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Enhanced Fracture Entry Friction Analysis of the Rate Step-Down Test

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Abstract

The procedures of the Rate Step-down Test (RST) also referred to as "Step-Down Test" (SDT), and of Conventional Fracture Entry Friction (FEF) Analysis have been used worldwide for over 15 years to separate the Measured Total System Friction (MTSF) into constituent components. The magnitude of the FEF components has served as guidance to design and/or modify the placement procedure and treatment schedule, in order to reduce unplanned terminations (screenouts) of propped hydrofrac treatments.

Conventional FEF Analysis has inherent limitations which produce non-unique (somewhat erroneous) results that can only be overcome with Enhanced FEF Analysis methodology; which bypasses these limitations with innovative methods: appropriately corrected fluid friction factors, non-uniform perforation discharge coefficient, application of Maximum Drag Reduction (MDR) asymptote, and, matching of MTSF with Calculated Total System Friction (CTSF) at all rates of the RST. Several RST examples are analyzed with *FEF Analyzer* to illustrate and document the success in placing safe and effective propped hydrofrac treatments.

Real-world analogies are used as visual aids to explain the complex processes of FEF, along with RST design methodology, RST execution procedure, and detailed calculation procedures for performing Enhanced FEF Analysis.

Net-pressure history matching is significantly improved, due to the increased accuracy of calculating the magnitudes of the wellbore friction and of the FEF components.

Introduction

FFF is the most serious impediment to placing safe and effective propped hydraulic fracture treatments. The advent and widespread use of the RST, along with application of conventional FEF Analysis methodology reduced the abnormally high percentage of screenouts prevalent since the inception of hydraulic fracturing technology in 1947.

The major limitations of conventional FEF Analysis have been: over or under estimating both the MTSF and the CTSF, and, difficulty in achieving a unique (correct) solution. These limitations result from: 1) limited ability to separate wellbore friction from perforation friction, 2) application of incorrect correction to fluid friction factors, 3) absence of plotting and matching feature to compare MTSF with CTSF, 4) ignoring the effect of restriction(s) in the flow path.

FEF continues to adversely affect the safe and effective placement of propped hydraulic fracturing treatments in some regions of the world, a condition which can be improved with Enhanced FEF Analysis, which provides unique (correct) results by: 1) correctly extrapolating fluid friction data for a given conduit diameter to various conduit diameters, 2) applying correct corrections to the fluid friction factors, 3) correctly calculating friction in the perforations (by applying non-uniform perforation Discharge Coefficient) and in the near-wellbore region, 4) accounting for pressure losses due to restrictions in the flow path, 5) applying Maximum Drag Reduction (MDR) methods for improved prediction of friction factors for turbulent flow, 6) matching of MTSF to CTSF at all flow rates of the RST, 7) accurately separating MTSF into wellbore friction and FEF, and, 8) accurately separating FEF into perforation friction and near-wellbore (NWB) friction.

Computer analyzed case studies are presented, which illustrate: 1) the correct procedure for the RST, 2) the methodology of Enhanced FEF Analysis 3) the high level of accuracy possible, and, 4) how to increase the percentage propped hydrofrac treatments that can be placed safely and effectively.

The accuracy achieved with Enhanced FEF analysis greatly improves Net-pressure history-matching: matching of the Observed Net Pressure (ONP) with the Model Net Pressure

(MNP). This improves: 1) the on-site decision-making process, 2) helps to safely place optimum, and effective propped hydrofrac treatments, and 3) increases the assets with which one operates (reduces risk).

Venturi Flow Meter Analogous the Wellbore-Fracture System

The Venturi Flow Meter (VFM) is a measurement instrument which is analogous to the wellbore-fracture system. It is used extensively in the water supply and other industries. In the petroleum industry the VFM is used in surface well testing equipment, subsea wellhead installations, and, as a bottomhole flow meter in "intelligent" well completions.

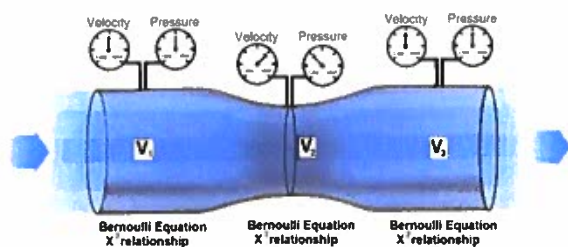


Figure 1: Standard VFM, showing velocity and pressure relationship, and that velocity is a function of flowrate squared, Q^2 , for all sectors. (Adapted and modified from ref. 1).

Figure 1 shows a standard VFM configuration. The fluid velocity, V_2 , in the narrow section (throat) is much higher than the fluid velocities upstream, V_1 , or downstream, V_3 . The velocity increase in the throat causes the pressure to decrease, due to conservation of energy. All sections (upstream, throat, and downstream) have circular cross section, thus, the Bernoulli equation (a flowrate squared, Q^2 , relationship) is used for mathematical analysis of all sections.

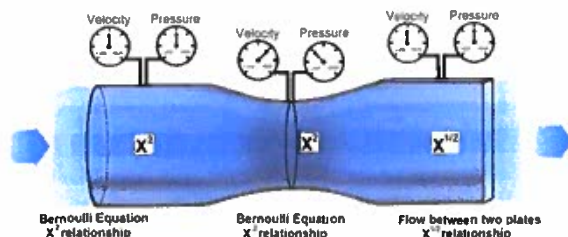


Figure 2: Conceptual VFM, showing velocity and pressure relationship and that velocity is function of square root of flowrate, $Q^{1/2}$, for the downstream sector. (Adapted and modified from ref. 1).

A conceptual VFM, whose downstream section is shaped like a parallelogram (rather than a tube) is shown in Figure 2. This configuration would exhibit pressure drop behavior analogous to a Wellbore-Perforation-Fracture System, thus, the equation for flow between two plates (a square root of flowrate, $Q^{1/2}$, relationship) would be used for mathematical analysis of this section. It should be noted that if the width between the plates remains fixed, the pressure drop is a linear function of flowrate (not a function of the square root of flowrate).

A web-based "hands-on" exercise with an animated VFM can be accessed by clicking at the link in ref. 21.

Stagnation Pressure

In a VFM the fluid continues flowing downstream, whereas, in a perforation/small-fracture system the fluid loses velocity and is forced to reverse direction, as shown in Figure 3. This pressure behavior is similar to that occurring in a VFM, as previously discussed.

The combination of flow reversal and velocity decrease create high pressure inside the small fracture, which is referred to as stagnation pressure, and which causes fracture initiation and propagation.

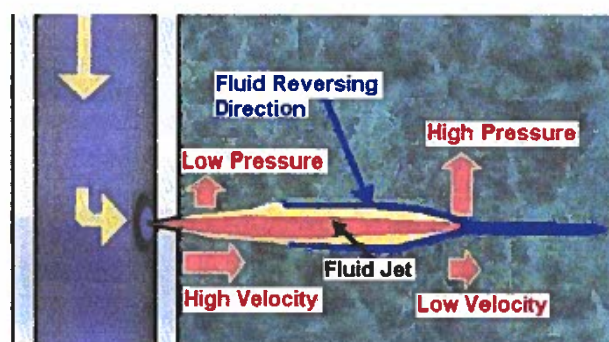


Figure 3: Perforation and fracture showing the velocity and pressure relationships, a combination of which causes high stagnation pressure.

During the flowrate reductions of the RST the high stagnation pressure decreases sharply very rapidly. Thus, FEF can be detected and measured only with an RST. Sharp rapid pressure changes in the fracture cannot be detected with a rate Step-Up Test (SUT), used to obtain other useful information.

Conventional vs. True Net Pressure

Prior to 1990 the ONP was conventionally calculated as per following equation², and as shown in Figure 4.

$$P_{net(conv)} = P_{avg2} - P_{cl} \dots \dots \dots (1);$$

Where, $P_{avg2} = (P_{bh} - F_{cp}) / 2$,

P_{bh} = Bottom hole pressure = $P_{st} + P_h - F_{mw}$

F_{cp} = Calculated Perforation Friction

P_{st} = Surface Treating Pressure

P_h = Hydrostatic Pressure

F_{mw} = Measured Wellbore Friction
(includes local losses)

P_{cl} = Closure Pressure

This will be referred to as "Conventional" ONP to differentiate it from the "true" ONP (subsequently discussed). In Equation 1 it is assumed that the pressure at the tip of the fracture is zero (0), as such, the pressure loss in the fracture, due to

friction is assumed to decrease linearly as a function of fracture length. Such a large pressure loss due to friction isn't possible, because, the fluid velocity in the far-field fracture is very low (approximately 2 ft/min or 0.65 m/min).

Equation 1 doesn't account for NWB friction, because, prior to 1990 it was thought that NWB friction occurs only in deviated or horizontal wellbores. The advent of the RST and Conventional FEF Analysis made quantification of FEF components easy, which, when considered in conjunction with fracture tip effects (Dilatancy) made Net- pressure history matching possible.

