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GEOTHERMAL RESERVOIR WELL STIMULATION PROGRAM: TECHNOLOGY TRANSFER

May 1980

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Republic Geothermal, Inc.
Santa Fe Springs, California

U. S. DEPARTMENT OF ENERGY

Geothermal Energy

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VOLUME IV

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by: Maurer Engineering, Inc.

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STIMULATION TECHNIQUES
FOR
GEOTHERMAL APPLICATIONS

Page

I. SUMMARY AND CONCLUSIONS

Present day stimulation techniques for oil and gas wells can be extended and used in lower temperature geothermal wells. The extremely high-temperature geothermal wells will require new developments with very careful engineering and planning to successfully stimulate these wells. Present day techniques ignore chemical reactions and interactions of the fluids, proppants and additives. The possibility of harmful interactions and incompatibilities indicate the need for further lab work and testing.

When geothermal wells have 300 to 500°F (150 to 260°C) bottom-hole temperatures, two methods appear to have direct promise of successfully stimulating the well. These are:

1. High-Rate Water Frac - a low viscosity high-rate treatment that loses a high percentage of the fluid to the formation. The cool fluid leakoff blocks the heat away from the fracture and allows a worthwhile stimulation treatment with a high-temperature proppant.
2. Kiel Frac - a pulse frac technique that uses slugs of proppant and alternate volumes of clear fluid. After one stage is completed, the fluid flow is reversed and pulsed so that the formation will spall and terminate one fracture wing. The next step (of perhaps five stages) will initiate a new fracture wing and may find new reserves. Good results have been achieved in fractured oil and gas formations. In nonfractured geothermal formations this technique may also be employed since it provides some additional safety factors not available with conventional or planar frac treatments.

II. INTRODUCTION

Well stimulation techniques are designed to reduce the restrictions to flow or pressure drop from the reservoir into the wellbore. Successful well stimulation permits more rapid and hence more profitable exploitation of a reservoir and often, though not always, results in greater ultimate recovery. In some cases the well cannot be produced without the application of some type of stimulation technique. Today, more than 50 percent of the wells now being completed will be artificially stimulated at some time during their lives. There are some situations where artificial stimulation of wells is unnecessary, such as in highly permeable homogeneous reservoirs containing low viscosity fluids; however, reservoirs of this type are in the minority. For oil and gas wells, hydraulic fracturing and acidizing are by far the most important stimulation methods currently being employed. Less widely used techinques,. thermal techniques and surface active agents. In this report, Volume I: Physical and Mechanical Stimulation will exclude chemical stimulation by the use of acidizing and the use of surfactants. These will be studied in great detail in Volume II: Chemical Stimulation.

Fracturing of oil producing formations was first accomplished about 1900 when liquid and later solidified nitroglycerin was used to stimulate wells. Although the hazards associated with the use of liquid explosives limited their use, these materials were immediately and spectacularly successful for oil well shooting. The object of shooting a well was to fracture or rubble the oil bearing formation to increase both the initial flow and the ultimate recovery of oil. This same fracturing principle was soon applied with

equal effectiveness to water and gas wells. Extensive shattering of the wellbore made major post-shooting cleanup operations necessary. The enlarged wellbores and frequently damaged well casing prevented subsequent selective treatment of the producing interval. The advent of commercial hydraulic fracturing coupled with the danger of damaging the well being treated and the possibility of severe injury or death to the person handling or loading the well with a high explosive charge has, for all practical purposes, eliminated oil and gas well shooting. Some experimentation is going on with the use of a pumpable liquid explosive which is placed into a fracture before it is exploded. Also, nuclear fracturing has been tested. Neither of these promise any economy or increase production without extreme safety precautions and potential environmental hazards.

A recognition of the fluid fracturing phenomena was reported in squeeze cementing as early as 1940. Geological and engineering information was presented to show that the fluid pressures involved in squeeze cementing part the rocks generally along bedding planes or other lines of sedimentary weakness. The fracture formed provides channels or passageways in which the cement slurry can lodge beyond the wall of the hole. Formation fracturing was also recognized as occurring in water injection wells. In these earliest papers, it was generally assumed that horizontal fractures took place.

