injection fluid, is actually the mud barrier breakdown pressure, rather than the fracture initiation pressure. It is also somewhat higher than fracture initiation pressure, as shown in Figure 5.

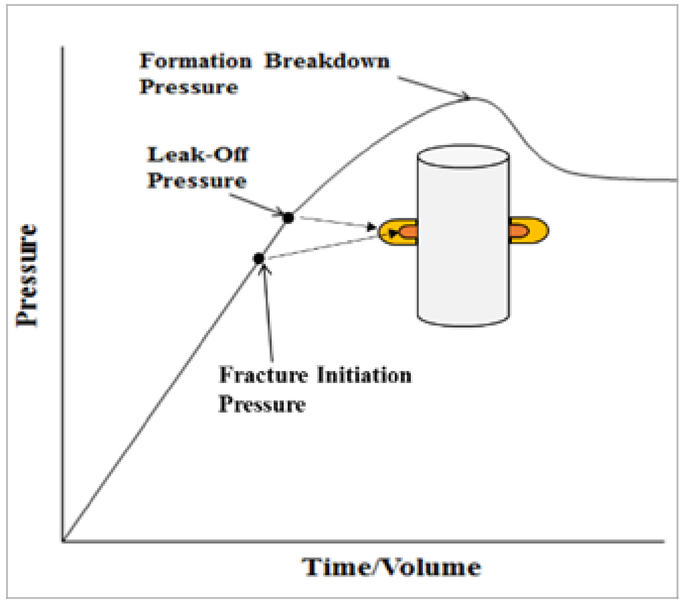

Figure 5. Leak-off pressure is higher than fracture initiation pressure with high solids-content injection fluid, due to mud cake sealing effect.

Fracture Propagation Pressure

Fracture propagation theory

Fracture propagation pressure is the wellbore pressure at which there is sustained unstable fracture growth. It is not a constant value but decreases in a wave-like pattern, as fracture length increases. Field and laboratory test examples are given in Figure 6, showing the wave-like pattern reduction of fracture propagation pressure. This pressure reduction and wave-like pattern fluctuation can be explained with a fracture mechanics model.

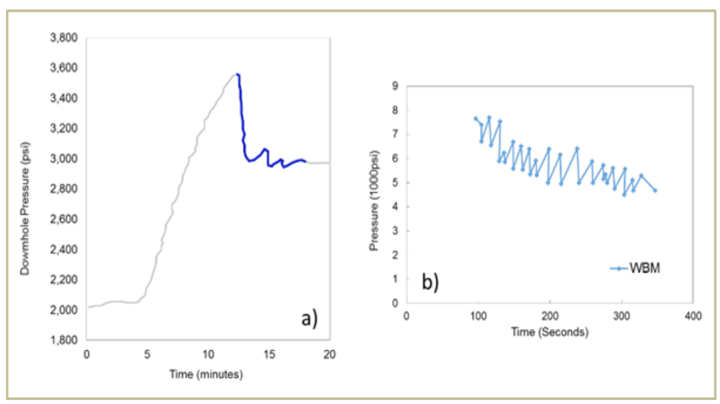

Figure 6. Wave-like pattern pressure drop with fracture propagation. a: field test (after Okland et al.[9]), b: lab test (after Morita et al.[10] and Fuh et al.[11]).

According to the theory of linear elastic fracture mechanics, a fracture starts to propagate when the stress intensity factor K_I at the fracture tip reaches the fracture toughness K_{IC} of the rock. Assuming injection of incompressible fluid into linear elastic rock, at constant rate Q, the fracture length, propagation pressure, and stress intensity factor, during fracture propagation, can be analytically solved as a function of injection time[12], as shown below:

$$a(t)=\left(\frac{E'Q(t-t_0)}{2\pi^{1/2}K_{IC}}\right)^{2/3}\propto t^{2/3} \tag{3}$$

$$p(t)=\frac{E'Q(t-t_0)}{2\pi a(t)^2}\propto t^{-1/3} \tag{4}$$

$$K_I(t)=\frac{E'Q(t-t_0)}{2\pi^{1/2}a(t)^{3/2}} \tag{5}$$

$a(t)$ is the fracture length, $p(t)$ is the fracture propagation pressure, $K_I(t)$ is the stress intensity factor at the fracture tip, E' is the plane strain modulus of the rock, t is the injection time, and t_0 is the fracture propagation start time.