Calculating "true" ONP (as per equation 2), and as shown in Figure 4, has greatly improved Net-pressure history matching.

$$P_{net}(true) = P_{avg}l - P_{cl} \quad \dots\dots\dots (2);$$

Where,

$$P_{avg}l = P_{bh} - FEF$$

$$P_{bh} = \text{Bottom hole pressure} = P_{st} + P_h - F_{mw}$$

$$P_{st} = \text{Surface Treating Pressure}$$

$$P_h = \text{Hydrostatic Pressure}$$

$$F_{mw} = \text{Measured Wellbore Friction (includes local losses)}$$

$$FEF = \text{Fracture Entry Friction} = F_{mp} + F_{mnw}$$

$$F_{mp} = \text{Measured Perforation Friction}$$

$$F_{mnw} = \text{Near-wellbore Friction}$$

$$P_{cl} = \text{Closure Pressure}$$

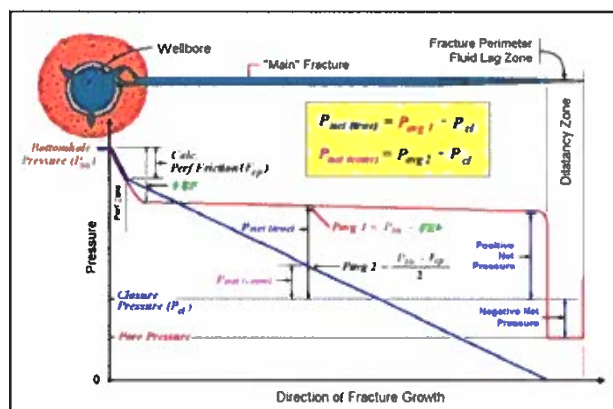


Figure 4: Graphic representation of FEF Components: Pressure as a function of fracture length, Calculation of Net-pressure, and Fracture tip Effects (Dilatancy). (Adopted and modified from ref. 9).

The ONP is easy to calculate from the recorded pressure data. However, in order to obtain a Net pressure history match, a 3D fracture propagation simulator is required. Real-time monitoring, recording, and analysis features are a distinct advantage, as the "true" ONP can be calculated while the treatment is in progress. It enables the engineer on-site to monitor and determine if the treatment is being placed as per design (safely and effectively), and, to be able to re-design the treatment in real-time if required.

Older 2D fracture propagation simulators have limitations: 1) underestimate the ONP, thus, a Net-pressure history match is not possible, 2) lack real-time monitoring and analysis capabilities, thus, real-time decision making is not possible.

Fluid Lag and Fracture Tip Dilatancy

For a complete understanding of the complex processes of hydraulic fracturing, one needs to understand and analyze not only what happens at the Fracture Entry (the subject of this paper), but also what happens at the tip of the fracture.

There seems to be agreement on the fact that large stress and large pressure loss occur at the fracture tip. There is disagreement as to the analysis methodology. Several theories have been presented^{3, 4}: 1) Dilatancy at the fracture tip (non-linear expansion of rock due to fluid lag), 2) Apparent Fracture Toughness, 3) Process zone, and 4) Continuum Damage Mechanics⁴ (CDM). Only Dilatancy at the fracture tip will be discussed to some detail. The reader is referred to the many publications on these subjects.

The tip of the fracture being created normally propagates through the formation much faster than the leading edge of the fracturing fluid, as shown in Figure 4. This means that the created fracture (fluid lag zone, ahead of the fluid) which has been propped open by the fluid is momentarily in vacuum and remains open for a very short time interval. The high overburden pressure dilates the rock (expands it non-linearly), and causes the fracture tip zone to re-close.

When the leading edge of the fracturing fluid arrives at the closed region (at the tip of the fracture), a large pressure is needed to re-open the fracture, as shown in Figure 4.

The Net-pressure in the dilatancy zone can be negative during a short time interval as a momentary vacuum is created and positive when the fluid arrives and fracture reopening occurs. See Figure 4. To achieve fracture propagation the Net-pressure in the rest of the fracture must be much higher.

Referring to Figure 4, one would note that: 1) large friction pressure loss occurs at the perforations and the near-wellbore area, 2) small amount of friction pressure loss occurs along the length of the main fracture (due to the very low velocity of the fluid in the fracture), 3) large pressure drop occurs at the tip of the fracture; therefore, the high pressure loss noted at the tip of the fracture can only be expended to re-open the closed fracture tip region.

Warpinski⁵, has conducted in-situ measurements (in deep underground caverns) focusing on fracture propagation. The results from these tests tend to support the Dilatancy theory for fracture mechanics at the tip of the fracture.

Another way to look at fracture tip dilatancy is to note that the stress intensity factor consists of a positive component from the positive net pressure in the fracture body, and a negative component from the negative net pressure in the fluid lag zone (Dilatancy Zone), as shown in Figure 4. The contribution of stress from the fluid lag zone, to the stress intensity factor, is much larger than the contribution from the "main" fracture. The absolute value of these two components is about the same, however, when the fracture has propagated some distance beyond the wellbore area, it is much larger than the fracture toughness. As such, fracture toughness is unimportant when the fracture is fairly large. This is evident from the following equation for calculating Net-pressure in a radial fracture:

$$P_{net} = K_{IC} / \sqrt{\pi a} \quad (3);$$

Where,

K_{IC} = Mode I fracture toughness critical stress intensity factor. (psi/in^{0.5})

a = radial distance to the fracture tip (in).

Since the radial distance term, a , is in the denominator, the magnitude of the Net-pressure required to propagate a small fracture is large, while the magnitude of the Net-pressure required to propagate a large fracture is small, as shown in the following table.

K_{IC} (psi/in ^{0.5})	Radial distance to fracture tip		Net Pressure, P_{net}	
	(ft)	(in)	(psi)	(bar)
1,000	0.083	1	565.0	38.9
1,000	12	144	47.0	3.2
1,000	100	1200	16.3	1.1

Since it takes very little Net-pressure to propagate a fracture, it follows that the high Net-pressure (noted in field operations) would be expended to reopen the fracture at the fluid lag zone (Dilatancy Zone) rather than to propagate it.

Fracture toughness plays an important role during fracture initiation, because, the magnitude of the Net-pressure is usually large. Fracture toughness plays a minor role during fracture propagation. The reason for this difference is the assumption that the pressure in the fracture is fairly uniform all along the fracture length, as shown in Figure 4.

Rate Step-Down Test (RST) Procedure

Cleary, et al.⁶ were the first to propose a RST procedure, which consisted of abrupt and closely spaced flowrate reductions (as opposed to a single flow rate reduction or widely spaced flowrate reductions), and the analysis methodology which separates the friction pressure losses into the various components that comprise the $MTSF$, which is calculated by taking the difference between Surface Treating Pressure, P_{st} , and the Instantaneous Shut-in Pressure (IS/P), as shown in Figure 9.

An RST procedure is very simple and inexpensive to perform. The injection flow rate is reduced to zero in 3 to 4 abrupt steps (preferably 4 steps). The durations of the flow rate reductions are about equal and long enough for the injection flowrate and pressure to stabilize, usually 10-20 seconds. The best and easiest way to perform the procedure is to pump with 4 pumps at about the same flowrate and take out (shut down) one pump at a time. Typical RST procedures are shown in Figures 7, 9, 12 and 13.

Measured Total System Friction

Cleary, et al.⁶ also proposed that the plot of ΔP vs. ΔQ , which fits the data of the RST, represents $MTSF$, and, that the data fit

with a single power law equation:

$$MTSF = K_{ff} Q^{\beta} \quad (4);$$

Where,

K_{ff} = Total Friction Coefficient,

Q = flowrate,

β = Total Friction Power exponent.

Curve fitting of the data can be performed with one of several techniques (least-squares, least vertical distance, etc.). If the measured perforation friction, F_{mp} , dominates, the exponent β will be approximately equal to 2 and the plot will be concave upwards. If the Measured Near-wellbore friction, F_{mw} , dominates, the exponent β will be approximately equal to 0.5 and the plot will be concave sideways. Note that the rounded values for the power exponents are used for demonstration purposes only.

The $MTSF$ can be separated into three constituent components and is calculated as per equation 5.

$$MTSF = F_{mw} + K_p Q^2 + K_{mw} Q^m \quad (5);$$

where,

F_{mw} = Measured wellbore friction,

Q = flowrate,

K_p = Coefficient of Perforation Friction,

K_{mw} = Coefficient of Near-Wellbore Friction,

m = near wellbore friction exponent,

(most accepted value = 0.5)

The last two terms comprise Measured FEF . The above calculations are almost always made from pressure measurements recorded at the earth surface (very near the wellhead valves). If the calculations are made from reflected ("deadstring") pressure measurements or from actual bottomhole pressure measurements (recorded near the perforations with Surface Read-Out (SRO) gauges, or, with Memory gauges), and excess pressure loss due to friction is noted, it will most likely be mostly near-wellbore friction, no evidence of perforations.