In the fall of 1948, the Stanolind Oil and Gas Company, now Amoco, announced its hydraulic process for increasing the productivity of wells. The process as originally predicated consisted in fracturing the reservoir rock by applying hydraulic pressure, and then forcing into the fracture thus formed a recoverable fluid acting as a vehicle for a solid agent which would remain within the fracture and hold it open after the pressure was relieved. The vehicle used was a kerosene napalm gel which was laden with sand to serve as a propping agent. After the formation was fractured and the sand-laden gel was injected into the fracture, a gel-breaker solution was then injected, which after about 24 hours would convert the gel to a low-viscosity liquid which could then flow back to the well, leaving the sand in the fracture as a permanent prop.

Initial fracturing jobs consisted of 750 to 1000 gallons of a gelled hydrocarbon containing about 1/2 pound of sand per gallon pumped into the formation at 2 to 5 bbl per minute. High-rate, high-volume jobs were not visualized initially. Today, jobs have been reported where a volume of over 1 million gallons was pumped into the formation at rates exceeding 500 bbl per minute. The rapid acceptance of hydraulic fracturing can be easily explained since the payout is rapid and the wellbore area can be cleared of any damaged zone. Many fields exist today because of the use of newer and better stimulation techniques. Without stimulation, many producing horizons very probably would have been bypassed as either barren or commercially nonproductive. It has been estimated that about 10 percent of all recoverable reserves in North America can be attributed to some type of stimulation.

III. TYPES OF STIMULATION

Literally hundreds of techniques have been developed to stimulate production from oil and gas wells. These schemes, which exclude chemical stimulation covered in another report, are variations of the basic stimulation techniques. These are:

- Hydraulic Fracturing,
- Thermal,
- Mechanical, Jetting and Drainhole Drilling,
- Explosive and Implosive, and
- Injection Methods.

Some of these work better than others and some techniques seem to have promise in geothermal wells. The following five sections will summarize and explain each of the above types of stimulation on a primary concept basis.

A. Hydraulic Fracturing

Summary

Hydraulic fracturing stimulates wells by cracking the formation's plane of weakness (caused by unequal earth stress) with a hydraulic or fluid wedge. Sand is normally pumped with the fluid at a pressure above the frac gradient so that the crack length grows to form a fracture void to hold the sand. After shutdown, the fluid is flowed or pumped out and the sand remains in the fracture to form a permeable pipeline from the formation to the wellbore. Stimulation ratios up to 10 are common with the average being from two to three times the prestimulation production value.

On the basis of energy payback, hydraulic fracturing is one of the most effective net energy generators. For example, on a medium to large frac job using 20,000 HHP/hr, a one barrel per day of oil stimulation pays back the HHP in only 5 days. With a more realistic 10 BOPD stimulation, only a few hours are required to payout. Economic payout takes longer but generally 90 day payback is expected by the producer.

Basic Concepts of Hydraulic Fracturing

Hydraulic fracturing is a production stimulation technique that has become widely used by the oil industry since its introduction 30 years ago. In a hydraulic fracturing treatment, fluid is injected down the well casing or tubing at rates higher than the reservoir matrix will accept. This rapid injection produces a buildup in wellbore pressure until a pressure large enough to overcome compressive earth stresses and tensile rock strength is reached. In at least 95% of all formations, the earth stresses are such that when the rock fails, a vertical crack (fracture) having a shape like that shown in Figure III-1 will be formed. Continuous fluid injection increases the fracture length and width.

