ON-SITE COMPUTER ANALYSIS OF FRACTURE TREATMENT PRESSURES IN THE PERMIAN BASIN

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ABSTRACT

The recent trends in the use of on-site computers to calculate bottom hole treating pressure has created a need for a better understanding of insitu fracturing pressures and treating fluid friction properties. This paper discusses several Permian Basin fracturing operations with special emphasis on optimum pressure monitoring procedures. The theories of critical pressure, height growth, closure pressure and formation heterogeneity are discussed in an effort to provide techniques for on-the-job interpretations. Actual job examples have been presented with analysis and discussions.

The analysis of net pressure frequently presents several problems unique to the formations and fields of the Permian Basin area. This paper analyzes those problems and provides on-the-job solutions and alternatives.

INTRODUCTION

The practice of monitoring bottom hole treating pressure (BHTP) during a hydraulic fracturing treatment was initially introduced by Nolte and Smith[1] for application in stimulating tight gas sand reservoirs. Extensive work was performed and several theories were proposed for predicting the behavior of a fracture as it conformed to the fracture geometry described by Perkins and Kern[2] and Nordgren.[3] In another paper, Nolte[4] describes how monitoring pressure decline after initiating a fracture can be used to calculate fracture height, length, width, closure and most importantly a formation's insitu leakoff coefficient. Other papers dealing with this technique include those by Schlottman, et al[5] Dobkins,[6] Veatch and Crowell,[7] and Smith.[8,9] Nolte[10,11] later wrote two additional papers, one summarizing the above techniques and another describing a method for designing proppant and fluid schedules from fracturing pressure decline analysis.

In response to the theories and methods introduced by the above papers, programs were initiated by several major service companies to develop on-site monitoring systems using computers. The use of these treatment monitoring systems (TMS) quickly spread out of the tight gas sand areas into almost every formation which utilizes hydraulic fracturing techniques. The following paper will focus on the use of the TMS in the Permian Basin fields of West Texas and Southeastern New Mexico (Fig. 1). The objective will be to give a general overview of the methods as they are applied and the problems which are frequently encountered. The discussion will include a brief description of on-site monitoring, prefrac testing and real time slope interpretation as defined by Nolte and Smith. The paper will then expand on the different theories of critical pressure, closure pressure, height growth and formation heterogeneity as they apply to different formations of the Permian Basin.

friction may be quite high and an accurate knowledge of perforation diameter number becomes critical.

$$\Delta P = \frac{2.93\ Q^2\ .\ \delta}{n^2\ .\ d^4} \qquad (2)$$

Where ΔP_p is perforation friction in psi, d is the perforation diameter in inches, Q is the rate in barrels per minute (BPM), n is number of perforations and δ is the specific gravity of the slurry. The computer solves equation (2) utilizing an imputed diameter and number of perforations. As seen in the following example, if either the perforation number or diameter are incorrect, a large error in perforation friction will occur. Figure 3 compares two cases with the same number of perforations. Case 1 assumes ten shots with a .40" diameter while Case 2 assumes ten shots with a .30" diameter. Both cases were fracture stimulated with the same fluid. Notice the difference in perforation friction as the rate is increased from zero up to 25 BPM. It is not difficult to see that a small inefficiency in perforation size can result in large unexpected errors in attempting to calculate a BHP during a frac job. This same error may occur when the wrong number of perforations is assumed as demonstrated in Figure 4. Both cases have the same size perforations (.30") but Case 1 has 10 holes while Case 2 has only 6 holes. Both wells were fractured with the same fluid at an increasing rate from zero to 15 BPM. Again, notice the difference in friction which could occur in calculating BHP from slightly erroneous information or an uncompensated efficiency in perforating.

The largest error usually occurs in estimating friction loss in the tubular goods. It is not uncommon when fracture stimulating down tubing for this friction pressure to account for 90% of the total friction. Most service companies have published data giving the estimated friction properties of their primary fracturing fluids. However, these tables rarely consider the large effects that temperature can have on the viscosity of the base gel and crosslink time of the fluid going downhole.

A popular method of shutting down during the pad stage of a treatment to obtain an instantaneous shutdown pressure (ISDP) has gained wide acceptance. This method helps in solving for friction using the following equations:

$$P_f = STP - ISDP \qquad (3)$$

Keeping in mind that:

$$P_f = \Delta P_p + P_{ft} + P_{fs} \qquad (4)$$

Where P_f is the total of all friction occuring during pumping, ΔP_p is perforation friction, ΔP_{ft} is friction due to movement down tubular goods and ΔP_{fs} is pressure due to movement of fluid thru surface equipment. Since all of these frictions are affected in different ways, it is not correct to assume that they have linear relationships, therefore each factor must be independently solved. Assuming the wrong factor for one variable obviously will lead to errors in others.

PREFRAC TESTING

Prefrac testing is the best method for collecting data to be used in designing and interpreting fracture stimulation programs. The most common tests are 1) Step

Rate test, 2) Flowback test and 3) Mini-Frac test. A combination of the Step Rate and Flowback tests are frequently performed to determine fracture initiation pressure and fracture closure pressure.

The most important prefrac test is the Mini-Frac test. This test can be very important in the Permian Basin in the design of economical fracture treatments. The wide variation in types of fields and formations in the Permian Basin leads to a wide range of accepted and necessary fracturing techniques. These range from the radial "penny" fracs in the San Andres formation of Ector County, Texas to the massive hydraulic fractures (MHF) in the deep Morrow gas sands of southeastern New Mexico. All these stimulations have one thing in common, to raise production to an economical level.

In developing a proper fracture stimulation for a given field and formation, several properties may be calculated by the proper use of a mini-frac/pressure decline analysis:

1. Insitu fluid-loss coefficient (C_c)
2. Gross fracture height
3. Net fracture height (leakoff height)
4. Young's or Shear Modulus of the rock
5. Fracture length (assuming a model)
6. Fracture width (assuming a model)
7. Closure pressure

A Mini-Frac test simply consists of pumping the fracturing fluid into the formation at essentially the same rate as the primary treatment and monitoring the pressure decline after shutdown. This fall-off test in conjunction with a temperature survey to determine fracture height can be used to calculate the insitu fluid-loss coefficient of the formation using curve matching techniques as described by Nolte. This fluid-loss coefficient is one of the most important factors in determining the fracture geometry. It is generally calculated from known properties such as formation permeability and porosity, differential pressure, reservoir fluid compressibility and viscosity and fracture fluid leakoff coefficients as described by Howard and Fast.[14] In most instances, these properties are unknown and have to be estimated. Generally, estimated fluid-loss coefficients tend to be too optimistic as they do not always account for the high leakoff to occurring hairline fractures. A derived insitu fluid-loss coefficient eliminates most of the guesswork and can be used with a much higher degree of accuracy in fracture design. Another method described by Nierode[15] which uses two ISDP's, can also be used to obtain an insitu fluid-loss coefficient. In situations where both the Nierode and Nolte analysis were applied they tended to agree within 30%. However, it was not uncommon for the calculated coefficient to be optimistic by as much as 300%. (Table 1) A separate technique has also been described by Nolte which is independent of height, leakoff or geometry and should prove very useful in unproven fields. Figure 5 shows a typical mini-frac used in many Permian Basin operations.

CLOSURE PRESSURE

Closure pressure (P_c) is defined as the sum of the horizontal stresses within a rock as they exert a force perpendicular to the walls of a hydraulically created fracture at the instant before the fracture closes. Fracture initiation pressure (P_{fi}) is defined as the pressure required to create a fracture and should not be confused with closure pressure. Fracture initiation pressure is always greater than closure pressure. In techniques described by Nolte and Smith for analysis of fracturing pressures, net pressure (P_n) is used and is defined as follows:

$$P_n = BHP - P_c \quad \ldots \quad (5)$$

The slope of the line formed by plotting log P_n versus log real time is used in analyzing fracture treatments and will be demonstrated later. It is obvious from equation (5) that an incorrect P_c will result in an erroneous slope of P_n which can lead to mode interpretation errors as demonstrated by the following example. A plot of net pressure for a given well is compared at two different closure pressures (Fig. 6). Case A assumes a P_c of 5500 psi while Case B assumes 6500 psi. It can be seen from the comparison that different interpretations would result when analyzing the slope of P_n during the treatments. The slope in Case A indicates screenout mode several minutes before Case B.

