STIMULATION TECHNIQUES USED IN THE AUSTIN CHALK

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ABSTRACT

The object of this paper is to discuss the most widely used stimulation techniques currently being employed in the Austin Chalk Formation in South Texas. Although this trend has been explored for years and continues to be one of the most active in the country, there remains a difference of opinion over how to effectively stimulate this reservoir.

Several schools of thought regarding types of fluids, additives, and general treating techniques will be examined. The fracture geometry of various treatments as predicted by pre-treatment computer designs will be compared to the parameters obtained from post-frac analysis.

INTRODUCTION

Exploration in and development of the Austin Chalk trend in South Texas has been on going since the 1920's when this formation was found to contain oil in the Luling, Texas area. In 1933 the Pearsall Field in Frio County was discovered. This area has enjoyed several periods of active development with interest being renewed periodically by increased oil prices and new geological methods for determining the most favorable drilling locations. In recent years the activity in this trend has moved northeastward into Fayette, Lee, and Burleson counties. Exploration continues to expand into East Texas and Louisiana.

The Austin Chalk is primarily composed of calcareous unicellular algal remains called cocospheres and their disarticulated gear shaped skeletal remains called cocoliths. After deposition, the cocoliths frequently broke into tiny calcite plates less than one micron in size. Due to the lack of significant rock strength, porosity rapidly decreases with burial as the uncemented platelets become compacted. In response to the tectonic forces created by the downwarping of this trend along the Gulf Coast, the Austin Chalk fractured. It is generally believed that hydrocarbons from the underlying Eagle Ford Shale then migrated into these fractures.[1]

Early stimulation procedures consisted of detonating nitroglycerin in the favorable zones, then acidizing with HCl. Many times this procedure resulted in high initial flows and has been applied even in recent years.

In the mid-1950's, hydraulic fracturing was attempted for a brief period. It was about this time, however, that drilling activity virtually ceased in the Austin Chalk and did not begin again until 1974. With fracturing having been well established as a stimulation method by this time, it was applied on a large scale. Processes and fracturing techniques varied widely for several years as operators and service companies attempted to find the best method of providing sustained production from this unpredictable reservoir. Fresh water, water with salts and friction reducer, gelled water, crosslinked gel, oil, gelled oil, oil and water emulsions, acid, gelled acid, acid with gelled water, foamed acid, foamed water, foamed oil, and gas were all used in an attempt to find the secret to stimulation in this area.

GENERAL DESIGN CONSIDERATIONS

Few wells in the Austin Chalk are plugged on the basis of open hole log evaluation. The vast majority of wells have pipe set and are allowed to produce naturally or an attempt is made to stimulate them into economic production. Most locations have the production and treating facilities built before the well is even perforated. In many areas, the stimulation treatment has become another routine step in the completion process. The stimulation company is usually on site to perform the treatment as soon as the well is perforated unless there is a strong indication during drilling that the well might produce on its own.

The majority of the Austin Chalk trend is being developed on 80-acre spacing. Most operators are trying to achieve a conductive frac length of approximately 75 percent of the theoretical drainage, or around 700 ft. The volume of fluid required to do this is, of course, directly affected by the gross fracture height. Large intervals of the Austin Chalk are fairly homogeneous with no apparent boundaries to vertical fracture growth. This makes fracture treatment design very difficult. In some cases it may be desirable to have a frac height of as little as 50 ft. while in others a height of several hundred feet may be necessary for an effective treatment. Techniques have been developed for extending the fracture height in massive sections, however, preventing the fracture from growing out of zone in smaller intervals continues to be a problem.

Two common methods are employed in an attempt to control the fracture height: variations in pump rate and fluid viscosity. It is generally believed that lowering either the pump rate and/or the viscosity will reduce the vertical fracture extension. There is some indication, for instance, that pumping water containing friction reducer at a high rate results in less frac height than pumping a viscous crosslinked gel at a much lower rate. Care must be taken when pumping proppant laden fluids to provide either sufficient apparent viscosity or fluid velocity in the fracture to transport the proppant. A fluid that is too viscous or, in some cases, excessive pumping rates can cause the fracture to extend above and/or below the producing interval. This not only reduces the effectiveness of the treatment by shortening the fracture length, but also causes needless expenses for both hydraulic horsepower and fluid viscosifiers.

Many operators are attempting to determine fracture height by post treatment analysis. In some cases, a radioactive tracer is included in the frac sand and a gamma ray log is run to indicate where the sand is located. A temperature survey is often run also to tell where the fluid has entered and cooled the formation. These two techniques, while helpful in determining if fluid has entered all the perforations, probably do not always indicate the true vertical extension of the fracture. A slight deviation between the plane of the wellbore and that of the fracture may give the indication that the frac height is only a fraction of what it actually is.