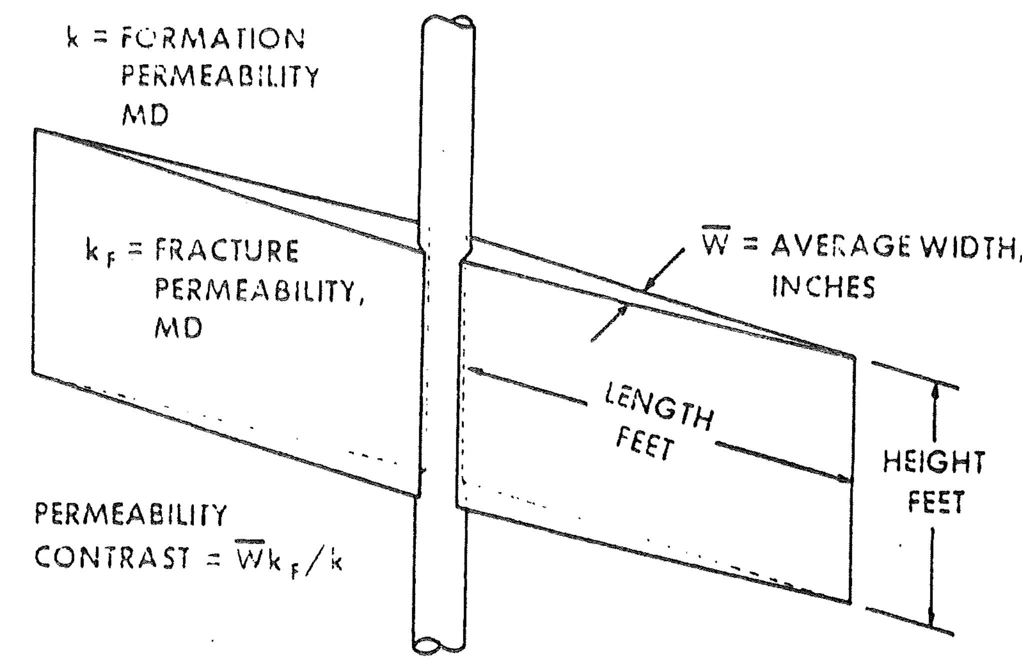


Figure III-1. Vertical Fracture Geometry

In order to achieve stimulation, the fracture conductivity (permeability times width) after the well is returned to production or injection must be much larger than the reservoir permeability. To obtain high conductivity a large granular solid propping agent (usually sand) is injected along with the fracturing fluid and deposited within the fracture. This material must be strong enough to maintain a high permeability when subjected to compressive earth stresses (closure stresses).

There are two ways that a propped fracture can provide well stimulation. First, in a well that has a zone of formation damage surrounding that wellbore (the "altered" zone in Figure III-2), the high-conductivity path provided by the fracture bypasses the damaged zone. Since damaged zones are generally believed to extend only a few feet into the formation, the required size of the fracture is not great. The result of bypassing the damaged zone may be a very large stimulation ratio.

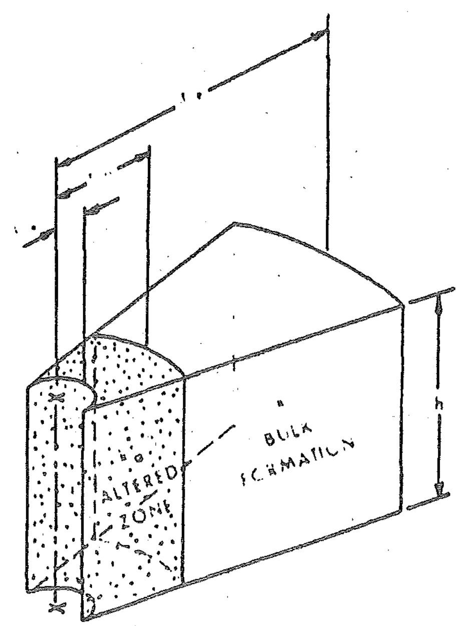


Figure III-2. Reservoir Model Showing Altered Zone

Second, if the high-conductivity path extends far into the bulk formation, the basic flow pattern of the reservoir is changed from the usual radial flow pattern to a linear flow pattern (Figure III-3). This new linear flow pattern can result in a many-fold increase in the productivity of the well, over and above any benefit realized from bypassing near-wellbore damage. The productivity increase resulting from the change in flow pattern is referred to as basic stimulation.

