Chapter 39

Importance of Fracture Closure to Cuttings Injection Efficiency

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Abstract

The major benefit of adequate fracture closure is to release injection pressure and restore it to its initial magnitude during the shut-in period to prevent gradual pressure build-up over the injection batches that follow. This paper examines a number of injection cases where the benefits of adequate fracture closure and the detrimental impacts of insufficient fracture closure are respectively revealed.

In-depth examination of fracture closure impact can be set for short durations with relatively fewer injection batches, as well as for long periods with numerous batch injections. The former scenario focuses on determining the physics of the individual fracture closure, while the latter situation emphasizes the general trend with respect to peak pressure at the end of injection and terminal pressure at the end of the shut-in period.

In addition, this paper addresses the added complexities during fracture closing after shut-in that can be identified from the relationship between injection pressure and the G function superposition derivative. Straight-line behavior usually indicates that the formation is homogeneous and leak-off from the fracture into the formation is linear. Other responses such as concave or convex shapes of the G superposition derivative relationship may indicate the formation is either naturally fractured or tight (i.e., low permeability). Or, the pressure decline shapes may imply fracture tip extension, or fracture height recession. Direct examination of the pressure decline curves may reveal the relationship between the fracture responses and formation characteristics.

1. Introduction

As regulatory restriction on the disposal of solid wastes such as drilling cuttings becomes increasingly tightened worldwide, cuttings injection (CI) into an existing well or a dedicated well becomes standard and required operation in drilling. Various guidelines and best practices in CI operations were established to accommodate local conditions and requirements. A systematically designed CI operation can be seen in reference [1].

One of the very important tasks to ensure a successful CI operation is to continuously monitor injection pressure behavior. Among various pressure responses, the characteristics of fracture closure after shut-in directly relate to the quality of pressure control and thus to the ability to prevent near-well screen outs and unexpected shut down of injection wells.

Fracture closure can be assessed empirically by capturing the inflection point in the pressure decline curve. The inflection point generally reflects the transition between linear or bi-linear flow within the hydraulic fracture and pseudo-radial flow outside the hydraulic fracture.

Fracture closure can also be evaluated more accurately using analytical methods. Among various methods, popular ones are: a) the square-root time method to determine the transition between bi-linear flow and pseudo-radial flow using the filtration theory proposed by reference [2]; b) the Horner time method to determine early time fracture flow and late time pseudo-radial flow (see reference [3]); c) the *G* function method to identify the onset of fracture closure by examining the transition of the flow pattern proposed by Knolte (see reference [4]); and d) the superposition *G* function derivative method to determine the reversal of the *G* derivative that signals the transition between bi-linear flow and pseudo-radial flow proposed by Barree (see reference [5]).

This paper is intended to explore the physics of fracture closure behind the pressure decline curves. By examining the pressure responses in the CI pressure monitoring cases, patterns of both successful and unsuccessful pressure control were captured. Observations reveal that the length of duration in the shut-in period between the injections is a critical parameter with respect to the quality of pressure dissipation and fracture closure. Cuttings injection efficiency is a function of the magnitude of the disposal domain of the stimulated fracture volume.

Sensibly interpreting the physics of fracture closure from bottom-hole pressure responses can be difficult due to the inability to directly measure hydraulic fracture evolution. By comparing various fracture decline curves with reference to their relation to the *G* function and superposition derivatives, this paper identifies the key parameter as the pressure decline curve shape. The conventional interpretation of pressure decline with regard to the physical behavior of hydraulic fractures appears to be insightful. However, verification of this interpretation continues to be a challenge to the current technology.

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2. Quality of pressure maintenance in CI operations

Figure 1 provides a long-term assessment on batch cuttings injection. Four periods of pressure responses can be divided into:

- Period A – gradual pressure build up and difficulty in fracture closing
- Period B – good fracture closure
- Period C - excellent fracture closing
- Period D - gradual pressure build up and difficulty in fracture closing

Periods A and D form a repeat cycle with slightly higher peak pressures in Period D than in Period A. It is easily seen that the longest time for pressure dissipation was during Period C. This also led to the best possible fracture closure and lowest terminal pressure among all pressure decline curves.

The physics of fracture closing and its relation to pressure response can be more complex than from the stated single event or relation alone. For example, the fracture could be closed on cuttings so that the terminal pressure is high. In general, a slow leakoff can be envisioned as the equivalence of difficult in fracture closing. The sufficient pressure dissipation can also be caused by the initiation of a new fracture in a different orientation from the previous one, or an increase in fracture aperture due to its connection to natural fractures, or anything else. For simplicity in this paper, however, we contribute the pressure dissipation to the fracture closure without resourcing to its physical origins.

Figure 2 shows the pressure responses from 28 batches of cuttings injection separated into five periods (A-E). Significant rising peak pressures during Periods A, B, C and E reflect difficulties in cuttings injection. This is in contrast to the smaller peak pressure increase in Period D that indicates relatively easy injections. A couple of good pressure relief or deep drop terminal pressures are seen in injection periods B and E.

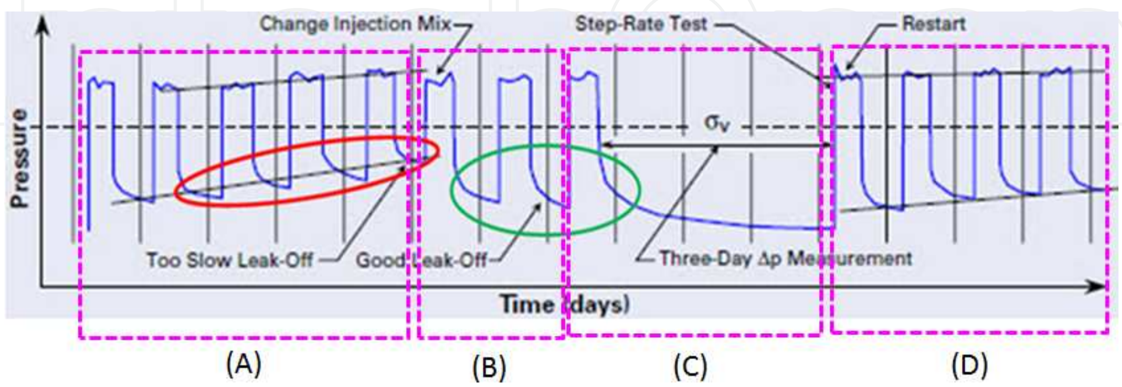

Figure 1. Pressure responses over long period of cuttings injection. (A): gradual pressure build up due to insufficient fracture closing; (B): good fracture closing; (C): excellent fracture closing with sufficient time; and (D): gradual pressure build up due to insufficient fracture closing.

