Basic Concepts of Fracture Treatment Design

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INTRODUCTION

Many engineers, when faced with the necessity of designing a fracture treatment for a well, will either look to the experience of other operators in the field, or will rely on a service company for the design. Although these courses of action have merit, they do not always result in the most effective treatment for a particular situation. The study of fracturing results in nearby wells is useful in analyzing the effectiveness of a particular treatment. The indiscriminate use, however, of this treatment is not always wise. Sometimes equally good results can be obtained with a smaller or cheaper treatment, or the results can be improved by changing the treatment design. In some cases, there may not be any treatment experience available for study, such as when a well is drilled in a wildcat location or in a relatively undeveloped area. The engineer should also utilize the knowledge of service companies, since they have vast experience in designing and performing fracture treatments. Different service companies, however, do not always agree on the treatment design for a particular well. It is essential, therefore, that the engineer have a knowledge of basic design methods and an understanding of fundamental fracturing concepts if he is to intelligently recommend a fracture treatment for a well. This knowledge will enable him to design a treatment himself or to judge the effectiveness of various treatments designed by others, especially in areas where there is little or no treatment experience to use as a guide.

The purpose of this paper is to present a brief summary of fracturing concepts and a design method for determining the size of the treatment. From the design procedure shown here, the engineer can determine the amount of frac fluid and the amount of sand to be injected. These are the fundamental considerations in designing any fracture treatment. Only the sandpacked fracture is considered. This type of treatment is still the most widely used today, although the sparse-propped, high-conductance fracture treatment is becoming more popular and should be considered when a sandpacked treatment cannot give the desired productivity increase or is too costly.

FRACTURE ORIENTATION

One of the disputable questions in fracturing theory is the orientation of the induced fracture, or in other words, whether the induced fracture lies in a horizontal or vertical plane. It is generally accepted that below a depth of about 3,000 ft. induced fractures will be vertical.[1] It is also believed that induced fractures will follow the orientation of any natural fractures existing in the formation near the wellbore.[2] Since most naturally fractured formations probably have vertical fractures, and since the majority of producing horizons now being found are deeper than 3,000 ft., the design method in this paper is limited to vertical fractures.

PRODUCTIVITY INCREASE
REALIZED BY FRACTURING

The first factor to consider in fracturing design is the productivity increase desired from the treatment. Obviously, the rate increase should be high enough to justify the expense of the treatment. Since the well's production rate will decline as it is produced, the treatment should also be large enough to permit the well to produce at the desired rate for a reasonable length of time.

Fig. 1 is a graph published in the literature[3] showing the effect of a vertical fracture on the productivity of a well, assuming no permeability damage, or skin effect, close to the wellbore. If damage close to the wellbore does exist, then the actual productivity increase will be greater than that predicted by this graph. An examination of this graph shows that the productivity increase obtained from a vertical fracture is dependent upon the effective length of the fracture and on the fracture conductivity, defined as the product of the propped fracture width and the propping material permeability. The longer the fracture, the greater is the productivity increase obtained. For a constant fracture length, the productivity increases with increased fracture conductivity, although an optimum point is reached beyond which increasing the fracture conductivity will cease to have an appreciable effect on productivity. It can also be seen from the abscissa term of this graph that the higher the formation permeability, the higher the fracture conductivity must be for a given productivity increase and fracture length.

From this graph, the required fracture length and conductivity can be determined for a given productivity increase. The desired productivity increase ratio (rate desired after fracturing divided by rate before fracturing) is corrected for well spacing by multiplying it by the correction factor:

$$\frac{7.13}{\ln 0.472\ r_e/r_w}$$

For r_e use the radius, in feet, of a circle whose area equals the well spacing. For r_w use the wellbore radius, in feet, obtained from logs or bit records. The selection of an r_w value is not too critical, since it is used in a logarithm term. Knowing the well spacing and formation permeability, the fracture conductivity can be calculated from the factor read off the abscissa of the graph. The best value to use for formation permeability is one calculated from bottom-hole pressure buildup tests or from drillstem test data. If these are not available, then estimate an order of magnitude permeability from core analysis or from personal judgment.

