A NEW APPROACH TO SCALE INHIBITOR APPLICATION DURING STIMULATION TREATMENT USING CROSSLINKED GELS

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ABSTRACT

The present energy situation has required the oil industry to evaluate all feasible methods to sustain and increase production in order to keep pace with our energy needs. Lost production due to scale deposition has been a major problem in the oil industry and has plugged many a good well while reducing production in most others.

Many different scale inhibition techniques exist today and all have varying degrees of success. It is well known that the most effective and least expensive way to protect against scale deposition is during the initial completion of the well before the problem occurs.

Most well completions today include hydraulic fracturing operation using an aqueous crosslinked fluid. These fluids, however, do not lend themselves to the use of scale inhibitors due to compatibility problems. This paper discusses the incompatibility of crosslinked gels with scale inhibitors along with experimental results. This paper attempts to solve the incompatibility problem by proposing three models to run scale inhibitors in conjunction with aqueous crosslinked stimulation fluids. The three models proposed are based on computer studies using a "partial pad" approach. All models have been described in detail and the results of the study have been graphically illustrated.

The paper also briefly discusses the different types of oilfield scales, their formation, deposition and mechanism of inhibition.

PURPOSE OF STUDY

To alleviate the scale deposition problem it is necessary to place a scale inhibitor around the wellbore and deep within the formation or fracture system as scales have been known to deposit in fractures some distance from the wellbore. It is generally agreed that the best prevention program is to squeeze an appropriate scale inhibitor in predetermined quantities during the stimulation treatment. However, recent developments in crosslinked stimulation gels precludes the use of scale inhibitors due to compatibility problems.

The study was conducted to overcome this problem and present a systematic and logical solution to optimize scale inhibitor response. The method presented allows an operator to use the most recently developed crosslinked gels in conjunction with scale inhibitors.

INTRODUCTION

Productivity impairment in producing oil and gas wells due to deposition of scaling material is an increasingly severe problem. Scale deposition occurs within the pores of the formation, at the faces of fractures in fractured reservoirs, around the wellbore, at the perforations and in the production equipment. This leads to severe losses in crude production and to expensive remedial treatments for formation and equipment cleanup and restoration of well productivity.

The direct cause of scaling is due to any one or a combination of factors like, pressure drop, temperature change, mixing of incompatible waters.

The composition of scales is as variable as the composition of waters that produce them.[1] The most commonly occuring scale deposits are calcium carbonate ($CaCO_3$), gypsum ($CaSO_4 \cdot 2H_2O$), or calcium sulfate ($CaSO_4$), barium sulfate ($BaSO_4$). Less common deposits are strontium sulfate ($SrSO_4$) and barium strontium sulfate ($BaSr(SO_4)_2$). Various corrosion products such as iron carbonate ($FeCO_3$), iron oxides (FE_2O_3) and (Fe_2O_4) and iron sulfide (FeS) occur due to CO_2, O_2 and H_2S dissolved in water. Usually scale deposits will be a complex mixture of one or more of the major inorganic components plus varying amounts of corrosion products, oil, silicates or sand, asphaltenes and paraffins. However, depending on the major component, a deposit could be classified as an acid soluble or an acid insoluble scale. Figures 1 through 6 are scanning electron micrographs of typical scale deposits showing various crystalline structures.

Depending on the speed with which a scale is deposited, it can be porous and easy to remove or dense and hard to remove. Scale that is deposited very rapidly is fluffy and porous, possibly due to gas channeling and is easy to remove chemically and mechanically. Scale that is deposited slowly may be very hard and dense and extremely difficult to remove.[2]

Scale depositions cause tremendous profit losses each year in the U.S. The profit losses are due to reduced hydrocarbon production and the expensive workover and remedial treatment programs that have to be initiated each year to overcome the scale buildup. Most of these remedial programs consist of costly acidizing and fracturing treatments, conversion of acid insoluble scales to acid soluble products, mechanically drilling out of scale and pulling jobs. Most of the time the remedial programs fail to bring production back to original levels. It is estimated that the majority of the million or so oil, gas and service wells in the U.S. have appreciably reduced productivity or injectivity due to scale buildup.

MECHANISM OF SCALE FORMATION

Scale deposition occurs mainly due to shifting of equilibrium during production of reservoir fluids. Due to sudden changes in environment, pressure drop occurs within the fracture system and in the vicinity of the wellbore allowing dissolved gases to escape from aqueous solution. This destroys equilibrium and salts in solution deposit until a new equilibrium is established. For instance, loss of minute amounts of CO_2 can cause $CaCO_3$ scale to deposit.

$$Ca(HCO_3)_2 \rightleftharpoons CaCO_3 + H_2O + CO_2\uparrow$$

It has also been shown that with pressure drop, the vapor pressure of formation brine increases causing the brine to vaporize. This is an endothermic process and results in an overall reduction in temperature and precipitation of calcium sulfate.[3]

Another factor that causes scale deposition is the concentration of uncommon ions such as chlorides. The evaporation of gases and vaporization of formation water decreases the total solution volume. This increases the overall ions and uncommon ions concentration. High uncommon ion (Cl^-) concentration can cause precipitation of salts like $CaSO_4$.[5]

Scale deposition also occurs due to mingling of incompatible waters. Waters mix because of crossflow from different zones within the wellbore or injection waters may mix with formation waters. The mixtures deposit scale if one water contains high calcium or barium ions and the other contains high sulfate or carbonate ions. Scale caused by incompatibility of waters is deposited on rods, tubing and flow lines.

Scale does not precipitate spontaneously but rather forms in three distinct stages. First stage, calcium ions combine with carbonate or sulfate ions in solution to form a molecule. Second, these molecules form a nuclei that act as growth sites. Third, clusters grow and develop at these sites to form a large crystal. When these crystals become too large to remain in solution, they precipitate as scale.

Depending on the method and time of deposition, some scales are soft, porous and fluffy and others are dense and hard. Crystals that grow slowly contain fewer imperfections in their lattice structure and are more compact.

Inorganic scales are deposited as thin fluffy scale or as laminated deposits or as highly crystalline deposits. Highly crystalline scale such as barite ($BaSO_4$) is so dense that it cannot be removed with a chemical.