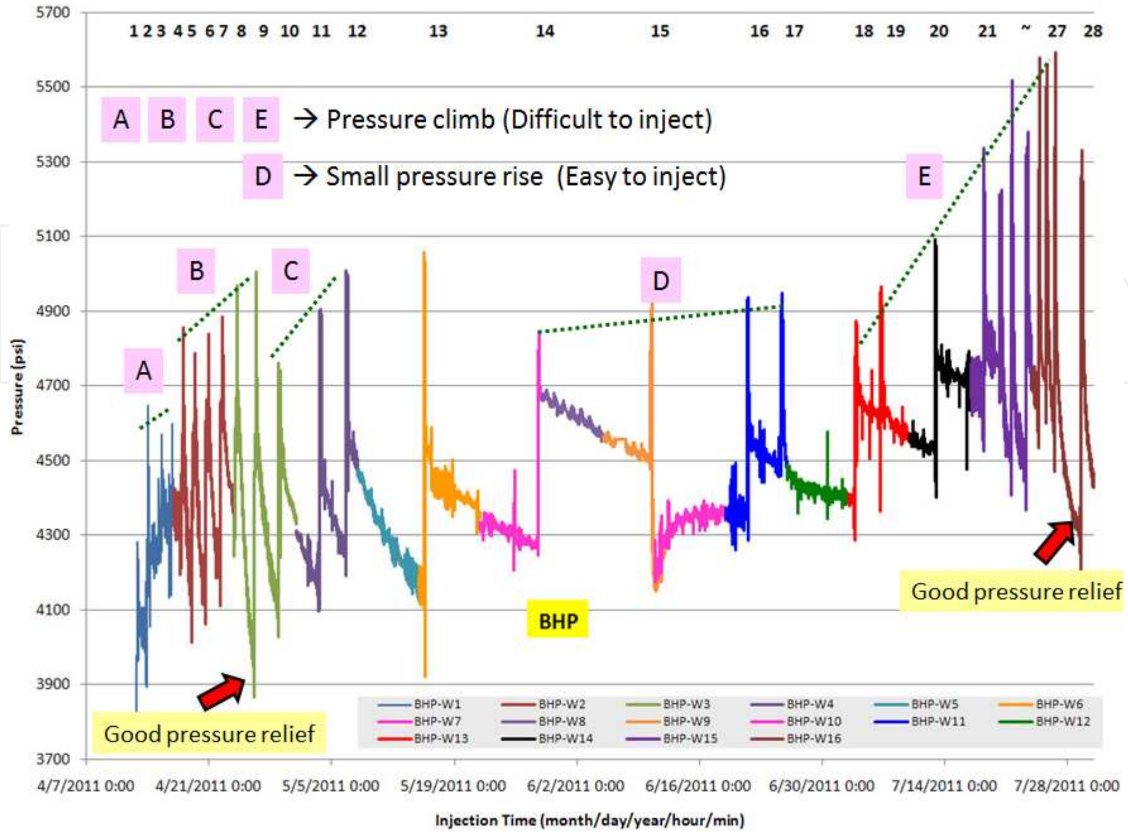

Figure 2. Observed bottom-hole pressures during 28 injection batches. Durations A, B, C and E show the rising peak pressures that are the indication of difficulties in cuttings injection. Duration D shows a slight rise of peak pressure that is the indication of easier cuttings injection.

When the injection batches were extended to 36 and we examined the well-head pressure, Figure 3 indicates that the average difference between the peak well-head pressure and terminal well-head pressure is 800 psi, while the average increase of well-head pressure (WHP) over the entire injection period is 400 psi. Therefore, the rate of pressure increase is 50% (i.e., rate = $\Delta P/P = 0.5$). Experience tells us that a 50% increase in pressure could be too high. For pressure to be manageable, the increase should be under 40%. Either injection pressure has reached its maximum value or the disposal domain capacity is restricted due to intersecting low permeable zones or as a result of stress reorientation when crossing the stress barrier. Either an adjustment to the injection plan or an alternative approach needs to be implemented. The good news from Figure 3 is that both peak pressure and terminal pressure at the final injection period show the declining trend, an indication of pressure relief.

The following information can be obtained from Figure 3 for each injection cycle:

- Peak value of well-head pressure
- Instantaneous shut-in well-head pressure (ISIP)
- Terminal well-head pressure

These three well-head pressure values can be simply divided into two pressure groups:

- Group A: injection pressure (before shut-in)
- Group B: declining pressure (after ISIP)

With respect to the trend of well-head pressure in peak, ISIP, and terminal values over time shown in Figure 3, Figure 4 shows the linear increasing trend correlating pressure and elapsed time with good correlation for the peak pressure, average correlation for the terminal value, and poor correlation for the ISIP value.

Examining four individual injections (i.e. injections A, B, C and D) as shown in Figure 5, it is noted that the time between injections A and B is quite short. As a result, there is not sufficient time for pressure to dissipate in injection A. For other injections (i.e. injections B, C, and D), there is sufficient time for the pressure to dissipate to the initial injection value.