In many instances, more than one reasonable fracture length and fracture conductivity can be determined from this graph. A design based on each set of conditions can then be made and the most reasonable or economical one chosen.

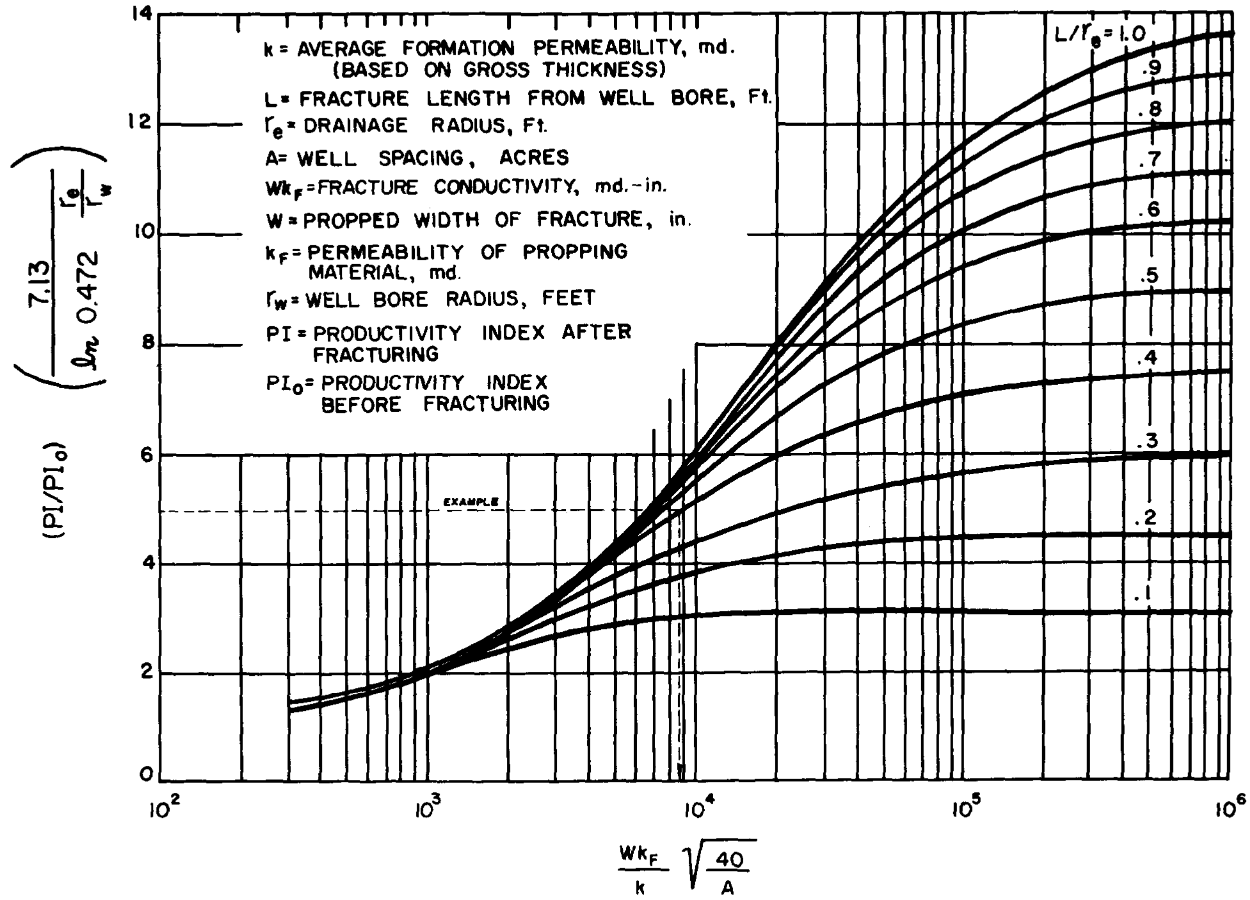

FIG. 1 - PRODUCTIVITY INCREASE FROM FRACTURING

FRACTURING FLUIDS

The fracturing fluid used in a fracture treatment serves a two-fold purpose: first, it creates and extends the fracture in the formation, and second, it carries the propping agent and deposits it in the fracture. The discussion at this point concerns only the fracture extension function of the fluid.