To obtain a closure pressure, a simple Flowback test is conducted. This test consists of pumping 100-150 bbls. of non-damaging fluid into the formation above the fracture initiation pressure. The fluid is then flowed back at a constant rate (approx. 2 BPM) using an adjustable choke and a flow meter while monitoring the pressure decline. Surface pressure is then plotted versus time. Closure pressure is indicated by an inflexion point which is shown in Figure 9. This inflexion point results as fluid leaves the fracture, either thru flowback or leakoff, and the fracture closes.

In many Permian Basin operations the interval of interest is too large and/or too permeable to sustain a fracture long enough to effectively flowback injected fluid. In these cases, leakoff modifiers such as gellants or fluid-loss additives may be added to the injected fluid. An inflexion point, indicating closure pressure, has also been observed in the pressure decline after a mini-frac. Utilizing the mini-frac to determine P_c is usually the most economical since it does not require an additional day of pumping charges.

NET PRESSURE ANALYSIS

The primary use of an on-site computer during a stimulation treatment is to monitor the slope of net pressure as defined and described by Nolte and Smith and to determine the mode in which the frac treatment is proceeding. For the sake of discussion, a brief description of each mode is shown in Figure 7 and listed below:

1. Mode I: Period of confined height and constant fracture length extension. Identified by a slope ranging between 0.12 and 0.25.

2. Mode II: Critical pressure - Period of excessive fluid leakoff either due to the presence of hairline fracture systems or due to height growth. Little or no length extension can be expected in this mode. Identified by a zero (0) slope.

3. Mode III: Screenout - Period of no length extension, no height growth, and no abnormal fluid leakoff. Restriction of fluid flow to tip of fracture causes a storage of fluid as width which in turn causes a rapid increase in pressure. Identified by a unit slope or greater.

4. Mode IV: Unlimited height growth - Period of no length extension and rapid height growth. A pressure decrease occurs as fluid stored in width escapes to a zone of lower pressure. Consequently, the width decreases as well as the pressure. Identified by a negative (<0) slope.

It should be noted that the above mode descriptions result from work conducted by Nolte and Smith in large homogeneous tight gas zones. Application of these modes to formations of the Permian Basin is complicated due to their lenticular and heterogeneous nature. Very few, if any, of these formations are bounded by adequate shale barriers thus, making it almost impossible to confine height growth during fracturing.

In many of the stimulation examples used in this study a cycling effect of the net pressure occurs. This is probably a result of periods of length extension followed by periods of height growth. It can be assumed that this is caused by heterogenetics within an individual zone causing several different breakdown pressures or horizontal stresses to occur. This fact is illustrated in case histories #2 (Fig. 13) and #3 (Fig. 15).

Not all zones however, portray these cycling characteristics. In many treatments. the log of P_n traces the following predictable pattern:

1. <u>Mode III</u> - Which is actually just a breakdown period of a few minutes (establishing a fracture).

2. <u>Mode IV</u> - Height growth to boundry zones as the fracture is initiated. Again, this period usually lasts just a few minutes (establishing a fracture height).

3. <u>Mode I</u> - Period of good fracture extension throughout the remainder of the treatment.

This sequence is exampled in case history #1 (Fig. 11). By theory, this would be a perfect treatment in a very homogeneous zone. Even though this does not occur with great consistency, it is quite common in the Yates, Queen and Seven Rivers formations. Heterogeneous carbonates and lenticular sands tend to follow the cycling mode as described previously.

In studying the net pressure plot of case history #1, another interesting observation can be made; the slope is consistently greater than the published acceptable .25 gradient, yet screenout (Mode III) never occurs and Mode I type conditions prevail. This phenomenon can be explained by studying Nordgren's original equations for pressure increases throughout a fracture treatment:

$$P_n \alpha\, t^e \quad \text{. . . . . (8)}$$

which says that net pressure is proportional to time raised to an exponent. This exponent, for a power-law fluid, is defined as being in the following range:

$$\frac{1}{2\ (2n' + 2)} < e < \frac{1}{2n' + 2} \quad \text{. (9)}$$

where n' is the flow behavior index of a fluid. Nolte and Smith solve for the above equation by using n' extremes of 1.0 and 0.5 where:

$n' = 1$ gives $e = .125$
and
$n' = .5$ gives $3 = .25$

However, it should be noted that many frac fluids used in the Permian Basin have a n' of less than .5. The most common fluids of this type are gelled oils and borate crosslinked quar gum systems. As an example, e is determined for a common n' of .35.

$n' = .35$ gives $e = .37$

This indicates a steeper slope than .25 and redefines the parameters for Mode I as being between .12 and .37. The flow behavior index (n') can usually be found in a service company's published literature. Caution should be exercised in the use of a n' since it is a function of temperature.

CRITICAL PRESSURE

Many zones can be identified as having a unique critical pressure which once reached, leads to excessive leakoff. This leakoff is due to the opening of hairline fractures or height growth. Because of the rapid escape of fluid from the existing fracture, a decrease in width occurs which can subsequently lead to screenout. Obviously, the sooner the treatment reaches this critical pressure, the shorter the fracture length. Since the n' of a fluid is directly proportional to the slope of the net pressure in Mode I, it can be assumed that the lower the n', the steeper the slope in Mode I, and the sooner critical pressure is reached. Since fracture length will not extend after reaching critical pressure, it is advantageous to delay reaching critical pressure as long as possible. This can be achieved by using a fluid of a higher n' since it will require less pressure to move thru the fracture. This theory is shown in graphic form in Figure 8. It can be seen from the graph that a fluid with less flow resistance would be advantageous in a zone where critical pressure was relatively close to closure pressure.

TYPICAL TMS PROCEDURE

In an effort to properly utilize the tools that the TMS brings to the field, a procedural flow path should be followed. The following procedure is in no way intended to fit every well, however, it is felt that most points can be applied to typical well conditions.

Breakdown

A very important part of any completion and subsequent production is the complete and satisfactory opening of all perforations. Breakdown fluids range from 2% KCl water to high strength acid and should always be compatible with the formation and drilling fluids. In wells with high shot density (> spf) blocking agents such as graded rock salt or benzoic acid flakes should be used to divert. In conditions with moderate shot density (~ 1 spf), ball sealers may be applied successfully. In treatment situations which will utilize limited entry techniques, the perforation should either be broken down using ball sealers or independently isolated and stimulated.

Treatment Parameters

The next step in successfully fracturing a zone revolves around the proper choice of a transporting fluid. Obviously, the fluid should be non-damaging and capable of adequately placing the chosen proppant. The friction properties of this fluid should then be used along with an estimated ISIP and desired rate to predict treating pressures. These rates and pressures should then be used to determine the proper conductor keeping in mind that the dead string method of monitoring bottom hole pressure is desired.

Prefrac Testing

Closure pressure, the fluids leakoff coefficient and a frac height are the three important factors in designing a proper fracture treatment. The first series of tests, pump-in/flowback, should provide a closure pressure and consist of pumping 2,000-5,000 gallons of non-damaging formation fluid at a rate of 2-5 BPM depending on the height of the zone. The larger the zone, the greater the leakoff and the greater the rate required to initiate a sufficient fracture. The fluid should be flowed back utilizing an adjustable choke and flow meter. As discussed previously, a change in the rate of pressure decline should indicate a closure pressure.

A mini-frac using the desired fracture fluid and pumped at the same rate as the major stimulation should be performed next. This test may be easily combined with the preceding flowback test. The mini-frac should be 5,000-20,000 gallons depending on the leakoff rate and height of zone. The pressure decline following the mini-frac should be monitored for two to five times the pump time of the mini-frac.