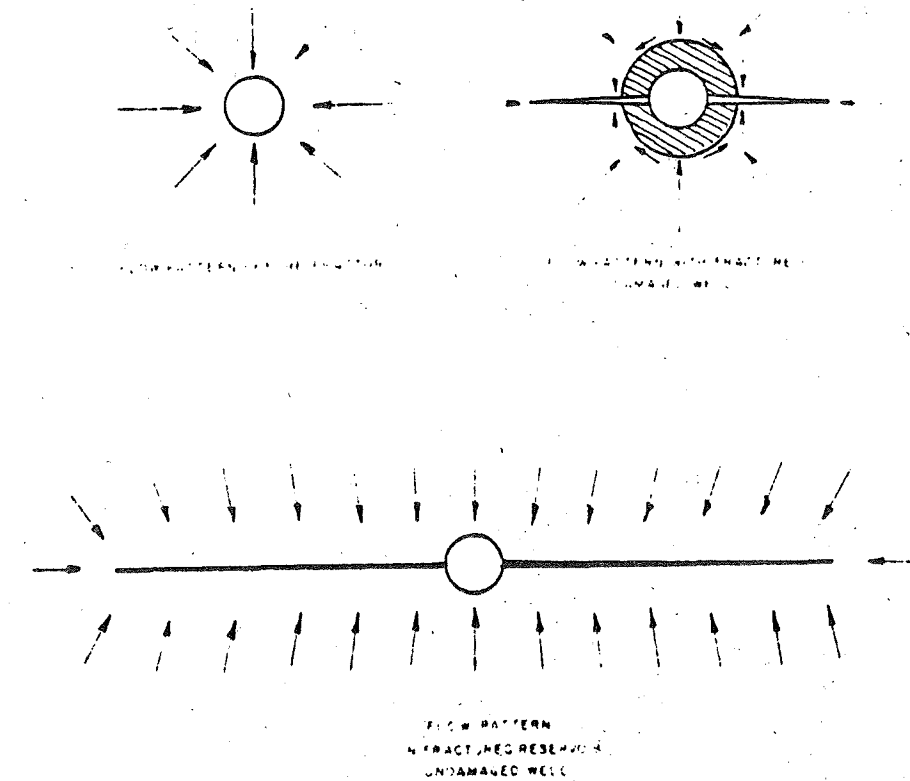


Figure III-3. Fluid Flow Pattern in Fractured Wells

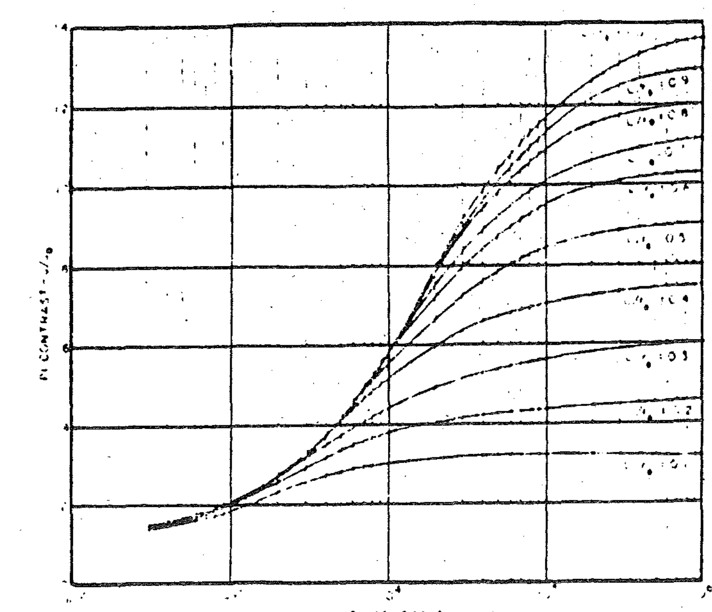


Figure III-4. Increases in Production from Vertical Fractures

Factors Controlling Productivity Increase

The amount of basic stimulation a fracture treatment will produce depends on packed fracture length, reservoir permeability and fracture conductivity. Figure III-4, the McGuire-Sikora correlation, is of fundamental importance in fracture design because it shows the relationship of these quantities. The abscissa of Figure III-4 is the quantity Wk_f/k, where:

W is the average fracture width, inches.

k_f is the permeability of the proppant in the fracture, md.

k is the bulk formation permeability, md.

