Design, Execution, and Evaluation of Mini-Fracs in the Field: A Practical Approach and Case Study

J.W. Thompson, Dowell Schlumberger
D.C. Church, Dowell Schlumberger

ABSTRACT

Numerous technical papers have been written on the subject of analyzing the pressure-decline data from a mini-frac. Most of the publications written, however, have dealt mainly with the theoretical modeling of the pressure decline and not the practical application of performing a mini-frac in the field.

The intent of this paper is not necessarily to discuss the theoretical analysis and design applications of modeling mini-fracs, but to discuss the practical steps involved to properly design, execute and evaluate a mini-frac. The basic concept of the mini-frac is presented. Guidelines are given on how to design a mini-frac, record bottomhole pressure (BHP), obtain closure and interpret the data. Field case studies are presented which illustrate the step processes involved in performing and evaluating a mini-frac.

INTRODUCTION

Several authors have discussed the theoretical aspects of using pumping tests and pressure analyses to obtain or validate critical design parameters for subsequent design and execution of a fracture treatment. These pumping tests, commonly referred to as mini-fracs, provide a method to determine the fracture geometry, efficiency, fluid-loss coefficient, fracture height, closure pressure and elastic rock properties as measured in-situ.

Each well possesses unique fracture length and conductivity requirements that will provide optimum well performance and maximize an operator's return on investment. When the critical design variables referred to above are assumed or provided from offset well data, they may not be accurate. The result is a less-than-predicted result. Figure 1 illustrates the effect of an overly pessimistic fluid-loss coefficient assumption during the design phase. If the actual coefficient is 50% less, a fracture length of 1400 feet will be achieved versus the optimum of 650 feet. The result is a lower conductivity fracture in which the proppant is distributed over a longer fracture. Figure 2 shows the impact of an inaccurate fracture height prediction. If the actual fracture height is 300 feet (as opposed to the assumed 100 feet utilized in the design), then a fracture length of 325 feet will be the result, not the desired 700 feet. Similar parametric sensitivity studies will all yield the same result, i.e., if inaccurate assumptions of key fracturing design variables are used, the subsequent fracture length and conductivity could be adversely affected, imposing a deletérious result on expected well performance.

Mini-fracs are composed of two basic injection tests which are conducted to ensure a reliable fracture analysis, a stress test and a calibration treatment. The stress test is a step-rate injection procedure followed by flowback or pressure-decline analysis to determine closure pressure which is equal to the minimum in-situ rock stress. It is extremely important that closure pressure be determined correctly since all subsequent fracture analyses and proppant selections reference it. This value is analogous to initial reservoir pressure in reservoir-performance studies. Other data obtained from this test are fracture extension and perforation and fluid friction pressures which are discussed later.

Once closure pressure is determined, the calibration test is performed. This injection test is conducted with the same fluid and at the same rate planned for the fracturing treatment. Following shutdown, the pressure decline is monitored until closure is attained. The pump-in portion of this procedure indicates the type of fracture being propagated. This information is used to determine which model to use for the decline analysis that follows as well as diagnose any undesirable features such as fissure opening and rapid height growth. The pressure-decline analysis should yield the in-situ fluid efficiency and the fluid-loss coefficient for this specific fluid in this particular well. Currently, there is no better method for determining these values.

Analysis of pressure against Castillo's G-Function is the preferred method as fracture extension following shutdown, and pressure-dependent leakoff can be noted. Once the analysis is complete, the actual fracture design parameters are utilized to optimize the fracturing operation.

GUIDELINES FOR MINI-FRAC JOB DESIGN AND EXECUTION

A mini-frac treatment can be designed to be performed as a separate treatment from the actual propped fracture treatment, or it can be designed to be performed on the same day as the actual propped fracture treatment. An example job-procedure outline for designing and executing a mini-frac is presented in Table 1. The first step in the design is to ensure all the perforations are open. This can be done by performing an acid ballout on the perforated interval.

STRESS TEST

The stress test should be designed for at least two step-rate/flowback/shut-in tests using a very inefficient fluid such as water or 2% KCl. If a very high permeability (> 5 md) formation is encountered, it may be necessary to gel the fluid in order to decrease the rate required for frac initiation. The pump rates for the step-rate test must be at least three or four steps below fracturing pressure and three or four above. It is important to remember that exact rates are not important - CONSTANT RATES ARE. The time step for each rate will need to ensure a steady rate, with both rate and pressure being recorded prior to the next step rate. Usually this can be achieved by having each step rate last from two to four minutes. The final step rate should be pumped two times longer than the previous step rates. It is important that enough fluid is injected into the formation to ensure the fracture remains open long enough to accurately determine closure. Prior to shutdown, reduce the pump rate to 10 to 20% of the final pump rate for 5 to 10 seconds. This is to reduce the water-hammer effects caused by shutting the pumps down too quickly. If surface pressure readings are used to record the job, it is important to ensure that the hole is filled with a fluid of known density.

Flowback should be started immediately after the pumps have shut down and held at a constant rate. If the formation permeability is high (> 1.5 md) do not flow back, just shut down and monitor the pressure decline. If flowback is required, the flowback rate should be between 10 and 25% of the final pump rate. Exact rates are not important - CONSTANT RATES ARE. Flow back until closure has been determined or until the BHP has fallen to about 200 psi above the initial BHP. To keep the original reservoir fluid from flowing into the wellbore, do not flow back more than the volume of fluid pumped into the formation . The choke used to control the flowback rate should be preset at the desired flowback rate before starting the job. Flowback should be conducted immediately after shut down with the pumps isolated. If the formation permeability is not known, do not perform a flowback on the first step-rate test. Just shut down and monitor the pressure decline. Depending on the results of the initial step-rate test, a second test may need to be performed at a different flowback rate or by just shutting down and monitoring the pressure decline. The second pump-in test may not need to include the step-rate procedure if a reliable fracture extension pressure has been determined.

Closure pressure can be determined from the BHP-versus-time plot (Fig. 3, 5). The pressure response from the decline will show a distinct reversal in curvature once closure has occurred. Closure occurs at the inflection point of the pressure decline where the slope changes from concave up to concave down. This value should be below the predetermined fracture extension pressure. If flowback is too low, a curvature reversal will never take place with only a concave upward portion plotted. If the flowback is too high, only a concave downward portion (which will drop off very rapidly) will develop . To more easily observe a closure pressure, it may be necessary to isolate or zoom-in on a specific time interval. Closure can also be observed from either a square root of time plot or from a G-Function plot. For these plots, the point of deviation from the straight line should correspond to closure. If a closure pressure cannot be determined by the methods above after several step-rate/shut-in/flowback attempts, the fracture extension pressure can be used as closure pressure with the option of taking off 50 psi, if so desired.