System pressure has tremendous effect on solubility of $CaSO_4$. The size of $CaSO_4$ molecule decreases with pressure, thus allowing more of it to go in solution. $CaSO_4$ therefore precipitates from a solution when a pressure drop is encountered. A pressure change of 1500 psi will change $CaSO_4$ solubility by 20%.

SCALE FORMATION WITHIN A FRACTURE WING

The pressure changes within a created fracture wing are presented in Figure 7. The pressure changes can be represented by the following equation:[3]

Flowing Pressure = Reservoir Pressure - P_1 - P_2 - P_3 where:
P_1 = Pressure drop from the formature to the fracture
P_2 = Pressure drop within the sandpack
P_3 = Pressure drop across the skin (and the perforations)

To provide adequate protection against scale formation and deposition, it is necessary that these three pressure drops be considered. It is not enough, as is done in most cases, to consider P_3 alone and provide scale protection in and around the vicinity of the wellbore. Most inhibitor applications are small squeeze treatments which leave a majority of the fracture wing unprotected. It is our opinion that if the operator performs an expensive fracture treatment capable of developing fractures penetrating 600 ft. or more, then he should provide protection to keep these channels open by addition of scale inhibitor to combat scale deposition due to P_1 and P_2. This long term protection can be achieved by a technique that is outlined later.

Some operators add liquid scale inhibitor in the last part (20% or so) of the stimulation treatment, hoping that this will provide protection around the wellbore. However, during the later stages of the treatment the zone around the wellbore is saturated and the scale inhibitor does not leakoff but remains in the fracture and a major portion of it flows back when the well is opened.

SELECTION OF SCALE INHIBITOR

Scale inhibitors can be classified as liquid and solid scale inhibitors. Solid scale inhibitors were quite popular at one time, but have now almost completely been replaced by liquid inhibitors for several reasons. The solid scale inhibitors are composed of polymetaphosphate glass and are difficult to handle and place within the formation. Liquid scale inhibitors are composed of organic phosphates (phosphonates), phosphate esters and polyacrylate polymer. Liquid inhibitors are quite flexible and easier to handle. The types and effectiveness of liquid scale inhibitors are presented in Table 1.

Solid scale inhibitors are subject to chemical reversion.[2,4] Improper placement of a solid polyphosphate or a change in the amount of fluids produced during the treatment could result in overtreatment. Overtreatment may cause the polyphosphate to revert to an orthophosphate which forms a scale deposit harder to remove than any sulfate or carbonate. Liquid scale inhibitors do not exhibit any tendency towards reversion.

SCALE INHIBITOR ACTION

The most commonly used methods of preventing scale deposition are sequestering the metal cation or by crystal growth modification. Sequestering prevents formation of molecules by tying up the metal cations. Crystal growth modifiers allow nucleation of the initial submicroscopic formation of scale crystals or seeds but prevent their growth into scale deposits.[1,2] All the presently used scale inhibitors are growth modifier type or growth "poisons".

The mechanism of growth modifiers proceeds probably as follows: As small particles of scale begin to form, the inhibitors form a thin film on each submicroscopic particle, preventing further growth and adherence. The clustering of small crystals into larger particles is thus prevented. The adherence of these small particles to down-hole equipment and the formation fracture faces is also prevented. For this mechanism to function it is necessary to have a certain minimum inhibitor concentration present in produced water at all times.

LIQUID SCALE INHIBITOR ADSORPTION/DESORPTION PROPERTIES

The major problem in using liquid inhibitos is accomplishing a long lasting treatment. To develop a lasting treatment the inhibitors have been modified to have surface active properties that adsorb on the rock matrix. The inhibitor then functions by desorbing at a very slow rate while mixing with the produced water. The use of scale inhibitor has to be justified by having an effective concentration present in produced water for at least 6 months to a year. Adequate protection for the producing zone can be provided by having a residual phosphate concentration of 5 to 20 ppm. Effectiveness of phosphate ester is presented in Table II. An effective scale inhibitor must be rapidly adsorped in substantial quantities on the rock matrix, slowly desorbed in appropriate quantities and have good scale inhibition properties.

The typical adsorption isotherm for liquid (phosphate ester) on a sand is presented in Figure 8. The isotherm rises very rapidly at low concentrations and then levels off, which indicates that the inhibitor is adsorbed rapidly and will desorb slowly. It shows for instance that at an equilibrium concentration of only 0.08 gal/1000 gal the inhibitor solution is in balance with a rock surface that has adsorbed 0.025 gal/1000 lbs of sand. This is more than half the amount that is required for saturation and long continued desorption can be expected.

Figure 9 (solid line) presents desorption data for a phosphate ester on a sand core. The desorption effluent concentration is initially very high, around 5000 mg/liter and then decreases to 50 mg/liter after a flow of about 100 pore volumes. The concentration continues to drop at a low rate for several pore volumes. It is predicted that by changing the technique of inhibitor application, the desorption curve in Figure 9 can be altered to look like the dotted curve. The dotted curve shows a higher residual concentration for several pore volumes.

It should be noted that there is a certain minimum concentration beyond which the residual concentration will not fall. This limiting concentration is defined by the principle of chemical adsorption (irreversible), and the application program should be designed so that the amount of inhibitor adsorbed is always higher than this number. Subsequent applications can be designed with lower inhibitor concentrations. Once the chemical adsorption is satisfied only the amount of chemical required for physical adsorption (reversible) for this volume of rock need be injected.

CALCULATING SCALE INHIBITOR QUANTITY

There is no cut and dry formula for estimating the exact amount of scale inhibitor to be squeezed in a given zone. Rather, it is a combination of field experience and logical reasoning. It is known that the quantity of scale inhibitor (Q) gals. required for protection is directly proportional to:

(1) Amount of water produced per day (Qw),
(2) Desired protection duration (P) in days,
(3) Adsorptive capacity of pore space (C) in gal/bbl,

and is inversely proportional to:

(1) Pore volume of produced water throughput required to reach ±15 ppm of inhibitor concentration in the produced water (V).

$$Q = \frac{(Qw) \cdot (P) \cdot (C)}{V}$$

From Figure 9 it can be seen that V is usually around 200 to 300 pore volumes. C is 1.3 to 1.5 for clean sands.

The solid scale inhibitor quantity to be placed within the fracture is proportional to BHT, mineral content of produced water and rate of production of formation water. The average treatments in West Texas area consist of 300 to 1200 lbs. of phosphate.