Equations 3 and 4 predict that fracture length increases smoothly and proportionally to $t^{2/3}$, and fracture propagation pressure decreases proportionally to $t^{-1/3}$, as schematically shown in Figures 7 and 8, respectively.

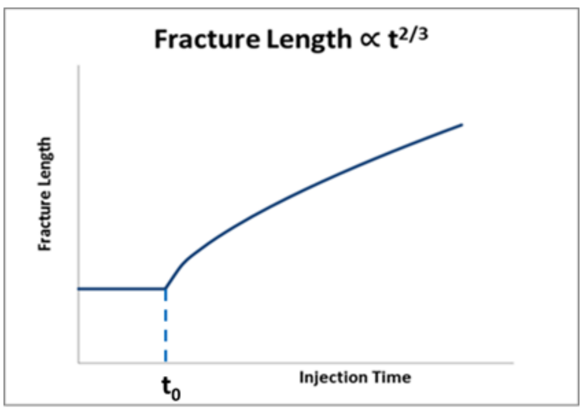

Figure 7. Theoretical prediction of fracture length increase with injection time.

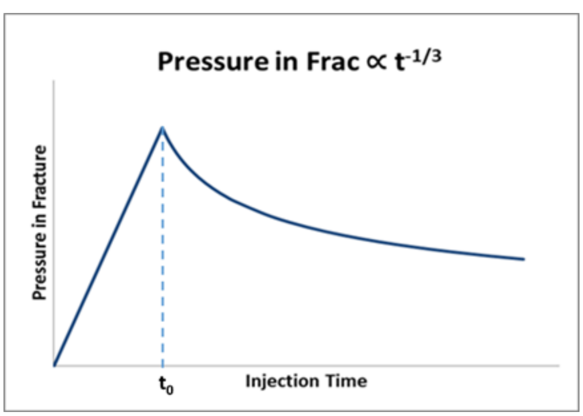

Figure 8. Theoretical prediction of fracture propagation pressure decrease with injection time.

In theory, the stress intensity factor (Equation 5) should maintain a constant value equal to fracture toughness, with smooth fracture propagation. In reality, when the stress intensity factor $K_I(t)$ reaches fracture toughness K_{IC}, the fracture will have a sudden growth in length. According to Equation 5, the stress intensity factor will decrease immediately with this fracture length increase. The fracture will stop propagating until the stress intensity factor again reaches K_{IC} with continued pumping. This length jump and fracture propagation stop process will repeat multiple times during fracture propagation, so the stress intensity factor fluctuates in a "saw-tooth" pattern with injection (Figure 9).

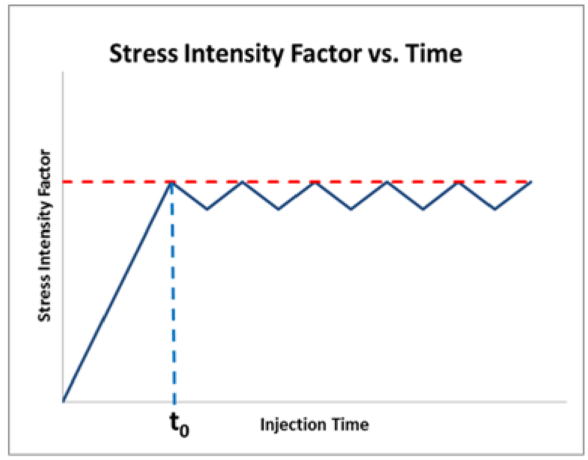

Figure 9. Change of stress intensity factor with injection.

Similarly, when the fracture length increases suddenly, the stress intensity factor will drop immediately to a value below fracture toughness. The fracture will stop propagating until the stress intensity factor increases sufficiently with continued pumping. Therefore, fracture length increase is not a smooth process as shown in Figure 7, but rather a step by step process as shown in Figure10.