Pressure buildup analysis is also commonly used to evaluate the fracture treatment. This data may be extremely helpful; however, in the Austin Chalk, interpretation is often very difficult. This is due in part to the influence of natural fractures in the formation and the fact that two phase flow is almost always present. Fig. 1 illustrates a Horner plot of buildup data taken after an acid ballout but before a frac treatment was performed on the well. Fig. 2 presents the post-frac buildup and calculated parameters. As is often the case, the effective fracture length as indicated from the pressure buildup is only a fraction of the designed length. Figs. 3 and 4 further illustrate this point for other frac fluids.

Another major design consideration affecting the fracture geometry is the control of fluid loss in the fracture. Since the Austin Chalk has very little matrix porosity or permeability, this might not appear to be a problem. However, due to the fact that the production is from natural fractures, the intervals that are most often stimulated are those in which the fluid loss is most severe. For years the most popular method of fluid loss control was to add 100 mesh sand to the treating fluid. This is still done today, but other fluid loss additives have gained more widespread acceptance. As the gelling agents became more residue free, "cleaner" fluid loss materials were developed in an attempt to make the entire system as non-damaging as possible. The most popular of these is a combination of a water soluble polymer and an oil soluble resin. In some cases, a fluid loss additive composed of 100 percent resin has been used. Nitrogen has also been used quite extensively for fluid loss control; either alone or in conjunction with a particulate additive. When used in ratios of from 100 SCF/Bbl. to 500 SCF/Bbl., it also aids in fluid recovery after the treatment.

Most core studies on the Austin Chalk indicate that a very small percentage of swellable clays are present. Some operators, however, use KCl and clay stabilizers in their treating fluids while others simply use fresh water. Normally, .5 percent to 2 percent KCl is mixed in the frac fluid and seems to adequately prevent any formation damage from being caused by clay swelling.

A major problem encountered in stimulating this reservoir has been the forming of emulsions between the treating fluid and the formation oil. Due to the fact that the vast majority of the stimulation fluids used are either acid or water base, care must be taken in selecting the proper surfactant or non-emulsifier. This selection is complicated by the fact that the Austin Chalk oil properties may vary significantly from one part of the field to the next. This variation may be enough to cause a non-emulsifier that worked well in one treatment to have little effect on preventing emulsions in the next one. Nonionic surfactants have been the most popular for several years. They are compatible with the crosslinked fluids and do not tend to adsorb out on the formation as quickly as the cationic additives.

CURRENT STIMULATION TECHNIQUES

Acidizing

Almost every well completed in the Austin Chalk is acidized prior to being fractured. Often times this acid treatment is performed immediately before the fracturing treatment, using ball sealers to insure that sufficient perforations are open to accept the treatment. Many operators are performing acid treatments just after perforating in an attempt to slightly stimulate the wells and to give them an opportunity to evaluate the potential production and determine the viable options for further stimulation. Ball sealers are used in these operations to insure that the perforations are open.

There are many different types of acid mixtures being used to perform these acid jobs. As a general rule, the acid type used in the Austin Chalk is hydrochloric, or a mixture of hydrochloric and acetic acid, or hydrochloric and formic acid. The acid strengths being used range from 7-1/2 percent to 28 percent with the norm being 15 percent hydrochloric acid. The treatment volumes range from as little as 2,000 gals. to 20,000 gals. or more. An average treatment volume is

10,000 gals. of hydrochloric acid. Many times nitrogen is incorporated into these acid treatments at a rate of 500 to 1,000 SCF/Bbl to aid in flow back and removal of any undissolved fines. The common acid mixtures in use all contain corrosion inhibitors to protect tubulars from the acid. Non-emulsifying surfactants, both cationic and nonionic, are used between 0.1 percent and 0.5 percent to prevent stable emulsions and to lower surface tension. These additives have proven very effective in that emulsion problems are seldom encountered when they are used.

When acidizing the Austin Chalk, some insoluble fines are released into the fluid. For this reason, many acids have fines suspending agents added to them which enable these released fines to be carried out of the formation and thus prevent them from plugging the flow channels. Iron sequestrants are also added to many acids to prevent the undesired precipitation of iron oxide from the dissolved iron in the formation and tubular goods. Many operators feel that there are enough clays present in the Austin Chalk to warrant the use of clay stabilizers in all their acid treatments to protect against swelling and migration. Since the Austin Chalk oil has a relatively high amount of paraffin present in it, paraffin dispersants and other paraffin control agents are many times used in acid treatments to keep this paraffin from crystalizing and solidifying to restrict flow.