SCALE INHIBITOR APPLICATION

Liquid scale inhibitors are generally applied via chemical squeeze treatments, or in conjunction with a stimulation treatment. It is generally agreed that the best and least expensive application is during the initial stimulation treatment as it does not involve any additional equipment or labor.

Liquid scale inhibitors can be pumped in conjunction with acids and gels both aqueous and hydrocarbon based. It is necessary to check compatibility of these inhibitors with other additives of the stimulation fluids. When run in conjunction with acids the concentration should range from 1 to 5 gal/1000 gal as higher concentrations cause compatibility problems. When run in aqueous (non-crosslinked) and oil based gels, they can be run from 1 to 25 gal/1000 gal depending on the amount required. However, the scale inhibitors cannot be used in conjunction with crosslinked aqueous fracturing gels because of compatibility problems. Since most of the wells fractured today employ crosslinked fluids, it has become necessary to devise a technique to run scale inhibitors mixed with these gels.

Basically there are two ways in which a scale inhibitor will prevent crosslinking. One way is to tie up the metal crosslinker while the other is to block or cover up the reactive sites on the polymer chain where crosslinking would have taken place. All the commonly used scale inhibitors are known to be strong "chelators" and the predominant way in which they affect the complex gel systems is by chelating the metal crosslinker. The inorganic scale inhibitors (solids) do not affect the crosslinking as dramatically as the liquid (organic) scale inhibitors because of their solubility characteristics. Table III presents the effect of a solid inhibitor on a 30 lb/1000 gal. crosslinked system. Up to a loading of 40 lb phosphate/1000 gal of gel there is no substantial affect on crosslinking for a period of 15 minutes. These materials dissolve slowly and therfore do not readily produce chelating action as do the organic liquids. However, the higher the loading of inorganic material, the greater the effect on crosslinking. Although apparently minor in effect, all of the inhibitors will also react with crosslinking sites on the polymer and cause a weaker (less stable) crosslink than normal.

Figure 10 presents the effect of organic polyphosphate on aqueous crosslinked gel systems. It can be seen that at low inhibitor concentrations shown, the system crosslinked with borate ions has no effect whatsoever. However, the systems complexed with metal ions (as most systems today utilize) are very sensitive to inhibitor concentrations. At concentrations above 0.2 gal inhibitor per 1000 gal of gel, the crosslinking mechanism fails and the gel has a residual viscosity close to that of the base gel of 25 centipoise. When running a liquid scale inhibitor in a metal complexed gel, the inhibitor concentration should be below 0.18 gal/1000 gal of gel.

SCALE INHIBITOR APPLICATION IN CONJUNCTION WITH CROSSLINKED FLUIDS

In designing an inhibitor application program it is essential to define the "partial pad" stimulation approach. In partial pad analysis a pad volume is pumped ahead of the fracturing gel such that it (the pad volume) is completely dissipated or leaked off when the fracturing fluid reaches the desired penetration. This means that when the proppant laden frac fluid reaches the very tip of the fracture generated, the pad is completely leaked off. This concept is used in determining the quantity of fluid that will act as a carrier fluid for the liquid scale inhibitor. The stimulation program should be designed such that the pad fluid carries with it the predetermined amount of scale inhibitor. Since the pad leaks off from the wellbore to the tip, the scale inhibitor will adsorb on the rock surface from the wellbore to the tip of the fracture. It is essential to run large quantities of inhibitor to take into account both the chemical and physical adsorption. Table IV presents the depth of invasion of pad fluid as simulated by a computer model. The reservoir data for this model is presented in Table V.

Since the pad fluid does not carry any proppant it is not necessary to have it crosslinked. A convenient pad fluid design will consist of the frac fluid without the addition of the crosslinker. During the actual performance of the stimulation treatment the crosslinker injector pump is shut down during the pumping of the pad fluid. The pad fluid will have a lower viscosity and consequently a higher leakoff coefficient. This is a desirable property since the pad will dissipate faster providing more adsorption of the inhibitor on the rock. It should be noted that the "spurt loss" factor of the frac fluid (leakoff at time = 0) will cause an excessive leakoff around the vicinity of the wellbore providing additional protection. The pad fluid properties have been presented in Table VI.

The scale inhibitor should be placed predominantly at the portion of the reservoir that is the source of water production. If it can be determined from the logs that water production will occur from below the pay zone, as is the case in most instances, then the pad fluid should be made with a heavier (9.5 lb/gal) clean brine. This would cause the denser pad fluid to predominantly stay in the lower part of the fracture and the lighter frac fluid to "override" the pad; thus providing more protection at the source of water production.

The pad and the frac volumes are determined based on a computer study; the results of the study are presented in Figures 11 through 13. These figures provide the quantity of pad and frac fluid that should be pumped for a desired penetration.

Solid scale inhibitors may be pumped in the frac fluid in conjunction with the proppant as long as the concentration is below the limit shown in Table III. We recommend that solid inhibitor concentration should be maintained below 40 lb/1000 gal. of gel.

Before beginning the treatment the reservoir fracturing pressure should be calculated. During the initial perforation breakdown with acid, the injection rates should be maintained below fracture pressure (to achieve "matrix" acidizing) so as to distribute fluid radially in the vicinity of the wellbore. Diversion to treat every perforation is provided by using ball sealers. Treating the acid and the displacement fluid with inhibitor will ensure inhibitor adsorption radially around the wellbore.

We have presented three models which will provide long term sustained protection against scale deposition. Each model has its own advantages and disadvantages and the operator should select the one that will best suit his needs.

MODEL I

Figure 14 presents schematically the scale inhibitor placement at the conclusion of the stimulation treatment performed using Model I. The following procedure should be followed:

STEP 1
Acidize the perforations with acid treated with 2 to 5 gal. inhibitor per 1000 gal at low injection rates (below frac pressures) and divert acid using ball sealers.

STEP 2
Overflush with 20 to 40 bbl. treated 2% KCl water containing 1/2 to 1 drum of scale inhibitor.

STEP 3
Leave well shut-in overnight.

STEP 4
Determine based on computer studies the quantity of pad and frac fluid required to achieve the desired penetration.

