EFFECT OF INCOMPLETE FRACTURE FILL-UP AT THE WELLBORE ON PRODUCTIVITY RATIO

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INTRODUCTION

The process of hydraulic fracturing has been used extensively for well stimulation by the petroleum industry for over two decades. During this time the ability to successfully execute a fracturing treatment has increased to the point where very few mechanical failures currently occur. In addition, the development of treatment design and evaluation procedures has evolved to the point where fracturing is now considered a science rather than an art. As the science progresses, new problems concerning the design and evaluation of optimum fracturing treatments arise frequently. One of the most pertinent of these problems is what effect incomplete fracture fill-up at the wellbore has on productivity ratio. Solution of this problem will be useful in treatment planning to accomplish desired production goals.

The purpose of this paper is to evaluate the effect of incomplete fracture fill-up at the wellbore on productivity ratio, and to present the findings of a controlled screen-out fracturing program which was initiated for the purpose of obtaining field results to substantiate the theory presented in the paper.

THEORETICAL EVIDENCE

Most of the hydraulic fracture treatment design methods currently employed in the petroleum industry assume that proppants can be uniformly placed in a vertical fracture in the horizontal plane (Fig. 1[1]). In the section of the fracture directly adjacent to the wellbore (Fig. 2), this assumption may be in error for the following reasons:

1. As the injected fluid enters the fracture, turbulence can cause the proppant to be swept farther back into the fracture.
2. Fluid loss from the fracture results in the formation around the fracture face being pressurized during a fracturing operation. Since the portion of the fracture adjacent to the wellbore is exposed to the entire volume of fracturing fluid, the formation in the vicinity of the wellbore will have the highest pressure at the conclusion of a fracturing treatment.

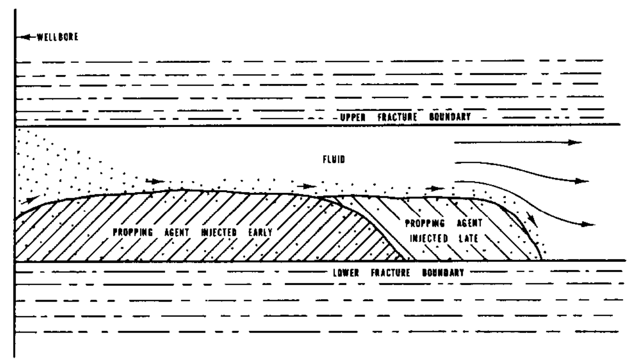

FIG. 1—IDEALIZED PROPPING AGENT DISTRIBUTION IN VERTICAL FRACTURES

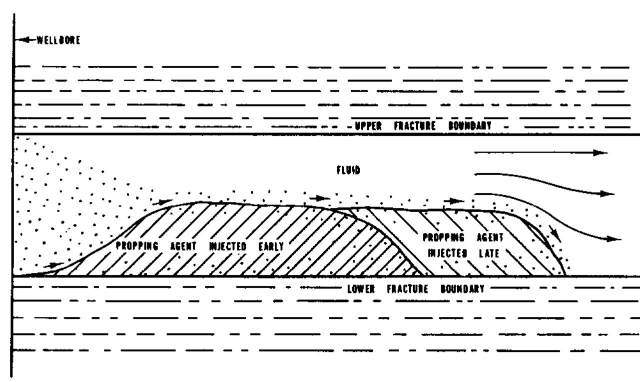

FIG. 2—PROPPING AGENT DISTRIBUTION IN VERTICAL FRACTURES WITH INCOMPLETE FRACTURE FILL-UP AT THE WELLBORE

Following a fracturing operation, fluid from the highly pressurized area adjacent to the wellbore will enter the mouth of the fracture and flow into the wellbore. This phenomenon tends to sweep proppant from the mouth of the fracture into the wellbore, thus intensifying the problem of nonuniform fracture conductivity at the mouth of the fracture.

The above hypothesis is very difficult to prove; however, the writer personally knows of one field case which substantiates the theory. Mobil's H& J Section 329 Well No. 6 located in the Robertson Field in Gaines County, Texas was fractured on August 4, 1962, using heated refined oil. The purpose for heating the refined oil was to locate the zones that had been fractured through the use of a temperature survey. Following the fracturing treatment, three runs were made with the temperature tool at approximately one-hour intervals. On each of these three runs, no problem was encountered in reaching the bottom of the well with the temperature tool. When the fourth run was made, it was discovered that the well had fill-up almost to the top of the perforations. Each of the four runs was made under static pressurized conditions. Sand-pumping operations later proved the fill-up to be frac sand of the identical type that was used in fracturing the well.

Figure 3 pictorially presents the effect that is desired through the use of controlled screen-out treatments, and a schematic view of the fracture situation under study in this paper is given in Fig. 4.

The importance of complete fracture fill-up was investigated by Raymond and Binder[2] through the use of a mathematical model of a vertically fractured well. Results of their investigation are presented graphically in Figs. 5 through 7.