If sufficient time is not given between injections, the result of the injection will not be as effective. Figure 6 shows that batches 17 and 19 are almost unnecessary because they are close to batches 16 and 18 so the pressure decline curves follow the same trend lines of batches 16 and 18 without being affected by injections 17 and 19. On the other hand, injections 17 and 19 may be viewed as two "free" injections because the general pressure fall-off behavior has not been affected. Figure 6 also shows the gradual increase of ISIP from 4627 psi in batch 16 to 4724 psi in batch 18, and finally to 4820 psi in batch 20. The rising ISIP is an indication in the increase of fracture closure pressure and collectively the pressure build up due to insufficient fracture closing.

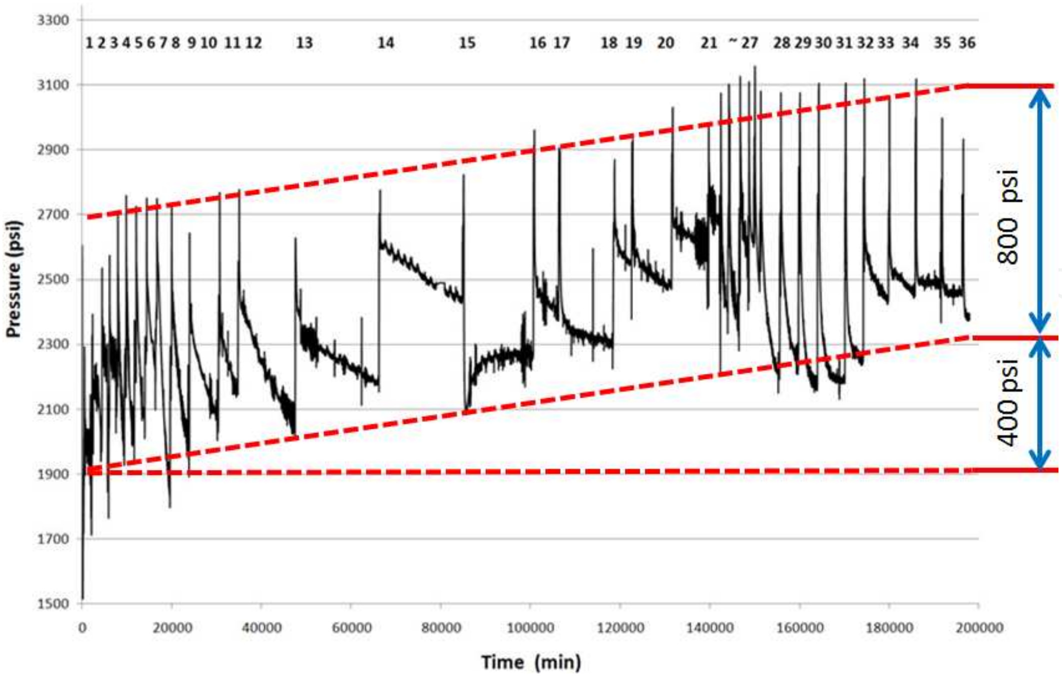

Figure 3. Observed WHP over 36 injection batches with an average pressure increase of 400 psi and differences between peak WHP and terminal WHP of 800 psi. The rate of pressure increase is 50%.

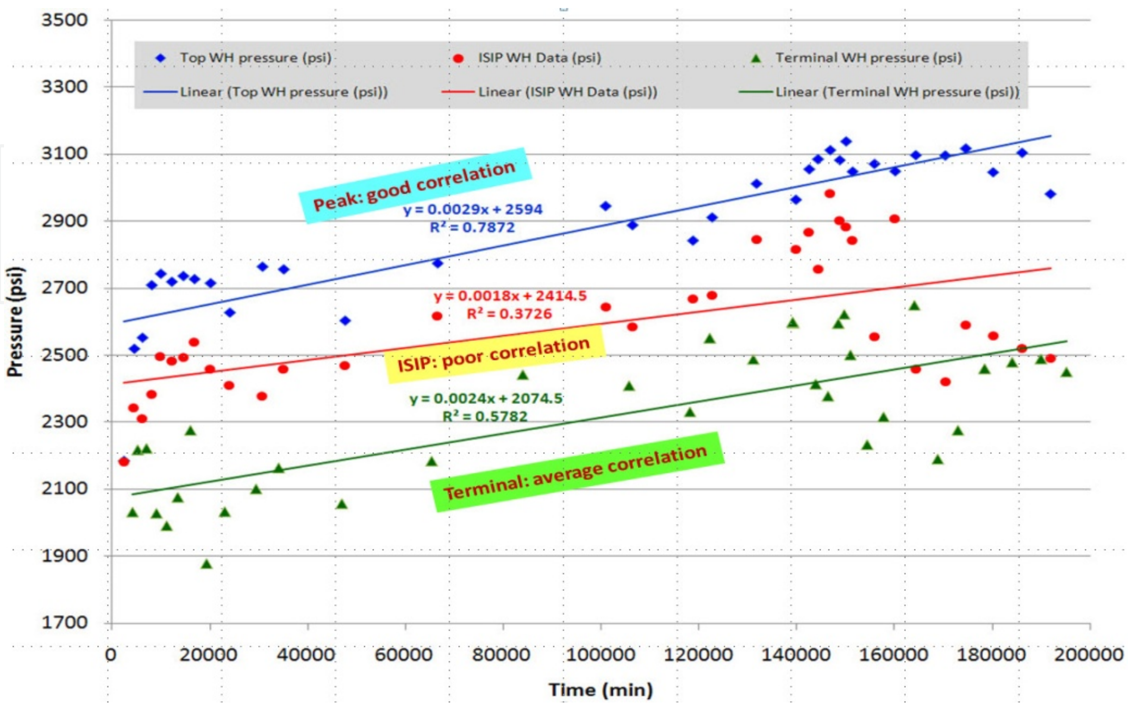

Figure 4. The trend of the well-head pressure in peak, ISIP, and terminal values over the injection period showing good linear correlation for the peak value, average linear correlation for the ISIP value, and poor linear correlation for the terminal value.