STEP 5
Rig-up to fracture stimulate and pump as follows:
a. Pump calculated amount of pad fluid (made with 2% KCl water or 9.5 lb/gal NaCl brine if lower portion of the pay needs preferential treatment) with 2 drums of scale inhibitor
b. Pump crosslinked frac fluid with proppant
c. Run diverting material (ball sealers or benzoic acid flakes) if the pay consists of more than one zone
d. Repeat steps "a" and "b" to treat all the remaining zones

STEP 6
Shut-in overnight or at least 3 hours if CO_2 or N_2 is used with the frac fluid.

MODEL II

Figure 15 presents schematically the placement of the inhibitor at the conclusion of the stimulation treatment performed using Model II. The following procedure should be followed:

STEP 1
Acidize the perforations with acid treated with 2 to 5 gal inhibitor per 1000 gal at low injection rates (below frac pressures) and divert acid using ball sealers.

STEP 2
Overflush with 20 to 40 bbl. treated 2% KCl water containing 1/2 to 1 drum of scale inhibitor.

STEP 3
Leave well shut-in overnight.

STEP 4
Determine based on computer studies the quantity of pad and frac fluid required to achieve the desired penetration.

STEP 5
Rig-up to fracture stimulate and pump as follows:
a. Pump calculated amount of pad fluid (made with 2% KCl water or 9.5 lb/gal. NaCl brine) with 2 drums of liquid scale inhibitor
b. Pump crosslinked frac fluid with proppant and in the last 4000 gal. run 40 lb/1000 gal of solid scale inhibitor. The solid scale inhibitor will be placed around the wellbore in the sandpack.
c. Run diverting material if the pay consists of more than one zone.
d. Repeat steps "a" and "b" to treat all the remaining zones.

STEP 6
Shut-in overnight or at least 3 hours if CO_2 or N_2 is used with the frac fluid.

MODEL III

Model III is proposed for MHF (Massive Hydraulic Fractures) treatments. It is conceivable that large quantities of brines pumped could cause scale deposition due to interaction with the formation water. The following procedure should be followed:

STEP 1
Acidize the perforations with acid treated with 2 to 5 gal. inhibitor per 1000 gal. at low injection rates (below frac pressures) and divert acid using ball sealers.

STEP 2
Overflush with 20 to 40 bbl. treated 2% KCl water containing 1/2 to 1 drum of scale inhibitor.

STEP 3
Leave well shut-in overnight.

STEP 4

Determine based on computer studies the quantity of pad and frac fluid required to achieve the desired penetration.

STEP 5

Rig-up to fracture stimulate and pump as follows:

a. Pump calculated amount of pad fluid (made with 2% KCl water or 9.5 lb/gal. NaCl brine) with 2 drums of liquid scale inhibitor
b. Pump frac fluid with proppant and in the last 4000 gal. run 40 lb. per 1000 gal. of solid scale inhibitor. Treat all frac fluid with 0.18 to 0.20 gal/1000 gal.* liquid scale inhibitor all through the frac fluid. This should stabilize the frac fluid.
c. Run diverting material if the pay consists of more than one zone.
d. Repeat steps "a" and "b" to treat all the remaining zones.

STEP 6

Shut-in overnight or at least 3 hours if CO_2 or N_2 is pumped with the frac fluid.

*Determine if the liquid scale inhibitor concentration is compatible with the gel.

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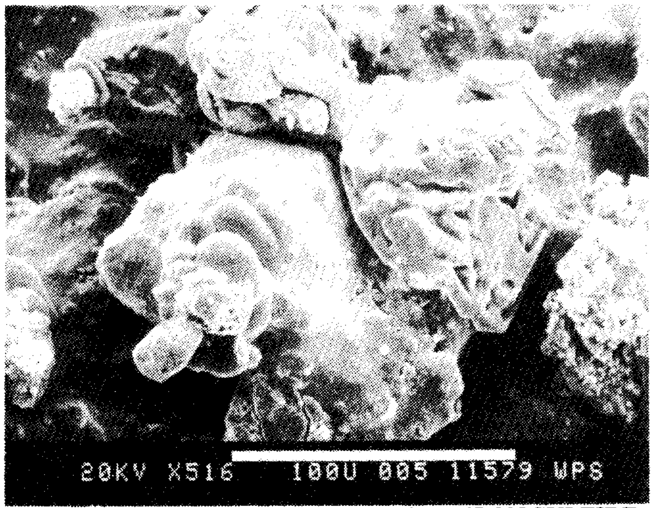

FIGURE 1—VIEW OF SIDERITE ($FeCO_3$)/IRON SULFIDE SCALE. THE GLOBULAR CONCRETIONS LEFT OF CENTER ARE BELIEVED TO BE SIDERITE. THE CRYSTALS AT UPPER RIGHT WITH HEXAGONAL EDGES ARE PYRRHOTITE (AN IRON SULFIDE).

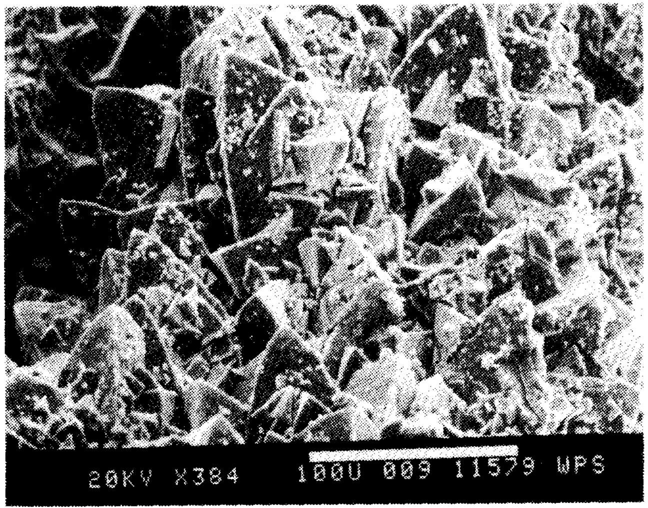

FIGURE 2—VIEW OF CRYSTAL STRUCTURE IN A CALCITE SCALE.