Another important piece of information gained from the this test is perforation friction. Upon shutdown, the immediate BHP drop (when using a BHP gauge or dead string) is the pressure loss across the perforations at the last pump rate.

The fracture extension pressure can be determined by plotting the BHP-versus-pump rate as illustrated in Fig. 4. The plotting points should be recorded just before each rate change. This will show two distinct slopes, one representing matrix conditions and the other indicating fracturing conditions. The intersection of these two lines represents the fracture extension pressure which is usually 50 to 150 psi higher than closure pressure. Fracture extension pressure can also be observed by plotting the BHP versus time. Each rate change will have a round shoulder under matrix conditions until fracture extension occurs and the rounded shoulders will become squared. This is illustrated in Figure 5. Using this method, it is more difficult to observe the fracture extension pressure than from the method of plotting the BHP versus rate. Fracture extension pressure will not show up well if a BHP gauge or dead string is not used. This is because of the excess friction pressure encountered during the injection. In some cases an extension pressure can be detected when pumping down casing where friction pressures are negligible. Do not attempt to obtain an extension pressure when pumping down tubing without a BHP gauge or dead string unless the anticipated pump rates are low.

CALIBRATION TEST

The calibration test is designed to estimate the efficiency of the treatment. Therefore, the fluid planned for the fracture treatment is required for this test. Ideally the same volume would be used, however this is not practical for most cases. As a result, most calibration tests are designed using the same fluid and volume as the pad of the anticipated fracture treatment. A simple 2D simulator (radial and PKN) can be used to determine the volume required to "test" the potential barriers. Radioactive tracers should also be included. The pump rate should be equal to that of the anticipated fracture treatment. It is important for this treatment to define the height growth which will be experienced during the actual fracture treatment.

If the initial fluid in the casing/tubing to be displaced is more than 10% of the calibration test, then efforts should be made to circulate the calibration fluid to the perforations before starting the test. If this is not possible, bullhead the fluid in the workstring into the formation at a slow rate and shut down to allow the pressure to fall below closure before starting injection. Long shut downs should be avoided when pumping into a hot well, so as not to affect the fluid properties. When pumping into deeper, hotter formations (temperature >200° F), the expansion of the fluid caused by heat up should be taken into consideration during the pressure decline. The surface pressures can actually increase while BHP decreases, therefore making surface pressure readings inaccurate at early times. Flush the treatment to a point above the top perforations. Isolate the pumps and monitor the pressure decline for 1.25 times closure time or for twice the injection time whichever is longer. After the pressure decline is finished, the post-fracture logs can be run to determine the fracture height.

DETERMINING FRACTURE HEIGHT

It is critical to define the fracture-height growth during the calibration test. Both pre-frac and post-frac logs should be used to aid in determining the fracture height. Pre-frac logs such as a fracture-height log or a mechanical property log can be very informative in estimating the anticipated fracture-height growth and Young's modulus. Gamma ray and temperature survey logs should always be run to get a reasonable estimate of the fracture height. A baseline gamma ray and temperature survey log performed prior to the mini-frac will enhance the interpretation.

SPECIAL EQUIPMENT NEEDED

A treating van with a computer can be used to properly monitor and record the required information obtained during the mini-frac. If the step-rate test includes pump rates lower than 1.5 bbl/min, a low-rate pump will be required. To maintain a constant rate during the flowback test, a flowback manifold with an adjustable choke and flowmeter is recommended.

RECORDING BOTTOMHOLE PRESSURE (BHP)

An accurate BHP measurement is essential for a correct analysis of the mini-frac. Some of the more common methods to measure BHP include

* Real-time BHP gauge with surface readout
* Retrievable BHP gauge (post job)
* Dead tubing string or live annulus
* Surface pressure readings to calculate BHP

The most useful and accurate method to measure BHP is by a real-time BHP gauge. This method enables BHP measurements to be read instantly (real-time) at the surface. It also ensures that the measurements are an accurate representation of the BHP. The wireline used to achieve the surface readout must not exceed the wireline tension safety level. The line tension is due to fluid drag and can be estimated by calculating friction for the intended rate and tubing size.

A retrievable BHP gauge can also be used. It can be placed into the well either inside or outside the tubing string. Placing the gauge inside the pipe can be done using a wireline or by attaching the gauge at the end of the tubing. To place the gauge on the outside of the tubing, a special joint of pipe is used. This joint of pipe contains a pup joint welded to its side. The BHP gauge can be placed inside the pup joint to keep the gauge isolated from the fluids being pumped, a good technique to use when pumping acid. When using a post-job, retrievable BHP gauge, it is always good practice to use at least two pressure gauges in case one of the gauges fail. The disadvantage of using this technique is that the pressure measurements obtained will not be available until after the gauge is retrieved from the well.

A dead tubing string or a live annulus can provide reliable data under certain circumstances. The static string must be able to hold a column of fluid and the fluid density must be known. In hot formations, the decrease in the hydrostatic column due to the temperature increase of the static fluid column should be calculated and used in the analysis.

Surface pressure readings can be used to calculate BHP, but this has obvious limitations. The hole must first withstand a column of fluid, and the fluid must be of a known density. Another limitation is that the friction pressures incurred during the mini-frac will make it extremely difficult to get an accurate extension pressure. Also, the friction pressure of the fluids and perforations cannot be determined accurately. Using this technique to measure BHP should be done only as a last resort and with a full understanding of the limitations involved.

Summary of guidelines for placing and using BHP measuring devices:

* When using a real-time BHP gauge inside the tubing and pumping down the annulus, keep the gauge inside the tubing.
* When using a real-time BHP gauge inside the casing and pumping down the casing, place the gauge below the perforations and note the depth.
* When using a dead tubing string or live, annulus circulate the hole with a fluid of known density and ensure the static string will hold a column of fluid.
* Record all options of BHP in case the preferred method fails.
* Do not exceed the maximum line tension the wireline can withstand.
* If a retrievable BHP gauge is used, make sure the recording time is no more than 15 seconds (preferably every 5 to 10 seconds), and record the depth at which the gauge is set.

EVALUATION AND INTERPRETATION OF RESULTS

The main purpose for conducting a mini-frac is to determine the fluid efficiency and fluid-loss coefficient. The G-Function plot and match pressure P* are used to calculate these parameters. If the proper height (both gross and leakoff) and Young's modulus are known, the fluid loss coefficient can be determined. It is essential that the other variables used in the analysis are accurate.