In an effort to determine fracture height, a temperature survey should be run prior to the mini-frac to obtain a base temperature gradient and then another survey should be done following the pressure decline after the mini-frac. Sometimes it can be very useful to run several post frac surveys in an effort to obtain a rate of temperature change in each zone thereby giving some clue as to the volumes injected into each zone.

Along with the above height and pressure decline data, an accurate knowledge of net height and the sheer modulus of the formation will be needed in order to calculate a total insitu leakoff coefficient. This leakoff coefficient should then be used along with the fracture height to simulate the desired fracture geometry for the major treatment. Pad volumes, proppant schedules and fluid loss additives can then be scheduled in an effort to achieve the desired proppant penetration and conductivity.

Major Treatment

After the proposed treatment has been approved by all those concerned, the field personnel should be notified and preparation for the treatment should begin. Frac tanks can be set and filled along with proppant storage facilities.

In the case where a dead string will be used, the computer model should be capable of adding the hydrostatic head of the column of fluid and subtracting the perforation friction from the surface pressure. This method will give the bottom hole treating pressure outside the casing in the zone of interest.

If no dead string will be used and bottom hole pressure will be calculated from surface parameters, the computer model should be capable of compensating for changes in hydrostatic head and friction due to the addition of proppant. Using the ISIP and treating rates and pressures from the mini-frac can prove very helpful in obtaining fluid friction properties. Caution should be exercised when analysing bottom hole pressures which are totally calculated from surface parameters because of the many potential errors.

Plot of Net Pressure

The previously derived closure pressure should be subtracted from the bottom hole treating pressure and plotted on a graph of real time versus net pressure. The plot should be plotted on an even cycle log-log graph (square). The plot should begin as the main fracturing fluid enters the formation and should continue throughout the treatment.

Following the fracture treatment, it can prove very informative to monitor the pressure decline for at least the length of pump time and run a post frac height survey. Again, this pressure decline and height can be used to calculate an insitu leakoff coefficient and may prove helpful in designing the offset treatment.

CASE HISTORY #1

The first well discussed is a Pecos County, Texas well completed in a 100' Wolfcamp zone at approximately 11,000'. Prior to the major stimulation several prefrac tests were performed. Two stages of 5,000 gallons condensate were injected at rates of 5 and 10 BPM and allowed to leakoff. The fall-off following both injections did not indicate an inflexion point. A third injection was performed at 23 BPM using gelled condensate. The fall-off of this pump-in indicated a textbook example of an inflexion point as shown in Figure 9. This fall-off and closure pressure (from inflexion point) were used to calculate an insitu fluid-loss coefficient of 2.37 x 10^{-3} ft/$\sqrt{\text{min}}$ which in turn was used to design the major stimulation. The frac treatment consisted of 100,000 gallons of gelled condensate, 64,500 lbs. Ottawa sand and 25,000 lbs. of intermediate density proppant pumped at 22 BPM via 2-7/8" tubing. The job was successfully pumped as indicated by the chart in Figure 10. The plot of net pressure in Figure 11 indicates a 10 minute breakdown period followed by about a 15 minute period of height growth. The remainder of the treatment appears to demonstrate good fracture extension with confined height.

CASE HISTORY #2

A second case history involves hydraulically stimulating the San Andres zone of a well in Winkler County, Texas. The first treatment consisted of a 5,000 gallon mini-frac followed by a 30,000 gallon frac using a 40 lbm/1000 titanate crosslinked HPG water based system. A period of pressure fall-off was monitored after this prepad. The frac was then attempted at a rate of 25 BPM via 2-7/8" tubing. After three stages of proppant, the well screened out on 3 lbm/gal sand.

Insitu fluid-loss coefficients were then calculated using methods described by Nolte and Nierode. The Nierode method for analysing two ISIP's gave a combined C of

3.23×10^{-3} ft/$\sqrt{min}$ which agreed well with the 2.85×10^{-3} ft/$\sqrt{min}$ derived using Nolte's method. Both of the leakoff coefficients were approximately three times the 9.52×10^{-4} ft/$\sqrt{min}$ used for design purposes. These results indicated that a redesign of the treatment was required and that a more efficient fluid was necessary. Since the bottom hole temperature (BHT) of the well was around 100°F, the decision was made to use 30,000 gallons of a 40 lbm/1000 borate crosslinked HPG water based system. The pad was enlarged and a refrac was attempted at 20 BPM. The treatment successfully put away 160,000 lbs. of 10-20 mesh sand reaching a concentration of 9 ppg. A chart of this treatment is presented in Figure 12 and a plot of the net pressure is shown in Figure 13. The path of net pressure indicates good length extension followed by a period of height growth. This situation appears to occur three times. The post frac temperature survey indicated that everything stayed in zone so this would indicate that boundries were being broken within the pay zone.

CASE HISTORY #3

The third well discussed is a Reeves County, Texas well completed in the Wolfcamp formation at approximately 15,000'. A prepad of 7,500 gallons was pumped at 10 BPM and monitored for leakoff. Two ISDP's were also taken in an attempt to compare the Nolte and Nierode leakoff analyses. The fluid consisted of 80,000 gallons crosslinked 50 lbm/1000 HPG with a 5% diesel phase for fluid-loss. The treatment was pumped via the tubing and carried 200,000 lbs. of bauxite. The treatment screened out 70 bbls. before the proppant was completely flushed. A chart of the treatment can be seen in Figure 14. The net pressure as seen in Figure 15 shows a very interesting phenomenon; the calculated P_n appears to cycle with peaks coming at a net pressure of 1600 psi. Following all three peaks is a period of height growth which is subsequently followed by a period of fracture extension with confined height. This situation agrees with the lithology of this formation in this area as being very lenticular. The pressure at the three peaks may be defined as the critical pressure since it seems to indicate the amount of force required to overcome the horizontal stresses in the boundry zones of each lens. Finally, the well screens out since this cycling of fluid-loss was not incorporated into the design. It should be noted that since P_n is calculated from surface parameters there exists a possibility that this cycling effect could come from viscosity fluctuations. Every effort was made to ensure this was not the case and the author feels confident of the calculated pressures.

CASE HISTORY #4

This fourth well is being used as an example to demonstrate a possible variance from published theories. This Mississippian well was completed in Midland County, Texas at 11,500' with 60,000 gallons gelled condensate and 80,000 lbs. of an intermediate density proppant. The treatment was pumped at 16 BPM via 2-7/8" tubing (Fig. 16). The treatment was a success and it should be noted that the pressure increase at the end of the job is due to a friction increase from the flush fluid. A chart of the net pressure (Fig. 17) shows a constant negative slope over the entire treatment. This corresponds to a Mode IV condition as described by Nolte and Smith. Well logs indicate good barriers of 200' below and above this 25' zone. Even though a conclusive temperature survey was not run, it was felt the frac stayed in zone. If confined height existed, then good fracture extension was achieved in Mode IV and this might suggest that a different fracture model is applicable in certain zones in the Permian Basin.

CASE HISTORY #5

The final well discussed is a Midland County, Texas completion in the Upper Spraberry at 7800'. The treatment consisted of 60,000 gallons of crosslinked 30 lbm/ 1000 HPG carrying 140,000 lbs. of 20-40 mesh sand and pumped via the annulus at 38 BPM with a surface pressure of 2600 psi. Bottom hole pressure was monitored using the tubing as a dead string. Hydrostatic head of the column of fluid in the tubing as a dead string. Hydrostatic head of the column of fluid in the tubing was added to the surface pressure on the tubing. Friction pressure across the perforations was then subtracted out to produce a bottom hole treating pressure which can be seen in the chart in Figure 18. A closure pressure of 3300 psi was subtracted from this bottom hole pressure and used to calculate the net pressure seen in Figure 19. This plot of net pressure indicates a small positive slope for approximately 30 minutes. The net pressure then turns upward into a Mode III slope or screenout mode. However, this treatment did not screenout and was completed successfully. It should be noted that a flowback test was not conducted so the closure pressure of 3300 psi was an estimation. If the actual closure pressure was several hundred pounds lower, the unit slope beginning at 30 minutes into the treatment would flatten out. This example points out the need for an accurate closure pressure.