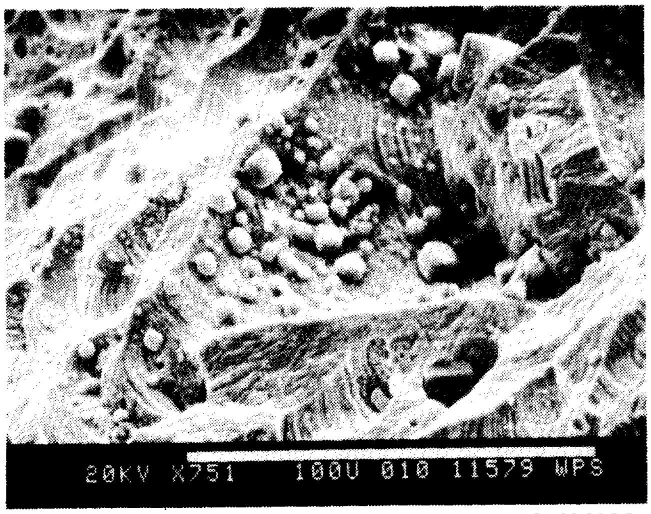

FIGURE 3—IRON SULFIDE SCALE SHOWING SMALL CUBIC CRYSTALS.

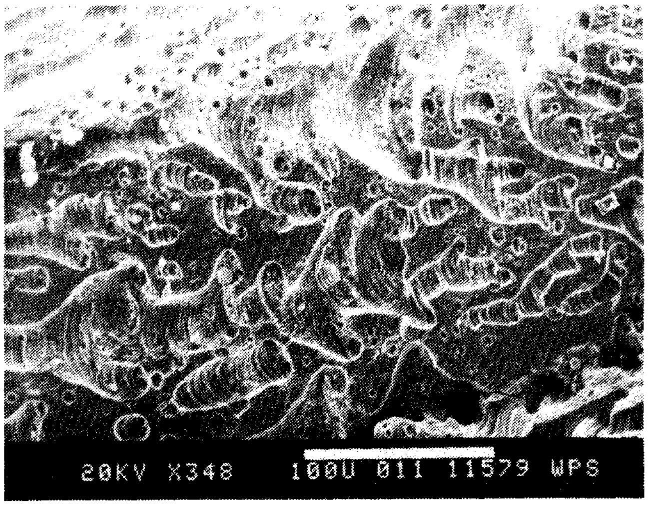

FIGURE 4—UNUSUAL PITS AND CAVITIES ARE PRESENT IN IRON SULFIDE SCALE.

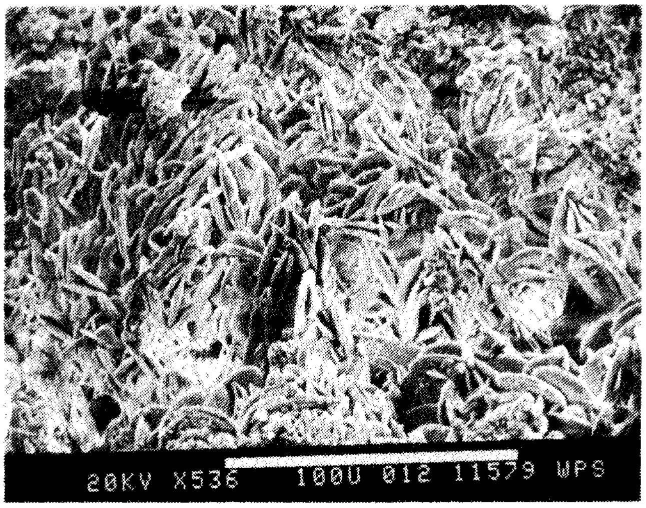

FIGURE 5—BARITE SCALE SHOWING "CRESTED BARITE" APPEARANCE.

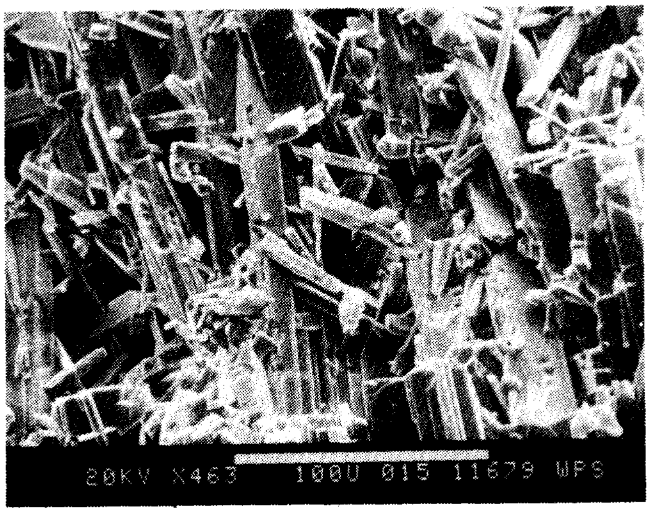

FIGURE 6—ANHYDRITE ($CaSO_4$) SCALE EXHIBITING PRISMATIC CRYSTAL HABIT.