Information which can be obtained from the mini-frac before performing the analysis of the pressure decline includes

* closure pressure
* fracture geometry model, PKN, Radial, KGD
* net pressure at shut-in
* pressure decline of the treating fluid at shut-in
* anticipated fracture height
* fluid-friction pressures
* perforation-friction pressures.
* pressure-dependent leakoff

The closure pressure, net pressure at shut-in and the pressure decline of the treating fluid are used to produce the G-Function plot as shown in Figure 6. The Nolte-Smith plot during the calibration treatment will give an indication of the fracture geometry model to use for the fracture design. Also, any anomalies in the slope will aid in determining excessive height growth or fissure openings. Fluid friction pressures experienced during the calibration test give an indication of the fluid-friction pressures which will be encountered during the fracture treatment. The perforation friction will help reveal if potential wellbore problems exist, i.e., unopened perforations or other restrictions between the well and fracture. Fracture height determined from the logs helps to define anticipated barriers and is one of the parameters used to calculate the leakoff coefficient from P*. The Young's modulus, which can be estimated from a fracture-height log, mechanical-property log, or from cores, is directly related to the fracture width and is also a parameter used to calculate the leakoff coefficient.

The most important step in evaluating the G-Function plot is to choose the correct linear portion of the G-plot. Be sure the decline set is consistent and does not include pressures recorded while the pumps were still rolling. Under normal circumstances, the instantaneous shut-in pressure (Pisip) after the calibration test should be greater than the fracture-extension pressure and the extension pressure should be greater than closure pressure. Ideally, the G-Function plot should result in a straight line during the closure period with slope equal to P* and y-intercept equal to a theoretical pressure at shut-in. The slope of this line is directly related to the leakoff coefficient. Closure time is related to fluid efficiency. Net pressure at shut-in is related to Young's modulus and gross fracture height. If the G-plot results in a non-ideal behavior (as seems to be the case in most field applications), then adjustments will need to be made as described by Nolte, Castillo and other authors, to account for natural fissures, fracture extension after shut-in, pressure-dependent leakoff, multiple fractures, or fracture-height growth into boundary layers near the wellbore.

After the correct straight line on the G-Plot has been defined, the value for the time function P* can be determined. Using the values of P* and net pressure at shut-in, the leakoff coefficient can then be determined by iterating the values of fracture height and Young's modulus in order to match a simulated net pressure with the actual net pressure recorded at shut-in from the calibration test.

The critical design parameters obtained using this technique are the leakoff coefficient, fluid efficiency, fracture geometry, Young's modulus, gross fracture height and closure pressure. Using these design parameters, the fracture treatment can be engineered more closely using the optimum pad volume and proppant scheduling needed to achieve the desired propped fracture length and fracture conductivity.

CASE HISTORY

In this section two case histories are presented to illustrate the steps involved in designing, executing and evaluating a mini-frac treatment. The first case history involves a mini-frac where the pressure decline illustrated a pressure dependent leakoff situation. The second involved a case where multiple closure pressures were experienced during the mini-frac due to natural fractures.

* Case 1. - Mini-Frac Pressure Decline Analysis Illustrating Pressure Dependent Leakoff

This mini-frac treatment was performed in the Grayburg Formation in Ector County, Texas. The treatment was pumped down the 2 3/8-in. by 5 1/2-in. annulus at a perforated depth of 3,990 - 4,170 feet. Prior to the mini-frac, an acid ballout was performed on the perforated interval and a baseline gamma ray and temperature survey log was run. The BHP was recorded during the mini-frac using a real-time BHP gauge set inside the bottom of the tubing at 3950 feet. The mini-frac and the actual fracture treatment were performed on the same day.

<u>Stress Test Determination</u>

The hole was circulated with 2% KCl water to allow the BHP to be measured by the dead tubing string and serve as a backup for the real-time BHP gauge. The step-rate test was performed using 2% KCl water. The rates were stepped from 1.0, 2.0, 3.0, 4.0, 6.0, 8.0, 12.0, 20.0, and 30 bbl/min in two-minute increments, with the last step rate for four minutes. From this, the fracture extension pressure was determined at approximately 2,450 psi by plotting the BHP-versus-pump rate as shown in Figure 7. The pumps were then shut down and flowback was conducted at approximately 3.5 bbl/min. The pressure falloff was monitored to determine the formation closure pressure by plotting BHP-versus-flowback time and observing an inflection point as shown in Figure 8. From this plot, closure appeared to occur around 2,398 psi. The square root of time in Figure 9 indicates closure occurred at about the same point.

<u>Calibration Test</u>

The calibration test was performed with 20,000 gallons of 40 lbm/1000 gal borate-crosslinked gel containing a radioactive isotope. The fluid was circulated to the bottom of the annulus at 3 bbl/min to displace out the 2% KCl water. The treatment was then pumped at a rate of 40 bbl/min. Following the treatment, the pumps were isolated, and the pressure decline was monitored past closure time. The well was logged with a gamma ray and temperature survey tool to determine the fracture height.

<u>Analysis of the Pressure Decline</u>

The Nolte-Smith plot showed a constant increase in net pressure (bottomhole treating pressure - closure pressure) which indicated that the fracture height was relatively constant (PKN) and the fracture length was steadily increasing throughout the injection (Fig. 10). This suggests that a PKN fracture geometry model be used for the design. A fracture height of 220 feet was determined from the logs.

The pressure decline of the G-Function plot is shown in Figure 11. The linear portion of the graph was defined during the middle portion of the pressure decline. As can be seen on Figure 11 the linear portion does not pass through the predetermined closure of 2,398 psi. Had the linear portion been defined to pass through closure, an overly optimistic efficiency of 79% would have been determined. As a result it was suspected that the pressure decline was characterized by a pressure-dependent leakoff environment.

From the G-Function plot, the match pressure P* was found to be 128 psi, with a closure time of 75 minutes and a fluid efficiency of 66%. Using the value for P* and net pressure at shut-in, the leakoff coefficient was determined to be between 0.00136 and 0.00129 ft/min^0.5 by iterating the values of fracture height and Young's modulus in order to match a simulated net pressure with the actual net pressure obtained from the calibration test. The results of the analysis are shown in Table 2. The leakoff coefficient of 0.00129 ft/min^0.5 was chosen because the initial Young's modulus used was an approximated value and was not obtained from a competent test. The fracture-design parameters obtained from the decline analysis are presented in Table 3.

Using these input parameters the fracture treatment was designed and pumped successfully using 84,000 gallons of 40 lbm/1000 gal borate-crosslinked gel with 251,000 pounds of 16/30 Ottawa Sand ramped from 2.0 to 14.0 lbm/gal at 40 bbl/min. The results of the fracture simulation design is shown Table 4.

*** Case 2. - Mini-Frac Pressure Decline Analysis Involving Multiple Closures**

This mini-frac treatment was performed in the Strawn Formation in Crocket County, Texas. The treatment design was pumped down 5 1/2-in. casing at a perforated depth of 9,242 - 9,346 feet. Prior to the mini-frac an acid ballout was performed on the perforated interval and a baseline gamma ray and temperature survey log was run. The BHP was recorded during the mini-frac using a retrievable BHP gauge placed below the perforations using wireline. For this case history the mini-frac and fracture treatment were performed on separate days.