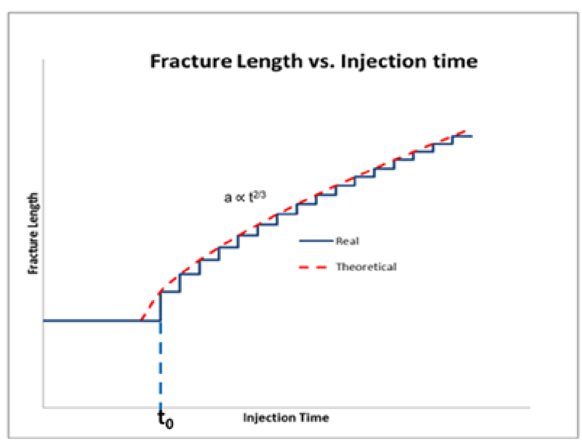

Figure 10. Fracture length increase during fracture propagation (blue solid line: real case; red dotted line: theoretical prediction).

Using the same arguments for a step by step increase in fracture length, rather than the smooth process shown in Figure 8, the pressure decrease with injection time should also be a step by step process (Figure 11). This explains why the fracture propagation pressures in laboratory and field tests, decrease in a wave-like pattern in Figure 6.

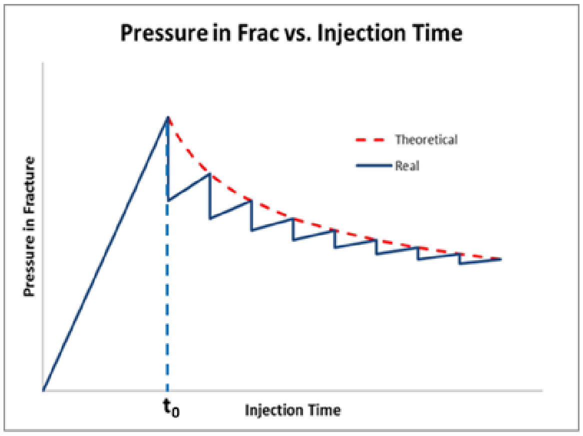

Figure 11. Fracture propagation decrease during injection (blue solid line: real case; red dot line: theoretical prediction).

Factors that affect fracture propagation pressure

Factors which influence fracture initiation pressure, including permeability, capillary entry pressure and mud barrier development can also significantly influence fracture propagation pressure. In more permeable formations with low capillary entry pressures and drilling mud as the injection fluid, a mud cake or mud plug can easily build up inside the fracture. Mud barriers, such as these, effectively isolate the fracture tip from pressure in the wellbore. For continued fracture propagation, additional wellbore pressure is required to overcome these mud barriers, resulting in higher observed fracture propagation pressures.

Conversely, in less permeable formations, especially with high capillary entry pressures due to immiscible wellbore and formation fluids (i.e. OBM and water-wet shale or silty-shale) leak-off and mud barrier buildup is much more restricted. In this case, the fracture tip is not effectively isolated from pressure in the wellbore, resulting in lower observed fracture propagation pressures.

These factors are extremely important for lost circulation mitigation and are consistent with the findings of wellbore strengthening studies. Wellbore strengthening is far more likely to be successful in high permeability/low capillary entry pressure sand and sandstone, than in low permeability/high capillary entry pressure shale and silty-shale.

Preventive and Remedial Wellbore Strengthening

Simply put, preventive wellbore strengthening methods attempt to “strengthen” the wellbore to prevent fluid loss due to hydraulic fracturing. Remedial wellbore strengthening methods attempt to “strengthen” the wellbore after fluid loss due to hydraulic fracturing has already occurred. Preventive methods focus both on fracture initiation and fracture propagation pressures, while remedial methods focus primarily on fracture propagation pressure, since a fracture has already been created.

In a preventive wellbore strengthening treatment, LCM has a dual purpose for preventing fracture initiation. First, LCM helps develop a mud filter cake with low permeability and high ductility. As discussed previously, this filter cake will help maintain a high fracture initiation pressure, by effectively isolating the formation from pressure in the wellbore, thus inhibiting any pore pressure increase in the vicinity of the wellbore wall.

Second, LCM particles can immediately plug any generated micro-fractures, preventing both fluid flow into the fracture and pressure communication between the wellbore and fracture tip. In theory, this process should restore (maintain) a leak-off pressure higher than fracture initiation pressure. This claim can be confirmed by the experimental wellbore strengthening study by Guo et al.[8].