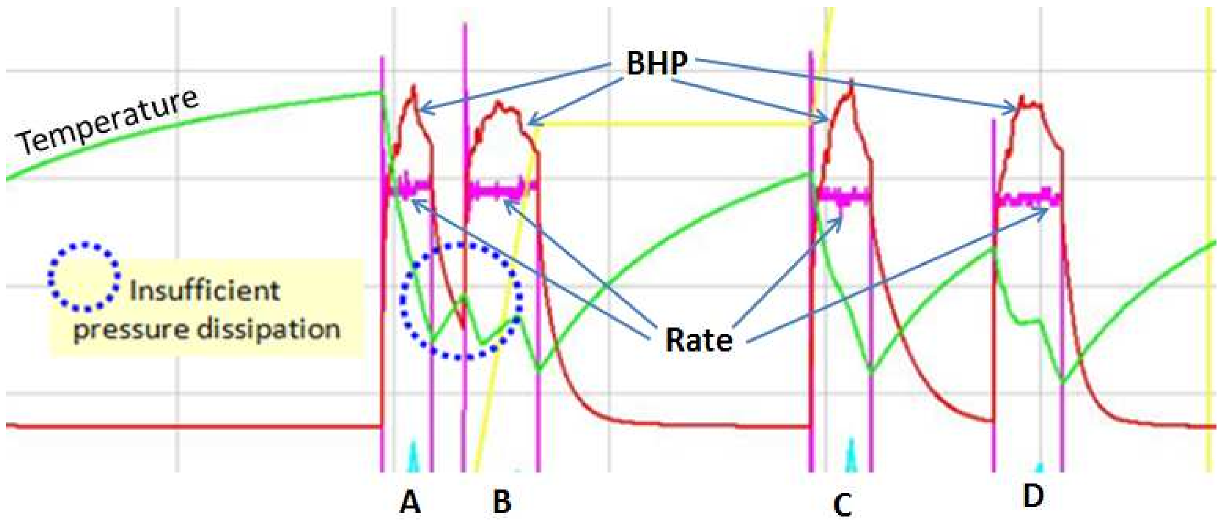

Figure 5. Pressure responses from four injections where the red line is bottom-hole pressure (BHP), the pink line is injection rate, and the green line is temperature. Pressure dissipation for injection A is insufficient. Pressure dissipations for injections B, C, and D are sufficient. The temperature drop validates the entry of injection fluid at the perforation.

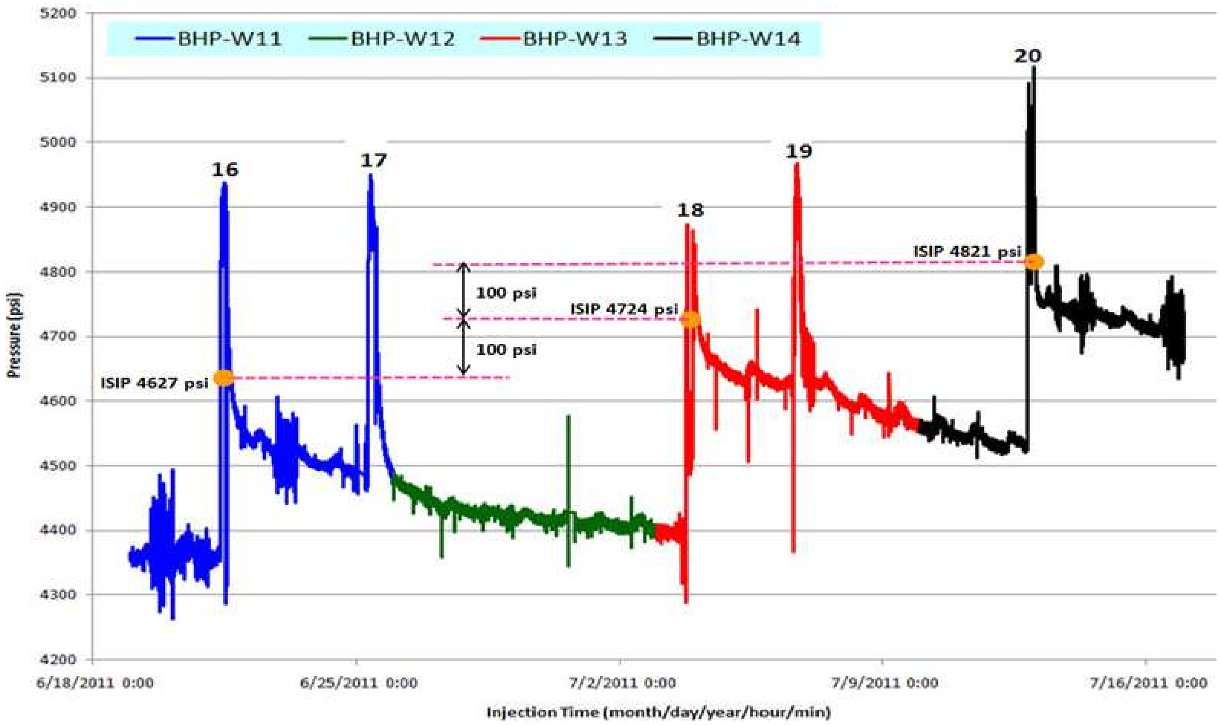

Figure 6. Injection pressure responses for batches 16 through 20. Injection batches 17 and 19 appear to be unnecessary because they are too close to batches 16 and 18, respectively. The pressure decline for batches 17 and 19 follows the same trend lines as batches 16 and 18.