As the fluid is pumped into the formation, some of it leaks off into the formation matrix. That which remains in the fracture is pushed ahead by the fluid being pumped in behind it and thus extends the fracture deeper into the formation. Obviously, that fluid which leaks off into the formation matrix is wasted, since it does not serve to extend the fracture. The greater the amount of fluid retained in the fracture, the more efficient is the treatment, with treatment efficiency being defined as fracture volume created per unit voluxe of fluid pumped into the formation.

For the comparison of the leak-off properties of various fluids, a fluid leak-off coefficient, C, is used, which has the dimensions of ft/$\sqrt{\text{min}}$. This coefficient provides a measure of the leak-off rate, so that a low C value indicates a low leak-off rate. There are 3 types of flow mechanisms which control the leak-off rate of a fluid.

One of the flow mechanisms controlling fluid leak-off rate is dependent upon the viscosity of the fracturing fluid. The leak-off rate will be controlled if the fracturing fluid has an appreciably higher viscosity than the formation fluid. Examples of this mechanism would be the use of various refined oils for the fracturing fluid. The second mechanism is dependent upon the reservoir fluid compressibility and viscosity. These factors become dominant when the fracturing fluid has physical properties nearly identical to the reservoir fluid and the reservoir is completely liquid saturated. Fracturing fluids in this category would be lease crude and water which do not contain fluid loss additives. The addition of fluid loss additives to a fracturing fluid constitutes the third leak-off control mechanism. These additives deposit a temporary filter cake on the walls of the fracture which prevents leak-off. This filter cake is flushed out of the formation when the well is produced after the treatment.

Although each mechanism has some effect on the fluid's leak-off properties, usually one of them will be very predominant. The predominant mechanism will be that which gives the lowest C, and this C should be used in designing the treatment.

The C factors for the first 2 mechanisms described above are calculated from the following formulas:

$$C_v = 0.0469\sqrt{\frac{k\phi\Delta P}{1000u_f}} \quad (1)$$

$$C_c = 0.0374\,\Delta P\sqrt{\frac{k\phi C_r}{1000u_r}} \quad (2)$$

where C_v = viscosity controlled fluid coefficient, ft./$\sqrt{\text{min.}}$

C_c = reservoir fluid controlled coefficient, ft./$\sqrt{\text{min.}}$
k = formation permeability, md.
ϕ = effective formation porosity, fraction
ΔP = pressure differential across fracture face, psi
C_r = compressibility of reservoir fluid, psi^{-1}
u_f = viscosity of fracturing fluid, cps.
u_r = viscosity of reservoir fluid, cps.

It is important to note that in Eq. 1 the fracturing fluid viscosity is used, but in Eq. 2 the viscosity used is that of the reservoir fluid. Both viscosities should be at formation temperature. If the reservoir fluid compressibility is not known, a value of 1×10^{-5} may be used for completely liquid filled reservoirs.[4] The pressure differential across the fracture face equals the fracturing fluid pressure in the fracture minus the normal reservoir pressure.

The C for wall-building fluids containing fluid-loss additives, must be determined experimentally in the laboratory, and any service company will perform this service. A high pressure filter press containing one or more layers of filter paper is used. The fluid is subjected to pressure and the volume of filtrate recovery for several given time intervals is measured. When the filtrate recovery, in cubic centimeters, is plotted on straight coordinate paper against the square root of time in minutes, the points should form a straight line as shown in Fig. 2. The slope of this straight line and the surface area of the filter paper are measured, and the C factor is calculated by the following formula:

$$C_w = 0.0164\frac{m}{a} \quad (3)$$

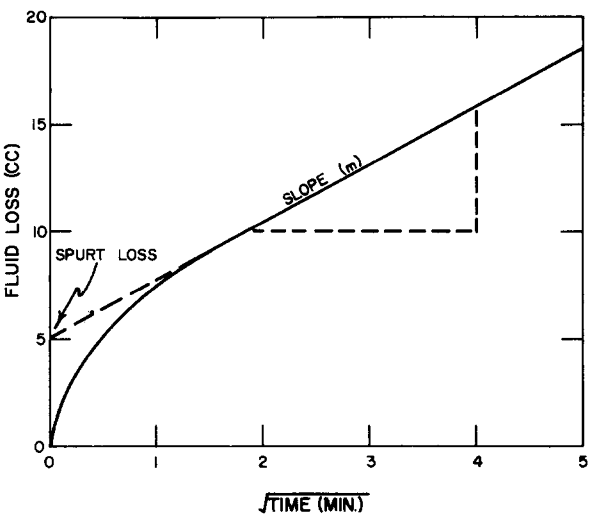

FIG. 2 - EXAMPLE FLUID LOSS CURVE FOR FLUID CONTAINING FLUID LOSS ADDITIVE

where C_w = wall-building fluid coefficient, ft./$\sqrt{\text{min.}}$
m = slope of fluid loss curve, cc /$\sqrt{\text{min.}}$
a = area of filter paper, sq. cm.

The test in the filter press is usually run with a pressure differential of 1,000 psi and at a temperature of 125° F. It should, however, be run at the bottom hole temperature and pressure differential actually anticipated during the treatment. If representative core samples of the formation to be fractured are available, core discs should be used instead of filter paper for the filter medium.

If the straight line of the fluid loss curve, as shown in Fig. 2, is extrapolated to zero time, it will intersect the ordinate at some filtrate volume. This volume is known as the spurt loss. It is a measure of the fluid which will be lost through the fracture walls before an effective filter cake is deposited. Since this loss is not accounted for in the C_w factor, it must be considered as a separate factor in design calculations, but only when fluid-loss additives are used. Obviously, the spurt loss should be kept as low as possible.

When designing a fracture treatment, the most economical fluid is usually used. However, care must be taken that the fluid will not have detrimental effects on the formation. As an example, water should not be used if the formation contains clays which are susceptible to swelling. If the reservoir contains dry gas, then heavy oils, such as lease crudes, should not be injected, as they will leave a residual oil saturation which will cause a decrease in formation permeability to gas.

By the use of gelling agents and fluid-loss additives, a fracturing fluid having almost any desired properties can be obtained. A typical fracturing fluid containing fluid-loss additives may have a C_w of 1.0×10^{-3} to 3.0×10^{-3} with a spurt loss ranging from 2 to 12 cc. These are example values, and should not be used indiscriminately for design purposes.

DETERMINATION OF INJECTED FRACTURING FLUID VOLUME

After the fracture length and fracture fluid properties have been determined, it is possible to calculate the amount of fluid required for injection in order to produce the desired fracture. Fig. 3 is a graphical solution which has been published in the literature[5] of the classical fracture area equation presented by Howard and Fast in 1957.[6]

The fracture height in the ordinate term will usually be equal to the net pay thickness, since hard, impermeable sections will limit the vertical extent of the fracture. If no such restrictions are present, then assume that the fracture height is equal to fracture length. The factor 2 is used because it is assumed that the fracture extends in opposite directions from the well bore.

The average crack width is assumed to be 0.1 in. Although this is a broad assumption, experience has shown that this is a good value to use. Perkins and Kern have presented a study showing that the fracture width can be estimated, and that it is dependent upon fluid injection rate, fluid viscosity, and amount of fluid injected.[7] The results of their study, as well as fracturing experience, indicate that a width of 0.1 in. is a reasonable estimate.

An examination of Fig. 3 shows the effect of injection rate on the size of the fracture generated.