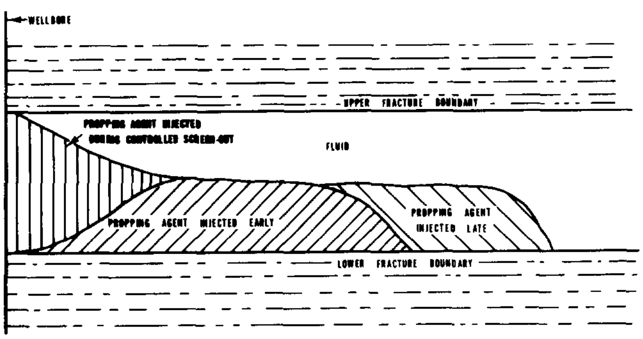

FIG. 3—PROPPING AGENT DISTRIBUTION IN VERTICAL FRACTURES FOLLOWING A CONTROLLED SCREEN-OUT TREATMENT

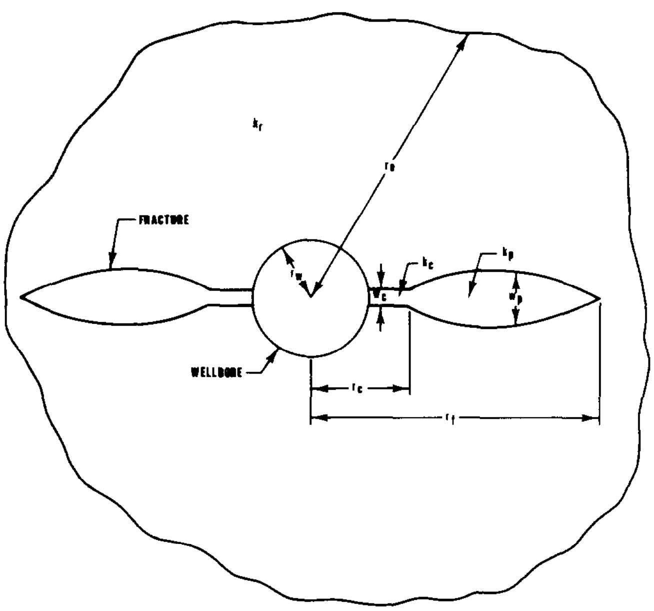

FIG. 4—SCHEMATIC OF A VERTICALLY FRACTURED WELL WITH FRACTURE CLOSURE AT THE WELLBORE

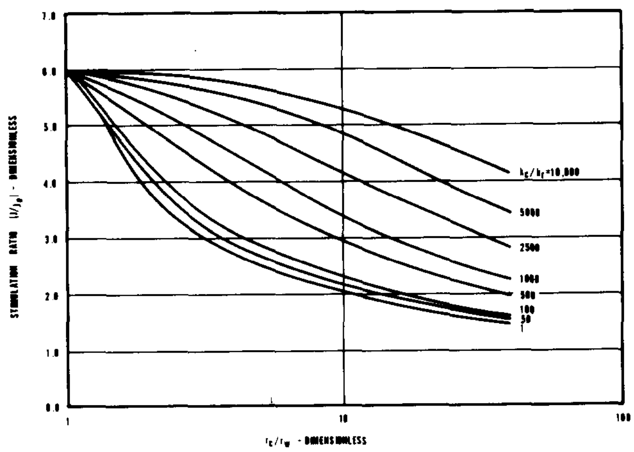

FIG. 5—EFFECT OF INCOMPLETE FRACTURE FILL-UP AT THE WELLBORE ON STIMULATION RATIO

Figure 5 presents values of stimulation ratio (J/J_o) for various values of the ratio of fracture closure radius to wellbore radius (r_c/r_w) with values of permeability contrast (k_c/k_r) as the variable parameter. In this figure, it is assumed that the portion of the fracture between the fracture closure radius (r_c) and the fracture radius (r_f) has infinite conductivity. In addition, the figure is based on the following parameters:

r_e = drainage radius = 660 ft

r_w = wellbore radius = 5.0 in.

r_f/r_e = fracture penetration = 30%

W_p = width of the propped portion of the fracture = 0.10 in.

At a value of r_c/r_w=1.0, all the curves in Fig. 5 converge to a stimulation ratio of approximately 6. This point represents the stimulation ratio for an infinitely conductive fracture that extends to 30% of the drainage radius and is 0.10 in. wide. The rapid decline in stimulation ratio as a function of r_c/r_w illustrates the necessity for filling the fracture near the wellbore.

Figure 6 illustrates the effect of percent fracture fill-up on stimulation ratio. This figure shows that if, at the mouth of the fracture, only a small fraction (1-2%) of the total fracture length is not filled with proppant, a large amount of the potential stimulation increase is lost.

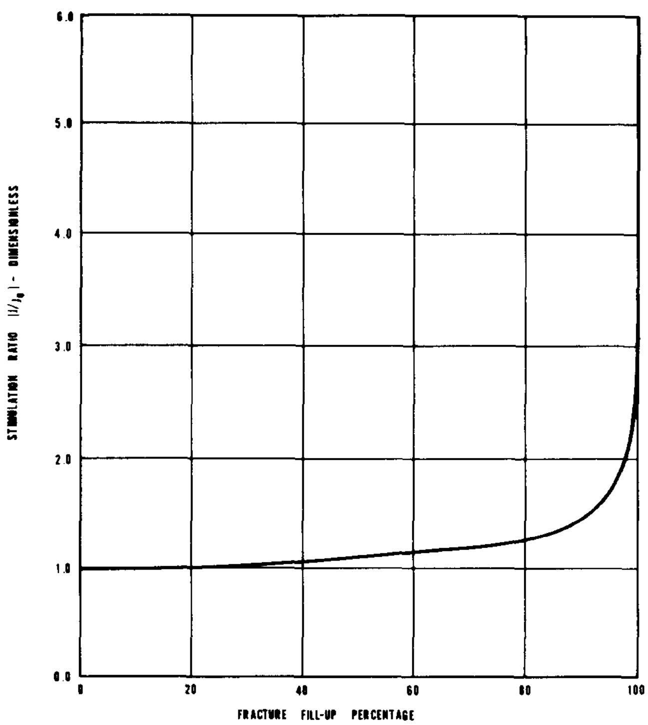

FIG. 6—STIMULATION RATIO AS A FUNCTION OF PERCENT OF FRACTURE FILL-UP

If a cross-section of a fracture with incomplete fill-up at the wellbore is taken through and parallel to the fracture, the permeability profile of the fracture will appear as illustrated in Fig. 7. To make a thorough analysis of this figure, assume that the permeability throughout the fracture can be represented by zones of constant permeability as shown by the dashed lines. If desired, the fracture could be divided into more than two zones; however, since this paper is concerned only with the incomplete filling phenomenon adjacent to the wellbore, it is necessary to consider only the two-zone model.