Figure 12 shows the pressure build-up curve, when using a drilling fluid with 20 ppb graphitic LCM, during a preventive treatment test[8]. The pressure was increased to 2500 psi (test device limit) without apparent leak-off. Since no leak-off response was observed, it might be concluded that the formation had not been fractured. In fact, the test block was fractured completely to its edges (Figure 13). A reasonable explanation for this observation is that fractures initiated on the wellbore wall were immediately sealed by LCM in the mud. Therefore, no significant mud loss or noticeable pressure response occurred. This test demonstrates that observed leak-off pressure is not necessarily equal to fracture initiation pressure, especially when LCM is used. Leak-off pressure can be somewhat higher than fracture initiation pressure (Figure 5) and fracture initiation can occur without fluid loss. This test also confirms that leak-off pressure can be significantly increased by using LCM in a preventive wellbore strengthening treatment.

After fracture initiation and fluid loss have occurred, preventive wellbore strengthening treatments work in the same manner as remedial treatments. With fluid loss, LCM particles are forced into the fracture to form a solid bridge or filter cake within the fracture, and thereby increase fracture propagation resistance. However, fracture initiation and leak-off pressures are not generally restored to their original values by remedial treatments.

This assertion is confirmed by the DEA-13 experimental study[13] (Figure 14). This repeated test included 3 cycles. In the first cycle the intact wellbore was fractured with a fluid containing LCM, and a relatively high leak-off pressure was observed. The second cycle was a repeat of the first cycle, but without LCM. In this case, leak-off pressure was much lower than in the first cycle, because the mud barrier on the wellbore wall was previously destroyed. Fracture propagation pressure was also much lower since there was no effective bridge or filter cake development without LCM. In the third cycle, LCM was added back to the fluid, simulating a remedial wellbore strengthening treatment. In this case, leak-off pressure did not change compared to the second cycle. However, fracture propagation pressure did significantly increase.

From this analysis, it can be claimed that both fracture initiation and propagation pressure can be increased by wellbore strengthening treatments. Preventive treatments can increase both pressures, while remedial treatments only alter fracture propagation pressure. However, significant mud loss in a drilling well will only occur if fracture propagation pressure is exceeded. It is also worth repeating, that these treatments work much better in more permeable formations with low capillary entry pressures. An illustration of both methods is shown in Figure 15.

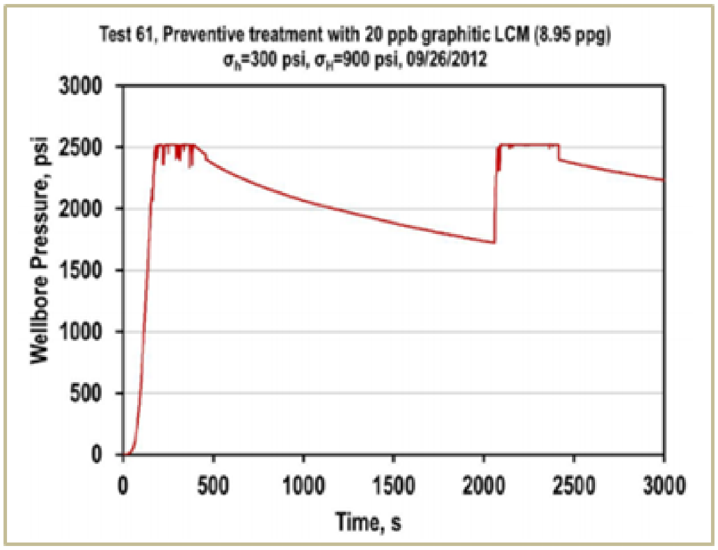

Figure 12. An example of a preventive wellbore strengthening test on a sandstone block (after Guo, et al.[8]).