Calculated Total System Friction

The $CTSF$ is determined using various parameters: flow path geometry (wellbore, perforations, near-wellbore), fluid density, fluid viscosity, fluid friction, etc. It is also composed of three components and is calculated as per equation 6.

$$CTSF = F_{cw} + F_{cp} + F_{cnw} \quad (6);$$

Where,

F_{cw} = Calculated wellbore friction

(Includes local losses),

F_{cp} = Calculated perforation friction,

F_{cnw} = Calculated near-wellbore friction.

The last two terms comprise Calculated FEF:

$$FEF = F_{cp} + F_{cmw} \dots\dots\dots (7);$$

Unique values of the magnitude of all friction components in the system will be calculated only when a match of *MTSF* and *CTSF* (at all flow rates of the RST) has been achieved, i.e., $MTSF = CTSF$, as per equation 8, and as shown in Figure 5.

$$F_{mw} + K_p Q^2 + K_{mb} Q^m = F_{cw} + F_{cp} + F_{cmw} \dots\dots(8);$$

Due to the trial-and-error nature of the analysis, it is best to perform the analysis with specialized software such as *FEF Analyzer*, as shown in Figures 7, 9, 12 and 13.

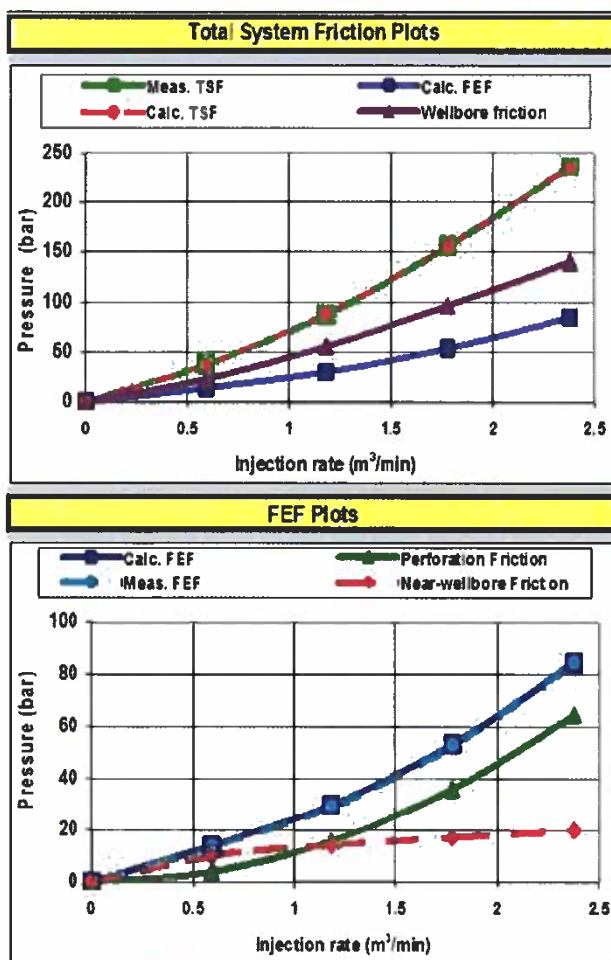


Figure 5: Plots of MTSF matched with CTSF, and, of Measured FEF matched with Calculated FEF.

Conventional FEF Analysis of the RST

Conventional FEF Analysis of the RST utilizes regression analysis and a dual curve-fitting technique to separate and quantify the two FEF components. The match of *MTSF* with

CTSF is not unique, as the match is made only at the highest injection rate. This causes incorrect allocation and distribution of the *CTSF* into the various constituent components, as shown in Figure 6 and in the following table.

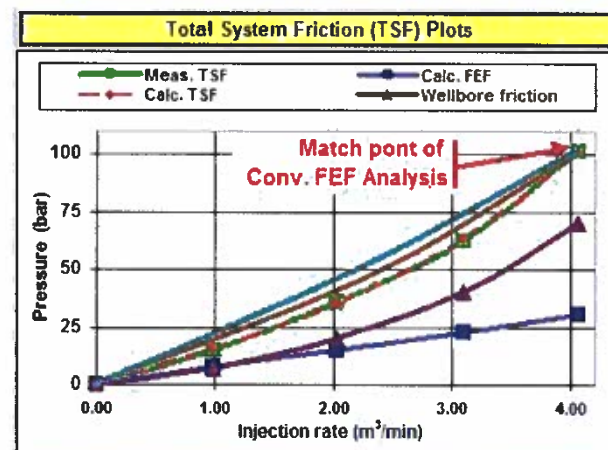


Figure 6: Conventional FEF Analysis showing how the TSF is allocated incorrectly to the various FEF Components.

It is obvious from the plots of Figure 6 that if excess wellbore friction is subtracted, an equivalent amount will be added to FEF (to be able to match *MTSF* with *CTSF*). This changes the shape of the FEF curve, making it more linear. A linear curve can easily be composed from an $f = f(Q^2)$ curve and an $F = f(Q^{1/2})$ curve because one curve is concave upwards, and the other is concave sideways (down). In such a case, measured *FEF* matches calculated *FEF* and *MTSF* matches *CTSF*. However, the magnitude of both FEF components would be incorrect.

The issues outlined above are exacerbated by the difficulty to accurately estimate Wellbore Friction. Keck et al.⁷ compared calculated Bottomhole (BH) pressures (derived from pressure data recorded at the surface), with measured BH pressures (recorded with memory gauges). They report variance in the range of 30-60% in the magnitude of the calculated BH pressures.

A summation check of results as obtained from Conventional FEF Analysis shows correct results, where in fact there are many solutions. The color coded rows correspond to the color coded plot lines in Figure 6.

	Calc. Wellbore Friction (bar)	Calc. Perforation Friction (bar)	Calc. Near-wellbore Friction (bar)	Calc. Total System Friction (bar)
Incorrect Match	50	25	25	100
Incorrect Match	60	20	20	100
Perfect Match	70	18	12	100

Enhanced FEF Analysis of the RST

Enhanced FEF analysis of the RST calculates unique (accurate) values for the magnitude of the two FEF components. *FEF Analyzer* can easily accomplish this, as shown in Figures 7, 9, 12 and 13. All known constants are input first, followed by input of the variables. A trial-and-error procedure is required because of the unknown variables.

Many variables can be changed; however, to simplify the solution procedure only three variables are normally varied until a solution is obtained. These variables are: Fluid Friction Coefficient, Number of open perforations, and, Coefficient of NWB Friction (Tortuosity Coeff.). Solution is reached when the plot of the *MTSF* matches the plot of the *CTSF*, at all flow rates (not just at the maximum flow rate).

The magnitudes of most of the terms of the *CTSF* are calculated using equations and algorithms found in standard Petroleum Engineering and Fluid Mechanics textbooks. Detailed calculation procedures are presented in the appendices as follows:

Appendix	Calculation Procedure
A	Wellbore Friction
B	Perforation Friction
C	Near-wellbore Friction

Enhanced FEF Analysis of the RST calculates very accurate values of all friction components because it incorporates unique features: 1) unique capability to correct fluid friction factors accurately, 2) use of non-uniform perforation discharge coefficient, 3) accurately separating wellbore from perforation friction (difficult because they exhibit similar concave upwards behavior), 4) accounting for the effect of restriction(s) in the flow path, 5) applying Maximum Drag Reduction (MDR) methodology, 6) Matching of *MTSF* to *CTSF* at all rates of the RST.



Figure 7: Enhanced FEF Analysis

Enhanced FEF Analysis when utilized properly can and has achieved significant decreases in the percentages of screened-out propped hydrofrac treatments. These percentages remain high in some regions of the world. Usually, in medium and high

permeability reservoirs it is as high as 30%. In low permeability reservoirs it is as low as 1-5%.

The above stated percentages indicate that even though the current RST procedure is adequate, Conventional FEF Analysis methodology isn't. Enhanced FEF Analysis is required to achieve significant improvements.

Basis of FEF Analysis

Energy storage considerations (in a fairly large fracture), preclude abrupt changes of the ONP (pressure which holds the fracture open). The RST takes advantage of this phenomenon. If an abrupt change in the calculated Net-pressure is noted, then it must be due to the fact that wellbore friction or one or more of the FEF components used for the ONP calculation is calculated incorrectly. The concept is illustrated in Figure 11.

The SDT is also based on the difference in the friction pressure loss behavior, between the perforations, and, the tortuous near-wellbore area of the fracture.

The perforation pressure loss due to friction is a function of the square of the flow rate $f(Q^2)$, whereas, the near-wellbore pressure loss due to friction in most cases (not always) is a function of the square-root of the flow rate $f(Q^m)$, $m=0.5$ (see appendix C).

As shown in Figure 9 the difference in friction pressure loss behavior can be utilized for analysis in order to determine values for the FEF components.