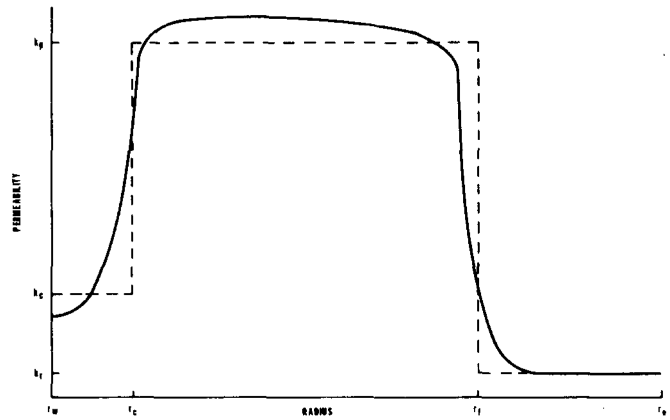

FIG. 7—PERMEABILITY PROFILE OF A FRACTURE WITH CLOSURE AT THE WELLBORE

Wood and Junkin[3] through the use of a mathematical model of a vertically fractured well showed that fracture closure near the wellbore greatly reduces the stimulation ratio achieved by a fracturing treatment. Graphic results of their investigation are presented in Fig. 8.

In Fig. 8, stimulation ratio (J/J_o) is plotted against fracture closure radius (r_c). Each curve in this figure is based on a different value of fracture conductivity (C_p) for the portion of the fracture between the fracture closure radius (r_c) and the fracture radius (r_f). In addition, the figure is based on the following parameters:

r_e = drainage radius = 660 ft

r_w = wellbore radius = 3.0 in.

C_c = conductivity of the closed portion of the fracture =

$$\frac{W_c \, k_c}{k_r} = 1.0 \text{ ft and } 10 \text{ ft}$$

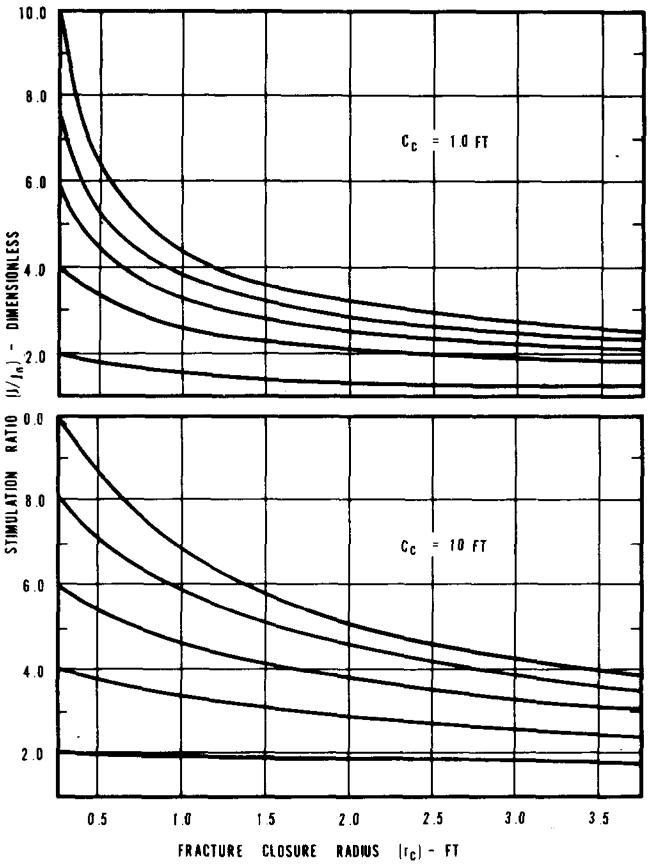

FIG. 8—STIMULATION LOSS FROM FRACTURE CLOSURE AT THE WELLBORE

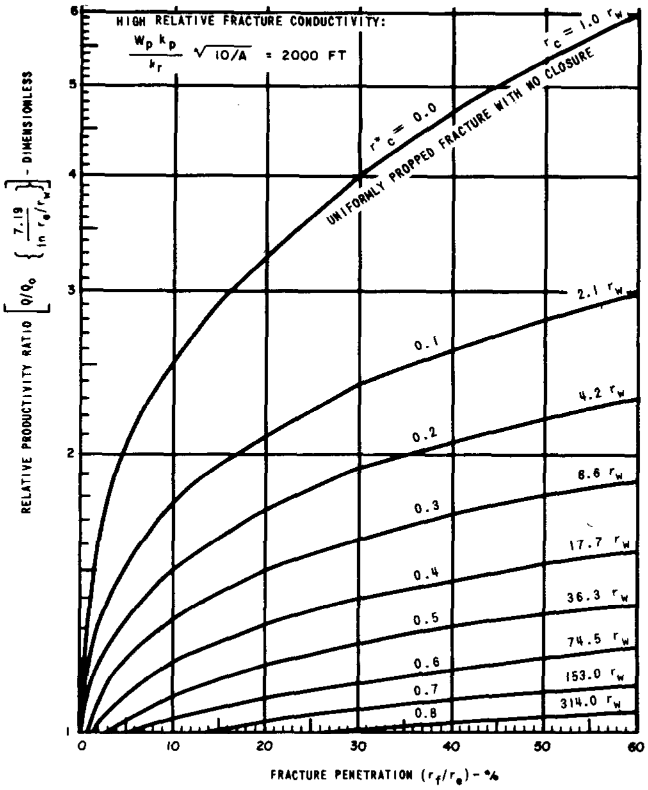

FIG. 9—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR HIGH RELATIVE FRACTURE CONDUCTIVITY OF 2000 FT

In Fig. 8, the value of J/J_o for r_c-r_w = 0 is the stimulation ratio that would be achieved if the fracture were completely propped. It is difficult to estimate a reasonable value for the conductivity of the closed part of the fracture. It may be no more conductive than the original reservoir rock; or if the fracture remains open slightly, it could be relatively conductive. For the values of C_c considered in the figure, about half the stimulation potential of a treatment is lost if approximately 2 ft of the fracture is closed at the wellbore.