CONCLUSIONS

1. The original work of Nolte and Smith in the analysis of bottom hole treating pressure was applied to hydraulic fracturing operations of large homogeneous tight gas zones within adequate boundry zones. Some reevaluation must occur in order to bring their theories to the harder heterogeneous rocks of the Permian Basin.

2. The methods of using bottom hole pressure sensing tools or dead strings to determine bottom hole pressures can be more accurate than surface calculated methods. However, due to the typical completion practices in the Permian Basin area, the calculated method of bottom hole pressure determination is the most economical.

3. Several predictable net pressure patterns occur in like formations of the Permian Basin.

4. In the calculation of bottom hole treating pressure via surface measured parameters, special consideration should be given to accurate data.

5. Several methods for calculating insitu fluid-loss coefficients have been introduced. The results of these insitu coefficients are typically pessimistic when compared to calculated coefficients.

6. An accurate closure pressure is critical for accurate interpretation of the plot of net pressure.

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Table 1
Comparison of Combined Fluid Loss Coefficients (C_c)

FORMATION	COUNTY, STATE	DEPTH	FLUID*	C_c (NOLTE)	C_c (NIERODE)**	C_c (Calculated)
Cherry Canyon	Eddy, N.M.	5,025'	1	0.000534	***	0.000316
L. Clearfork	Ector, Tx.	6,500'	2	0.00278	na	0.000756
Dean	Reagan, Tx.	6,400'	3	0.000815	0.00302	0.000413
Mississippian	Midland, Tx.	11,540'	4	0.000190	***	0.000214
Queen	Gaines, Tx.	4,320'	1	0.00477	na	0,00175
San Andres	Winkler, Tx.	4,300'	2	0.00285	0.00397	0.000952
L. Spraberry	Midland, Tx.	8,400'	1	0.00104	***	0.000840
L. Spraberry	Reagan, Tx.	5,900'	3	0.00184	0.000934	0.000623
U. Spraberry	Reagan, Tx.	5,400'	3	0.00164	***	0.000681
Wolfcamp	Pecos, Tx.	11,050'	5	0.00237	na	0.000483
Wolfcamp	Reagan, Tx.	6,700'	3	0.000854	0.00510	0.000401
Wolfcamp	Reeves, Tx.	15,350'	6	0.000435	0.00156	0.000372

*Fluid Description

1. 30 lbm/1000 gal. crosslinked HPG
2. 40 lbm/1000 gal. crosslinked HPG
3. 30 lbm/1000 gal. crosslinked HPG w/20 lbm/1000 gal. FLA
4. Gelled lease crude w/20 lbm/1000 gal. FLA
5. Gelled lease crude
6. 50 lbm/1000 gal. crosslinked HPG w/5% Hydrocarbon phase