Some operators like to use foaming agents in their acid treatments with the thought that any gas produced would then be aided by these foamers in cleaning up the treatment. This is especially true when nitrogen is commingled with the acid treatments. These evaluation treatments are usually performed down the tubing with a packer in the well. Rates vary from 3 BPM to 8 BPM, depending on the maximum allowable surface pressure. In order to reduce the friction loss in the tubing and maximize the rate, friction reducing compounds are used in almost all acid treatments done for pre-frac evaluation.

Foamed Acid

Another type of acid treatment that has been used in the Austin Chalk is foamed acid. Relatively few of these treatments have been performed. The idea behind them is to achieve greater penetration per volume of acid and extend the reaction time of the acid by creating a foam. For example, 1,000 gals. of unfoamed acid would only extend a short distance into the highly soluble chalk. This same volume, when foamed, becomes about 5,000 gals. of foamed acid that will penetrate much further and stay reactive longer. This extended reaction time is due to the viscosity of the stable foam and the frac width it creates. Even longer reaction times may be achieved by the addition of chemical retarders to the acid.

This type of treatment is not normally as large as the other types discussed herein. It does, however, provide more penetration than an acid ballout without the cost of a large sand frac or viscous fingering type of job. It also exposes the formation to much less fluid and cleans up very quickly due to the nitrogen available to aid in the flowback. It is an excellent process for cleaning up deep formation damage.

Viscous Fingering

An acidizing technique that has gained fairly widespread acceptance in treating carbonate formations and has been applied with success to the Austin Chalk is the use of differential viscosities to achieve a "fingering" effect of acid in the reservoir. This allows deeper penetration of fairly low volumes of acid and results in an uneven etching pattern that provides highly conductive flow channels to the wellbore.

Normally, a non-viscous prepad is pumped to cool the formation and establish the fracture. A viscous fluid follows to widen the fracture and increase the penetration distance of live acid by increasing the diffusion distance of the acid and reducing the surface area to volume relationship within the fracture. This fluid may be a gelled water containing a secondary gelling agent or a crosslinked gel. A stage of acid equal to about 70 percent of the gelled phase is pumped next. This acid may be fairly weak or strong HCl or a blend of HCl and organic acid. The less viscous acid seeks flow channels through the gel and dissolves the formation in an irregular manner. It may be necessary to include a chemical retarder in part of the acid in order to keep it "live" throughout the treatment. The amount of retarder is dictated by the strength of the acid used, the length of time the acid is in contact with the formation, and the reaction rate between the acid and the formation. It may be necessary to pump several alternate stages of viscous gel and acid to periodically replenish the pad. This is done to prevent the viscous fluid from being swept away from the wellbore, thereby allowing the acid to react uniformly along the fracture face. After the last stage of acid, a non-viscous overflush is pumped.

This approach is advantageous in a situation where the fracture height must be limited. The pad may be designed such that the fluid is not so viscous as to contribute to creating excessive frac height. Since there is no sand to settle out, the pump rate may be much lower than in conventional fracs which will also help minimize the vertical extension of the fracture.

It is usually recommended that the well be flowed back as soon as possible after this type of treatment. Leaving the acid in contact with the formation for extended periods of time may soften the fracture faces and reduce the flow capacity. Also, a quick turnaround of the treatment will help assure that the viscous pad is not fully degraded as it is flowed out of the fracture. This is advantageous because it aids in removing insoluble fines that may be released when the acid reacts with the formation.

Alternating Stage

One type of fracturing technique that is currently seeing limited use in the Austin Chalk is a carryover from the earlier days of fracturing treatments. This type of treatment is the so-called "uncrosslinked gel alternating stage" frac. In these treatments, a large supply of ungelled water must be available on location. A typical job volume would be 300,000 gals., with 500,000 gals. not uncommon. The amount of proppant used on a treatment of this size would be 300,000 lbs. to 400,000 lbs.

These jobs are performed at rates of 65 BPM to 100 BPM with all the chemicals and additives being added "on the fly" as the job is being pumped. The fracturing fluid viscosity is usually no more than 15 to 20 cp for the sand carrying fluid and only 5 cp for the intermediate stages which carry no sand. These fluids are made by adding approximately 20 lbs. of guar gum or hydroxypropylguar gelling agent per 1,000 gals. of water for the sand stages and approximately 10 lbs. per 1,000 gals. for those without sand. These gelling agents have incorporated in them the necessary buffers and degrading agents to allow them to hydrate rapidly and thin back when desired for continuous mix operations.

The above concentrations of gel give good friction reduction and adequate viscosity to carry the sand concentrations used in these types of treatments. Some companies prefer to use polyacrylamide friction reducers in the non-sand stages of these jobs. Field experience has shown that both the gel and friction reducers work well and there is only a small difference in cost between the two methods. If pipe friction becomes a limiting factor, both gelling agent and polyacrylamide may be run simultaneously to keep the surface pressure low and the pump rate high.