Through the use of a mathematical model of a vertically fractured well, Uhri et al[4] examined a case of nonuniform fracture fill-up, viz., a vertical fracture with complete closure extending over its entire height and for some fraction of its length. Results of their investigation are presented graphically in Figs. 9 through 12. Each of the figures was prepared using a different value of relative fracture conductivity. High, medium, low, and very low relative fracture conductivity were used in preparation of the figures.

Figure 9 is based on high relative fracture conductivity. High relative fracture conductivity is obtained when low formation permeability and high fracture permeability are present. This is the condition that is normally encountered in fracturing operations; hence, this figure fits more fracturing situations than any of the other figures. Examination of the figure illustrates that, under certain conditions, fracture closure near the wellbore in the order of inches can decrease productivity to approximately half of the predicted value for a completely propped fracture. These results are in qualitative agreement with those of Raymond and Binder and Wood and Junkin.

Presented in Figs. 13 through 16 is a set of working curves which can be used to evaluate fracturing treatments from the standpoint of fracture closure at the wellbore. These figures are based on the work of Uhri et al[4]. Each figure was prepared for an 8-in. wellbore and a different value

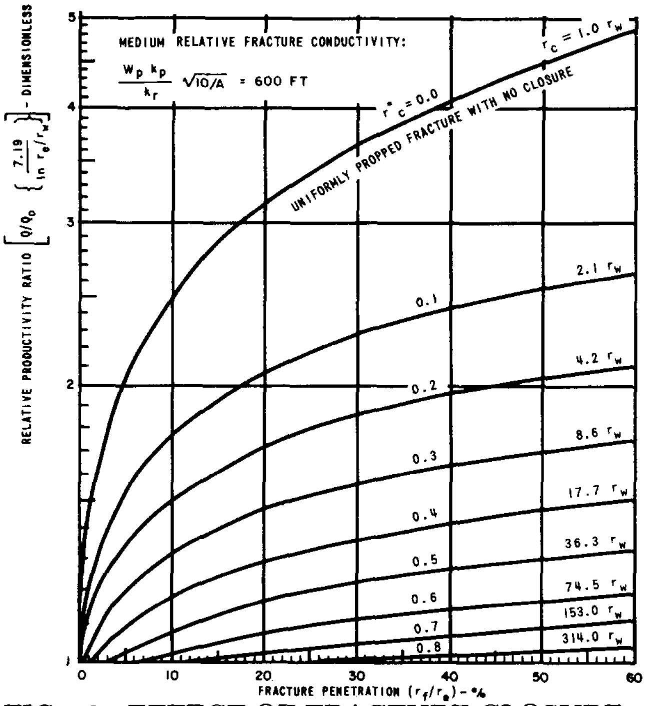

FIG. 10—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR MEDIUM RELATIVE FRACTURE CONDUCTIVITY OF 600 FT

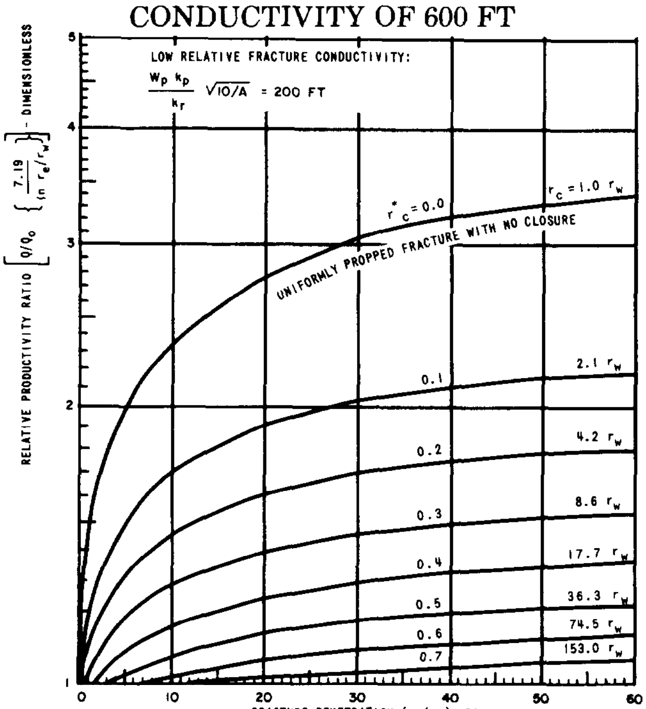