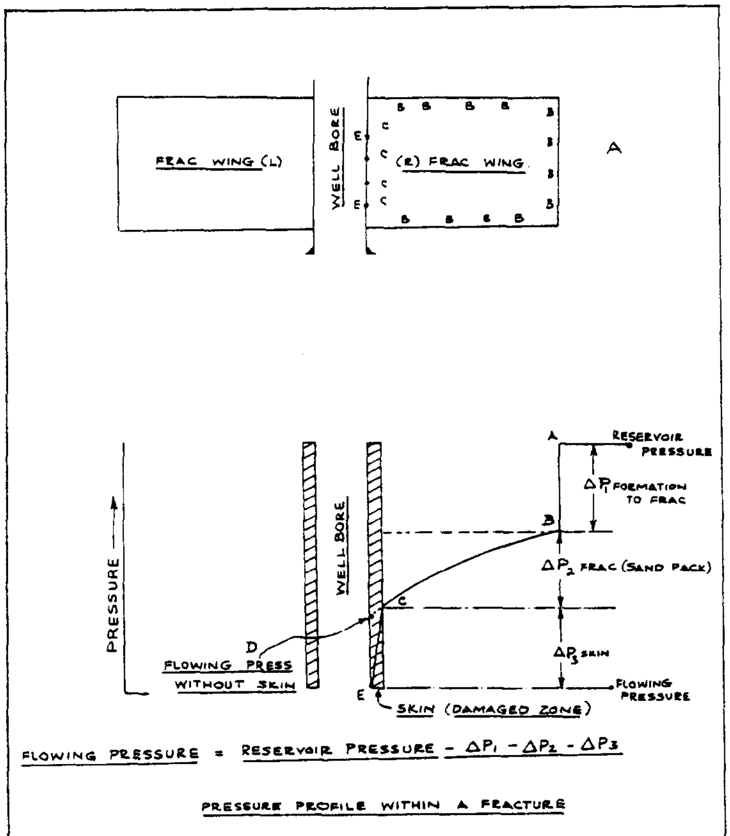

FIGURE 7

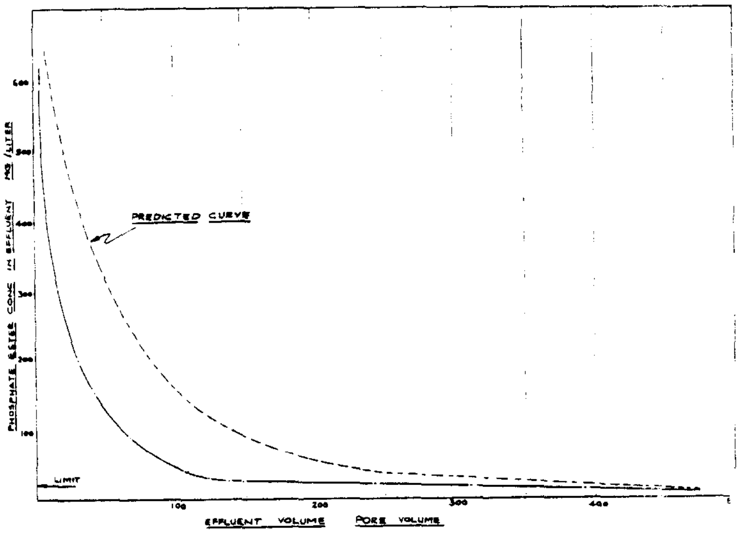

FIGURE 9—DESORPTION CURVE FOR PHOSPHATE ESTER

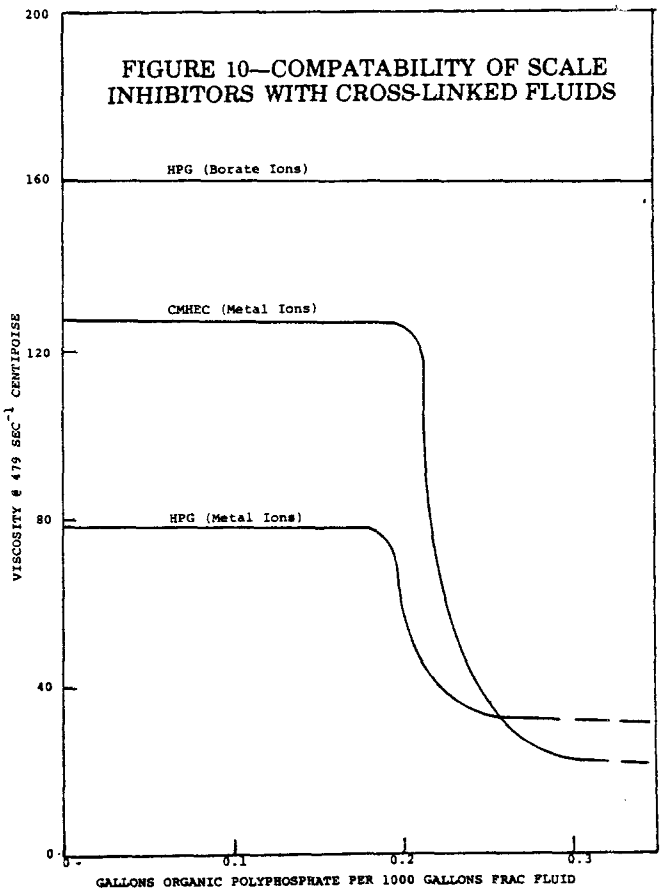

FIGURE 10—COMPATABILITY OF SCALE INHIBITORS WITH CROSS-LINKED FLUIDS

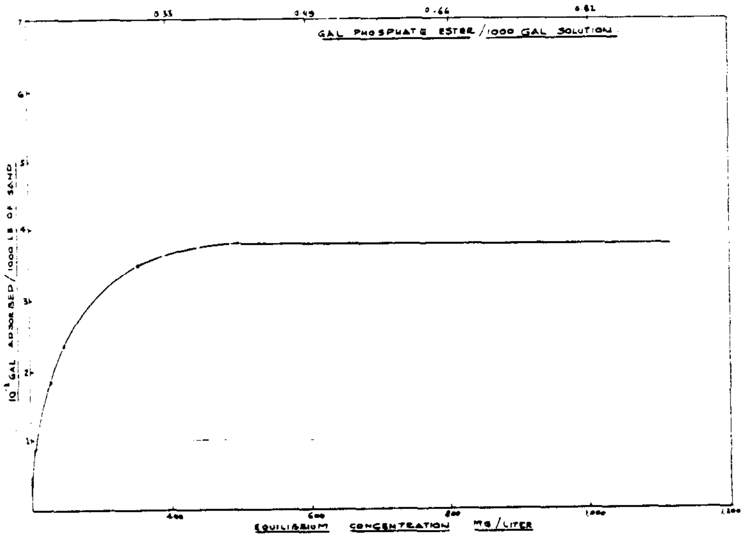

FIGURE 8—ADSORPTION ISOTHERM FOR PHOSPHATE ESTER

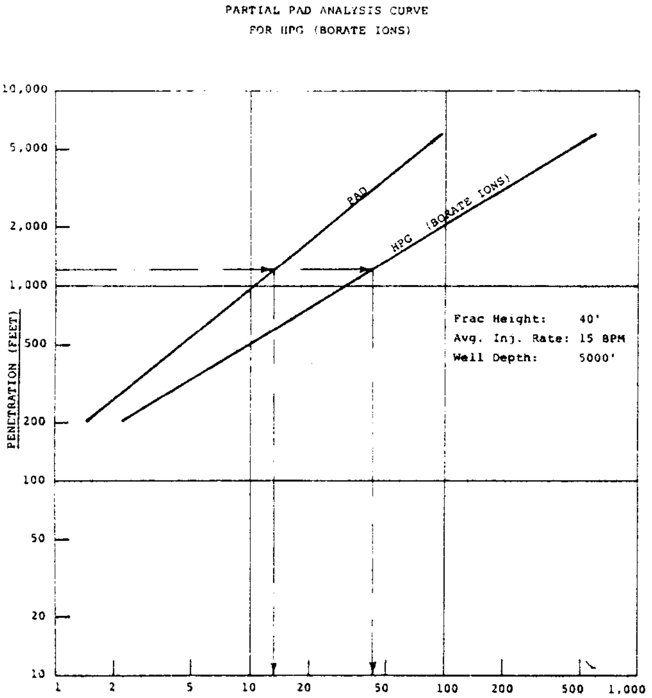

FIGURE 11—FRAC FLUID VOLUME X 1000 GALLONS
VOLUME VS. PENETRATION

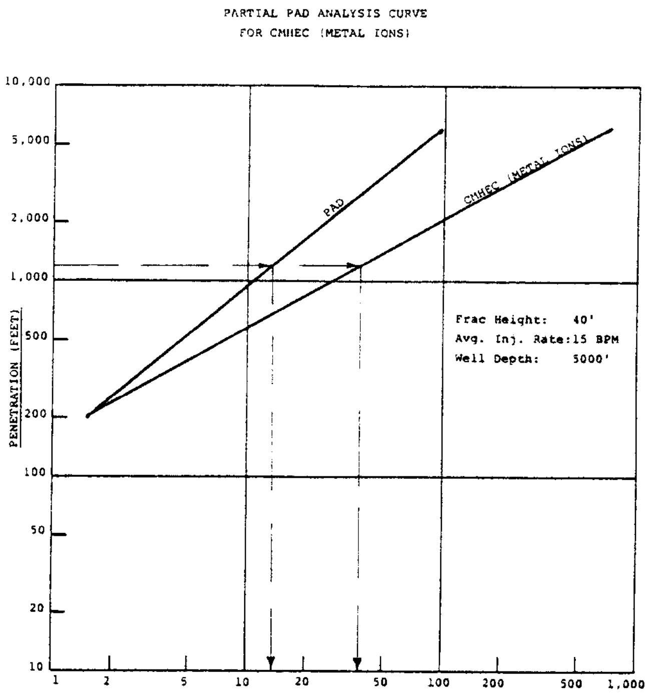

FIGURE 12—FRAC FLUID VOLUME X 1000 GALLONS
VOLUME VS. PENETRATION

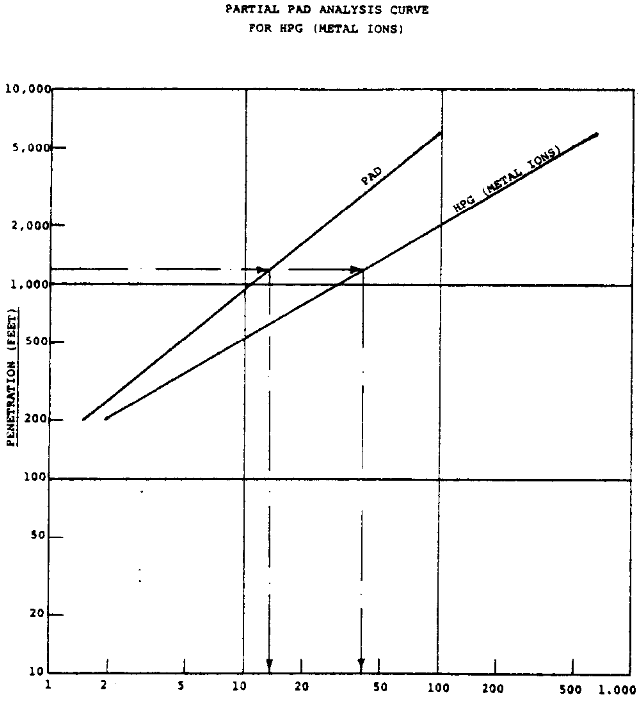

FIGURE 13—FRAC FLUID VOLUME X 1000 GALLONS
VOLUME VS. PENETRATION

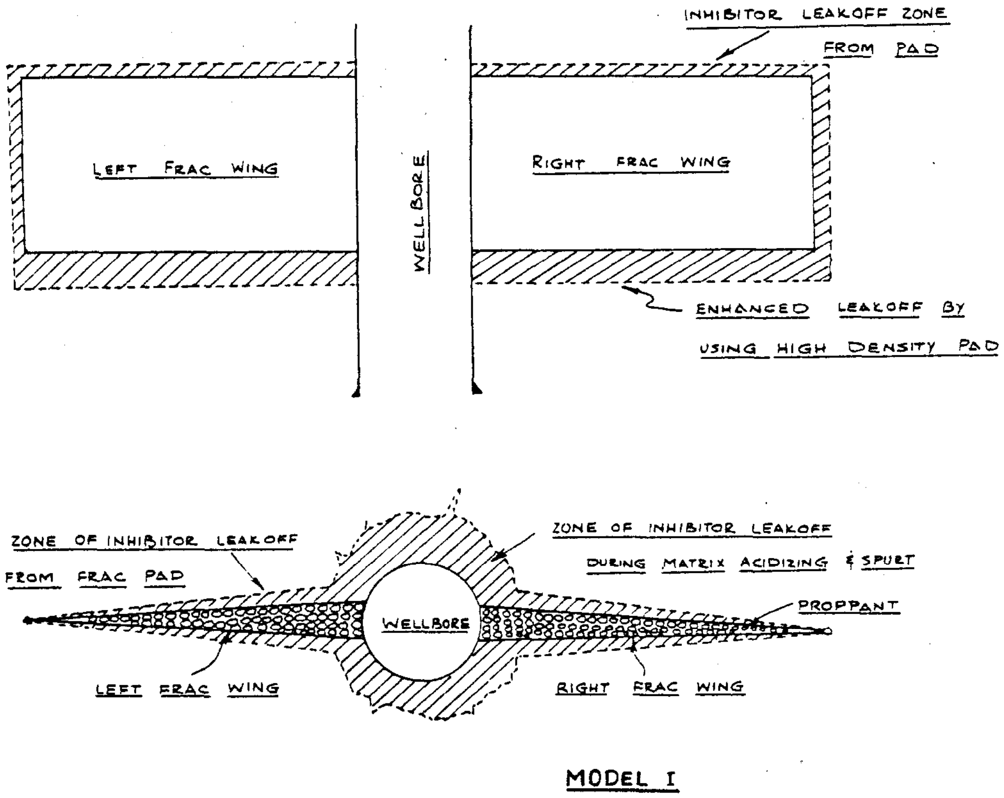

FIGURE 14—SCALE INHIBITOR APPLICATION WITHIN A FRACTURE SYSTEM

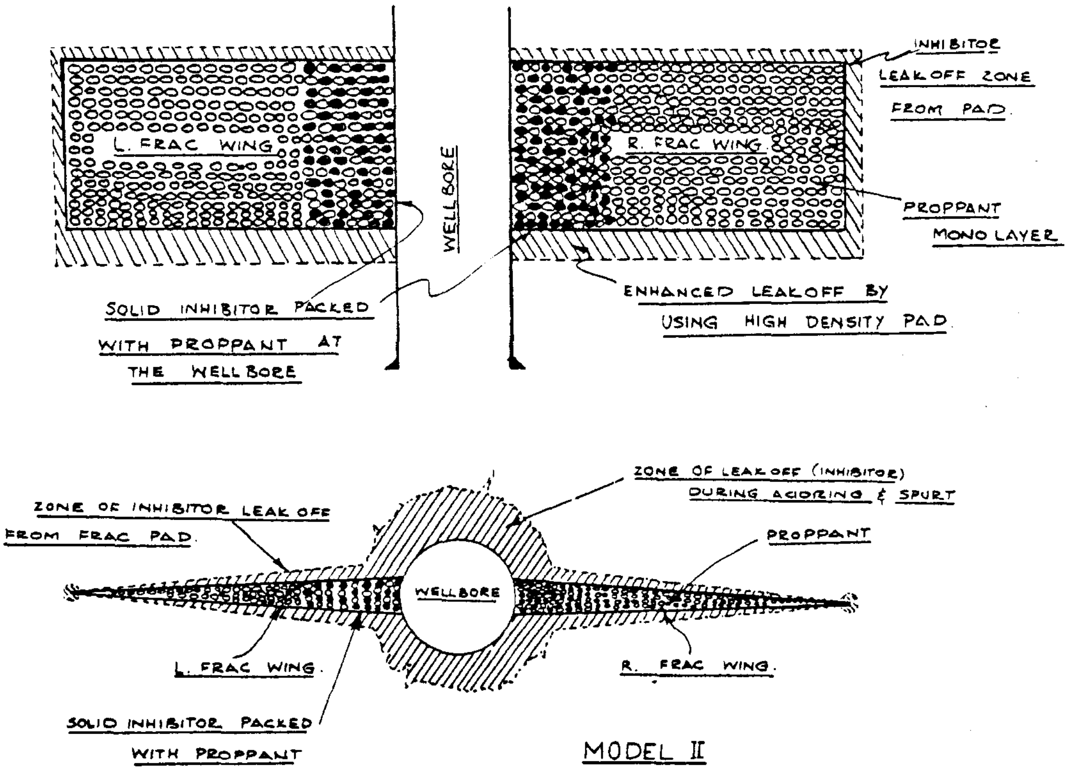

FIGURE 15—SCALE INHIBITOR APPLICATION WITHIN A FRACTURE SYSTEM

TABLE 1—TYPES OF ORGANIC (LIQUID) SCALE INHIBITORS