3. Fracture closure analysis

Accurately determining fracture closure pressure is important for the following factors: a) minimum horizontal stress or fracture gradient, b) fracture efficiency, and c) formation properties and responses. The most popular method used to determine closure pressure is a MiniFrac test. Figure 7 shows the BHP and corresponding step injection rate from a MiniFrac test. The point of LOP in BHP is defined as the leakoff point that is an indication of initial near-well fracturing. LOP is also termed as an extension pressure point. The point of BP in BHP is defined as the breakdown pressure that may indicate the initiation of substantial fracturing into the formation. The vertical pressure drop after the peak of BHP depicts the range of the instantaneous shut-in pressure (i.e., upper and lower boundaries of ISIP). The vertical pressure drop is the result of perforation friction loss. After ISIP, pressure declines are accompanied by injection fluid leakoff and fracture closing. Fracturing treatment efficiency is defined as the ratio of fracture volume at the end of pumping to the total injected volume (see reference [6]).

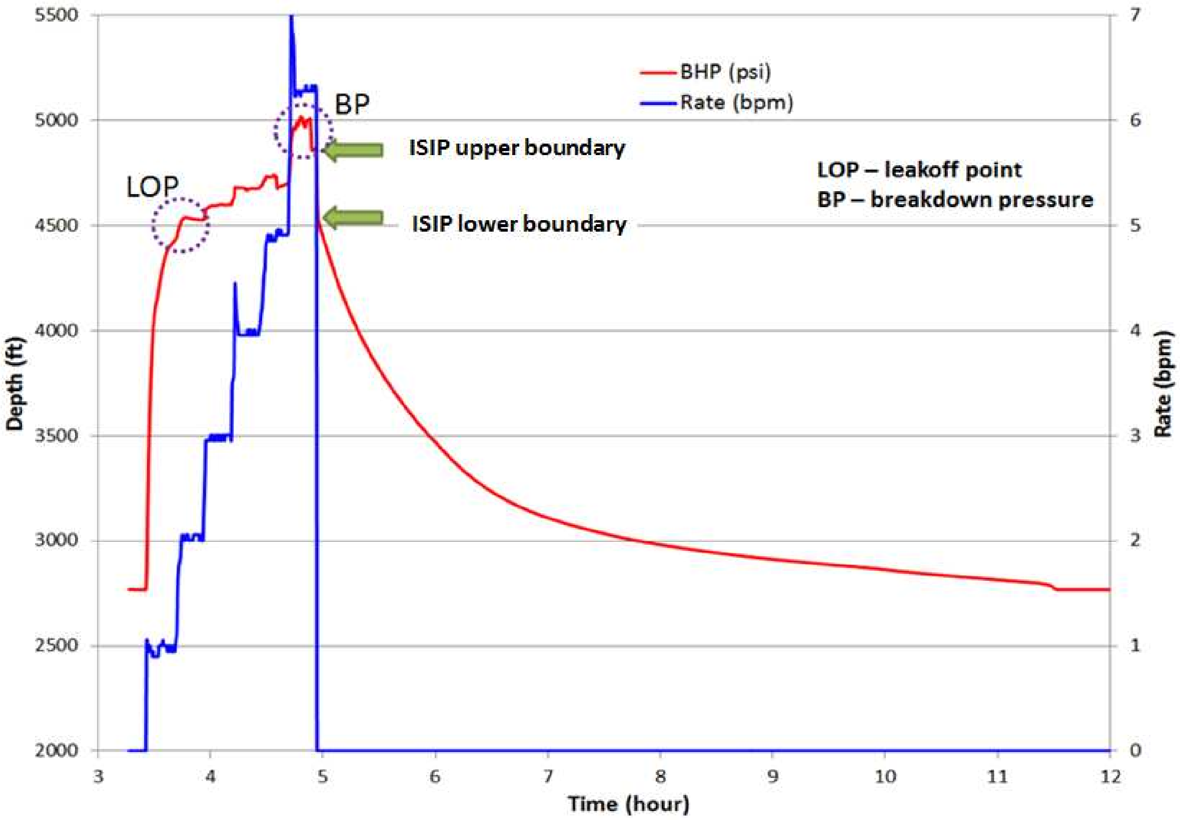

Figure 7. Responses of BHP (in red) and corresponding injection rate (step rate, in blue) from a MiniFrac test: a) pressure increased sharply until generating a small fracture in LOP; b) formation breakdown at BP and small fracture propagation; c) shut-in, and d) pressure leakoff and fracture closing.

4. Implications of fracture behavior from *G* function superposition derivative

In Figure 8, Barree, et al. (reference [5]) suggested that the normal leakoff (NL) from hydraulic fracture after shut-in leads to a straight line originated from the *G* function time in the form of the *G* function superposition derivative (i.e. G dP/dG). Fracture closure time is identified when the *G* function superposition derivative (GFSD) deviates from the straight line in a critical curve slope change.

Any initial response of GFSD that is different from a straight line as shown in Figure 8 can be interpreted as an abnormal leakoff. In addition, the non-straight-line behavior can be caused by events other than leakoff, such as fracture tip growth or height reduction, etc. In Figure 9, nine cases of the pressure to *G* time relationship are shown as follows:

- Case (a): normal leakoff Case 1 (NL-1)
- Case (b): normal leakoff Case 2 (NL-2)
- Case (c): normal leakoff Case 3 (NL-3)