Also included in the fracturing fluids for these treatments is approximately 0.1 percent, by volume, of a non-emulsifying surfactant to prevent the creation of stable emulsions with the formation fluids. Some jobs are designed using 1 percent potassium chloride for clay protection, but the majority of them are fresh water only. As might be expected when pumping at these high rates, some air is entrained in the fluid and some foaming occurs. For this reason, as an operational consideration for a smoother job, a de-foamer is metered into the fluid as it is being mixed.

These fluids are pumped in alternating stages of sand laden and clean fluid. A pad of about 10 percent to 15 percent of the total volume is pumped before the alternating stages are started. The sand stages are usually not larger than the capacity of the casing (approximately 200 Bbls.), but they may get as small as 25 Bbls. The proppant is 20/40 mesh sand and is usually run at concentrations ranging from 1/2 lb/gal up to 2 or occasionally 3 lb/gal. The pumping schedule might consist of 4,000 to 6,000 gals. of hydrochloric acid with ball sealers used to open all the perforations. After allowing the balls to fall to bottom, the fracturing treatment is continued with a pad of 1,000 to 1,500 Bbls., then 15 to 20 alternating stages of 200 Bbls. of fluid with 1 lb/gal of sand and 100 Bbls. with no sand. Next, 6 to 10 stages with 200 Bbls. of 1-1/2 lb/gal sand and 100 Bbls. of non-sand laden fluid. The 2 and 3 lb/gal stages follow with 4 to 6 repetitions and then the flush.

Gelled Water with Secondary Gelling Agent

Another type of fracturing treatment that has been used some in the Austin Chalk is the uncrosslinked base gel system with delayed reacting secondary gelling agents added to maintain viscosity at reservoir temperatures. These gels are usually cellulose derivatives that are residue free. The cost of this type system is higher than most other gel systems; therefore, its usage has been small. When these treatments are used, their size is comparable to that of a crosslinked gel system. A typical treatment would be about 240,000 gals. of fluid carrying 350,000 lbs. of proppant. The proppant is generally 20/40 mesh sand with some bauxite being used for tail in on the deeper wells. Pump rates are between 40 and 50 BPM.

These treatments, as most others, are preceded by 4,000 to 6,000 gals. of hydrochloric acid with ball sealers being injected to open all the perforations. A pre-pad of treated water is pumped as the first part of the treatment. This is a combination of friction reducing agent and non-emulsifying surfactant used to establish the injection rate and to cool down the well. This is followed by a viscous pad of the uncrosslinked gel with the secondary gelling agent being added continuously to the fluid as it is being pumped. The proppant is then started in this same fluid at concentrations ranging from 1 lb/gal up to 5 lb/gal. The wells are flushed with the same treated water used as the cooling pre-pad.

The base fluid for this type of system is either fresh water or potassium chloride water at 1 percent to 2 percent by the weight of the fluid. The base gel is composed of 50 or 60 lbs. per 1,000 gals. of the cellulose derivative primary gelling agent. Also included in this are pH control agents and buffers to keep the fluid in the correct pH range. Often times, especially in the deeper wells below 10,000 ft., additives are mixed in the gel to increase the stability of the system at these higher temperatures. In this type of system there are three such temperature stabilizers that may be used. This base gel also includes a non-emulsifying surfactant to prevent stable emulsions and degrading agents to insure that the viscosity will thin back for clean-up of the well.

Generally, fluid loss control additives are used in this type of system to try to control the leakoff rate into the formation. These additives are mixtures of particulate matter such as silica flour, swellable gums, non-refined guar gums, oil soluble resins, and talc in various combinations. Since the cellulose gelling agent is an ultra-clean fluid, these fluid loss agents are essential to have a wall building fluid loss effect.[2]

The secondary gelling agent is the final and most important additive to this system. This is a retarded or delayed reaction gel that hydrates only after it reaches a certain temperature. This allows the gel to be added as the fluid is being pumped into the well and the viscosity does not increase until it is out in the formation. The secondary gel hydrates and gains viscosity at the same time that the primary gel is degrading so that sufficient viscosity is maintained to transport the proppant out into the formation and suspend it for a given time.

This uncrosslinked secondary gelling agent system has given way to the now more popular crosslinked gel systems because of their improved temperature stability and their cost advantage.

Crosslinked Gel

This type of treatment, by far, comprises the largest percentage of stimulation jobs performed in the Austin Chalk today. The excellent proppant transport capabilities of a crosslinked fluid make it ideal for suspending large amounts of sand evenly throughout long, high fractures. The versatility of this type of system makes it applicable to both the shallow and deep areas of this trend. When treating at lower temperatures or in fairly small jobs where gel stability is not a problem, as low as 30 to 40 lbs. of gel per 1,000 gals. of water may be used. Hydroxypropylguar gelling agents are the most popular for this type of treatment, though others may be used. In deeper areas or where long pumping times at high temperatures are anticipated, the gelling agent concentration may be increased and chemical stabilizers may be added for increased gel "life". Gel concentrations may be easily decreased throughout the job as the fracture is cooled, thus maximizing the effectiveness of the fluid and decreasing the cost.