A minimum of three and preferably four abrupt flow rate changes are required. The duration of the "steps" must be very small. The subsequent sections entitled "RST Design" and "RST Procedure", present design reasoning, detailed procedure, and methodology.

RST Design

To correctly design an RST it is necessary to understand that the fracture geometry should change very little during the test. This avoids introduction of error(s) in the friction calculations. A relatively large fluid volume should be injected prior to initiating the RST procedure of abrupt flow rate changes.

The RST's plotted on the left side of Figure 8 would be designed improperly: the first has a small volume pumped ahead followed by long steps in the RST, while the second has a small volume pumped ahead followed by short steps in the RST.

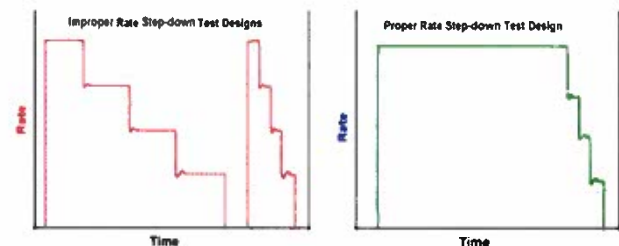


Figure 8: Improperly and properly designed Rate Step-down Tests. (Adopted and modified from ref. 9).

A proper RST design is shown on the right side of Figure 8. During this RST the fracture geometry will not change dramatically during the very short RST procedure, because, a significantly large fluid volume was injected prior to initiation of abrupt flow rate reductions.

RST Procedure

A Step-by-step procedure for the RST follows:

1. A minimum of three and preferably four instantaneous flowrate reductions are required, for example: 2.4, 1.8, 1.2, 0.6 and 0 m³/min. It is not required that all flowrate reductions be equal, however, they should be abrupt. It is easiest and most convenient to pump with four pumps at about equal rate each, and take out one pump at a time. The last rate reduction **must** be to zero m³/min. The reasons for this are: a) Plots of Δp vs. ΔQ have 0, 0 origin. See Figures 7, 9, 12 and 13, b) ISIP must be recorded for use in calculating Total System Friction, etc., and, c) Need to record hydraulic transient harmonic response (water hammer).
2. Each step of the flow rate reductions should be about 10-20 seconds long. Enough for the flow rate and pressure to stabilize.
3. Fracture geometry should change very little during the RST. Therefore, the volume pumped prior to initiation of the abrupt flowrate reductions must be fairly large. See previous section entitled "RST Design."
4. There should be only one fluid in the wellbore and in the near-wellbore region (preferably linear gel with low gelling agent concentration). Both density and viscosity of the fluid must be uniform; thus, the hydrostatic pressure and the wellbore friction will be constant.

Most situations dictate that cross-linked fluids should not be in the wellbore, perforation, or near-wellbore zone during the RST, because, the pressure is not transmitted very well through the wellbore. Usually, the Fracture/Fluid Efficiency Test (FET) is performed with crosslinked gel, which is overdisplaced with linear gel prior to performing the RST.

RST Analysis and Interpretation

When does Perforation Friction Dominate?

On the left side of Figure 9 the plots show data and analysis of a typical RST where perforation friction is larger than (dominates) near-wellbore friction. This can be seen from the large pressure change corresponding to the initial rate reduction.

Upon close visual inspection of the plots, one will note that the change in perforation friction ($\Delta P1$) plot has large values corresponding to the first flow rate change ($\Delta Q1$), and that the entire plot is above the Near-wellbore Friction plot, i.e., Perforation friction dominates. If this situation exists, remedial measures can be taken to reduce perforation friction.

When Does Near-wellbore Friction Dominate?

The plots on the right side of Figure 9 show data and analysis of a typical RST case where wellbore friction is larger than (dominates) perforation friction.

This can be seen from the large pressure change corresponding to the final rate reduction.

Upon close visual inspection of the plots, one will note that the change in the Near-wellbore friction plot ($\Delta P4$) has large values corresponding to the last flow rate change ($\Delta Q4$), and that the entire plot is above the Perforation Friction plot, i.e., Near-wellbore friction dominates. If this situation exists, remedial measures can be taken to reduce near-wellbore friction.

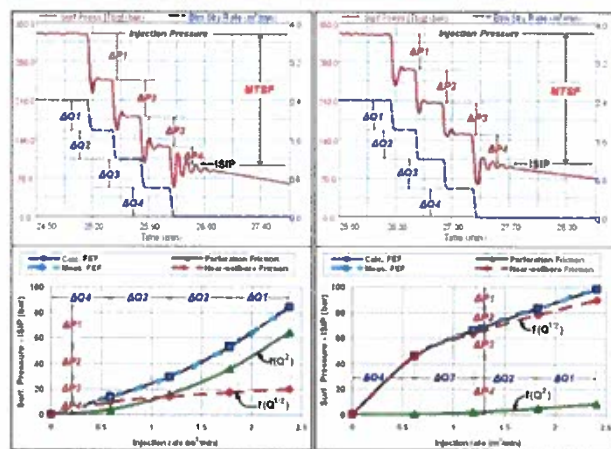


Figure 9: Plots on the left show that perforation friction dominates, while plots on the right show that near-wellbore friction dominates. (Adopted and modified from ref. 8 and 9).

Memory Device (Mnemonic)

An easy way to determine which FEF Component is larger is to note that the fluid goes through the perforations first and through the near-wellbore zone last (second). So, if the first pressure change is larger than the last pressure change, you have more perforation friction.

By the same logic, the fluid goes through the near-wellbore area last (second). So, if the last pressure change is larger than the first pressure changes, you have more near-wellbore friction.

It should be noted, that in the event wellbore friction dominates, it can "mask" the FEF signature (it won't be reflected clearly in the surface pressure drop). Thus, it can be difficult to ascertain which FEF component dominates.

Abrupt Changes in ONP Not Possible

Energy storage considerations dictate that it isn't possible to have abrupt changes in the ONP. This fact can be used to determine if the ONP is calculated correctly, i.e., if the correct friction values are used for wellbore friction or for the NWB friction components.

The procedure is very simple. A flow rate reduction or a very short shut-in is performed. See Figure 11. If an abrupt change in the ONP occurs, it must be that either the wellbore friction or one of the NWB friction components is incorrect.

If the ONP is calculated with surface pressure data, it is very likely that most of the error is introduced at the wellbore friction component. If reflected (annulus/deadstring) pressure is used to

calculate the ONP, then it follows that one of the FEF components is incorrect (most likely the error is introduced at the near-wellbore friction). If actual BH Pressure is used to calculate the ONP, then most all the friction “seen” by the gauge is near wellbore friction. So, there is no error issue.

Enhanced FEF Analysis Improves Net-Pressure History Matching

Enhanced FEF Analysis is necessary for accurate Net-pressure history-matching. Normally, the surface pressure is measured; however, sometimes the BH pressure is also measured. The hydrostatic pressure is calculated from fluid density. The wellbore friction is estimated from fluid friction database data. Conventional FEF Analysis is usually used to determine the magnitude of the FEF components. All pressure components are shown in diagram format in Figure 4.

With Enhanced FEF Analysis, a quality plot of ONP can be made, which is matched with the MNP calculated by a mathematical model. The mathematical formula used to calculate the ONP, $P_{net (obs)}$, would depend on the wellbore configuration (vertical, horizontal), and the location where the surface treating pressure, P_{st} , is measured: tubing-packer, reflected or “deadstring” (annulus side or tubing side), and tubing-packer BH gauge. These wellbore configurations and the corresponding ONP equations are shown in Figures 10a, 10b, and 10c, respectively.

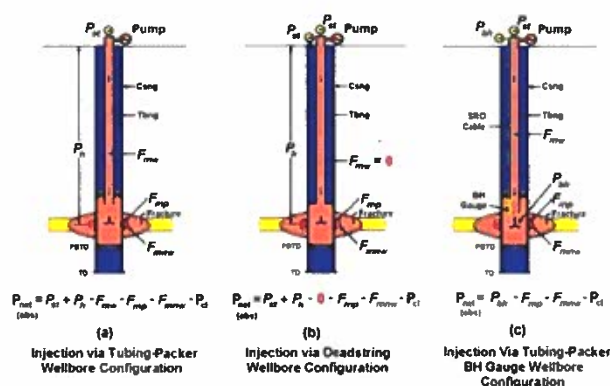


Figure 10: Calculating ONP, $P_{net (obs)}$, under various wellbore configurations. (Adopted and modified from ref. 8).

Thus, for injection via the tubing and pressure measurement at the tubing side (Fig. 10a), all pressure and FEF components would be used. For injection via the tubing side or the annulus side, and pressure measurements at the other side (Fig 10b), the wellbore friction would be ignored. For injection via the tubing side or annulus side, and pressure measurements downhole (with memory gauge or SRO) (Fig 10c), the wellbore friction and the hydrostatic pressure would be ignored, as the wellbore friction is by-passed, and the hydrostatic pressure is included in the bottomhole pressure measurement, P_{bh} .