FIG. 11—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR LOW RELATIVE FRACTURE CONDUCTIVITY OF 200 FT

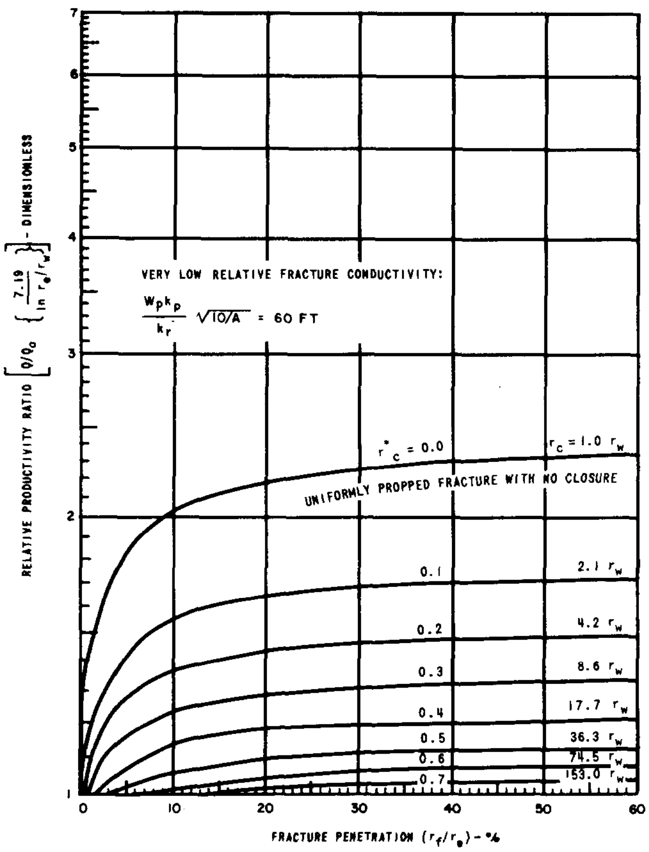

FIG. 12—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR VERY LOW RELATIVE FRACTURE CONDUCTIVITY OF 60 FT

of relative fracture conductivity. High, medium, low, and very low relative fracture conductivity was used in preparation of the figures. The design engineer should find these figures especially useful when evaluating subpar treatments. By knowing relative fracture conductivity, fracture penetration, and productivity ratio reduction, fracture closure radius can be estimated with a reasonable degree of accuracy from the figures.

Laboratory experiments[5] indicate controlled screen-outs can be obtained if the fracturing slurry is injected at a rate that will result in a velocity of approximately 0.5 ft/sec above the settled propping agent bed in a vertical fracture. Under normal conditions, an injection rate of less than 1 BPM will be required to obtain this velocity. Propping agent transport calculations [1,6,7,8] also indicate an injection rate of less than 1 BPM is necessary to obtain controlled screen-outs. In most

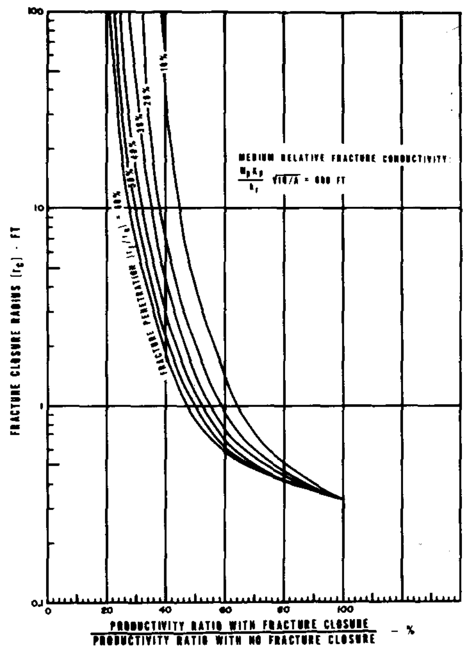

FIG. 13—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR AN EIGHT IN. WELLBORE AND HIGH RELATIVE FRACTURE CONDUCTIVITY OF 2000 FT

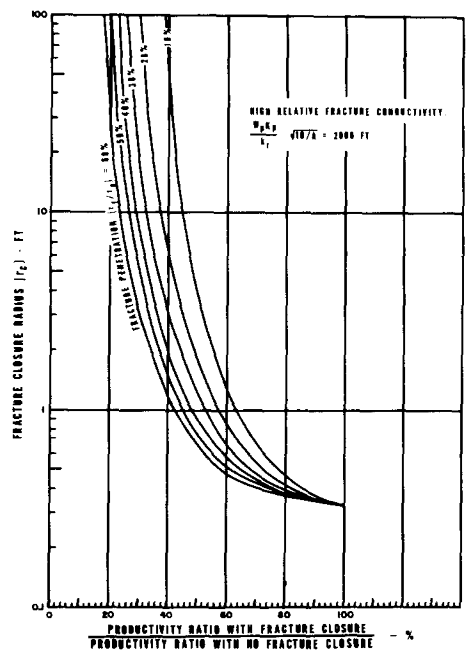

FIG. 14—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR AN EIGHT IN. WELLBORE AND MEDIUM RELATIVE FRACTURE CONDUCTIVITY OF 600 FT

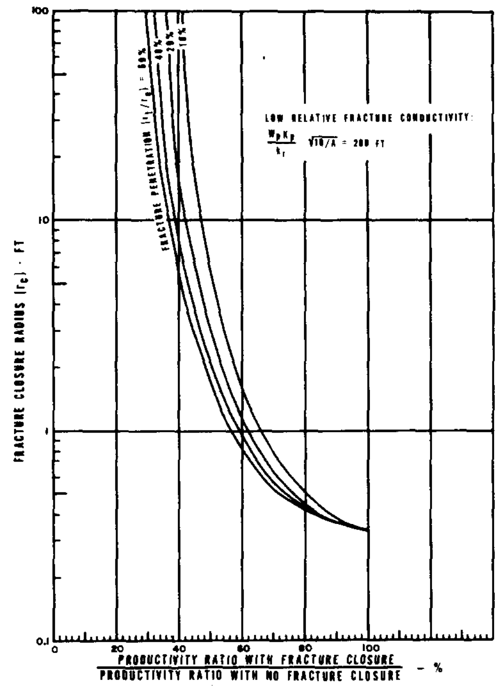

FIG. 15—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR AN EIGHT IN. WELLBORE AND LOW RELATIVE FRACTURE CONDUCTIVITY OF 200 FT