Normally, an acid ballout precedes these treatments to assure that all the perforations are open and accepting fluid. A non viscous pre-pad is then pumped to initiate the fracture and cool the formation somewhat. This thin fluid also provides a large portion of the spurt and fluid loss to the formation, thus allowing the more expensive crosslinked gel to remain in the fracture. A crosslinked gel pad follows to widen the fracture enough to accept proppant. A volume of this pad is normally 25 percent to 35 percent of the total gelled fluid volume.

To achieve sufficient fracture flow capacity, a proppant concentration of at least 1 lb./ft.^{2} of fracture face is needed in most cases. This normally requires concentrations of up to 5 lb/gal of proppant. In the deeper areas of the Austin Chalk where high closure pressures are anticipated, sintered bauxite is commonly used as a proppant.

CONCLUSION

Each of the fracturing techniques and processes discussed herein is currently being used in the Austin Chalk. No single method has yet proven to be effective in all situations. However, with careful examination of the design objectives for each well, one of these types of treatments may be applied to successfully stimulate this formation.

References

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2. Ely, John, "Fracturing Fluid Systems State of the Art," Southwestern Petroleum Short Course, Texas Tech Univ., Lubbock, Texas, April 1981.

Acknowledgments

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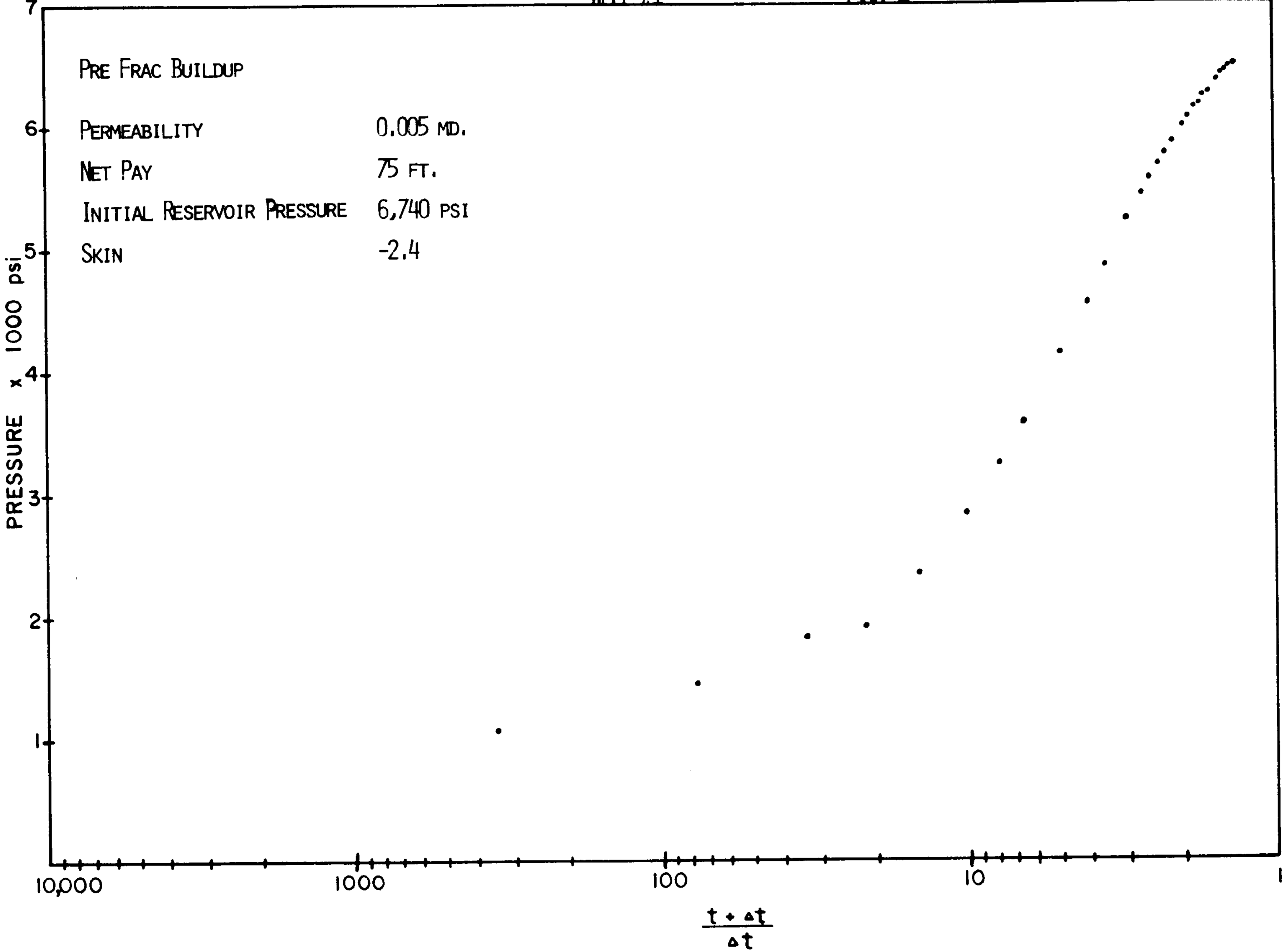
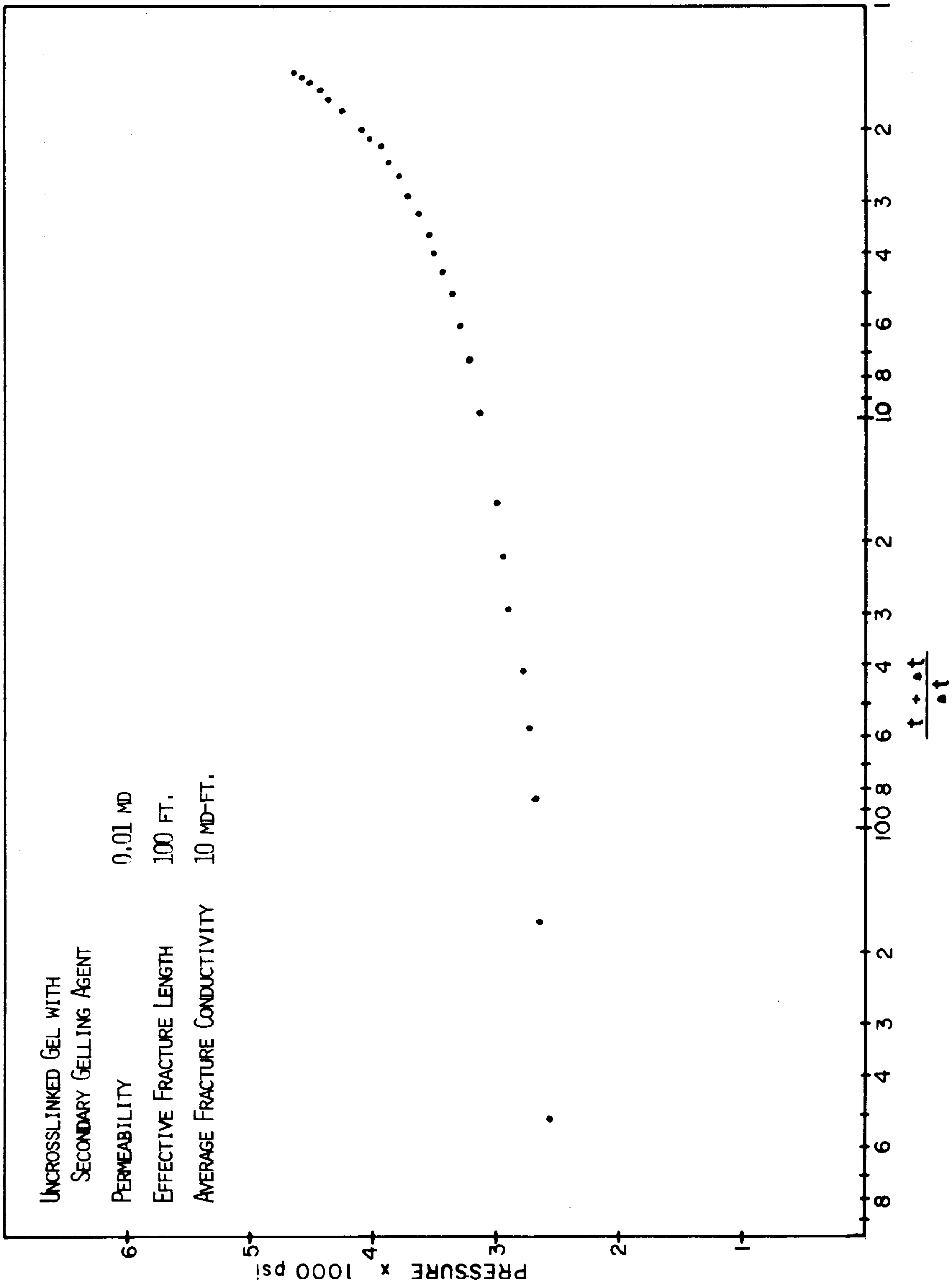
WELL #1 FIG. I