The $MTSF$ in the system is very easy to determine: It is the difference between Injection Pressure prior to ISIP and ISIP, as shown in Figure 9. It is composed of four components: Measured

Wellbore Friction, Measured Perforation Friction, Measured NWB friction, and, Far-field fracture friction.

The Far-field fracture friction is normally ignored. It has very small magnitude, because the velocity of the fluid in the far-field fracture is very low (approximately 2 ft / min).

To correct for friction in real-time, all that is needed, is to perform a momentary rate change or shut-in as shown in Figure 11. If the net pressure changes, the friction used in calculating Net-Pressure is wrong.

After correcting for friction, the simulation is run again until a plot on Net-pressure without abrupt changes is obtained. This is the correct Net-Pressure. The concept is shown in Figure 11.

Writing equation 2 out completely and analyzing it carefully, one would note that errors can only be introduced at the friction terms, as the other terms are measured, or can be calculated accurately. If the ONP is calculated from surface treating pressure, (P_{st}), most of the error introduced will be at the wellbore friction term.

$$P_{net (true)} = P_{st} + P_h - F_{mw} - F_{mfp} + F_{mnw} - P_{cl} \dots \dots (2);$$

So,

- If the ONP goes up, not enough friction is being subtracted.
- If the ONP goes down, excess friction is subtracted.

FEF Analyzer calculates all friction components accurately. Thus, it improves Net-pressure history-matching.

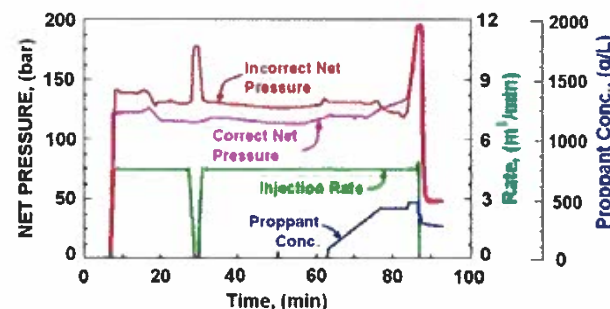


Figure 11: Net-pressure plots showing how to correct for friction in real-time. (Adopted and modified from ref. 8).

Typical Cases

Two typical cases are presented in Figures 12 and 13. For both cases the dominance of NWB friction is clearly evident, as it plots above perforation friction. Because of the high NWB friction, both treatments screened out early leaving the wellbore full of proppant. These examples illustrate the need to accurately calculate the magnitude of the FEF components and use the information wisely.

Case 1

In the case shown in Figure 12, the NWB friction is about 38.5 bars, clearly in the danger range outlined in the decision control guidelines (see next section). Of the planned 120 tons of proppant, only 70 tons were placed in the formation. In addition, the large wellbore volume was left full of proppant.

This increased the cost of the treatment (for wellbore cleanout), and the well will not produce as predicted as the fracture size is much smaller than designed.

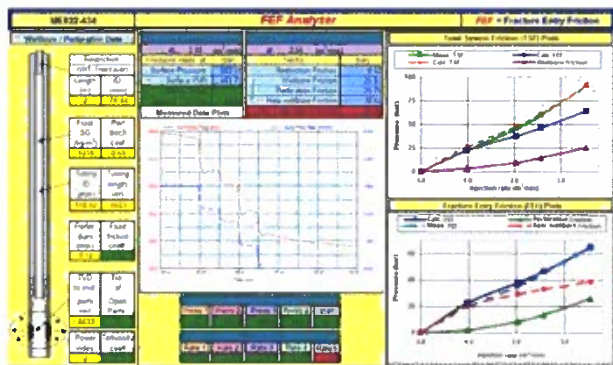


Figure 12: Example Enhanced FEF Analysis showing very high near-wellbore friction. The treatment screened out early.

Case 2

In the case shown in Figure 13, the NWB friction is about 43.5 bars, also in the danger range outlined in the decision control guidelines (see next section).

The treatment screened out twice, the first time when proppant arrived at the perforations. The treatment was redesigned: the proppant tonnage was reduced, the design ramp was made gentler, and the maximum proppant concentration was lowered.

Of the planned 50 tons of proppant only 12 tons were placed in the formation. Once again, this increased the cost of the treatment (for wellbore cleanout), and the well will not produce as predicted as the fracture size is much smaller than designed.

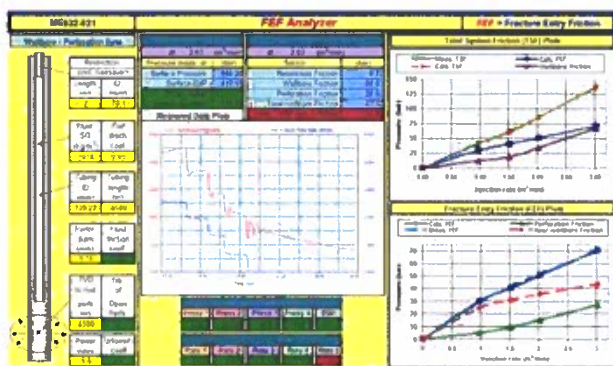


Figure 13: Example Enhanced FEF Analysis showing very high near-wellbore friction. The treatment screened out twice.

Decision Control Based on Enhanced FEF Analysis

Although decision making based on Enhanced FEF Analysis would be sufficient to reduce screenouts, one should consider additional FEF Diagnostics: proppant slug response, hydraulic transient response (water hammer), etc.

Generally each field and formation has its own special characteristics; so, one would have to establish guidelines not only by field, but by formation. This is best accomplished with statistical analysis of consistent data provided by Enhanced FEF Analysis.

Based on both Conventional and Enhanced FEF analysis of over 400 RST's, and close inspection of an additional 1600 RST's, from around the world, general guidelines for decision control have been established, as shown in the following table:

General Decision Control Guideline Based on Ranges of FEF Component Values				
Perforation Friction		Near-wellbore Friction		Remarks
(bar)	(psi)	(bar)	(psi)	
0-15	0- 218	0 - 15	0- 218	Very low probability for screenout
15-30	218 - 435	15 -30	218- 435	Caution required
30-50	435-725	30-50	435-725	Screenout highly probable
> 50	> 725	> 50	> 725	Screenout almost certain

Note

The example data (perforation depth, pressures, flow rates, etc.) presented in this paper have been shifted or changed slightly, so, they do not represent actual cases.

Conclusions

Based on data and analysis presented in this paper the following conclusions can be drawn:

1. The RST is an easy and inexpensive test to perform.
2. The RST along with Conventional FEF Analysis must be performed correctly, otherwise incorrect allocation of friction values are assigned to each flow path segment: wellbore, perforations, and near-wellbore.
3. The RST along with Enhanced FEF Analysis calculates and allocates correct friction values to each flow path segment.
4. Enhanced FEF Analysis improves the accuracy with which both the ONP and the MNP are calculated, thus it improves Net-pressure history-matching.
5. Enhanced FEF Analysis increases the chances of placing safe and effective propped hydrofrac treatments.
6. Reduction in unplanned terminations (screenouts) of propped hydrofrac treatments reduces up front costs for wellbore cleanout.
7. Reduction in unplanned terminations (screenouts) increases the assets with which one operates (reduces risk), thus, it increases long-term revenues and the RoI of most projects.
8. Correct design of the RST and Enhanced FEF Analysis in conjunction with other FEF indicators (proppant slug response, hydraulic transient response (water hammer)), can dramatically reduce unplanned terminations (screenouts) of propped hydrofrac treatments.

9. The decision control guidelines are based on statistical analysis of a vast number of RST's, and routine usage. The indications are that they are reliable.

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Appendix A

Wellbore friction correlations in FEF Analyzer Discussion

The wellbore friction data (available in databases) which have been built into commercially available Fracture Propagation Simulators, were developed in a lab environment with 2 in ID flow loop, and extrapolated to various conduit diameters and/or geometries, e.g., tubing, casing or annulus.

The extrapolated friction values for the various conduit diameters may or may not match the friction value determined by analyzing the RST.

To bypass this issue, FEF Analyzer adjusts the friction data in the database. Algorithms and methods originally presented Hannah, et al.¹¹ and by Keck, et al.¹², were modified in order to obtain reasonable values for wellbore friction.

Wellbore Friction Calculations

Newtonian fluids

A computation algorithm for longitudinal friction losses in conduits with circular cross-sectional area and for Newtonian fluids is presented below. Water is the most common Newtonian fluid. For all flow regimes the Darcy-Weisbach Equation^{21, 22} is recommended:

$$\Delta P = f \frac{l}{d} \rho \frac{v^2}{2} \quad (\text{A-1});$$

Where,

f = longitudinal friction losses coefficient
(Fanning friction factor);

l = pipe length; d = pipe ID;

ρ = Fluid density;

v = Average velocity of fluid in pipe,
(flowrate divided by flowing cross-sectional area).