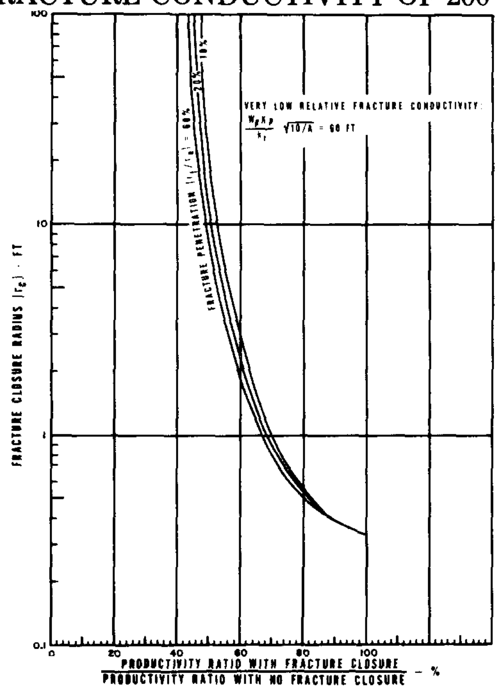

FIG. 16—EFFECT OF FRACTURE CLOSURE AT THE WELLBORE ON PREDICTED PRODUCTIVITY IMPROVEMENT FOR AN EIGHT IN. WELLBORE AND VERY LOW RELATIVE FRACTURE CONDUCTIVITY OF 60 FT

cases, an injection rate of less than 1 BPM is not sufficient to prevent propping agents from settling out in the wellbore. Usually, 1-3 BPM are required to move propping agents out of the wellbore into the fracture.

In view of the above discussion, it is obvious that a method of obtaining controlled screen-outs has to be devised that will satisfy the movement of propping agents in both the fracture and wellbore. The following discussion presents a logical means of securing controlled screen-outs.

Controlled screen-outs should be accomplished by simultaneously lowering the injection rate and increasing the propping agent concentration at the end of a treatment. Ideally, a controlled screen-out treatment will result in the fracture void space at the wellbore (Fig. 3) being filled with propping agent with very little or no propping agent left in the wellbore itself. Propping agent transport calculations can be made for any specific fracturing operation to determine the required rate and necessary propping agent quantity to accomplish the controlled screen-out; however, the following rules of thumb work with a surprising degree of accuracy:

1. The injection rate should be reduced gradually from the recommended treating rate to between 1 and 3 BPM, and the propping agent concentration should be increased from the recommended treating concentration to between 6 and 10 ppg.
2. The rate reduction and propping agent concentration increase should be done while injecting approximately the last 5% of the propping agent.

After a controlled screen-out has been obtained, the well should be shut-in immediately. No additional pressure should be applied to the well, and no additional fracturing fluid should be pumped through the propping agent pack. This procedure will eliminate the following two possibilities of failure:

1. Applying additional pressure to the well could cause the fracture to reopen and result in the propping agent at the mouth of fracture being transported back into the fracture.
2. Pumping additional fracturing fluid containing fracturing additives through the propping agent pack could result in filtering-out of the fracturing fluid additives in the propping agent pack at the mouth of the fracture. Deposition of these additives in the propping agent pack can result in as much as 50-60% reduction of the permeability of the propping agent pack.[9]

Initially on any type of fracturing treatment design, a decision has to be made as to whether selectivity agents are needed. The following information can be used as a guide to determine this.

Using standard treating rates of approximately 20 BPM for refined oil (18 to 22° API), 40 BPM for lease oil (30 to 40° API), and 50 BPM for gelled water (9 to 10 ppg), selectivity agents should be employed if the fracture length-to-height ratio is two or smaller. If the fracture length-to-height ratio is greater than two, selectivity agents are probably not required.

If pressure limitations, small tubular goods, etc. result in the standard fracture treating rates being reduced to approximately 10 BPM for refined oil, 20 BPM for lease oil, and 25 BPM for gelled water, selectivity agents should be used when the fracture length-to-height ratio is four or smaller. When the fracture length-to-height ratio is greater than four, selectivity agents are probably not required.

If super-thick fracturing fluids such as My-T-Frac, YFGO, etc. are used as fracturing fluids, injection rates of 8-15 BPM are usually required. When using super-thick fracturing fluids at these rates, selectivity agents should be employed if the fracture length-to-height ratio is one or smaller. If the fracture length-to-height ratio is greater than one, selectivity agents are probably not required.

When using selectivity agents in a controlled screen-out treatment, only the portion of the fracture that is open at the end of the treatment will be screened out. Keeping this in mind, each controlled screen-out treatment should be examined from a potential production increase viewpoint to determine if selectivity agents are warranted. That is, will fracturing only a part of the formation using no selectivity agents and screening out all of the fracture result in a higher potential production increase than fracturing all of the formation using selectivity agents and screening out only the portion of the fracture that is open at the end of the treatment?

It should be pointed out that more clean-out time will be required following a controlled screen-out treatment than is normally required following a

TABLE 1—ECONOMIC ANALYSIS OF ADDITIONAL CLEAN-OUT TIME RESULTING FROM CONTROLLED SCREEN-OUT TREATMENTS

Producing Rate Before Stimulation (BOPD)	Standard Productivity Ratio (Dimensionless)	Producing Rate After Stimulation (BOPD)	Controlled Screen-out Productivity Ratio (Dimensionless)	Producing Rate After Stimulation (BOPD)	Differential Producing Rate After Stimulation (BOPD)	Net Oil Value ($/Bbl)	Clean-out Time Increase (Hr)	Clean-out Time Cost ($/Hr)	Clean-out Time Cost ($)	Clean-out Time Payout (Days)
10	2.0	20	4.0	40	20	4.00	24	53	1272	16
20	2.0	40	4.0	80	40	4.00	24	53	1272	8
30	2.0	60	4.0	120	60	4.00	24	53	1272	5
40	2.0	80	4.0	160	80	4.00	24	53	1272	4
50	2.0	100	4.0	200	100	4.00	24	53	1272	3
75	2.0	150	4.0	300	150	4.00	24	53	1272	2
100	2.0	200	4.0	400	200	4.00	24	53	1272	2
200	2.0	400	4.0	800	400	4.00	24	53	1272	1

standard fracturing treatment; however, the potential production increase to be obtained from controlled screen-out treatments more than offsets the expense of the additional clean-out time. Normally, 24-36 hr clean-out time are required on most fracturing treatments. It is estimated that the application of the controlled screen-out technique will increase this clean-out time by 12-24 hr. Economic analysis of 24 hr of additional clean-out time is presented in Table 1. This table was prepared using average values of data obtained from previous fracturing treatments performed in Mobil's Midland Area.