** Perkins & Kern geometry
*** Final ISIP lower then first ISIP

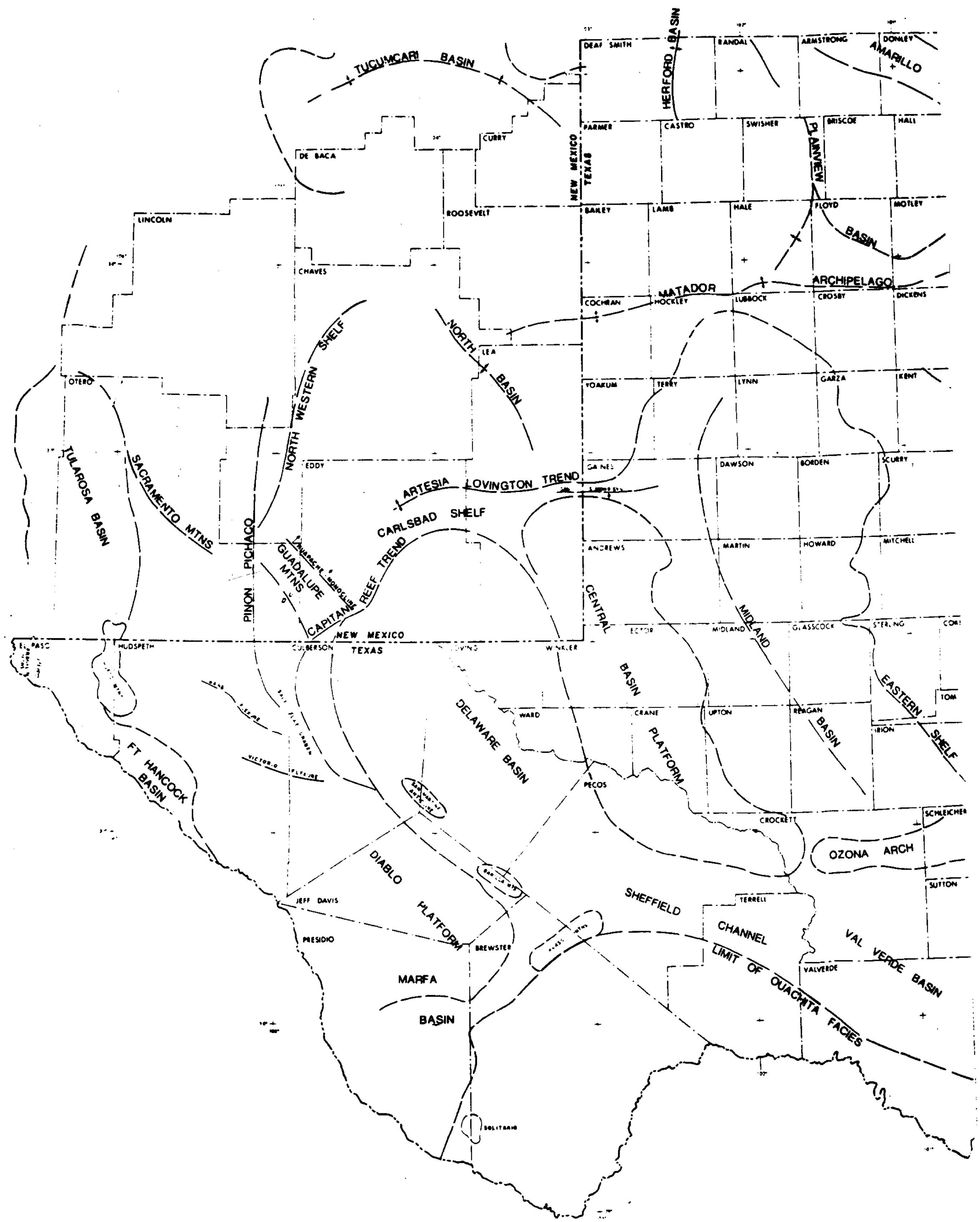


Figure 1 - Map of Permian Basin

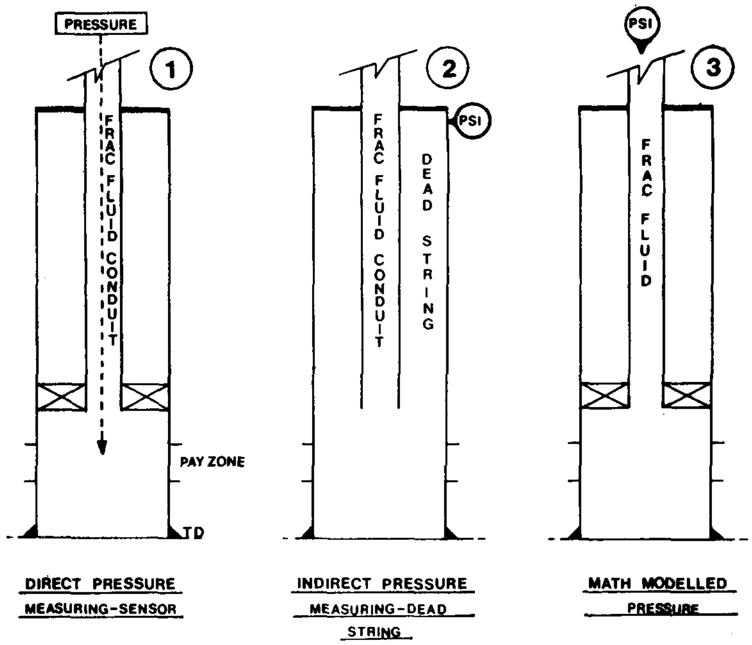


Figure 2 - Well configuration for monitoring BHP

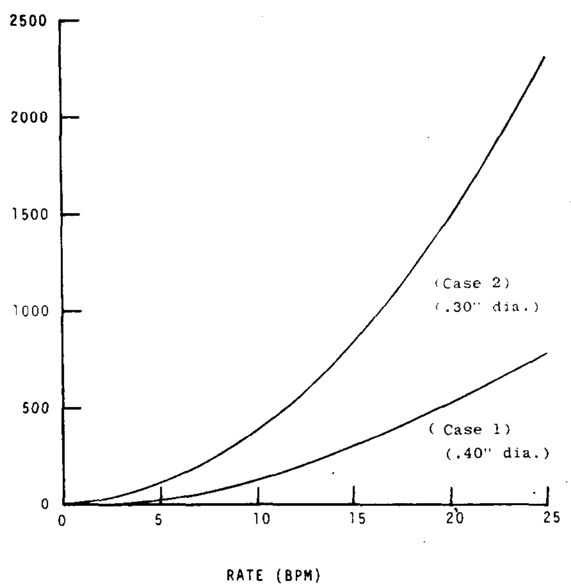


Figure 3 - Perforation friction

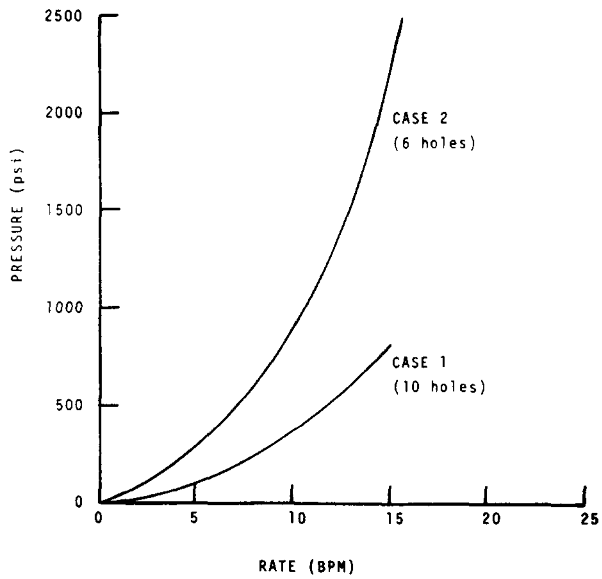
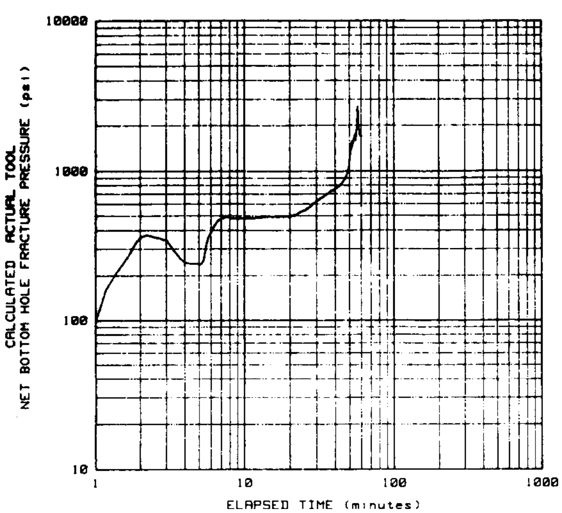


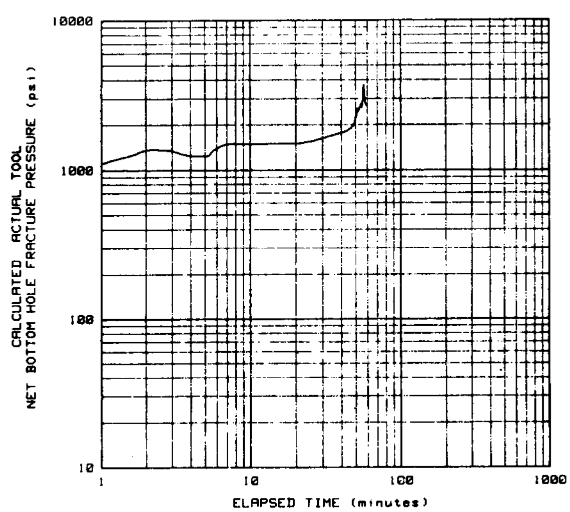
Figure 4 - Perforation friction

1. Run in hole with tubing and packer to ±100' above top perforation. Set packer.
2. Run base temperature and gamma survey.
3. Pressure annulus to ±500 psi.
4. Pump 10,000 gals. 40 lb/m/1000 crosslinked HPG at 15 BPM. Tag with R/A material throughout.
5. Flush to top perf with slick water at 15 BPM.
6. Monitor pressure decline for approximately 1 hour.
7. Run temperature and gamma survey to determine height.
8. Solve equation for fluid loss coefficient.
9. Adjust frac treatment as necessary.

Figure 5 - MINI FRAC procedure



CASE A (P_c = 6500)



CASE B (P_c = 5500)