TYPE	THERMAL LIMIT	$CaCO_3$ EFFECTIVENESS	$CaSO_4$ & $BaSO_4$ EFFECTIVENESS
Phosphate Ester	$\sim 200^{\circ}$ F	3	1
Phosphonate	$\sim 300^{\circ}$ F	1	2
Acrylate Polymer	$\sim 375^{\circ}$ F	2	3

TABLE 2—CALCIUM SULFATE INHIBITION BY RESIDUAL PHOSPHATE ESTER TEST

PHOSPHATE ESTER CONC. PPM.	LB. $CaSO_4$ INHIBITED/1000 GAL.	% INHIBITION
4	5.30	7
8	8.34	11
10	10.26	21
15	28.32	60
20	45.48	84
32	70.63	93

TABLE 3—EFFECT OF SOLID SCALE INHIBITOR ON CROSS LINKED GEL

Type Scale Inhibitor - Sodium Calcium Polymetaphosphate
Test Temperature - 110° F
Fracturing Gel - 30 lb. CMHEC/1000 gal. Water Cross Linked
Test Time - 15 minutes

LOADING SCHEDULE lb./1000 gal. Gel	EFFECT ON CROSS LINK
15	No Effect
20	No Effect
25	No Effect
30	No Effect
35	No Effect
40	No Effect
45	Slight Effect
50	No Cross Link
60	No Cross Link

TABLE 4—FLUID INVASION DEPTH INTO THE FRACTURE WALL

FRACTURE PENETRATION:	1,200 feet
PAD FLUID REQUIRED:	13,000 gallons
FRAC FLUID:	45,000 gal. HPG (metal ions)