<u>Closure Pressure Determination</u>

Since the BHP gauge measurements would not be available until after the mini-frac, the BHP was initially recorded using the surface pressure readings plus the hydrostatic pressure and assuming the friction pressure to be negligible. The step-rate test was performed using 2% KCl water at step rates from 0.5, 1.0, 1.5, 2.0, 3.0, 5.0, 7.0, 10.0, and 15.0 bbl/min. The fracture-extension pressure was determined at a surface pressure reading of 3,180 psi which corresponds to a BHP of 7,251 psi. As seen in Figure 12, the initial two step rates did not fall in line with the other matrix pressure points because a sustained surface pressure reading was not obtained during those rates. This occurred because some of the fluid in the casing was evidently gas cut even though it was initially believed the hole contained only 2% KCl water.

The first attempt to get closure involved flowing the well back at a constant rate of 2.0 bbl/min but only a rapidly decreasing slope occured. From this, closure could not be determined. At this point, it was suspected that the formation contained natural fractures since the matrix permeability was known to be very low. Another pump-in test was conducted using 8,400 gallons of 2% KCl water pumped at a constant rate of 30 bbl/min and without flowing back the well upon shutdown. The pressure decline from this test showed a distinct inflection point at a surface pressure reading around 3,100 psi. This corresponded to a closure pressure of approximately 7,200 psi which was obtained later from the BHP gauge as seen in Figure 13.

Calibration Test

The calibration test was performed with 33,600 gallons of 40 lbm/1000 gal borate-crosslinked gel containing a radioactive isotope. The treating fluid was initially pump at 2.5 bbl/min to the top of the perforated interval and then shut down until the pressure declined below closure. The treatment was then pumped at a rate of 40 bbl/min. Following the treatment the pumps were isolated, and the pressure decline was monitored past closure time. The well was logged with a gamma ray and temperature-survey tool to determine the fracture height.

Analysis of the Pressure Decline

As can be seen in Figure 14, because of the larger volume of fluid pumped, higher pump rate and a more viscous fluid, the calibration test resulted in higher fracturing pressures than were experienced during the step-rate test. The pressure decline also showed two distinct slopes and suggests that two closure pressures occurred during this treatment, with one closure being higher than the original closure pressure observed at 7,200 psi. The higher closure pressure was estimated at 7,512 psi from a square root of time plot (Fig. 15).

It was suspected that this treatment resulted in a different type of fracture than was created during the initial pump-in test. Interpreting the decline data suggests that either the treatment may have resulted in multiple fractures or have opened up more fissures which contained higher stresses and/or a different azimuth. Examining the post-fracture logs indicated that the fracture was well contained at a height of 140 feet and showed no evidence of multiple fractures. From this, it was assumed that the formation contained fissures which began to dilate as the net pressure overcame the threshold pressure of the fissures.

The G-Function plot is shown in Figure 16, with the linear portion defined. The higher closure pressure of 7,512 psi was used in the analysis in order to more realistically represent the higher leakoff which will be experienced from the fissures. The analysis of the pressure decline is presented in Table 5. Using the value for P* and net pressure at shut-in, the leakoff coefficient was determined at 0.00314 ft/min^0.5 with a fluid efficiency of 28%. The fracture design parameters obtained from the decline analysis are presented in Table 6. The fracture treatment was designed using the parameters obtained from the mini-frac except for the leakoff coefficient in which a value of 0.00274 ft/min^0.5 was used. The decision to use a lower leakoff coefficient was based on a well fracture previously in the same section where excessive leakoff was not experienced by the operator. A pump schedule for the fracture treatment design is shown in Table 7.

The fracture treatment screened out during the 8 lbm/gal proppant stage, thus cutting the job short by approximately 315 barrels. A computer simulator modeled the fracture treatment screenout by using the designed pump schedule on Table 7 and the leakoff coefficient obtained from the mini-frac, 0.00314 ft/min^0.5. The results of the simulation are shown in Table 8. The simulator predicted the fracture treatment to screenout after pumping 207 bbl into stage 8, the 8 lbm/gal stage. This was approximately the same place where the actual fracture treatment screened out. The simulator estimated that a 61% pad volume would be required to successfully pump the treatment using the leakoff number obtained from the mini-frac. A 51% pad volume was used on the original fracture treatment design based on the 0.00274 ft/min^0.5 leakoff coefficient.

SUMMARY AND CONCLUSIONS

1. Designing a fracture treatment using assumed design variables can result in a less-than-optimum fracture length and conductivity.

2. A mini-frac treatment can provide critical design parameters necessary for an optimum fracture treatment design.

3. Performing a mini-frac prior to the fracture treatment can reduce the risk of an unplanned screenout.

4 The mini-frac is composed of two basic tests: a stress test and a calibration test. It can be performed on the same day as the fracture treatment or on a separate day.

5. Guidelines are presented for the design, execution and evaluation of a mini-frac.

6. Various methods of recording BHP are presented.

7. The G-Function plot can be a reliable tool for evaluating ideal and non-ideal pressure-decline behavior.

ACKNOWLEDGMENTS

The authors of this paper wish to thank Dowell Schlumberger for permission to publish this paper. Thanks also goes to Jack Elbel who provided some valuable technical insight on this subject.

REFERENCES

1. Warpinski, N.R.: "Hydraulic Fracturing in Tight, Fissured Media," JPT (Feb. 1991) 146-209.

2. Warpinski, N.R. et al: "Case Study of a Stimulation Experiment in a Fluvial, Tight-Sandstone Gas Reservoir," SPE Production Engineering (Nov. 1990) 403-410.

3. Nolte, K.G.: "Fracturing Pressure Analysis: Deviations From Ideal Assumptions," paper SPE 20704 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.

4. Gu, H, and Leung, K.H.: "Three Dimensional Numerical Simulation of Hydraulic Fracture Closure With Application to Minifrac Analysis," paper SPE 20657 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.

5. Warpinski, N.R.: "Dual Leakoff Behavior in Hydraulic Fracturing of Tight, Lenticular Gas Sands," SPE Production Engineering, (August 1990) 243-252.

6. Moschovidis, Z.A.: "Interpretation of Pressure Decline for a Mini-Fracture Treatments Initiated at the Interface of Two Formations," SPE Production Engineering (Feb. 1990) 45-51.

7. Nolte, K.G.: "Fracturing Pressure Analysis," Chap 14, SPE Monograph, Vol. 12, Recent Advances in Hydraulic Fracturing, 1989.

8. Nolte, K.G. and Economides, M.J.: "Fracturing Diagnosis Using Pressure Analysis," Chap. 7, Reservoir Stimulation, Second Ed, Prentice Hall, 1989.