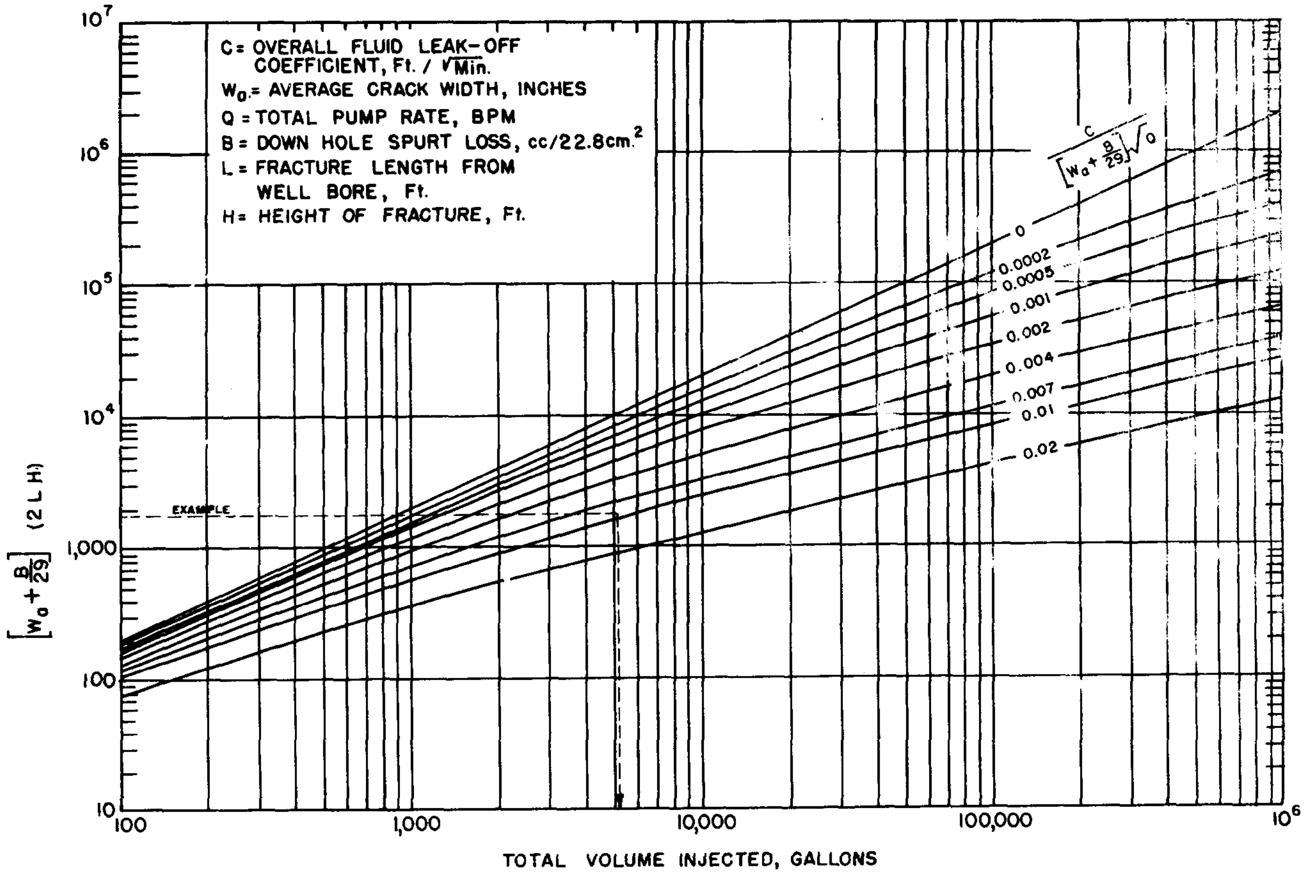

FIG. 3 - RELATIONSHIP BETWEEN VOLUME OF FLUID INJECTED AND SIZE OF FRACTURE GENERATED

For a given volume of fracturing fluid, the fracture area increases as the injection rate increases. It is usually beneficial, therefore, to perform a fracture treatment at the highest possible injection rate. If, however, the formation being fractured is very thin, too high an injection rate may wash the sand down the fracture and not allow it to settle near the wellbore.

DETERMINATION OF SAND QUANTITY

The final step in designing the treatment size is to determine the amount of sand to be injected. The sand quantity should be sufficient to give the required fracture conductivity (propping material permeability times propped fracture width) previously determined from Fig. 1. In order to obtain this conductivity, the sand pack must fill a volume equal to the fracture face area times the propped fracture width. This can be exqressed in equation form as:

$$S = 8.33\ (2LHW) \text{ - - - - - - - - - - - - - - - - (4)}$$

where S = amount of sand injected, pounds
L = length of fracture, ft.
H = height of fracture, ft.
W = propped width of fracture, in.
8.33 = constant for converting in. to ft. and cu. ft. to pounds

The propped fracture width used in Equation 4 can be calculated from the previously determined conductivity factor (abscissa term of Fig. 1), but first the packed sand permeability must be shown.