PRE FRAC BUILDUP
PERMEABILITY 0.005 MD.
NET PAY 75 FT.
INITIAL RESERVOIR PRESSURE 6,740 PSI
SKIN -2.4
PRESSURE x 1000 psi
7
6
5
4
3
2
1
10,000
1000
100
10
1
$\frac{t + \Delta t}{\Delta t}$


WELL #1
FIG. 2
UNCROSSLINKED GEL WITH
SECONDARY GELLING AGENT
PERMEABILITY 0.01 MD
EFFECTIVE FRACTURE LENGTH 100 FT.
AVERAGE FRACTURE CONDUCTIVITY 10 MD-FT.
PRESSURE x 1000 psi
1
2
3
4
5
6
t + Δt
Δt
1
2
3
4
6
8
10
2
3
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2
3
4
6
8

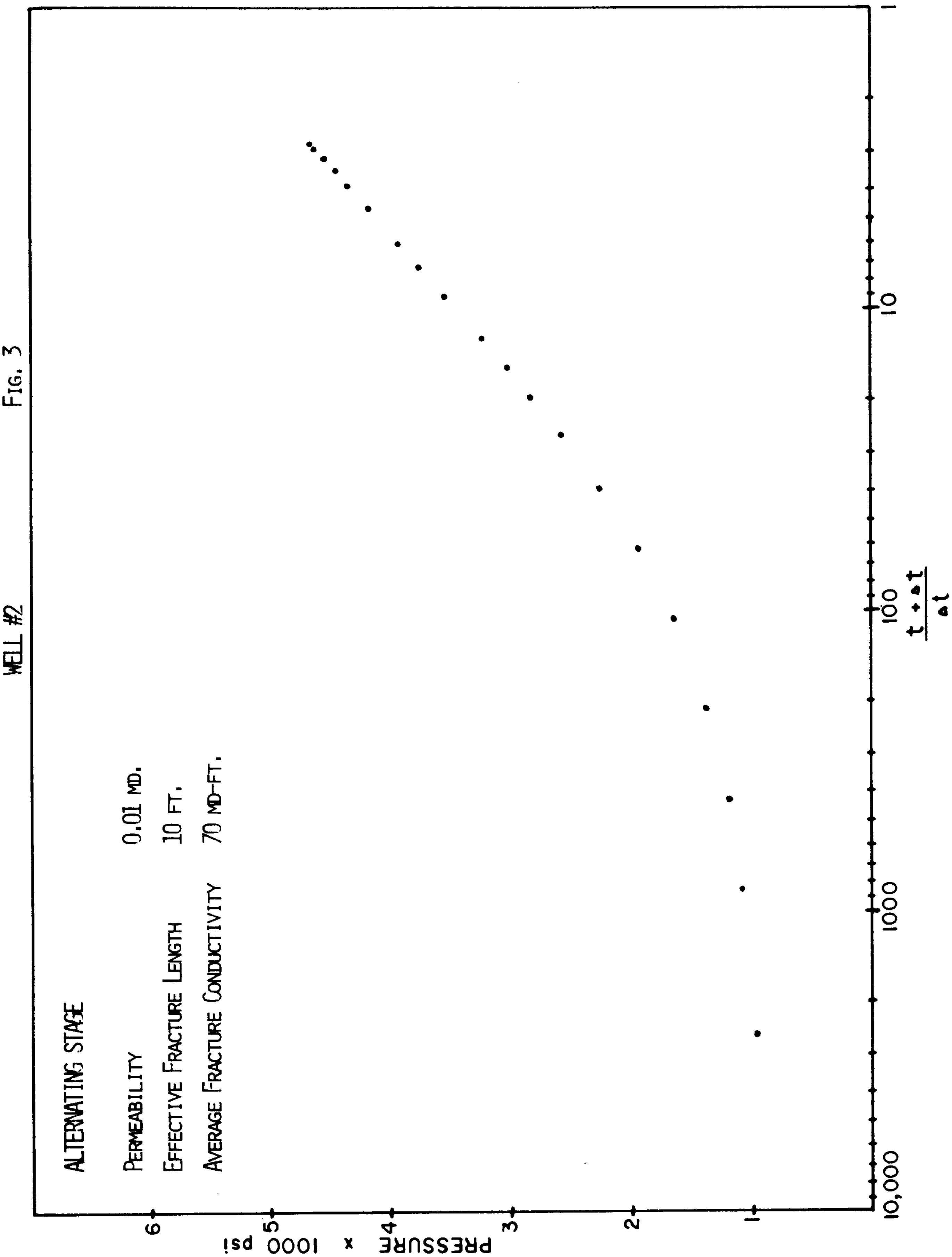
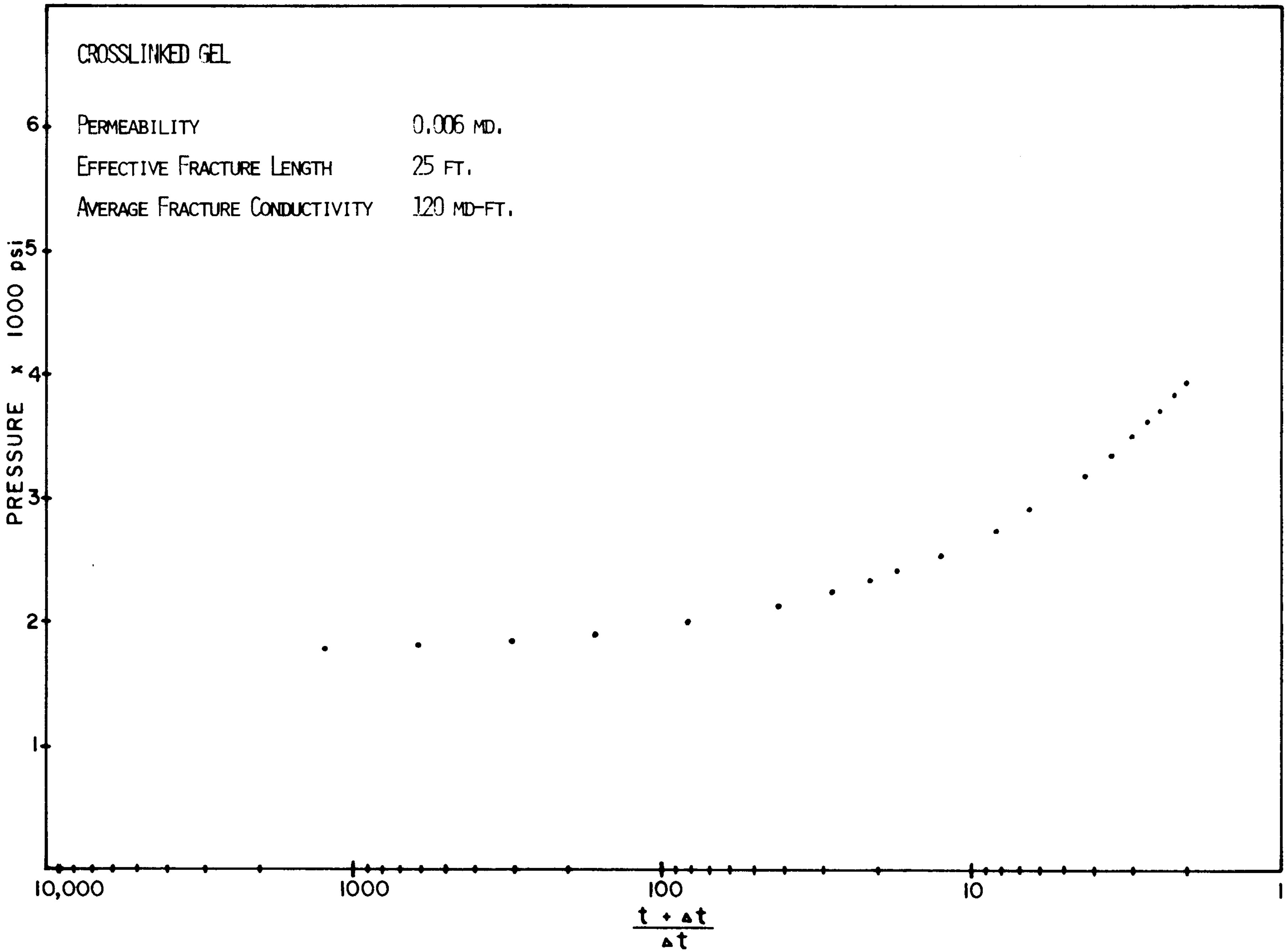

WELL #2
ALTERNATING STAGE
PERMEABILITY 0.01 MD.
EFFECTIVE FRACTURE LENGTH 10 FT.
AVERAGE FRACTURE CONDUCTIVITY 70 MD-FT.
PRESSURE x 1000 psi
1
2
3
4
5
6
1
10
100
1000
10,000
$\frac{t + \Delta t}{\Delta t}$

FIG. 3

WELL #3 FIG. 4


CROSSLINKED GEL
PERMEABILITY 0.006 MD.
EFFECTIVE FRACTURE LENGTH 25 FT.
AVERAGE FRACTURE CONDUCTIVITY 120 MD-FT.
PRESSURE x 1000 psi
1
2
3
4
5
6
10,000
1000
100
10
1
$\frac{t + \Delta t}{\Delta t}$