In addition, if clean-out operations are not performed correctly, more pump pulling operations could result following a controlled screen-out treatment than is normally required following a standard fracturing treatment. This problem should be eliminated, however, through the use of proper clean-out procedures.

FIELD RESULTS

In June 1972, a controlled screen-out fracturing program was initiated in Mobil's Midland Area which is comprised of West Texas, New Mexico, Arizona, Southern Utah, and Southwest Colorado. Since the program's conception, 34 controlled screen-out treatments have been performed in 13 fields which included six different formations ranging in depth from 2500 to 7500 ft. No past treatments were available with fracture closure at the wellbore; however, numerous treatments were available where no overflush was used, and the propping agent was flushed just to the mouth of the fracture. For this reason, the no-overflush (non-screen-out) treatments were compared with the controlled screen-out treatments. Results of the comparison are presented in Table 2 and summarized below:

1. Controlled screen-out treatments resulted in the highest initial productivity ratio in six fields, non-screen-out treatments resulted in the highest initial productivity ratio in one field, and no comparison was possible in the remaining six fields.
2. Controlled screen-out treatments resulted in the highest stabilized productivity ratio in four fields, non-screen-out treatments resulted in the highest stabilized productivity ratio in two fields, and no comparison was possible in the remaining seven fields.
3. The average initial productivity ratios of the controlled screen-out and non-screen-out treatments were equal. The average stabilized productivity ratio of the controlled screen-out treatments was approximately 13% greater than that of the non-screen-out treatments.
4. The average clean-out time for the controlled screen-out treatments was approximately twice that for the non-screen-out treatments. This difference is really not as severe as indicated since the average clean-out time for the controlled screen-out and the non-screen-out treatments was 11 and 6 hours, respectively.

Refined oil, lease oil, and gelled salt water were used as fracturing fluids, and 20-40 mesh frac sand was used as the propping agent on both the controlled screen-out and the non-screen-out treatments. Fracturing fluid volumes ranged from 10,000 to 70,000 gal. on the controlled screen-out treatments and from 10,000 to 90,000 gal. on the non-screen-out treatments. Sand quantities ranged from 30,000 to 135,000 lb on the controlled

TABLE 2—CONTROLLED SCREEN-OUT AND NON SCREEN-OUT TREATMENT EVALUATION

	No. Of Treatments Analyzed	Initial Productivity Ratio (Dimensionless)	Stabilized Productivity Ratio (Dimensionless)	Clean-out Time (Hr/Well)
Dune (San Andres) Field Crane County, Texas San Andres Formation - 3400 Ft				
Controlled Screen-out Treatments	1	6.1	2.8	29
Non Screen-out Treatments	7	5.0	4.2	7
Eumont Queen Gas Field Lea County, New Mexico Queen Formation - 3400 Ft				
Controlled Screen-out Treatments	1*	None	None	9
Non Screen-out Treatments	0	-	-	-
Howard Glasscock (Glorieta) Field Howard County, Texas Glorieta Formation - 2800 Ft				
Controlled Screen-out Treatments	2	5.0	5.0	18
Non Screen-out Treatments	21	4.2	4.6	11
Howard Glasscock (San Andres) Field Howard County, Texas San Andres Formation - 2500 Ft				
Controlled Screen-out Treatments	1*	None	None	6
Non Screen-out Treatments	3	-	-	4
Paddock (Glorieta) Field Lea County, New Mexico Glorieta Formation - 5100 Ft				
Controlled Screen-out Treatments	9	5.9	5.9	5
Non Screen-out Treatments	8	5.5	1.5	3
Papoose Canyon (Desert Creek) Field Dolores County, Colorado Pennsylvanian Formation - 6200 Ft				
Controlled Screen-out Treatments	1	1.5	1.3	23
Non Screen-out Treatments	0	-	-	-
Pegasus (San Andres) Field Midland County, Texas San Andres Formation - 5600 Ft				
Controlled Screen-out Treatments	2	2.5	2.2	12
Non Screen-out Treatments	8	2.0	2.6	5
Russell (6000 Ft Glorieta) Field Gaines County, Texas Glorieta Formation - 6100 Ft				
Controlled Screen-out Treatments	4	2.0	1.7	12
Non Screen-out Treatments	2	1.0	1.7	0
Russell (7000 Ft Clearfork Sand) Field Gaines County, Texas Clearfork Formation - 7500 Ft				
Controlled Screen-out Treatments	6	4.3	4.3	22
Non Screen-out Treatments	12	1.6	1.6	5
Russell, South (San Andres) Field Gaines County, Texas San Andres Formation - 4800 Ft				
Controlled Screen-out Treatments	1	2.9	2.9	12
Non Screen-out Treatments	4*	None	None	0
Tubb Gas Field Lea County, New Mexico Tubb Formation - 6000 Ft				
Controlled Screen-out Treatments	1*	None	None	3
Non Screen-out Treatments	0	-	-	-
Wasson (San Andres) Field Yoakum County, Texas San Andres Formation - 5000 Ft				
Controlled Screen-out Treatments	4	2.7	2.4	8
Non Screen-out Treatments	0	-	-	-
West (San Andres) Field Yoakum County, Texas San Andres Formation - 5200 Ft				
Controlled Screen-out Treatments	1	2.4	2.1	1
Non Screen-out Treatments	4	4.9	1.8	0
All Fields				
Controlled Screen-out Treatments	34	3.1	2.7	11
Non Screen-out Treatments	69	3.1	2.4	6

* - New Completions. No Prior Production Data.