The sand pack should have as high a permeability as possible. Normally, the permeability is a function of grain size, with the larger grains having a higher permeability. Large grains, however, are weaker than smaller ones and will crush easier when subjected to a load. Fig. 4 is a graph showing the permeabilities of various sand packs for different loads. Using this graph, the most effective sand grain size for a particular treatment can be determined. The load on the sand will be equivalent to the bottom hole fracturing pressure, which, for the purposes of this graph, can be estimated by multiplying 0.7 times the depth of the formation being treated.

After determining the sand pack permeability, the minimum propped fracture width required to give the desired fracture conductivity can be calculated from the abscissa term of Fig. 1. If this calculated width is greater than the assumed fracture width during injection of 0.1 in., then the sand quantity calculated from Equation 4 will theoretically have a greater volume than the fracture, thus creating a potential screenout condition. The most significant meaning of this situation, however, is that the desired fracture conductivity will not be obtained unless the actual fracture width equals the value calculated above. By the method presented by Perkins and Kern in Reference 7, the actual fracture width during injection can be approximated. If this shows that the necessary fracture width will not be obtained during the treatment, a smaller productivity increase must be designed for or

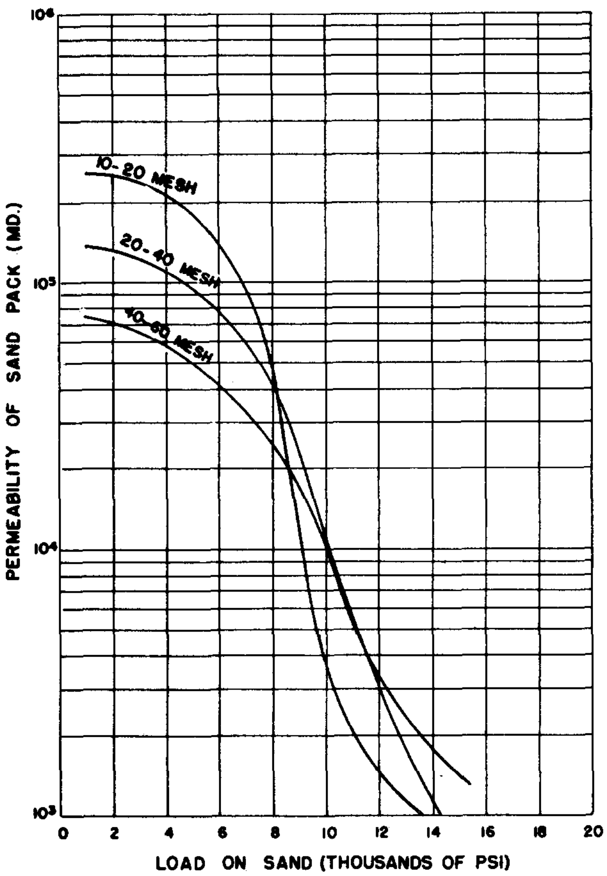

FIG. 4 - PERMEABILITIES OF OTTOWA SAND PACKS UNDER LOAD

a sparse-propped, high-conductance fracture should be considered.

The feasibility of injecting all of the sand calculated from Equation 4 should also be examined from the standpoint of the mechanics of sand movement in a fracture. Kern, Perkins, and Wyant have made laboratory studies of sand movement in a vertical fracture.[8] The results of their work showed that as sand and fluid are injected into a fracture, the sand almost immediately begins to settle to the bottom of the fracture near the wellbore. As more sand is injected the settled sand pack increases in height and length. As the sand pack height increases, the area in the fracture open to the fluid flow decreases, resulting in a higher fluid velocity. This continues until a critical fluid velocity is reached, at which point sand will no longer settle out of the fluid but will be carried farther into the fracture. This sand eventually settles when the fluid velocity decreases below the critical value due to fluid leak-off and greater area open to flow. If, during the treatment, the fluid velocity is increased above the critical value because of an increasing injection rate, some of the settled sand will be picked up by the fluid and washed out farther into the fracture. This creates a larger area open to flow, which allows the fluid velocity to decrease until critical velocity is again reached. The flow system, therefore, continually seeks an equilibrium condition which is reached when critical velocity is attained. It was found that critical velocity for most ungelled fluids is about 400 ft. per min. For gelled fluids and emulsions the critical velocity is considerably higher, possibly twice this value.