Figure 6 - Closure pressure comparison

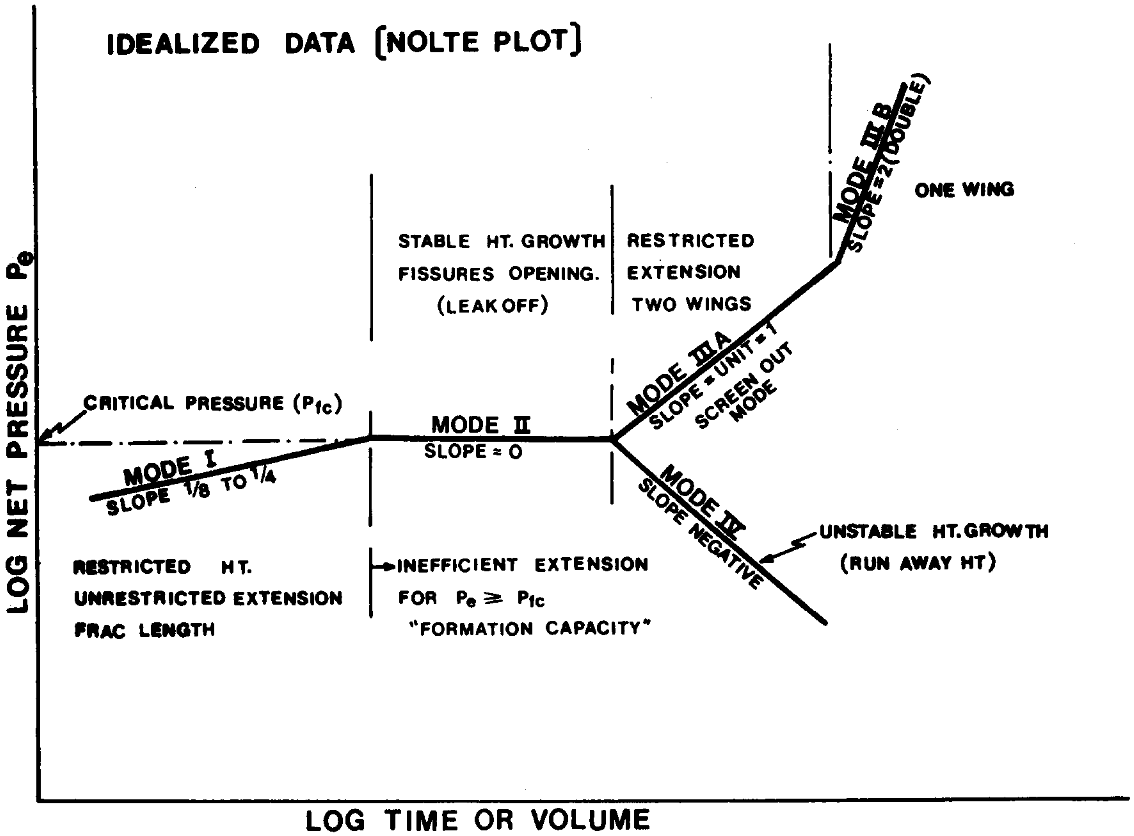


Figure 7 - Slope interpretation

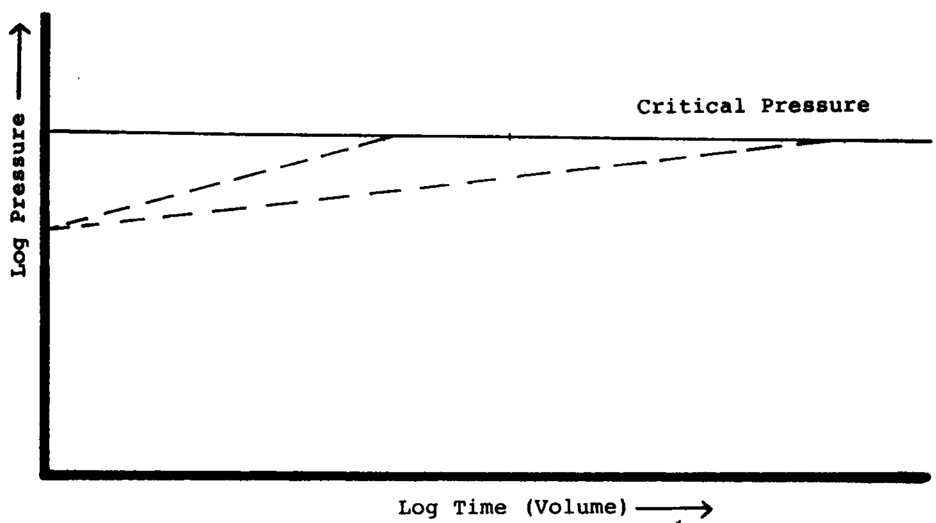


Figure 8 - Effect of flow behavior index (n')