There are different formulas for calculating f for each flow regime. The flow regime criteria and the corresponding algorithms are presented below. For each flow regime the most appropriate formula for calculating f is presented. From all the correlations in literature, the ones that produce the best results for circular conduits have been chosen.

First Re number and Re_k multiplied with relative roughness, are calculated using the following formulas:

$$Re = \frac{\rho v d}{\mu} \quad (\text{A-2});$$

$$Re_k = \frac{\rho v k}{\mu} \quad (\text{A-3});$$

Where, k is tubing pipe roughness and it has an approximate value equal to 0.001524 mm for most conduits.

Using the two Re numbers, presented above, the flow regime is determined, the f coefficient is calculated with the equation corresponding to each flow regime:

Laminar flow regime: $Re < 2100$ and $Re_k < 3$

$$f = \frac{64}{Re} \quad (\text{A-4});$$

Transition flow regime: $2100 < Re < 3000$

For transition flow regime f has an intermediate value between a value characteristic for laminar flow and a value characteristic for smooth pipes in the turbulent flow regime.

Turbulent flow in smooth pipes regime:

$$Re > 3000 \text{ and } Re_k < 3$$

For turbulent flow in smooth pipes regime, the Blasius correlation is recommended:

$$f = \frac{0.3164}{\sqrt[4]{Re}} \quad (\text{A.5});$$

It is valid for $3000 < Re < 100,000$. For the turbulent flow regime in smooth pipes, but for a more extended range the following two

correlations are used respectively:

For $3000 < Re < 3 \cdot 10^6$, the Von Kármán correlation can be used which has the following form:

$$\frac{1}{\sqrt{f}} = 2 \lg(0.5 Re \sqrt{f}) - 0.2 \quad (\text{A-6});$$

An explicit evaluation for f was presented by Drew, Koo and McAdams¹⁶ as follows:

$$f = 0.0056 + 0.5 Re^{-0.32} \quad (\text{A-7});$$

Turbulent flow in partially rough pipes regime:

For Turbulent flow in partially rough pipes, where, $Re > 3000$ and $3 < Re_k < 70$, it is recommended to use the correlation developed by Colebrook and White as follows:

$$\frac{1}{\sqrt{f}} = -2 \lg \left(\frac{2.51}{Re \sqrt{f}} + \frac{k}{3.71d} \right) \quad (\text{A-8});$$

For the same domain of Re and Re_k Colebrook has developed the following empirical equation:

$$\frac{1}{\sqrt{f}} = 2 \lg \frac{d}{2k} + 1.74 - 2 \lg \left(1 + 9.35 \frac{d}{k Re \sqrt{f}} \right) \quad (\text{A-9});$$

Turbulent flow in rough pipe regime:

For turbulent flow in rough pipe, where, $Re > 3000$ and $Re_k > 70$, the Nikuradse correlation is recommended:

$$\frac{1}{\sqrt{f}} = 2 \lg \frac{d}{2k} + 1.74 \quad (\text{A-10});$$

Polymer Based and Viscoelastic (VES) Fluids

A theoretical approach of flow of polymer based and viscoelastic fluids is very difficult. It doesn't provide accurate calculations of pressure losses due to friction.

Rheological measurements of polymer based fluids show behavior similar to a Power-law fluid. However, in the typical tubing/casing ID range, the real friction differs dramatically when compared with that calculated with the Power-law model. So, experimental data provided by the Service Companies are very useful.

From experiments performed with polymer based fluid and VES fluids the following phenomena have been noticed:

1. In the turbulent flow regime, the friction losses are reduced;

- For different conduit ID's, the friction losses coefficient, f , doesn't depend only on the Re number;
- There is a tendency of points $f = f(Re)$ to take minimum values in the turbulent flow regime far lower than those corresponding to the Power law model.

For certain conduit ID's, points $f = f(Re)$ plots on an asymptotic curve. The plot looks like an extension of the laminar flow regime curve, and is known as Virk's Maximum Drag Reduction (MDR) Asymptote¹⁰, as shown in Figure A-1.

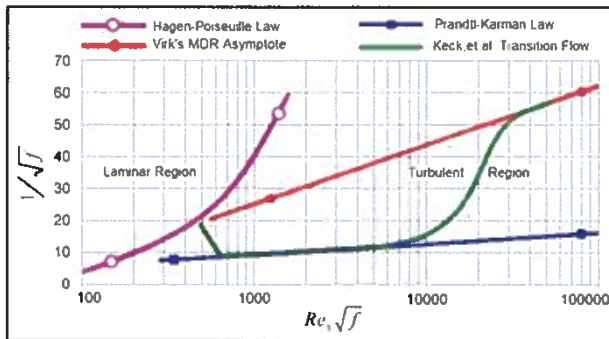


Figure A-1: Plots of various correlations: Hagen-Poiseuille, Prandtl-Karman, Virk's MDR Asymptote, and Keck, et al. Transition flow. (Adapted and modified from ref. 10).

For laminar flow regime $Re_s < 2300$ for longitudinal friction losses, the Power law fluid formula can be used as follows:

$$f = C64/Re_s \quad (A-11);$$

$$Re_s = 8^{1-n} \frac{\rho_n v_m^{2-n} d^n}{K} \quad (A-12);$$

Where,

K and n are coefficients characteristic of a Power-law fluid (measured using a Taylor-Couette type viscometer), (rotational viscometer).

C is a Correction coefficient (calculated using experimental data).

For the turbulent flow regime of viscoelastic fluids, Keck, et al.¹² have developed a correlation similar to that developed by Dodge and Metzner¹⁵ (for Power-law fluids), in which the coefficients A and B are not constant, instead, A and B vary as a function of the conduit ID.

$$\frac{1}{\sqrt{f}} = A(d, n) \log(Re \sqrt{f}) - B(d, n) \quad (A-13);$$

Re for the above equation is the Re for the solvent (in most cases water). For HPG and guar based fluids, Keck, et al.¹² have determined the following equations for the A and B coefficients:

$$A = 17.38 * n^{-1.6} d^{0.13} \quad (A-14);$$

$$B = 74.28 * n^{-1.9} d^{0.27} \quad (A-15);$$

Where,

d = conduit ID.

Note that the above equations have been adjusted to conform to the metric system of units. Equation A-13 is valid only for conduit ID's in the range of 2 in to 4 in.

In *FEF Analyzer*, the coefficients A and B, in equations A-14 and A-15 have been modified in order to allow for adjustments based on experimental data as follows:

$$A = C_1 17.38 * n^{-1.6} d^{0.13} \quad (A-16);$$

$$B = C_2 74.28 * n^{-1.9} d^{0.27} \quad (A-17);$$

Where, C_1 and C_2 are correction coefficients whose values are determined using experimental data.

If experimental data for the actual ID does not exist (available in databases furnished by the Service Companies), data for the closest ID is selected. For this ID, normally three data points of pressure loss due to friction are provided, which correspond to three rates (low, pivot, and high).

The coefficients C_1 and C_2 are calculated first for rates from low to pivot (using these two experimental points) and then from rates from pivot to high (using the second pair of experimental points). For the actual pipe ID the formula developed by Keck, et al.¹² is used, which is corrected using C_1 and C_2 obtained from experimental data.

Using the algorithm(s) presented above to calculate wellbore friction gives accurate values, which are close to the experimentally determined friction values. However, sometimes the calculated friction values can be different than the values measured with the RST.

The most reliable analysis of the RST is performed with bottomhole pressure data, as this procedure eliminates the need to perform correction(s) for wellbore friction, where most of the errors and uncertainty are introduced.

If it is reasonable to assume that the number of perforations accepting fluid during the RST remains constant (as the duration of the RST is very short). It follows that the bottomhole pressure should decrease (rather than increase), as the rapid flowrate reductions of the RST are executed.

In many RST analyses/interpretations, because the wellbore friction is over-estimated for high rates, the paradox of increasing bottomhole pressure is observed, which, of course, is physically impossible.

In such cases, the wellbore friction should be decreased. This adjustment is done by subtracting a certain percent to the calculated f . The calculated wellbore friction values are considered realistic when the calculated BHP is decreasing as the flow rates progress from maximum, to cessation of flow at ISIP. *FEF Analyzer* includes an algorithm to calculate wellbore friction with fluids containing suspended particles, e.g. gel containing proppant, known as slurry. Two-phase flow has a limited influence on pressure loss due to friction in the wellbore, but, it can dramatically influence perforation pressure loss, especially in the event of proppant bridging on the perforations

and/or the near-wellbore region.

The phenomenon of proppant bridging is totally uncontrolled and unpredictable. so, it is highly recommended to perform the RST with linear (not cross-linked) and clean (not proppant-laden) fluids. Considering the above it is not recommended to perform the RST in a way that a two-phase flow regime will be established.