Assuming a vertical fracture has a rectangular cross-section, an approximate relationship for determining the height of the open section above the settled sand pack at critical velocity is:

$$h_o = \frac{34Q}{W_a v} \quad \text{- - - - - - - - - - - - - - - - - - -} \quad (5)$$

where h_o = open section above sand pack, ft.
Q = injection rate, bbls./ min.
W_a = average fracture width, in.
v = critical fluid velocity, ft./min.

If the previously assumed value of 0.1 in. for fracture width and a critical velocity of 440 ft./ min. are used, then the equation reduces to:

$$h_o = 0.85Q \quad \text{- - - - - - - - - - - - - - - - - -} \quad (6)$$

If the height of the open area calculated in Equation 5 or 6 is almost equal to or greater than the estimated total fracture height, an effective sand pack will not be formed. It would then be wise to decrease the injection rate to allow more time for sand settling. On the other hand, if the calculated h_o is so small as to indicate critical velocity may never be reached, a potential screenout condition exists. In this case the injection rate should be increased.

If it is assumed that critical velocity is reached and an equilibrium condition exists during the treatment, the maximum amount of sand which can theoretically be injected is equal to the fracture volume minus the volume of open section above the sand pack. This can be expressed as

$$S_t = 8.33\,(H-h_o)\;2\;LW_a \quad \text{- - - - - - - - - - - -} \quad (7)$$

where S_t is the theoretical maximum sand quantity, in pounds, which can be injected. All the other factors in this equation have been previously defined. If the amount of sand calculated from Equation 4 greatly exceeds this theoretical sand quantity, there is danger of a screenout during the treatment.

INJECTION PROCEDURE

One method of injecting the sand is to maintain a constant sand concentration in the fluid during the entire treatment. Often, however, it is advisable to vary the concentration, starting with a low value and increasing it in increments as the treatment progresses. This technique is particularly useful if there is fear of a screenout.

At the beginning of the treatment, a spearhead volume of fluid containing no sand should be injected. The purpose of this spearhead is to initiate the fracture and open it to sufficient width to allow the sand to enter the crack. The spearhead volume should be about 20% of the total injected fluid volume. It can be a portion of the calculated fluid volume or it can be an additional volume added as a safety factor.

The practice of overflushing the pipe at the end of a treatment can be injurious, especially if the injection rate is high and the formation is thin. In these cases, sand may be washed away from the wellbore during overflush. To prevent this, a slight underflush should be applied, or the overflush should be carried out at low injection rates.

EXAMPLE TREATMENT DESIGN

Let us now utilize the concepts and design method just discussed by designing an example fracture treatment. Assume that these are the conditions for a well that has been producing for some time and has never been fractured:

r_w = wellbore radius = 0.25 ft.
k = formation permeability = 1.5 md.
ϕ = formation porosity = 0.12
A = well spacing = 40 acres
r_e = drainage radius = 745 ft.
pay thickness = 30 ft.
formation depth = 6100 ft.
current bottom hole pressure = 1800 psig
bottom hole temperature = 120° F.
current capacity producing rate = 35 BOPD

Also, assume that the bottom hole fracturing pressure gradient in this field is known to be 0.6 psi per ft. The bottom hole fracturing pressure will therefore be (0.6) (6100) or 3660 psi.