9. Castillo, J.L.: "Modified Fracture Pressure Decline Analysis Including Pressure-Dependent Leakoff," paper SPE 16417 presented at the 1987 SPE/DOE Low Permeability Reservoirs Symposium, Denver, May 18-19.

10. Lee, W.S.,: "Mini-Frac Analysis Based on Ellipsoidal Geometry," paper SPE 15369 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8.

11. Soliman, M.Y.: "Technique for Considering Fluid Compressibility and Temperature Changes in Mini-Frac Analysis," paper SPE 15370 presented at the 1986 Annual Technical Conference and Exhibition, New Orleans, Oct 5-8.

12. Martins, J.P. and Harper, T.R.: "Mini-Frac Pressure Decline Analysis for Fractures Evolving From Long Perforated Intervals and Unaffected by Confining Strata," paper SPE/DOE 13869 presented at the 1985 SPE/DOE Low Permeability Gas Reservoir Symposium, Denver, May 19-22.

13. Nolte, K.G.: "Fracture Design Consideration Based on Pressure Analysis" paper SPE 10911 presented at the 1982 Cotton Valley Symposium, Tyler, May 20.

14. Nolte K.G.: "Determination of Fracture Parameters From Fracturing Pressure Decline," paper SPE 8341 presented at the 1979 SPE Annual Fall Technical Conference and Exhibition, Las Vegas, Sept. 23-26.

Table 1
Example Mini-frac Job Procedure Outline: Pumping Down Casing Using a Real-time BHP Bomb

1. Ensure all perforations are open.
2. Run baseline gamma ray and temperature survey logs.
3. RIH with BHP bomb. Set just below bottom perforations.
4. Perform stress test with 2% KCl water.
   a) Be prepared to run at least two step-rate/flowback/shut-in tests.
   b) Pre-set the flowback manifold to the desired flowback rate.
   c) Obtain a stabilized pressure at the following rates: 0.5, 1.0, 2.0, 3.0, 5.0, 7.0, 10.0, 20.0 and 30.0 bpm. (Exact rates are not important - CONSTANT RATES ARE.)
   d) Pump each rate for 2 minutes and the final rate for 4 minutes. (Plot BHP vs pump rate prior to each rate change to determine extension pressure.)
   e) Prior to shut down reduce the rate to 20% of the final pump rate for 5 seconds.
   f) Flowback well at +/- 3.0 bbl/min (constant rate) and monitor pressure until closure is determined or to when the BHP has fallen to within 200 psi of the initial BHP.
   g) Repeat test if a closure pressure has not been clearly determined choosing the option to flowback at a different rate or to just shut down and monitor the pressure decline.
5. Pump the calibration test.
   a) The volume and fluid type should be the same as the anticipated pad for the actual fracture treatment.
   b) Bullhead the fluid to the perforations at a slow rate if the fluid volume in the casing is more than 10% of the calibration treatment. Shut down to allow the pressure to fall below closure before starting the calibration test.
   c) Pump the calibration treatment at a constant rate equal to the anticipated rate of the fracture treatment.
   d) Run R.A. tracers throughout the treatment.
   e) After shutdown, isolate the pumps and monitor the pressure decline through closure time.
6. Run post-treatment gamma ray and temperature survey logs.
7. Perform mini-frac pressure decline analysis.

Table 2
Case History - No. 1: Pressure-Decline Analysis

INPUT PARAMETERS

N prime	0.76	Young modulus	8.5E+6 psi
K prime	0.0270 lb*s/ft	Poisson ratio	0.22
Volume	30000.0 gal	Gross Height	220.0 ft
Pump Rate	40.0 bbl/min	Leakoff Height	115.0 ft
Pump Time	17.9 min	Perforated Height	180.0 ft
Analy Type	Manual	Rock Toughness	1000.0 psi*in^.5

PRESSURE DECLINE ANALYSIS using P.K.N.

PSTAR (psi)	CLOSURE PRESSURE (psi)	CLOSURE TIME (min)	YINT (psi)	ISIP (psi)	NET PRESS. SHUT IN (psi)	EFFICIENCY
128	2398	75.00	2871	2912	514	0.66

FRACTURE GEOMETRY AT THE END OF PUMPING

(Fracture Geometry is calculated using a net pressure estimated from the YINT)

	TOUGHNESS (psi*in^.5)	YOUNG MODULUS (psi)	HEIGHT (ft)	HALF LENGTH (ft)	AVERAGE WIDTH (in)	COMBINED LEAKOFF (ft/min^0.5)	EFF (*)	NET P PUMPING (psi)
P. K. N.								
	User Values							
Analysis :	1000.0	8.5E+6	220.0	425	0.171	1.11E-3	0.66	501
Simulation :	1000.0	8.5E+6	220.0	389	0.194	1.11E-3	0.69	568
	Adjusted Height = 1.1 * Input							
Analysis :	1000.0	8.5E+6	243.0	348	0.189	1.36E-3	0.66	501
Simulation :	1000.0	8.5E+6	243.0	347	0.189	1.36E-3	0.66	501
	Adjusted Modulus = 0.9 * Input							
Analysis :	1000.0	7.3E+6	220.0	366	0.198	1.29E-3	0.66	501
Simulation :	1000.0	7.3E+6	220.0	365	0.198	1.29E-3	0.66	501

Table 3
Case History - No. 1: Fracture Design Parameters Obtained from Mini-frac

Leakoff Coefficient	=	0.00129 ft/min^0.5	Fluid Efficiency	=	66%
Gross Height	=	220.0 feet	Pump Rate	=	40 bbl/min
Young's Modulus	=	7,300,000 psi	Fluid Type	=	40 lb/1000 gal borate-crosslinked gel
Closure Pressure	=	2,398 psi	Fluid Friction	=	463 psi/1000 ft
Fracture Model	=	PKN	Perforation Friction	=	70 psi

Table 4
Case History - No. 1: Computer Simulator Fracture Treatment Predictions

OUTPUT RESULTS

Propped Fracture Length	=	420.8 ft	Fracture Length	=	501.1 ft
Propped Width at Well	=	0.212 in	Hydraulic Width at Well	=	0.477 in
Average Propped Width	=	0.140 in	Net Pressure	=	732.6 psi
Average Gel Concentration	=	535.9 lb/Mgal	Efficiency	=	0.393
Average Fluid Retained Factor	=	0.350	Estimated Closure Time	=	10.000 min
Average Conductivity	=	1884. md*ft	Equivalent Leakoff	=	2.4E-03 ft/min^0.5
Average Fcd	=	2.238			

	END OF JOB				AFTER CLOSURE				
Distance from Well (ft)	Frac Height (ft)	Slurry Height (ft)	Pack Height (ft)	Prop Conc. (lb/gal)	Prop Width (in)	Prop Height (ft)	Prop Conc. (lb/ft^2)	Gel Conc. (lb/Mgal)	Conductivity (md*ft)
105.2	240.0	240.0	0.32	14.15	0.208	239.9	1.79	418.5	3495.1
210.4	240.0	239.8	0.25	11.24	0.165	139.8	1.45	495.8	1905.5
315.6	240.0	239.4	0.17	7.70	0.177	239.4	1.04	634.2	1340.7
420.8	240.0	217.3	0.05	4.86	0.071	238.5	0.63	768.1	793.9

Table 5
Case History - No. 2: Pressure Decline Analysis

INPUT PARAMETERS

N prime	:	0.40	Young modulus	:	3.2E+6 psi
K prime	:	0.1200 lb*s/ft	Poisson ratio	:	0.15
Volume	:	33600.0 gal	Gross Height	:	140.0 ft
Pump Rate	:	40.0 bbl/min	Leakoff Height	:	140.0 ft
Pump Time	:	20.9 min	Perforated Height	:	104.0 ft
Analy Type	:	Automatic	Rock Toughness	:	1000.0 psi*in^.5

PRESSURE DECLINE ANALYSIS using P.K.N.