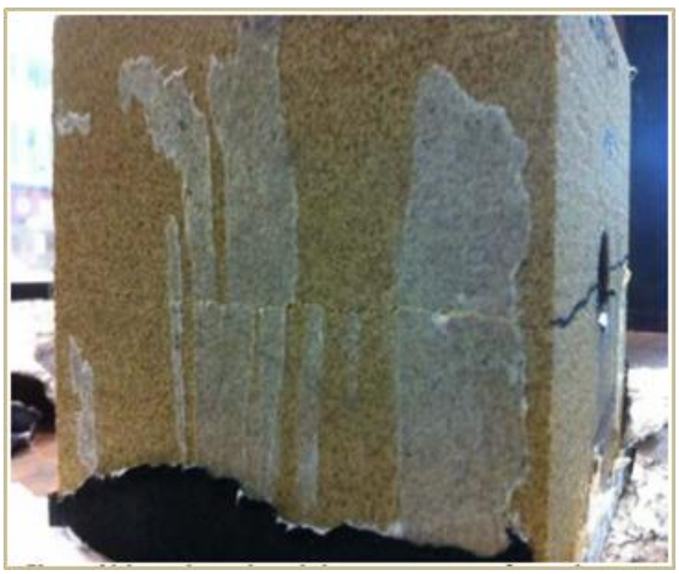

Figure 13. The sandstone test block for pressure build-up curve in Figure 12. The block was fractured to the edges without obvious fluid leak-off due to LCM sealing effect (after Guo, et al.[8]).

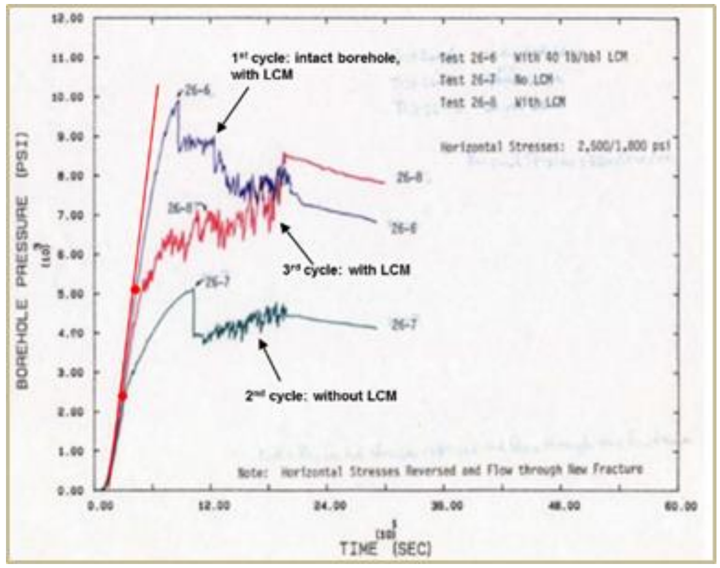

Figure 14. A repeated hydraulic fracturing test with LCM. 1st injection cycle (preventive treatment - intact wellbore, with LCM): high leak-off pressure and high propagation pressure. 2nd injection cycle (fractured wellbore, without LCM): low leak-off pressure and low propagation pressure. 3rd injection cycle (fractured wellbore, with LCM): low leak-off pressure, high (increased) propagation pressure. (after Black et al.[13]).

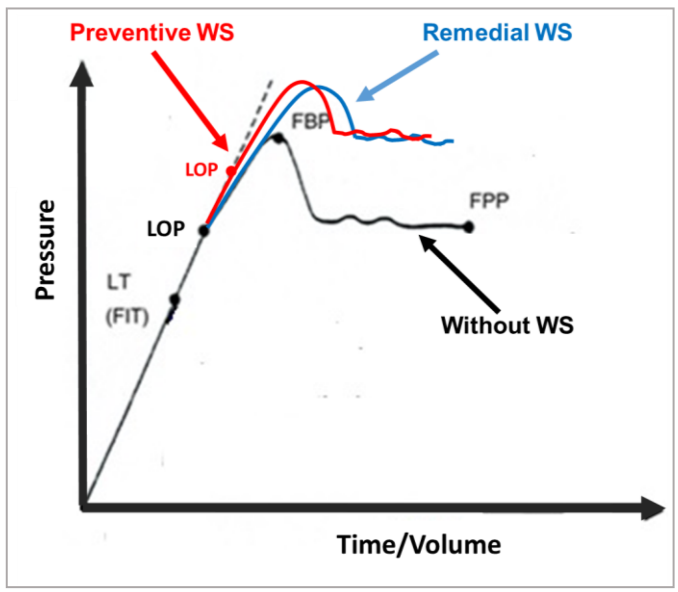

Figure 15. Preventive wellbore strengthening treatment enhances both leak-off pressure and fracture propagation pressure, while remedial wellbore strengthening treatment only enhances fracture propagation.