In an attempt to make this a top allowable well, it is decided to try for a 5-fold rate increase. Fig. 1 is used to determine the required fracture length and conductivity for this much increase. The ordinate term for Fig. 1 is

$$(PI/PI_o) \frac{7.13}{\ln 0.472 \frac{r_e}{r_w}} = (5) \frac{7.13}{\ln 0.472 \times \frac{745}{0.25}} = 4.95$$

Entering the ordinate of Fig. 1 at 4.95 and coming across in a horizontal line, it is seen that the L/r_e ratio can be 0.3 or greater. It is decided to design on a L/r_e ratio of 0.4. Therefore, the desired fracture length is

$$L = (0.4)(745) \cong 300 \text{ ft.}$$

Coming down vertically to the abscissa of the graph, the fracture conductivity factor is found to be 8.6×10^3.

It is decided to use a refined oil without a fluid-loss additive for the fracturing fluid. This oil has a viscosity of 60 cps. at bottom hole temperature. Since the reservoir is partially depleted and contains free gas, the compressibility of the reservoir fluid will be high and will offer little resistance to fracturing fluid leak-off. The leak-off rate will, therefore, be controlled by the viscosity of the fracturing fluid. The fluid coefficient is calculated from Equation 1 to be

$$C_v = 0.0469\sqrt{\frac{k\phi\Delta P}{1000\, u_f}}$$

$$C_v = 0.0469\sqrt{\frac{(1.5)(.12)(3660-1800)}{(1000)(60)}} = 3.5 \times 10^{-3}$$

Fig. 3 is now used to determine the fluid volume necessary to create the desired fracture. Assuming that the fracture height will be equal to the pay thickness, fracture width during injection will be 0.1 in.; and remembering that there is no spurt loss correction for viscosity controlled fluids, the necessary terms for using this graph are calculated to be

$$(Wa + \frac{B}{29})(2LH) = (0.1)(2)(300)(30) = 1800$$

It is determined that the well casing will permit an injection rate of 15 bbls. per min., so

$$\frac{C}{(Wa + \frac{B}{29})\sqrt{Q}} = \frac{3.5 \times 10^{-3}}{(0.1)\sqrt{15}} \cong .009$$

Entering Fig. 3 with these values, it is determined that the required fracturing fluid volume is 5000 gal.

To determine the size of the sand to be injected, Fig. 4 is consulted. This graph shows that at a load of 3660 psi (bottom hole fracturing pressure), 10-20 mesh sand will give the maximum conductivity and will have a permeability of 275,000 md. Having previously determined the fracture conductivity factor from Fig. 1 to be 8.6×10^3, the propped fracture width is calculated to be

$$\frac{Wk_f}{k}\sqrt{\frac{40}{A}} = 8.6 \times 10^3$$

and $$W = \frac{8.6 \times 10^3\ (1.5)}{220{,}000\ \sqrt{40/40}} \cong 0.06 \text{ in.}$$

Since the propped width is considerably less than the assumed injection width of 0.1 in., there should be no danger of a screenout during the treatment. Using Equation 4, the sand quantity is calculated to be

$$S = 8.33\ (2LHW)$$
$$S = 8.33\ (2)(300)(30)(.05) = 7500 \text{ lbs.}$$

Checking the amount of sand that can theoretically be injected, it is found from Equations 6 and 7 that

$$h_o = 0.85\ Q$$
$$h_o = 0.85\ (15) \cong 13 \text{ ft.}$$
and $$S_t = 8.33\ (H-h_o)\ 2\ LW$$
$$S_t = 8.33\ (30-13)(2)(300)(0.1) = 8500 \text{ lbs.}$$

Since the calculated sand quantity is less than the theoretical quantity, a screenout is not likely.

In summary, the treatment just designed consists of:

5,000 gal. of refined oil.
7,500 lbs. of 10-20 sand.

SUMMARY

Some of the basic concepts of fracturing have been discussed and a method for designing the size of the treatment has been shown. This method provides a sound engineering basis for designing a fracture treatment, especially in areas where there is little or no prior fracturing experience to act as a guide.

Several important assumptions have been made in order to simplify the design procedure. It is realized that as fracturing experience is acquired in a specific area, some of the data presented here will have to be modified to fit existing conditions. A sound knowledge of fracturing fundamentals will enable the engineer to intelligently design a treatment to suit his specific needs.

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