Appendix B

Perforation Friction Calculations

For perforation pressure drop the equation for pressure drop in a sharp-edged orifice was used.

$$\Delta P = \frac{\rho v^2}{2} = \frac{\rho \left(\frac{Q}{SC_D} \right)^2}{2} = \frac{\rho \left(\frac{Q}{N \frac{\pi d^2}{4} C_D} \right)^2}{2} \quad (\text{B-1});$$

$$= \frac{\rho \left(\frac{4Q}{N \pi d^2 C_D} \right)^2}{2} = \frac{\rho 16 Q^2}{2 N^2 \pi^2 d^4 C_D^2} = \frac{8 \rho Q^2}{\pi^2 N^2 d^4 C_D^2}$$

Where,

ρ = Fluid density (kg/m³);

Q = Injection Rate (m³/sec);

S = Flowing surface area (m²);

C_D = Discharge coefficient (dimensionless);

N = Number of opened perforations;

d = Perforation diameter (m).

Equation (B-1) is written in Metric Units. If the Oilfield system of units is used, it becomes:

$$\Delta P = \frac{0.2369 \rho \left(\frac{Q}{N} \right)^2}{d^4 C_D^2} \quad (\text{B-2});$$

In the *FEF Analyzer* program, the Discharge coefficient C_D is input, as it cannot be assumed to be a constant value for all fluids and perforation sizes. Recent studies by EL-Rabaa, et al.¹³ have shown that the coefficient of discharge depends significantly on the fluid viscosity and perforation size.

Based on equations B-1 or B-2, the wrong estimation of coefficient of discharge can introduce a serious error in the total pressure drop due to perforation pressure calculation.

The RST, and the associated FEF Analysis which calculates and distributes the pressure drop (into components of wellbore, perforation, and, near-wellbore), is not affected by the coefficient of discharge, because, the perforation pressure drop is still a function of Q^2 , which can be distinguished from the Total System Friction pressure drop.

Wrong calculation of perforation discharge coefficient causes incorrect calculation of the number of open perforations. It is obvious, that if a small value for C_D is estimated, a larger number of opened perforations will be estimated. RST and the associated FEF analysis are simply diagnostic tools for the on-site redesign of Propped Hydrofrac Treatments. Wrongly calculated number for opened perforations will affect the size of erosive stages that are necessary to be placed.

As previously mentioned, the most reliable RST is performed with linear fluid especially when no bottomhole pressure gauge data is available. Friction calculation with crosslinked gel which has variable cross linking time is very unreliable. For low-to-medium permeability formations, it is recommended to perform the RST with linear gel in the entire system (wellbore, perforations and near-wellbore region). For high permeability formations crosslinked gel must be used for the FET, which must be overdisplaced with linear gel, before the RST procedure can be started.

For clean fluids in general and for linear gel in particular, the coefficient of discharge is correlated with the apparent viscosity of the fluid and the perforation diameter.

Fluid apparent viscosity is considered the apparent viscosity for 511 sec⁻¹ shearing velocity. Using the Power-law fluid equation, the equation for apparent viscosity is derived as follows:

$$\mu_a = \frac{K (dv/dx)^n}{dv/dx} \quad (\text{B-3});$$

The 511 sec⁻¹ equation above can be written as follows:

$$\mu_a = K (511)^{n-1} \quad (\text{B-4});$$

Where,

μ_a = apparent viscosity (Pa sec);

K = Consistency index (Pa secⁿ);

n = Power-law index.

In Oilfield units, equation B-4 can be written:

$$\mu_a = 47880 K (511)^{n-1} \quad (\text{B-5});$$

EL-Rabaa, et al.¹³ developed a correlation for the coefficient of discharge of the perforations, which, is applicable to linear gel:

$$C_d = \left(1 - e^{\frac{-2.2d}{\mu_a^{0.1}}} \right)^{0.4} \quad (\text{B-6});$$

Where,

d = perforation diameter (in)

μ_a = apparent viscosity (cP)

Equation B-6 has been empirically developed using

experimental data, and is used in Fracture Entry Friction software. Used together with equation B-1 they provide the correct number of perforations open and accepting fluid, (assuming that the correct value for perforation friction pressure drop has been calculated).

EL-Rabaa, et al.¹³ discuss perforation friction in great detail, so, this subject will not be elaborated upon farther in this paper. The reader is referred to the many papers that have been published on this subject.

Appendix C

Near-wellbore Friction Calculations

In theoretical terms, development of a mathematical expression which relates near-wellbore friction as a function of flow rate is required to study the subject. This expression obviously differs from the mathematical expression for perforation friction.

Pressure loss due to perforation friction is a function of fluid velocity squared. It increases sharply as a function of flow rate. By contrast, a fracture entry restriction normally widens when the flowrate is increased, thus, the slope of the plot of NWB friction vs. flowrate decreases as a function of flowrate.

This is the distinguishing characteristic of this plot when compared to the plot for pressure loss due to perforation friction. It helps to distinguish perforation friction from near-wellbore friction.

If high pressure loss at the fracture entry manifests itself, it could be due to multiple fractures - narrow due to the splitting of the flow rate, or due to the complicated twisted flow path at the near-wellbore region.

In either case, increasing the flowrate rate increases the fracture entry width and causes the curve to plot with a decreasing trend (plot is concave sideways, (down)). In some cases the pressure loss due to near-wellbore friction is so high that it dominates the entire pressure loss in the system (the total pressure loss plots concave sideways (down)).

Near-wellbore friction due multiple (narrow width fractures)

Considering constant flow rate flow between two parallel plates, we can derive a pressure loss equation for a narrow fracture.

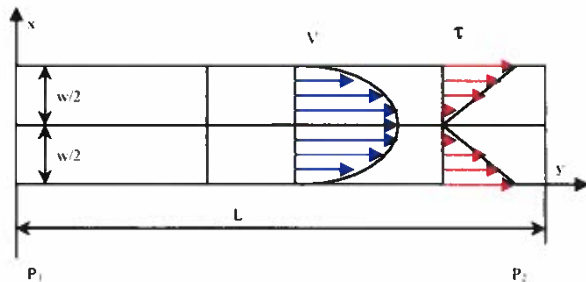


Figure C-1: Fluid Mechanics/Dynamics for a narrow fracture

Since the forces acting all along the fracture length are in equilibrium, an equation of forces in equilibrium can be written, which, integrates velocity on the fracture section surface. From this equation we can easily deduce a rate equation which is a function of pressure loss for a Newtonian fluid:

$$Q = \frac{\Delta P H w^3}{12 L \mu} \dots\dots\dots (C-1);$$

Where:

L = fracture length

H = fracture height

w = fracture width

Q = injection rate in the fracture

ΔP = Pressure drop along fracture length, L ,

μ = viscosity of Newtonian fluid

Equation C-1 is in the metric system of units, and is valid for laminar flow, from which we can conclude that for constant fracture width and a Newtonian fluid, the pressure loss increases linearly as a function of flowrate.

Since most pressure measurements are made at the surface of the earth (very close to the wellhead valves), this type of curve is not useful to distinguish which of the FEF components is dominant, due to "masking" wellbore friction.

If a non-Newtonian fluid is in the fracture, the fluid viscosity in the fracture is affected by the shearing rate and is not constant.

If we consider an equivalent viscosity in the fracture, the flowrate formula can be written as follows:

$$Q = \frac{\Delta P H w^3}{12 L \mu} \dots\dots\dots (C-2);$$

For a Power-law fluid, $(\tau = K \left(\frac{dv}{dx}\right)^n)$ writing a forces in

equilibrium equation along the fracture length, leads to the following equation:

$$Q = \frac{H}{2} \left(\frac{\Delta P}{2L} \right)^{\frac{1}{n}} \left(\frac{1}{K} \right)^{\frac{1}{n}} \left(\frac{n}{n+1} \right)^{\frac{2n+1}{n}} w^{\frac{2n+1}{n}} \left(\frac{n+1}{2n+1} \right) \dots\dots (C-3);$$

Or

$$Q^n = \left(\frac{H}{2} \right)^n \left(\frac{\Delta P}{2L} \right)^{\frac{n}{n+1}} \left(\frac{1}{K} \right)^{\frac{n}{n+1}} \left(\frac{n}{n+1} \right)^{\frac{2n+1}{n}} w^{2n+1} \left(\frac{n+1}{2n+1} \right)^n \dots\dots (C-4);$$

From the above expression for Power-law fluids the trend of the pressure loss plot is affected by the Power-law index of the fluid. In practice, if linear gel is used for the RST, the Power-law index is almost one and equation C-4 becomes equation C-2.

As previously mentioned, linear gel is recommended to be in the wellbore and near-wellbore region for the RST, because, the viscosity is not affected as much by the shearing rate. There are cases where a fracture cannot be initiated; because of the low

efficiency of linear fluids (linear gels), and only short superficial fractures can be created. In such cases, the fracture entry geometry is very different, so, crosslinked gel provides the necessary efficiency, thus, using crosslinked gel is recommended (instead of linear gel).