Wk_f is the fracture conductivity, md-inches.

The quantity Wk_f/k has units of inches and is called the *permeability contrast* or *conductivity contrast*. Only if the contrast between the fracture permeability and the formation permeability is high will the reservoir flow pattern be altered.

The ordinate of Figure VII-4 is the quantity J/J_o, where J is the productivity index after fracturing and J_o is the PI before fracturing. J/J_o is called the *PI contrast* or *stimulation ratio*.

The curves in Figure III-4 are shown for different values of L/r_e, where L is the length of the propped fracture, ft, and r_e is the drainage radius of the well, ft.

Fracture Treatment Design

Once the goal of the fracturing treatment is established (i.e., basic stimulation or damage removal), the problem is to determine how a fracture with the desired characteristics can be created. The problem is not simple; many of the major

variables such as formation rock and formation fluid properties are uncontrollable, and in some cases are not even accurately known. One does, however, have control over three major factors. The variation of these parameters form the basis of the many hydraulic fracturing techniques that are surveyed in the bibliography. These are:

1. Fracturing Fluid - type, viscosity, fluid loss characteristics, and volume.

2. Injection Rate.

3. Proppant - type, size, volume.

These three factors allow considerable flexibility in fracture design as a wide range of fluid viscosities and high-strength proppants are available. In addition, new fluids and proppants are constantly being introduced which generate new techniques and solve the ever increasing problems of how to stimulate problem formations. Some of the older techniques no longer used or some new ones may be adaptable to solve the problem of geothermal stimulation.

Effect of Major Design Variables

The propped width and length of a fracture and the permeability of the propped fracture are of primary importance in determining the effectiveness of a stimulation treatment. Thus, we need to know how the width and length of a fracture are affected by treatment design, how proppants are distributed in the fracture, and the permeability of various proppants.

Factors Affecting Fracture Geometry

The geometry of a fracture is related to the fracture fluid efficiency which is defined as follows:

$$\text{Fluid Efficiency} = \frac{\text{Volume of Fracture Produced}}{\text{Volume of Fluid Injected}}$$

Obviously, the higher the fluid efficiency, the larger the fracture for a given volume of fluid injected. The fluid efficiency is related to loss of fluid into the formation through the fracture walls. This loss is related to several variables including time, formation permeability and porosity and the viscosities of both the fracturing fluid and the reservoir fluid. Several of these variables can be controlled to affect the fluid efficiency. In general, the fluid efficiency increases as fluid viscosity is increased and as the amount of fluid-loss additive is increased. Increasing the injection rate causes fluid efficiency to increase, but the fluid efficiency always drops as the total amount of fluid injected increases. The effect of each of these variables on fracture geometry will be discussed. The following discussion pertains to a well having the following reservoir and fluid characteristics:

Depth	5,000 ft
Formation Thickness	20 ft
Permeability	10 md
Sonic Travel Time	82 - sec/ft
Porosity	20 percent
Reservoir Fluid Viscosity	3 cp
Reservoir Pressure (below bubble point).	2,000 psi

Fracture Fluid Properties

Increasing the viscosity of the fracturing fluid results in a much wider and slightly longer fracture as shown in Figure III-5. Since Figure III-5 pertains to a set injection volume (150 bbl), the fluid efficiency becomes greater as viscosity increases. Available fracture fluids covering a wide viscosity range will be discussed later. Fracture width is important since the conductivity of a fracture is proportional to the fracture width. Fluid loss can be reduced by adding special fluid-loss materials to the fracturing fluid. The effect of fluid-loss additive concentration on fracture geometry for a low viscosity fracture fluid at a given injection rate is illustrated in Figure III-6. As additive concentration is increased, the fracture width and length increase in about the same proportion. The increase in fracture size also shows an increase in fluid efficiency since a given amount of fluid (150 bbl) is involved. This is the result of the walls of the fracture being sealed by the additive.