PSTAR (psi)	CLOSURE PRESSURE (psi)	CLOSURE TIME (min)	YINT (psi)	ISIP (psi)	NET PRESS. SHUT IN (psi)	EFFICIENCY
438	7512	10.19	7840	7812	300	0.28

FRACTURE GEOMETRY AT THE END OF PUMPING

(Fracture Geometry is calculated using a net pressure estimated from the YINT)

	TOUGHNESS (psi*in^.5)	YOUNG MODULUS (psi)	HEIGHT (ft)	HALF LENGTH (ft)	AVERAGE WIDTH (in)	COMBINED LEAKOFF (ft/min^0.5)	EFF (*)	NET P PUMPING (psi)
P. K. N.								
	User Values							
Analysis :	1000.0	3.2E+6	140.0	274	0.195	3.09E-3	0.28	342
Simulation :	1000.0	3.2E+6	140.0	272	0.197	3.09E-3	0.28	346
	Adjusted Height = 1.0 * Input							
Analysis :	1000.0	3.2E+6	141.0	270	0.197	3.14E-3	0.28	342
Simulation :	1000.0	3.2E+6	141.0	269	0.197	3.14E-3	0.28	342
	Adjusted Modulus = 1.0 * Input							
Analysis :	1000.0	3.2E+6	140.0	271	0.197	3.13E-3	0.28	342
Simulation :	1000.0	3.2E+6	140.0	270	0.197	3.13E-3	0.28	342

Table 6
Case History - No. 2: Fracture Design Parameters
Obtained from Mini-frac

Leakoff Coefficient	=	0.00314 ft/min^0.5	Fluid Efficiency	=	28%
Gross Height	=	140.0 feet	Pump Rate	=	40 bbl/min
Young's Modulus	=	3,200,000 psi	Fluid Type	=	40 lb/1000 gal delayed borate-crosslinked gel
Closure Pressure	=	7,512 psi	Fluid Friction	=	98 psi/1000 ft
Fracture Model	=	PKN	Perforation Friction	=	920 psi

Table 7
Case History - No. 2: Fracture Design Pump Schedule

STAGE NO.	PUMP RATE (bbl/min)	FLUID TYPE	CLEAN FLUID VOLUME (Gallons)	PROPPANT TYPE	PROPPANT MASS (Pounds)
Pre-Pad	40	40# linear	8000	–	0
Pad	40	40# X-link	60000	–	0
1 PPA	40	40# X-link	2800	20/40 Ceramic	2800
2 PPA	40	40# X-link	2800	20/40 Ceramic	5600
3 PPA	40	40# X-link	2800	20/40 Ceramic	8400
5 PPA	40	40# X-link	8800	20/40 Ceramic	44000
7 PPA	40	40# X-link	17000	20/40 Ceramic	119000
8 PPA	40	40# X-link	11000	20/40 Ceramic	88000
Flush	40	40# linear	9005	–	0
		TOTALS:	17,005 gallons 40# linear gel 105,200 gallons 40# X-link gel		267,800 Lbs

Table 8
Case History - No. 2: Computer Simulator Fracture
Treatment Predictions

OUTPUT RESULTS

Propped Fracture Length	=	559.4 ft	Hydraulic Total Length	=	564.6 ft
Propped Width at Well	=	0.13369 in	Hydraulic Width at Well	=	0.589 in
Average Propped Width	=	0.141 in	Net Pressure	=	574.3 psi
Average Gel Concentration	=	903 lb/Mg	Efficiency	=	0.27
Average Conductivity	=	583 md*ft	Estimated Closure Time	=	19.0476 min
Average Fcd	=	34.7	Fracture Geometry	=	PKN
Fluid Material Balance	=	1.00006	Equivalent Leakoff	=	0.00328 ft/min^0.5
Prop Material Balance	=	1			

	END OF JOB			AFTER CLOSURE				
Distance from Well (ft)	Slurry Height (ft)	Pack Height (ft)	Prop Conc. (lb/gal)	Prop Width (in)	Prop Height (ft)	Prop Conc. (lb/ft^2)	Gel Conc. (lb/Mgal)	Conduc-tivity (md*ft)
139.85	139.99	0.0524	8.60365	0.1341	139.98	1.2333	1085.2	589.935
279.71	139.97	0.0429	9.61059	0.1333	139.97	1.2256	1040.2	587.569
419.56	139.93	0.0306	10.8595	0.1363	139.95	1.2538	914.73	587.569
559.41	139.81	0.0139	13.2778	0.1607	139.86	1.4776	793.9	566.689