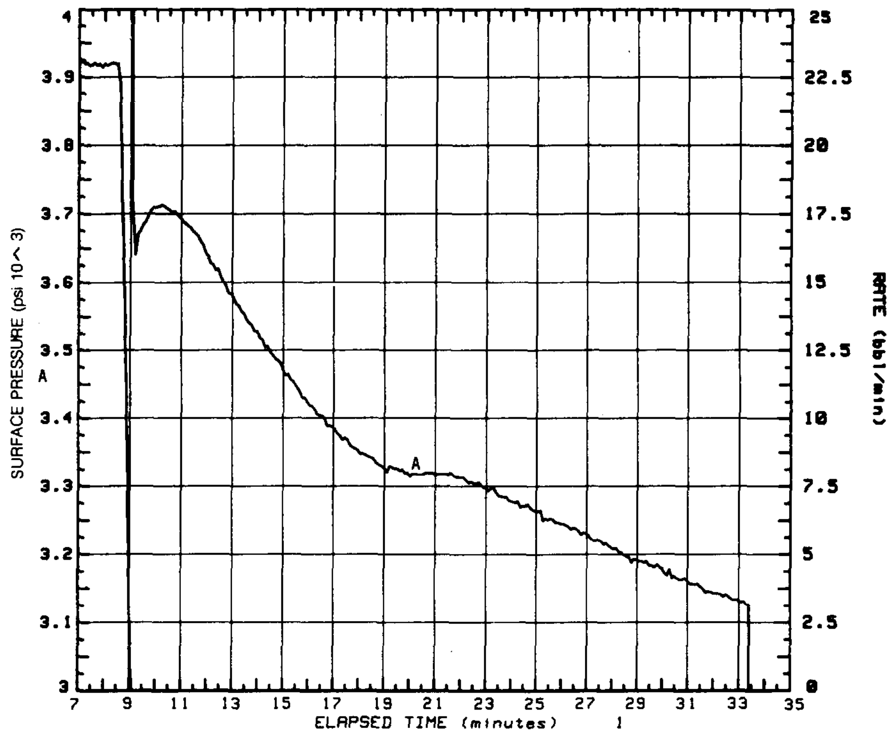


Figure 9 - Case History 1, inflexion point

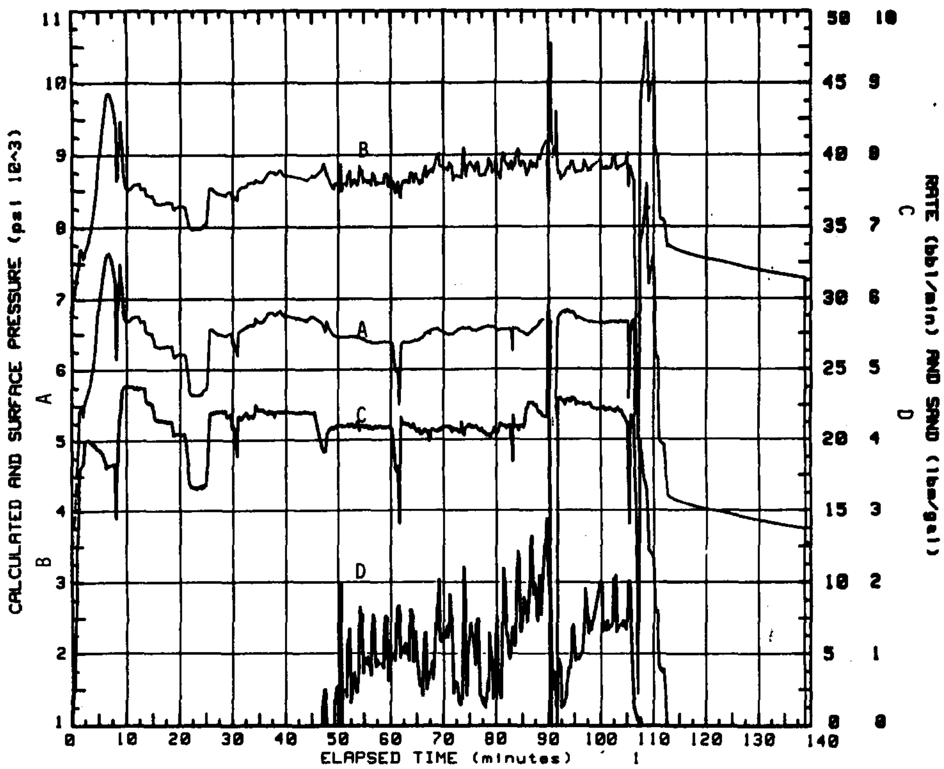


Figure 10 - Treatment chart for Case History 1

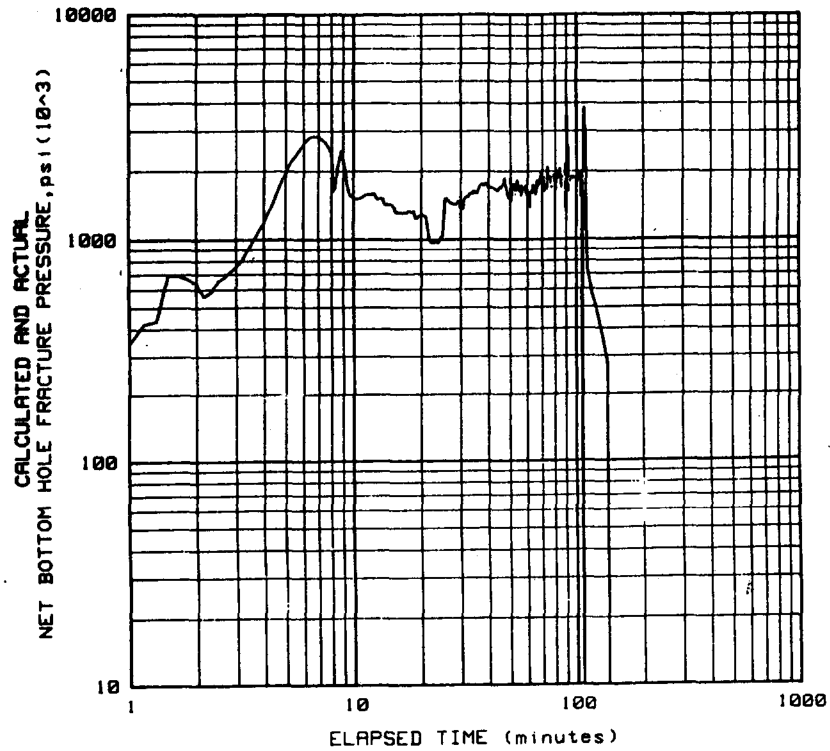


Figure 11 - Plot of net pressure for Case History 1

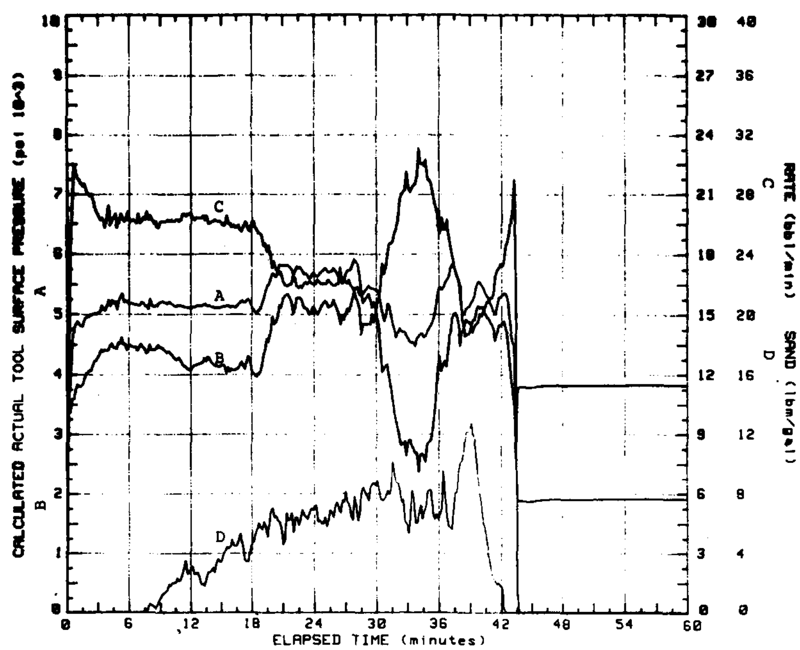


Figure 12 - Treatment chart for Case History 2

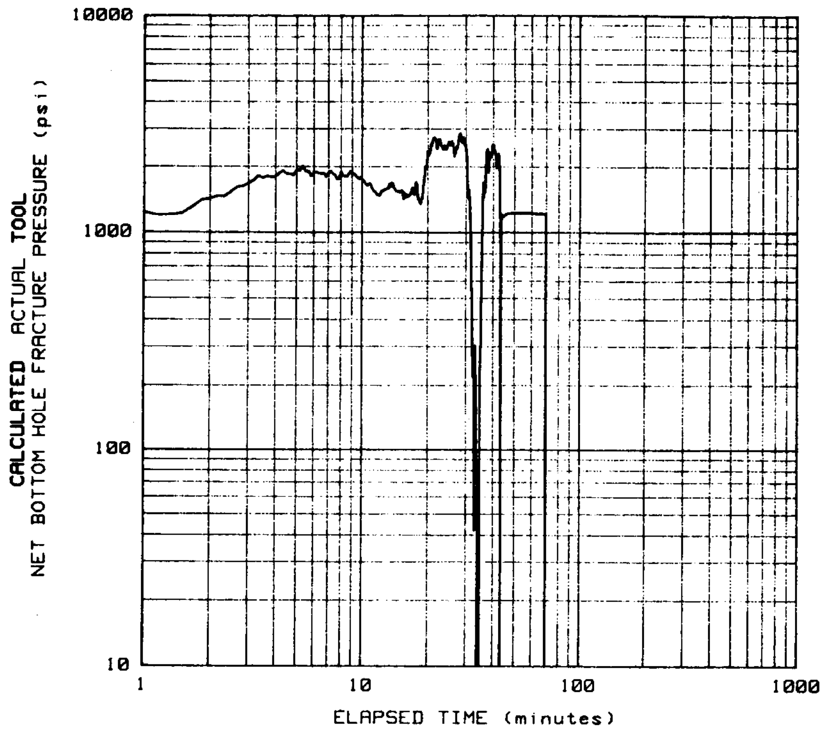


Figure 13 - Plot of net pressure for Case History 2

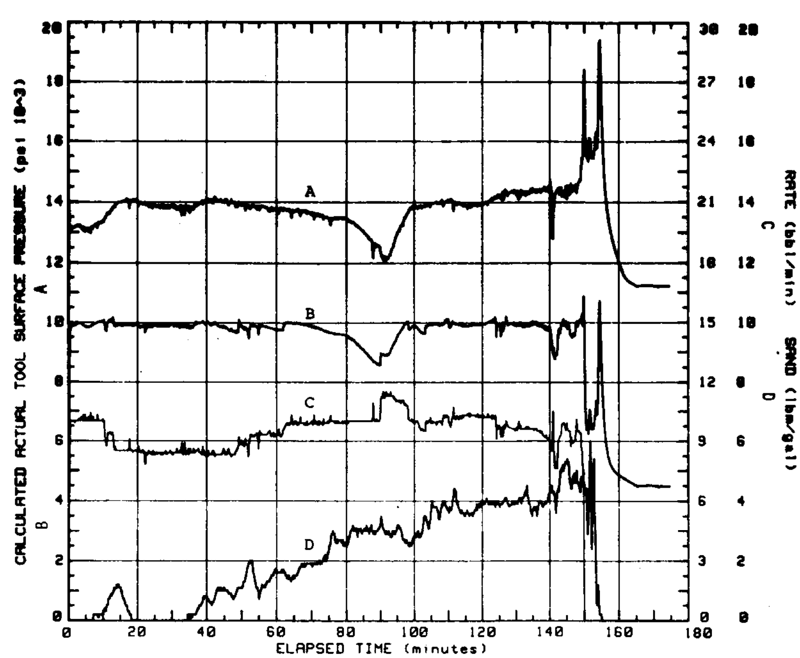