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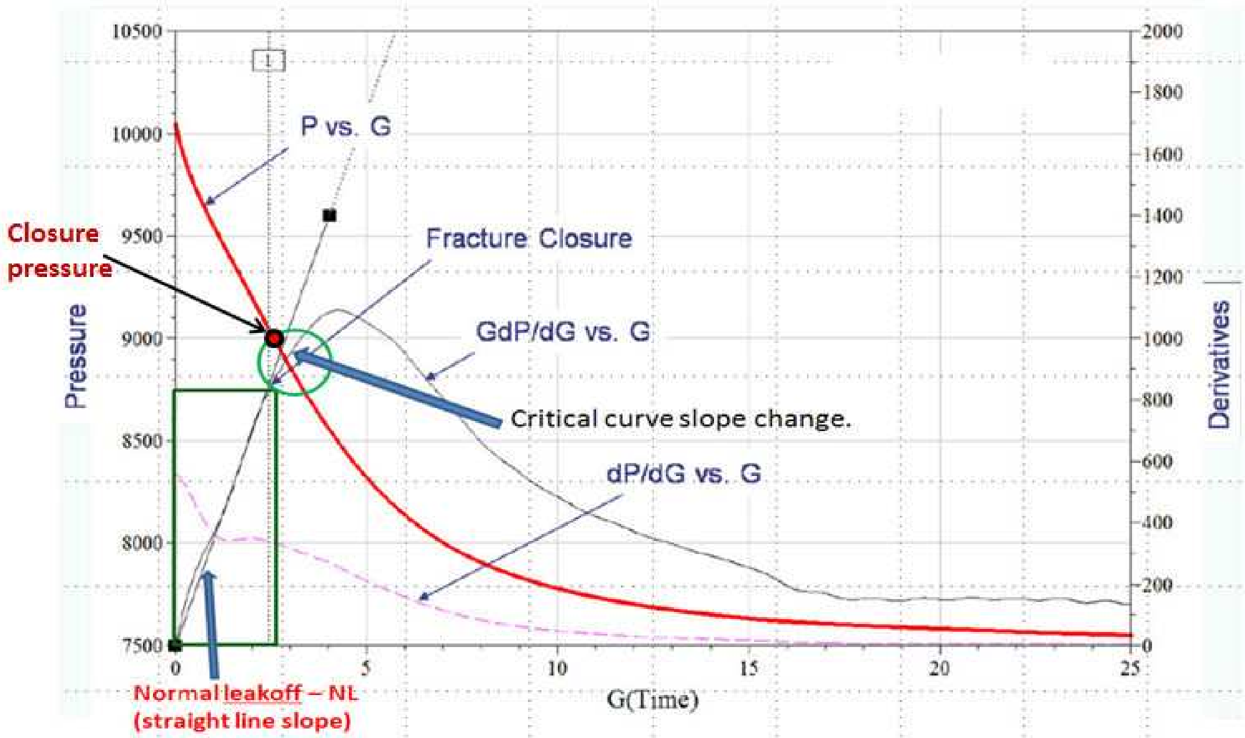

Figure 8. Determination of closure pressure from the GFSD curve to identify the critical curve slope change. The initial straight line indicates normal leakoff.

- Case (d): pressure-dependent leakoff Case 1 (PDL-1)
- Case (e): pressure-dependent leakoff Case 2 (PDL-2)
- Case (f): pressure-dependent leakoff Case 3 (PDL-3)
- Case (g): fracture tip extension Case 1 (FTE-1)
- Case (h): fracture height recession Case 1 (FHR-1)
- Case (i): fracture height recession Case 2 (FHR-2)

It is interesting to note that GFSD follows a straight line for NL from the beginning to the time when the GFSD changes slope, indicating a linear flow is maintained within the hydraulic fracture during the fracture closing.

For PDL, GFSD is above the straight line and becomes convex from the beginning; then the GFSD follows a straight line before the GFSD changes slope. In the convex portion of GFSD,