PROPPANT PACKED AT 559.41 ft AFTER 207.69 bbl IN STAGE: 8

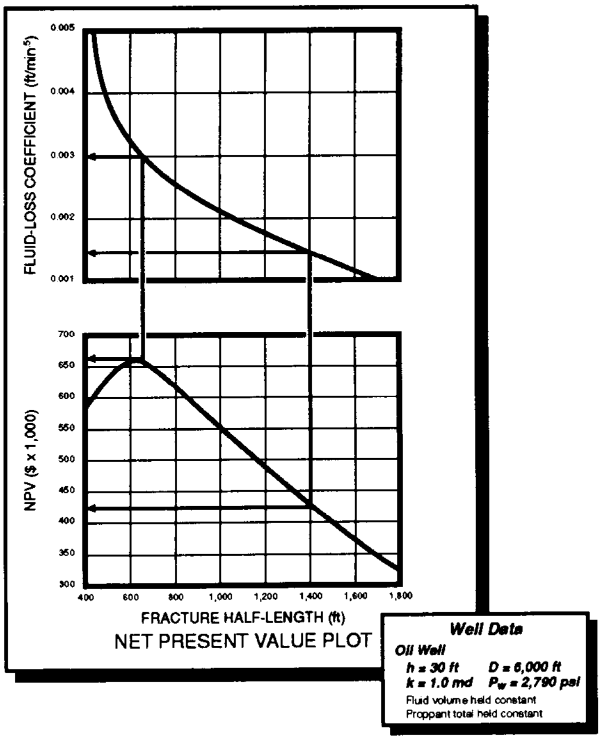

Figure 1 - Sensitivity to fluid-loss coefficient

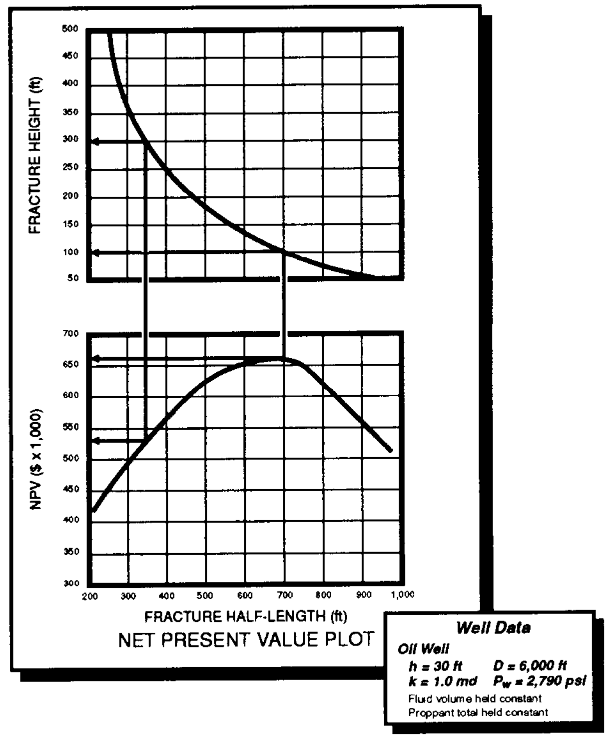

Figure 2 - Sensitivity to fracture-height

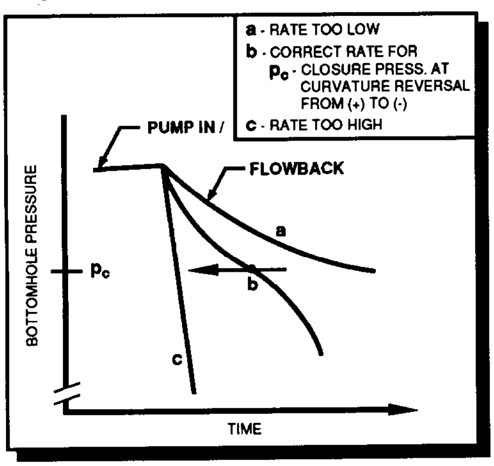

Figure 3 - Determining closure pressure from pump in/flowback test

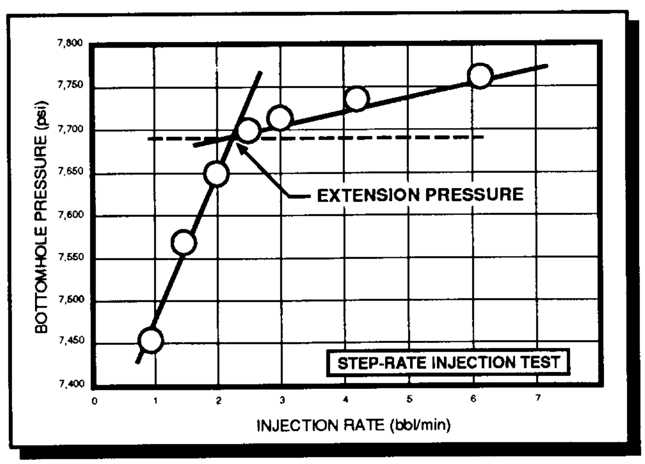

Figure 4 - Determining extension pressure from step-rate test

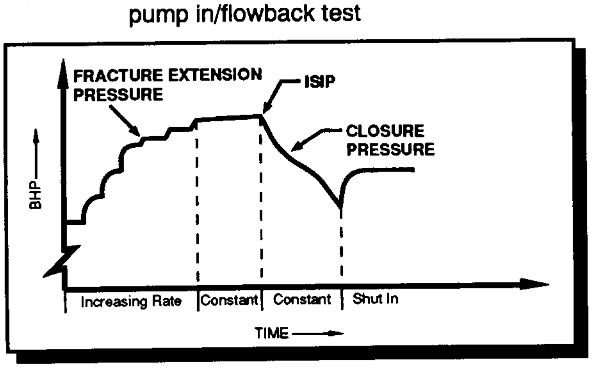

Figure 5 - Idealized pressure response of a stress test

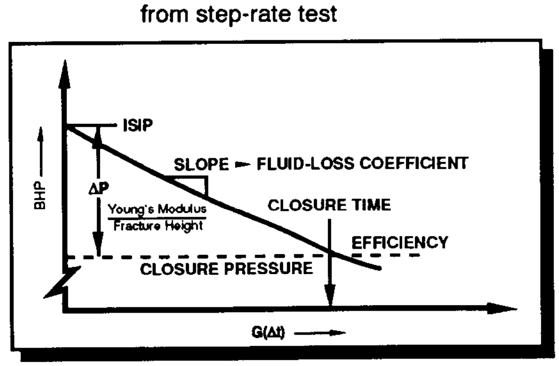

Figure 6 - Idealized G-function plot

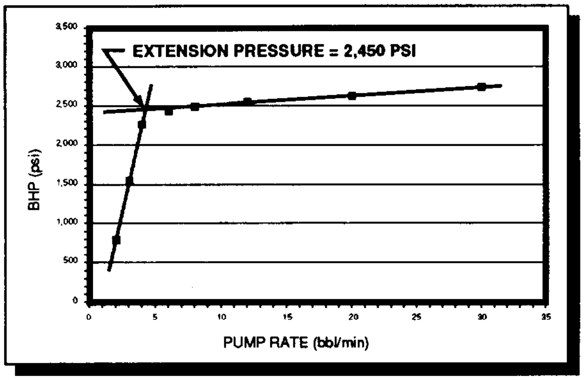

Figure 7 - Case history No. 1 - extension pressure

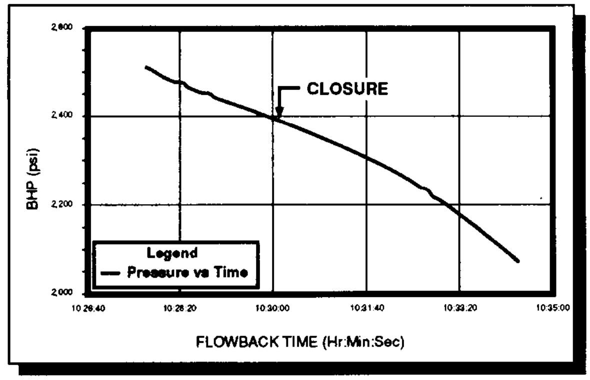

Figure 8 - Case history No. 1 - stress test flowback pressure decline