Distance From Wellbore (Feet)	Invasion Depth (Inches)
0	1.64
253	1.56
506	1.44
760	1.27
1,013	1.04
1,267	0.00

TABLE 5—RESERVOIR PROPERTIES

SAN ANDRES FORMATION
GAINES COUNTY, TEXAS

Well Depth	5,000 feet
Static Bottom Hole Temperature	120° F
Frac Height Considered	40 feet
Formation Permeability (k)	0.5 md
Formation Porosity (Ø)	15%
Bottom Hole Pressure	1,000 psi
Overburden Pressure	2,000 psi
Frac Gradient	0.6 psi/foot
Rock Young's Modulus	4.87×10^{6} psi
G.O.R. Considered	300 SCF/bbl
Reservoir Fluid Gravity	35° API
Reservoir Fluid Viscosity	3.0 cps
Reservoir Fluid Compressibility	7×10^{-5} 1/psi

TABLE 6—STIMULATION FLUID PROPERTIES

PROPERTIES	PAD FLUID	FRAC FLUIDS HPG (Borate)	HPG (Metal)	CMHEC (Metal)
Specific Gravity	1.02	1.02	1.02	1.02
Reservoir Permeability to Fluid (md)	0.30	0.30	0.03	0.30
Spurt Loss (cc)	4.00	0.00	0.00	0.00
n'	0.512	0.573	0.476	0.412
k' $(lb_f - sec^{n'}/ft^2)$	0.0038	0.03	0.04	0.08
Combined C $(ft/\sqrt{min})$	0.00105	0.00165	0.00172	0.00162