Lost Circulation as a Function of Formation Lithology

The fracture behavior in lost circulation and wellbore breathing is similar to that in a pump-in and flow-back test. A fracture initiates at the wellbore wall, and is then propagated to the far field by a fluid driven force. The main difference is that pump-in and flow-back tests are generally conducted at a constant rate into a known formation and depth. On the other hand, lost circulation generally occurs while circulating at a relatively constant wellbore pressure. The formation and depth where lost circulation is occurring is often unknown (at least initially) especially in long sections of open hole. It is not always correct to assume lost circulation is occurring near the previous casing shoe, where fracture gradient is presumed lowest.

Factors that affect pump-in and flow-back tests also influence lost circulation. From the above discussion, permeability, capillary entry pressure, and mud cake development on the wellbore wall and in the fracture can significantly affect fracture initiation and propagation pressures and therefore, lost circulation. These factors can vary significantly for different formation and fluid types.

Accurate identification of formation types where lost circulation is more likely to occur is extremely important for successful drilling operations[14]. In the following section, we will discuss the relative likelihood of lost circulation in salt, clean shale, clean sandstone, and silty-shale. Fractured carbonates are intentionally omitted from this discussion, since they are better handled as a separate topic.

Due to its high plasticity, in-situ stresses in massive salt (halite) tend to be uniform[15]. Simple rock mechanics models show that under the same load condition (i.e. overburden) uniform stresses lead to higher fracture initiation pressures, compared to anisotropic stresses. Additionally, massive salt has extremely low permeability and is therefore not penetrated by the drilling fluid. Lost circulation is rarely a problem in massive salt, except under certain conditions where inclusions or sutures are present.

Clean shale (typically high clay content, high Poisson's ratio, low Young's modulus mud rock) also has very low permeability and relatively high plasticity and fracture initiation pressure[14]. Due to its small pore throat sizes, clean (usually water-wet) shale has relatively large capillary entry pressures for immiscible oil or synthetic based drilling fluids. The combination of low permeability and high capillary entry pressure greatly inhibits fluid invasion into clean shale, preserving its relatively high fracture initiation pressure. Compared to silty-shale, sandstone, siltstone and fractured carbonates, lost circulation is usually much less of a problem in clean shale,

In theory, sandstone has relatively low fracture initiation and propagation pressures compared to shale, silty-shale and salt[14,15]. However, due to its high permeability, large pore throat sizes and low capillary entry pressures, a high quality filter cake can easily develop on the wellbore wall or inside a fracture. This filter cake effectively maintains fracture initiation pressures and can significantly increase fracture propagation pressure, if a fracture is created. Therefore, lost circulation is usually manageable in sandstone if appropriate drilling fluids (including LCM) are used. Pressure depleted sandstones present an additional challenge, since a reduction in pore pressure will also reduce fracture initiation and propagation pressures. Fracture initiation pressures may also be reduced depending on wellbore trajectory and the relative magnitudes of principal in-situ stresses. The last statement is true for all formation types, except where in-situ stresses are uniform or nearly uniform.

Silty-shale is a term commonly used to describe formations with properties between those of clean shale and sandstone. It therefore encompasses a relatively wide range of formation types and is not a precise lithological description. Silty-shale is commonly encountered in transition zones between clean shale and sandstone, but it can occur anywhere in the wellbore. Many reservoir top seals in deep water are comprised of shale, with silt contents ranging from 17 to 41 percent[16]. Therefore, much analysis has been performed on these types of formations, with respect to mineralogy, capillarity and reservoir fluid sealing capacity.

Silty-shale has intermediate permeability and capillary entry pressures, compared with clean shale and clean sandstone. However, capillary entry pressures for water-wet silty-shale are too high to be ignored, and likely hold the key to understanding the differences in apparent fracturing behavior, when silty-shale is drilled with oil or synthetic based fluid versus water based fluid.

When water-wet silty-shale is drilled with water based fluid, it generally behaves much like permeable (albeit tight) sandstone, with an effective filter cake formed on the wellbore wall or inside a fracture. Therefore, fracture initiation and propagation are no more likely to occur than in sandstone.