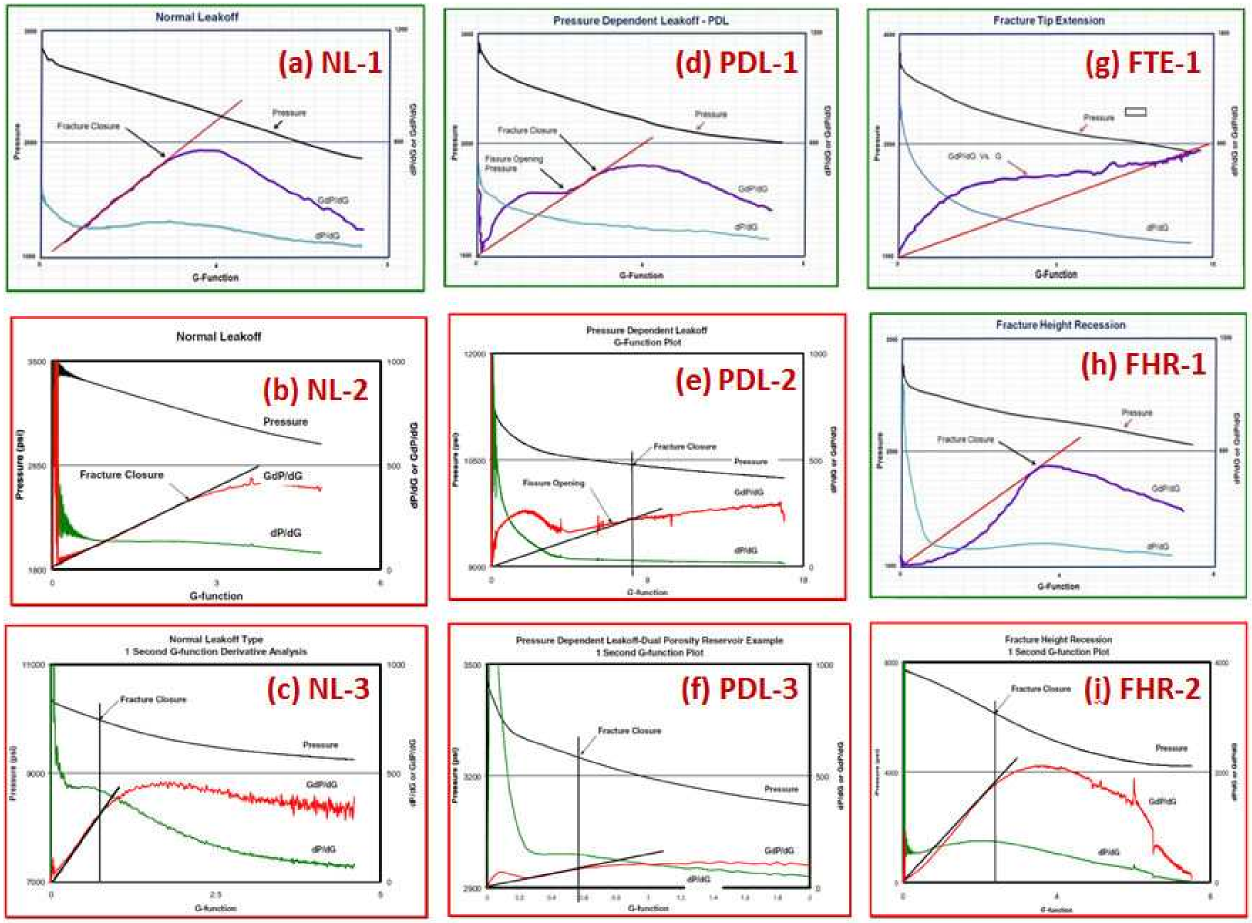

Figure 9. After shut-in fracture responses from the *G* function superposition derivative: normal leakoff Cases a, b, and c (NL-1, NL-2, and NL-3); pressure dependent leakoff Cases d, e, and f (PDL-1, PDL-2, and PDL-3); fracture tip extension Case g (FTE-1); and fracture height recession Cases h and i (FHR-1 and FHR-2).

the flow within the hydraulic fracture is affected by 'back stress' in the far field, a poro-elastic coupled response that demonstrates the interactive behavior between rock deformation and fluid flow. Another interpretation of pressure-dependent leakoff is that the existence of natural fractures deviates the path of GFSD from the straight line to a convex curve.

The response of GFSD from fracture tip extension (FTE) is similar to PDL except that there is no linear leakoff period after the convex portion of the GFSD curve.

For fracture height recession (FHR), the GFSD curve is concave from the beginning until the GFSD changes slope. The greater pressure drop within the hydraulic fracture is the result of fracture geometric reduction or fracture height recession.

Comparing the selected cases using the relationship between BHP and the linear *G* function in Figure 10, the following interesting observations can be made:

- Normal leakoff cases (NL-1 and NL-2) lead to straight lines between P and G.

- Pressure-dependent leakoff cases (PDL-1 and PDL-3) result in the concave shapes of the P - G relationship.
- Fracture tip extension cases (FTE-1) and fracture height recession cases (FHR-1) result in a concave shape of the P – G relationship in the beginning and then change to convex.

Cases c (NL-3) and e (PDL-2) have different pressure magnitudes than the other cases. Figure 11 indicates that PDL-2 maintains the concave shape of the P – G relationship, while NL-3 shows an extended linear line immediately after shut-in before changing to another linear line with a different slope. The initial linear lines after shut-in for Cases a (NL-1) and b (NL-2) are very short (see Figure 10).