NOTE: On The Non Screen-out Treatments Analyzed In This Table, No Overflush Was Used And the Propping Agent Was Flushed Just To The Mouth Of The Fracture.

screen-out treatments and from 30,000 to 130,000 lb on the non-screen-out treatments. Sand concentrations ranged from 1-3 ppg on the controlled screen-out treatments prior to performing screen-out operations and from 1-3 ppg on the non-screen-out treatments.

Gelling agents were used at a concentration of 20 lb/1000 gal., fluid-loss additives were used at a concentration ranging from 15 to 25 lb/1000 gal. and nonemulsifying agents were used at a concentration of 2 gal./1000 gal. on both the controlled screen-out and non-screen-out treatments.

Rubber-covered nylon ball sealers, benzoic acid flakes, and graded rock salt were used as selectivity agents on both the controlled screen-out and non-screen-out treatments. Because of the difference in the footage treated in various wells, the quantity of selectivity agents that was used varied widely. In general, however, 80-90% perforation coverage was obtained when ball sealers were employed; and when granular blocking agents were utilized, concentrations of 1.75 to 2.50 lb/ft of hole height per in. of hole diameter were used.

Injection rates varied from 17-54 BPM on the controlled screen-out treatments prior to performing screen-out operations and from 10-60 BPM on the non-screen-out treatments.

The controlled screen-outs were obtained by simultaneously reducing the injection rate and increasing the propping agent concentration while pumping approximately the last 5% of the propping agent. The injection rate was reduced gradually from the recommended treating rate to between 1 and 3 BPM, and the propping agent concentration was increased gradually from the recommended treating concentration to between 6 and 10 ppg. Following a controlled screen-out operation, the well was shut-in immediately. No additional pressure was applied to the well, and no additional fracturing fluid was pumped through the propping agent pack.

A complete screen-out was not obtained on any of the controlled screen-out treatments. In fact, on several treatments, the last 20 to 30 minutes of pumping operations were conducted at 1 BPM while injecting 8-10 ppg sand. In addition, very little sand fill-up was found in these wells.

Selectivity agents were used on all but one of the controlled screen-out treatments. This well's performance was about the same as that of the other wells; therefore, no definite conclusions concerning the use of selectivity agents in controlled screen-out treatments can be made.

CONCLUSIONS

Conclusions reached in this paper are as follows:

1. Depending on several fracturing treatment variables, but primarily on the length of the zone of closure at the mouth of the fracture, theoretical evidence indicates that wellbore fracture closure can result in a reduction in productivity ratio of approximately 30-70% with an average of about 50%.
2. In the fracturing treatments evaluated, the con-

trolled screen-out treatments were better than the non-screen-out treatments; however, the degree of superiority was not great.

3. The average clean-out time of the controlled screen-out treatments was approximately twice that of the non-screen-out treatments; however, the difference was only 5 hrs.
4. The relative closeness of the results obtained from the controlled screen-out and non-screen-out treatments is believed to be due to Mobil's past practice of not overflushing fracturing treatments, thereby, flushing the propping agent just to the mouth of the fracture. Results would probably have varied much more had the non-screen-out treatments been overflushed.
5. If conditions exist that prevent a controlled screen-out from being obtained, the well should be overflushed with no more fluid than is necessary to clear the surface lines and fracturing equipment. Usually, 15-25 bbl will be adequate; however, service company personnel can furnish the exact volume required for any particular fracturing operation. All flush and overflush fluid should be pumped at a rate no greater than the fracture treatment rate. Adherence to these procedures will lessen the possibility of washing any propping agent off the top of the propping agent pack.
6. Results presented emphasize the importance of complete fracture fill-up near the wellbore. Money spent in increasing fracture conductivity will be wasted unless good fracture-to-well communication is achieved. Techniques to insure that the fracture is filled at the wellbore should be applied in all fracturing treatments except where prohibited by unusual conditions (weak pipe, fracturing under a packer, etc.).

NOMENCLATURE

A = well spacing, acres

C_c = $\frac{W_c k_c}{k_r}$ = conductivity of the closed portion of the fracture, ft

C = $\frac{W_p k_p}{k_r}$ = conductivity of the propped portion of the fracture, ft

J = productivity index after fracturing, B/D/psi

J_o = productivity index before fracturing, B/D/psi

J/J_o = stimulation ratio, dimensionless

k_c = permeability of the closed portion of the fracture, md

k_p = permeability of the propped portion of the fracture, md

k_r = permeability of the reservoir, md

Q = producing rate after fracturing under the same drawdown as for Q_o, B/D

Q_o = producing rate before fracturing, B/D

Q/Q_o $\left(\frac{7.19}{\ln r_e/r_w}\right)$ = relative productivity ratio, dimensionless

r_c = fracture closure radius, ft

$r_c{}^*$ = $\ln(r_c/r_w)/\ln(r_e/r_w)$ = dimensionless fracture closure

r_e = drainage radius, ft

r_w = wellbore radius, ft

W_c = width of the closed portion of the fracture, ft

W_p = width of the propped portion of fracture, ft

$W_c K_c$ = conductivity of the closed portion of the fracture, md-ft

$W_p k_p$ = conductivity of the propped portion of the fracture, md-ft

$\frac{W_p k_p}{k_r}\sqrt{10/A}$ = relative conductivity of the propped portion of the fracture, ft

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