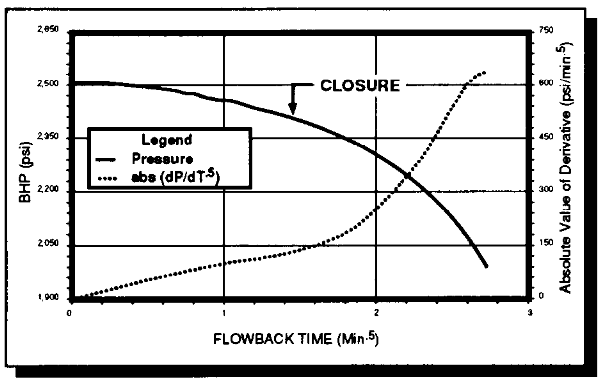

Figure 9 - Case history No. 1 - stress test flowback pressure decline

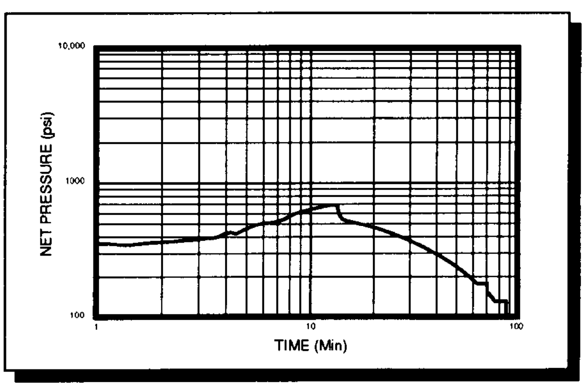

Figure 10 - Case history No. 1 - calibration test net-pressure plot

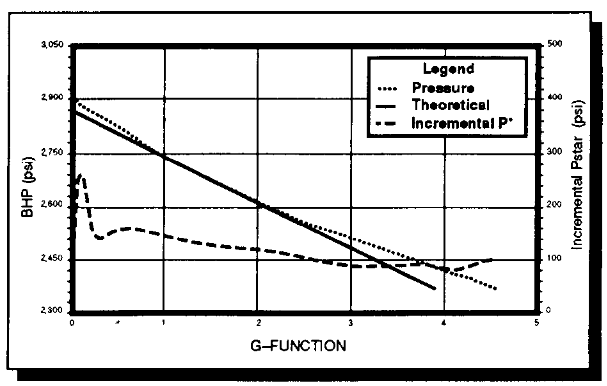

Figure 11 - Case history No. 1 - G-function plot

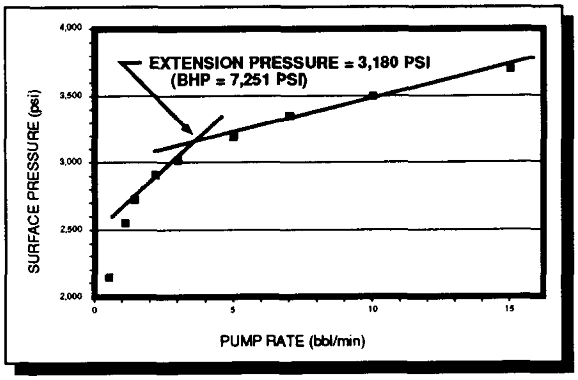

Figure 12 - Case history No. 2 - extension pressure

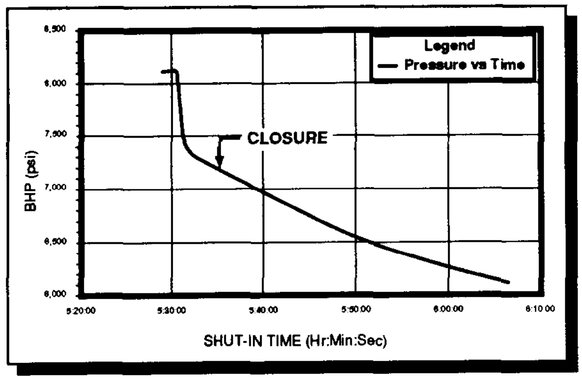

Figure 13 - Case history No. 2 - stress test pressure decline

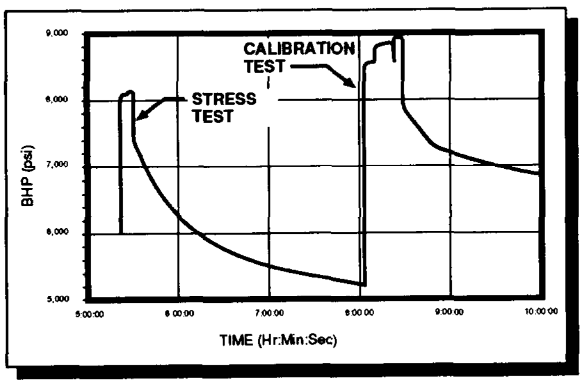

Figure 14 - Case history No. 2 - stress test and calibration test pressure decline

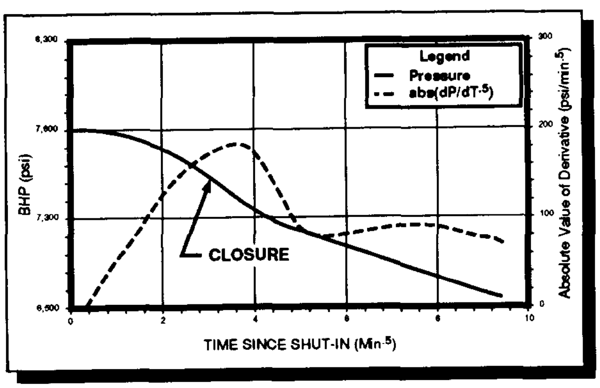

Figure 15 - Case history No. 2 - calibration test pressure decline

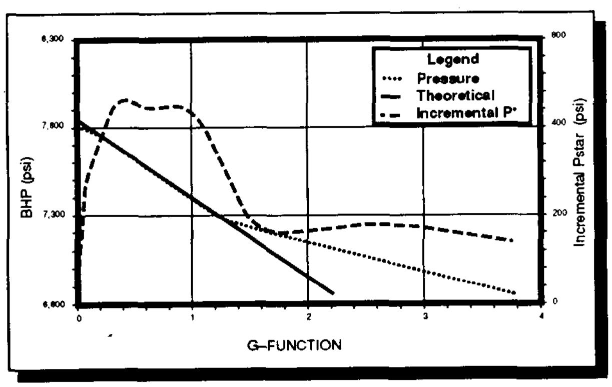

Figure 16 - Case history No. 2 - G-function plot