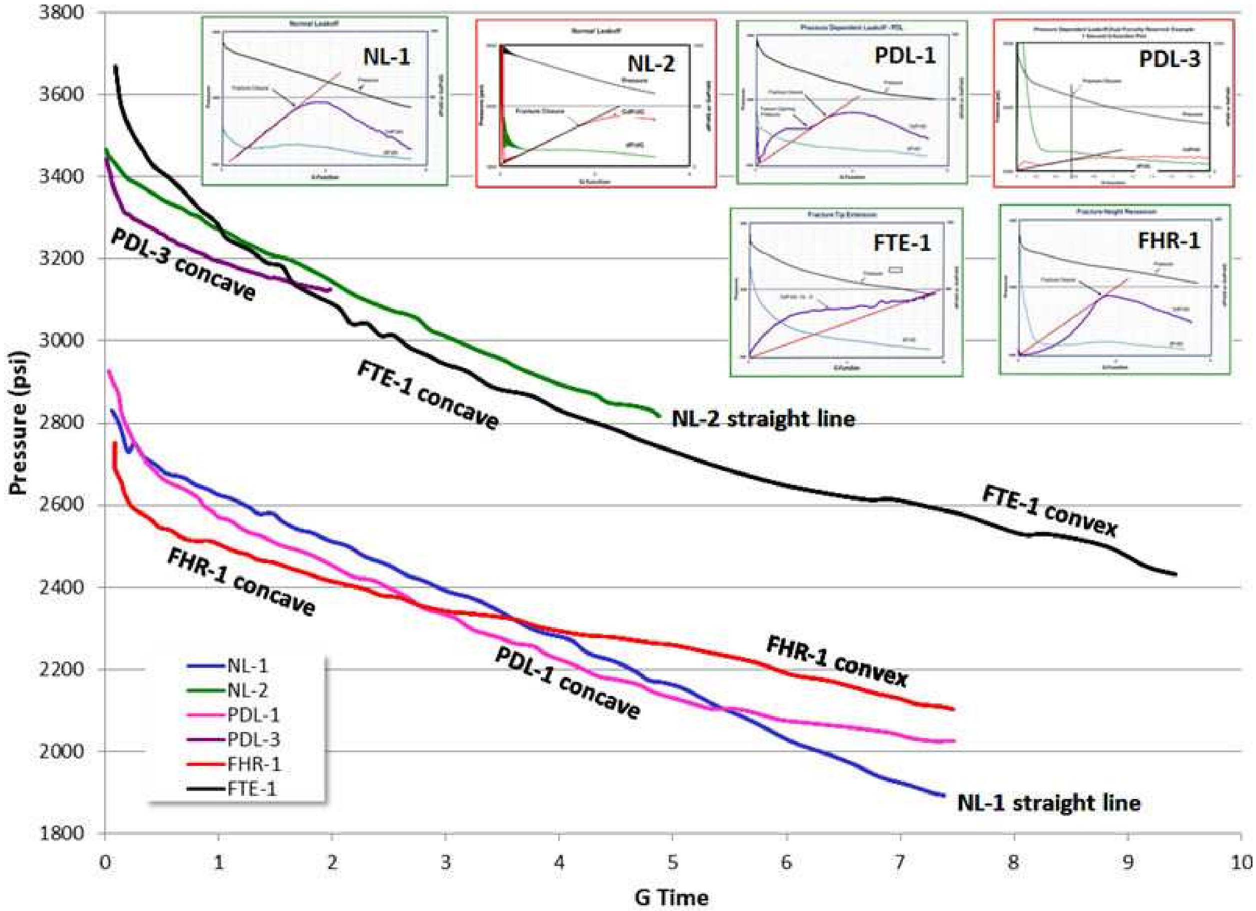

Figure 10. Comparison of six cases of NL, PDL, FTE, and FHR: a) linear lines of the P – G relationship from normal leak-off (NL-1 and NL-2); b) concave curves of the P – G relationship from pressure-dependent leakoff (PDL-1 and PDL-3), and c) initial concave and later convex curves of the P – G relationship from fracture tip extension and fracture height recession (FTE-1 and FHR-1).

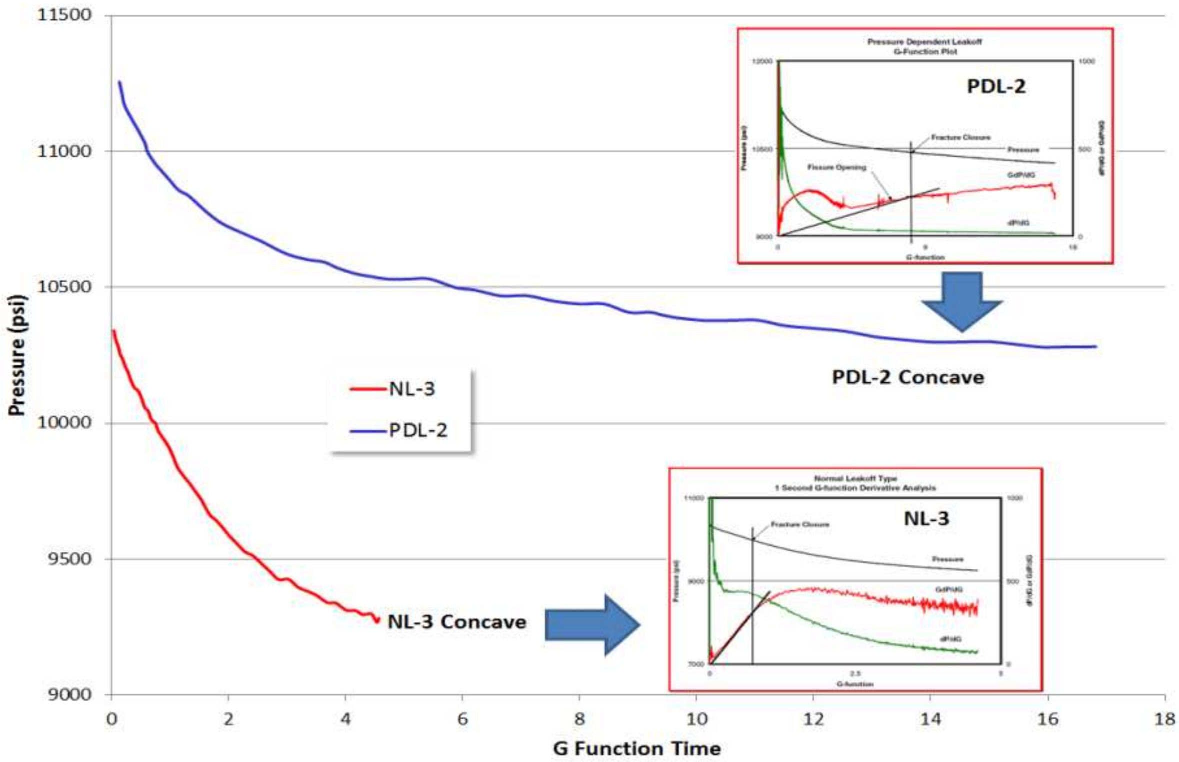

Figure 11. Comparison of two cases of (NL-3 and PDL-2): a) initial linear line and late linear line with a different slope for the P - G relationship with normal leakoff; and b) concave curves for the P – G relationship with pressure-dependent leakoff.

5. Conclusions

Based on past experience in cuttings injection monitoring, it can be concluded that the quality of fracture closure after shut-in has a critical impact on the efficiency of a cuttings injection operation. Cuttings injection is inefficient when the fracture closure cannot be assured as a result of an insufficient shut-in period between batch injection operations. Conversely, cuttings injection becomes efficient when sufficient time is provided between batch injections to allow adequate fracture closure.

The quality of the cuttings injection can be evaluated by analyzing the trend of batch injections. The rising peak batch pressures during injection and slow declining of terminal batch pressures during shut-in are indications of poor pressure maintenance and thus poor cuttings injection management. Rising batch injection pressure usually reveals difficulties in maintaining needed injectivity while slow pressure decline can be the result of insufficient shut-in time in a low permeability disposal domain. The required solutions include but are not limited to: a) mitigating the injection pressure or pump power and ensuring the proper breakdown of the injected formation, b) extending the shut-in period to dissipate injection pressure, and c) adjusting the injected batch volume or injection rate to allow the relevant acceptance of the disposal formation for the injected cuttings.

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The quality of fracture closure analysis also affects the quality of cuttings injection management. Among various methods, using GFSD in interpreting BHP responses to the cuttings injection operation appears to be an efficient way to identify the occurrence of fracture closure. Interpreting the shapes of GFSD over the P – G relationship may help identify the different responses from various formations such as injection in naturally fractured reservoirs, reflect various behaviors involved in the injection process such as the pressure/stress dependency in a poro-elastic formation, or reveal the outcome from the complex, coupled process of rock deformation and fluid flow under various reservoir boundary conditions.

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