In cases where DH pressure data is not available, it is recommended to overdisplace with linear gel prior to starting the RST. Only after linear gel has passed the perforation near-wellbore area the RST can be started.

In practice, as the abrupt pressure declines of the RST occur the viscosity of crosslinked gel doesn't increase instantaneously. Normally, it takes some time to recover, thus, the plot of pressure loss vs. flowrate is not affected by the Power-law index as much as theory would predict.

Pseudo-plastic behavior of the fluid would affect the trend of the pressure change plot in the same manner as the variation of fracture width would, i.e., the slope is decreasing as a function of flow rate (the plot is concave sideways (down)).

Considering equation C-2 valid for pressure loss, the pressure dependence on flow rate is affected basically by fracture width increasing with pressure.

Expressing fracture width as a function of Net-pressure in the fracture entry region, equation C-2 becomes:

$$Q = \frac{\Delta PH (w(P_{med} - \sigma_o))^3}{12L\bar{\mu}} \quad \text{..... (C-5)}$$

Where,

$$P_{med} = (P_w + P_f)/2$$

P_{med} = average pressure in fracture-entry region,

σ_o = closure stress,

P_w = pressure in fracture immediately near the wellbore, (immediately beyond the perforations),

P_f = pressure in fracture (beyond fracture entry restrictions)

$\bar{\mu}$ = equivalent viscosity in the fracture

The dependence of fracture width as a function of net-pressure is different for different fracture entry geometries, and most certainly it is different for the various fracture propagation simulation models.

In all fracture propagation simulation models the fracture width is proportional to one characteristic fracture dimension and net-pressure. The decrease varies proportionally as a function of Young's modulus.

The PKN model predicts a fracture length far longer than fracture height (which is almost never the case). As such, the width equation of the KGD model has been chosen for inclusion in *FEF Analyzer*.

$$\begin{aligned} w &= \frac{4}{E'} LP_{net} = \frac{4}{E'} L(P_{med} - \sigma_o) \\ &= \frac{4}{E'} L \left[\frac{(2P_f + \Delta P)}{2} - \sigma_o \right] \quad \text{..... (C-6)} \end{aligned}$$

Where,

$$E' = E/(1-\nu)^2$$

E = Young modulus

ν = Poisson's ratio

Merging equations C-5 and C-6, results in the following relationship, which relates flowrate to pressure loss.

$$\begin{aligned} Q &= \frac{\Delta PH \left[\frac{4}{E'} L(P_f + \Delta P/2 - \sigma_o) \right]^3}{12L\bar{\mu}} \\ &= \frac{\Delta PH 16 L^2 [(P_f + \Delta P/2 - \sigma_o)]^3}{3\bar{\mu}(E')^3} \quad \text{..... (C-7)} \end{aligned}$$

As it can be seen from equation C-7, $Q = f(\Delta P)$ is a polynomial function not a power function. So, for flow rates less than 4 m³/min (very common in RST applications), the function $\Delta P = f(Q)$ can be approximated with a power function as follows.

$$\Delta P = K_m Q^m \quad \text{..... (C-8)}$$

The value of 0.5 for the near-wellbore friction coefficient exponent, m , is a commonly accepted average value used for convenience, it can be more or less than 0.5.

The near-wellbore friction coefficient exponent, m differs for different Young's moduli and stress conditions.

The following three interpolation examples of the function $\Delta P = f(Q)$, for three different values of Young's modulus and stress conditions are plotted on the same graph for comparison purposes:

- 1) DP theoretical,
- 2) The approximation equation C-8 (with $m=0.5$),
- 3) Equation C-7.

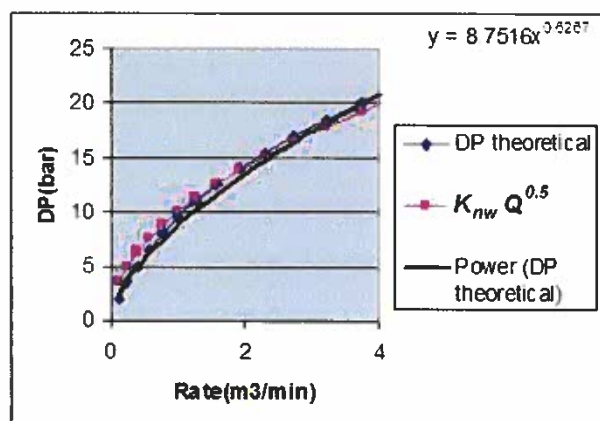


Figure C-2: Case 1: Young's modulus = 68965 bar (1000000Psi), Stress=200 bars

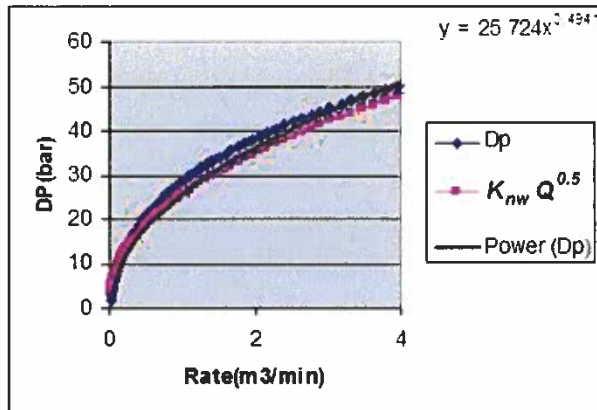


Figure C-2: Case 2: Young's modulus = 137931 bar (2000000Psi), Stress=350 bars

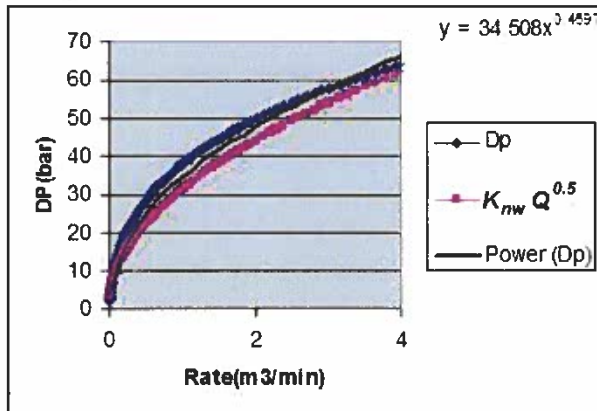


Figure C-2: Case 3: Young's modulus = 172413 bar (2500000Psi), Stress=350 bars

As it can be seen, the value of the near-wellbore friction coefficient exponent, m , resulting from the sensitivity analysis is not always 0.5.:

- For shallow depth it is slightly larger than 0.5.
- For hard rock and high stress conditions, it is less than 0.5.
- For tough rock at great depth, the approximate value of $m=0.5$ is used, instead of the first real point of measured fracture entry friction (at a min flow rate of 500-600 l/min). This is because, it plots higher than the curve calculated with $m=0.5$. However, in most of the cases using $m=0.5$ is a good approximation.

High near wellbore friction due to inertial forces

In some cases it has been noticed that even in open hole completions, near-wellbore friction could be approximated with a curve given by equation C-8. However, the exponent m is >1 ¹⁴. In an open hole completion (without perforations), if $m>1$, it is obvious that pressure losses due to near-wellbore friction occur due to inertial forces, i.e., $\Delta P=f(\rho V^2)$.

Inertial forces manifest themselves if the fracture entry geometry is complicated, and the flowrate is high. If there are flow cross-section changes in the fracture entry geometry, the near-wellbore friction plot can become convex, in such a case, it is quite impossible to distinguish between perforation friction losses and near-wellbore friction losses.

In practice, a robust method to approximate near-wellbore friction losses generated by tortuosity or by a narrow fracture is to use equation C-8, with $m=(0.4-0.6)$, which is what is used in *FEF Analyzer*. In the bar metric system of units of flow rate is m³/min and the unit for pressure loss is bars.

Using the bar metric system of units, the value of the coefficient of near wellbore friction, K_{nw} , is in the range of 1-50. By varying K_{nw} we can quantitatively compare the severity of fracture entry restrictions for various reservoirs and wells. Based on statistical analysis, for every reservoir, critical values for fracture entry friction can be established. See section entitled "Decision Control Based on Enhanced FEF Analysis guideline."

Conclusions:

1. Normally, near-wellbore friction loss manifests itself due to the narrow and tortuous fracture(s) at the near-wellbore region. The plot is concave sideways (down).
2. A good approximation for near wellbore friction losses can be calculated using the function $\Delta P = K_{nw} Q^m$.
3. The coefficient, m , is not always 0.5. If fractures restrictions do not widen with increasing flow rate and pressure, it will be equal to 1. For high stress conditions and tough rock is less than 0.5. However, 0.5 is a good approximation for most cases.
4. Inertial forces in the fracture entry region can cause the plot of near-wellbore friction to be concave upwards. In such a case, most of pressure loss will be attributed to perforation friction, and the pressure loss due to near-wellbore friction will be underestimated.