Figure 14 - Treatment chart for Case History 3

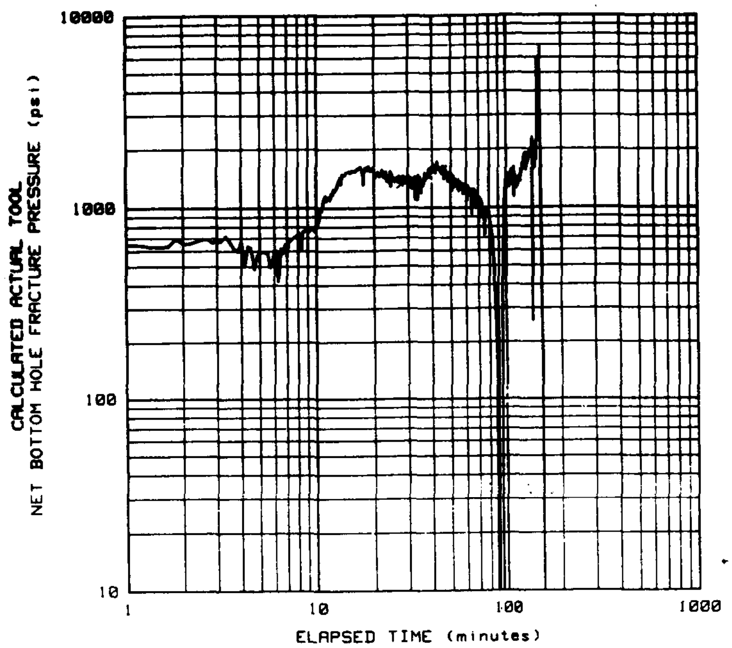


Figure 15 - Plot of net pressure for Case History 3

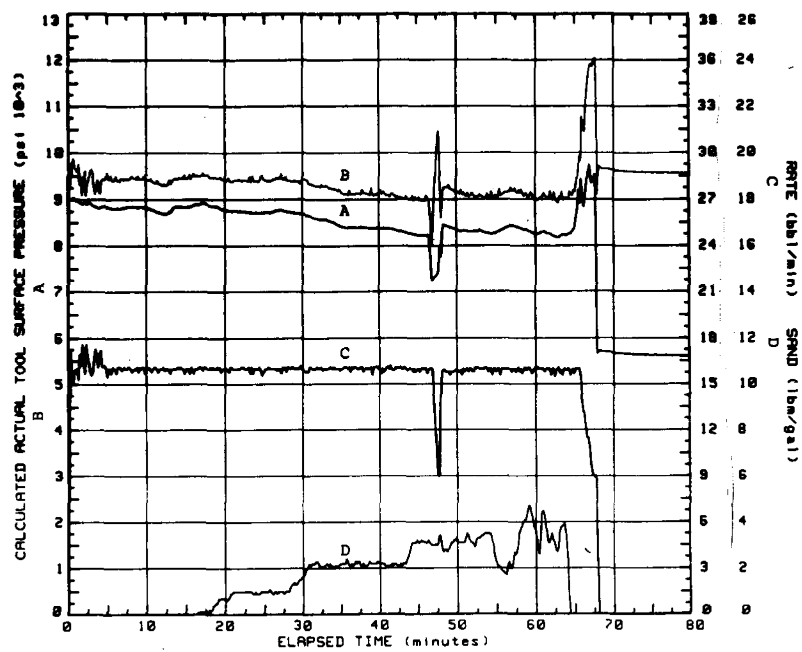


Figure 16 - Treatment chart for Case History 4

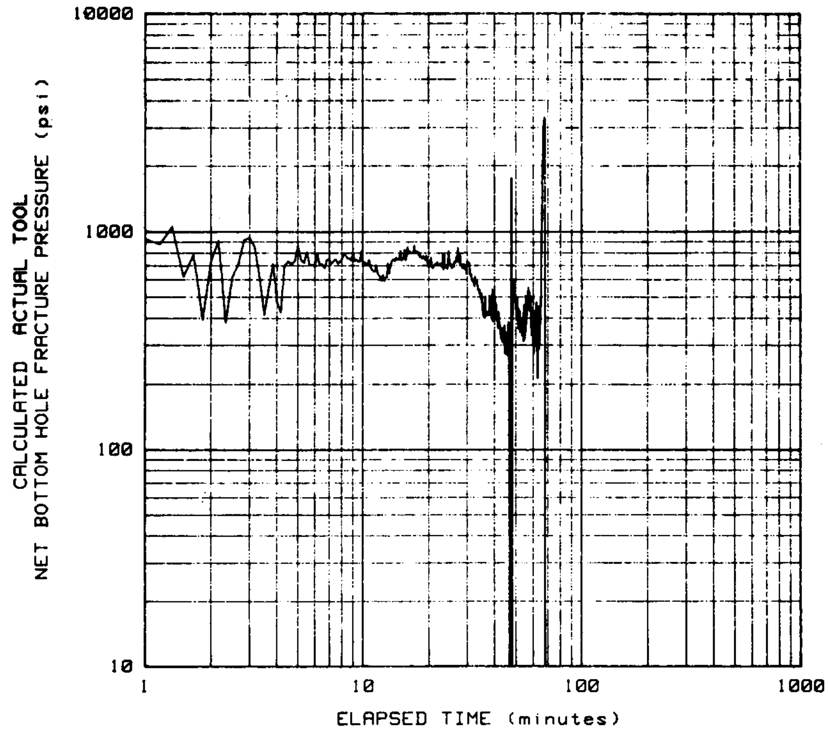


Figure 17 - Plot of net pressure for Case History 4

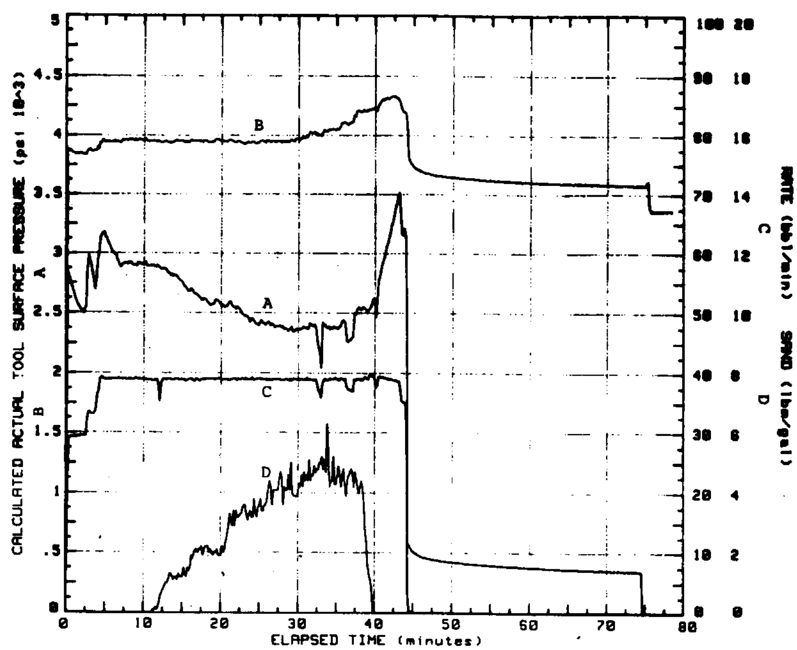


Figure 18 - Treatment chart for Case History 5

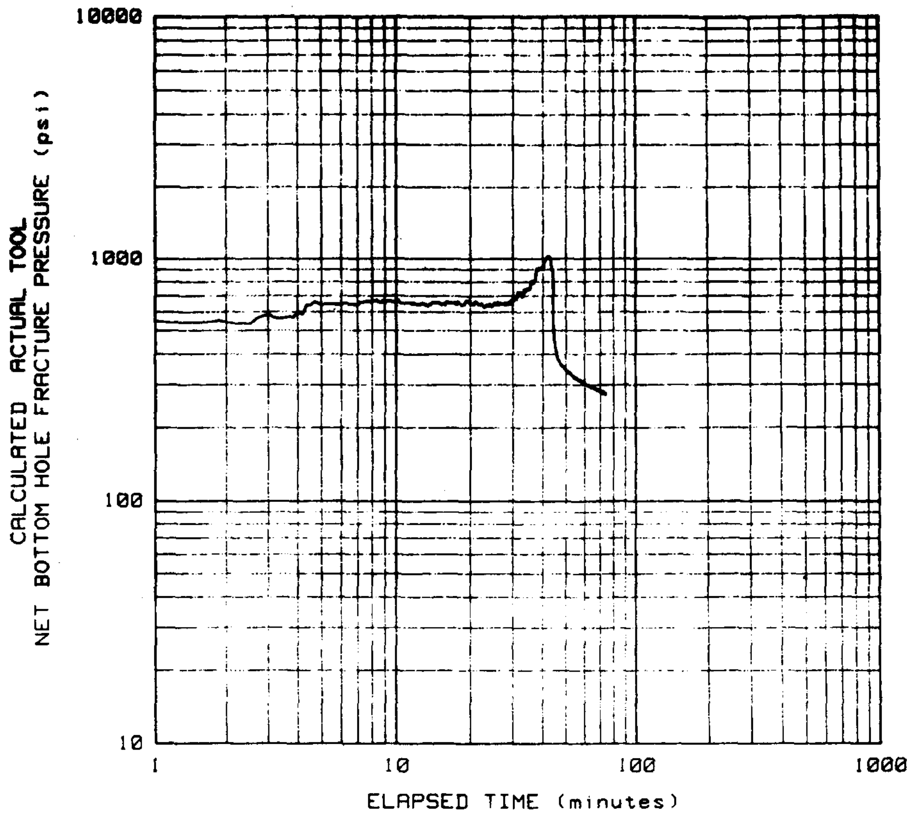


Figure 19 - Plot of net pressure for Case History 5