However, when water-wet silty-shale is drilled with oil or synthetic based fluid, capillary entry pressures are high enough to significantly inhibit leak off and filter cake development, similar to clean shale but with lower fracture initiation and propagation pressures. Therefore, without a protective filter cake, water-wet silty-shale drilled with oil or synthetic based fluid, is the most likely formation type to undergo hydraulic fracture initiation and propagation. Since permeability is higher than for clean shale, it may also be possible that wellbore pressure can be communicated to both the wellbore wall and potentially to the far-field, via natural fractures or interconnected pore space. These conditions also mean that both preventive and remedial wellbore strengthening methods are less likely to be successful.

Wellbore breathing, which is loosely described as fluid losses while circulating, followed by fluid flow back when the pumps are stopped, is almost always associated with oil or synthetic based fluids and water-wet silty-shale. Wellbore breathing is very similar to a pump-in and flow-back test, where a fracture is initiated and propagated while circulating. Since capillary entry pressures prevent fluid penetration and leak-off inside the fracture, fluids lost while circulating return to the wellbore when the pumps are stopped and the fracture closes.

Figure 16 shows logging data from two lost circulation and wellbore breathing events, in the same wellbore, drilled with synthetic based drilling fluid. Both loss zones are clearly identified by repeated resistivity measurements, while the gamma ray data clearly indicates that both fluid loss events occurred in silty-shale, rather than clean shale or sandstone[15].

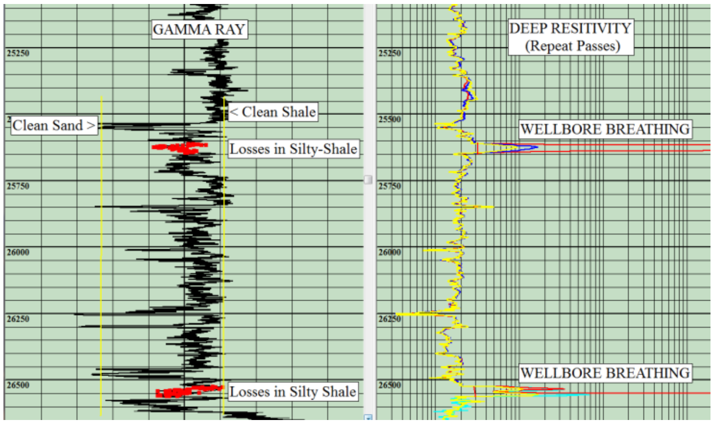

Figure 16. Two lost circulation and wellbore breathing events occurred in silty shale formations, rather than in clean shale or clean sand formations[14, 15].

Conclusions

Various types of injectivity tests, for interpreting fracture parameters and minimum in-situ stress, are reviewed in this paper, including FIT, LOT, XLOT, and pump-in and flow-back tests (XLOT with flow-back phase). Then, a number of factors that affect fracture initiation and propagation pressures are discussed. Finally, the implications of pump-in and flow-back tests on understanding, preventing, and mitigating lost circulation problems are provided. Specific conclusions critical to pump-in and flow-back test interpretation and lost circulation prevention and mitigation include:

1) An LOT does not usually provide sufficient information for evaluation of far-field stresses, due to its limited injection volume. Conversely, an XLOT with shut-in phase can give a sufficiently accurate prediction of minimum far-field stress for high permeability formations such as sandstone. For relatively low permeability formations like shale, an accurate evaluation of minimum far-field stress is best obtained from a pump-in and flow-back test.

2) Low permeability, high capillary entry pressure, and quality mud cake development, all contribute to maintaining high fracture initiation and leak-off pressures.

3) Leak-off pressure may not be equivalent to fracture initiation pressure when a high solids content fluid is injected. Due to the continuous sealing effect of solid particles, the observable leak-off pressure can be higher than fracture initiation pressure.

4) Fracture propagation pressure is significantly related to mud cake development inside the fracture. In formations with relatively high permeability and low capillary entry pressures, a quality filter cake usually develops inside the fracture, increasing fracture propagation pressure/resistance.

5) Using the same arguments for pump-in and flow-back test interpretation, a preventive wellbore strengthening treatment can increase both fracture initiation and propagation pressures, while a remedial treatment can only increase fracture propagation pressure.

6) Disregarding fractured carbonates, lost circulation and wellbore breathing are highly related to formation and fluid type and are most likely to occur in water-wet silty-shale drilled with oil or synthetic based fluids.

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