The effect of injection rate on fracture geoemetry is shown in Figure III-7. Fracture dimensions after 150 barrels of injection increase as the injection rate increases. This is because less time is available for fluid loss to take place at high rates.

The width and length of a fracture increases as the volume of fluid injected increases as shown in Figure III-8. The fracture dimensions plotted against the square root of the volume injected gives an approximate straight line. This trend suggests that the fluid efficiency becomes less as more fluid is injected. This is to be expected since the area of fluid loss increases as does the time for fluid loss to take place.

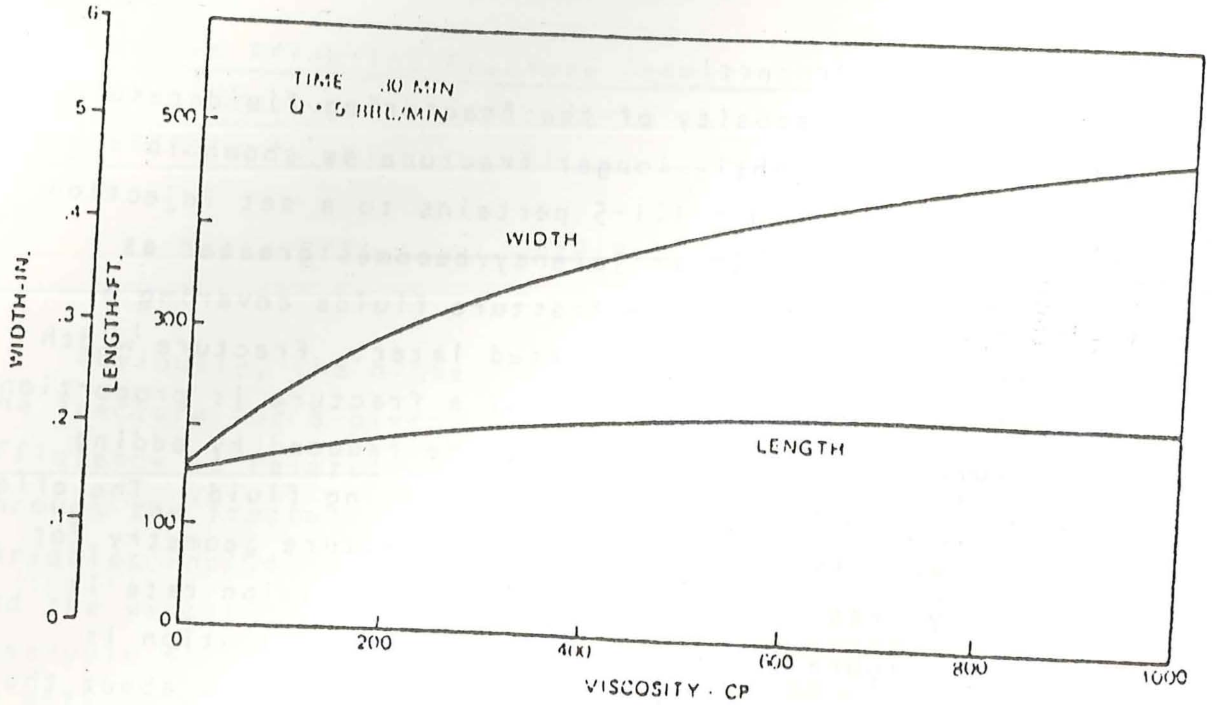


Figure III-5. Effect of Fluid Viscosity on Fracture Geometry

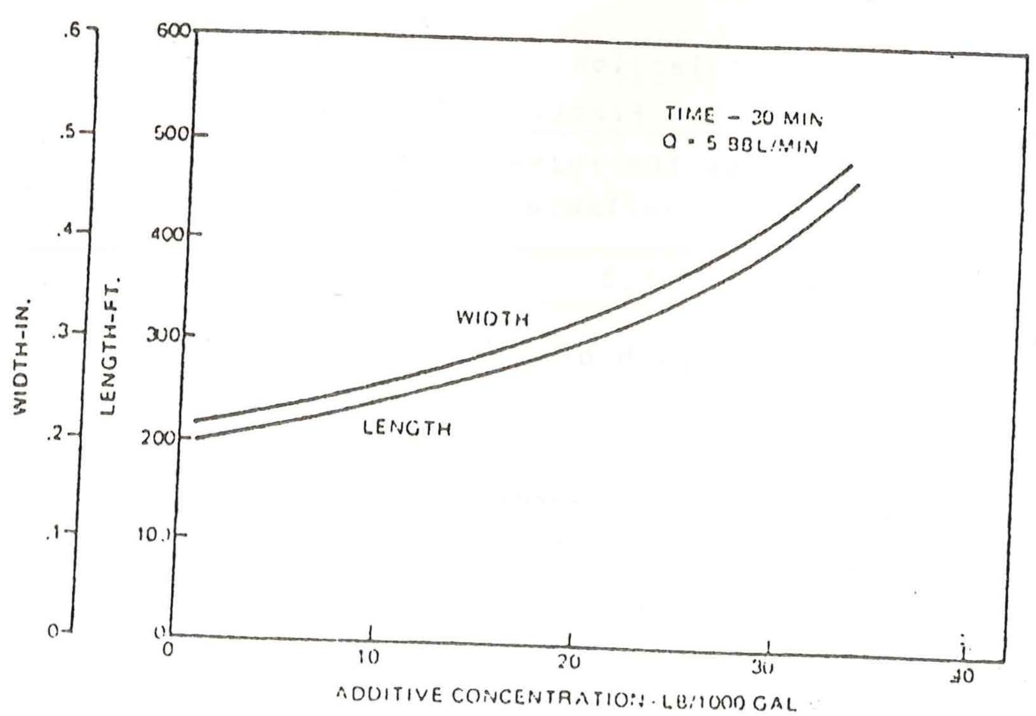


Figure III-6. Effect of Additive Concentration on Fracture Geometry

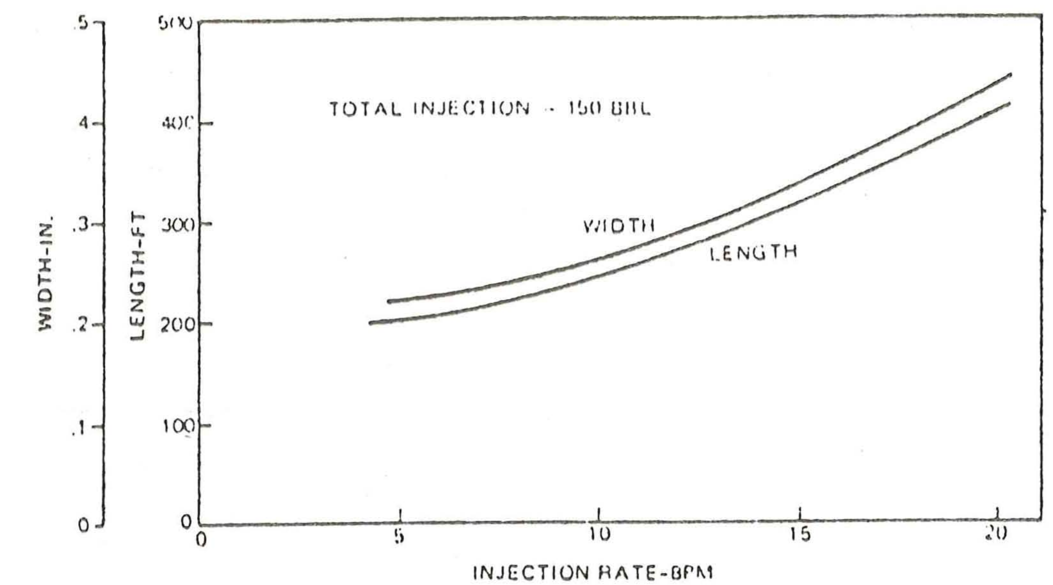


Figure III-7. Effect of Injection Rate on Fracture Geometry

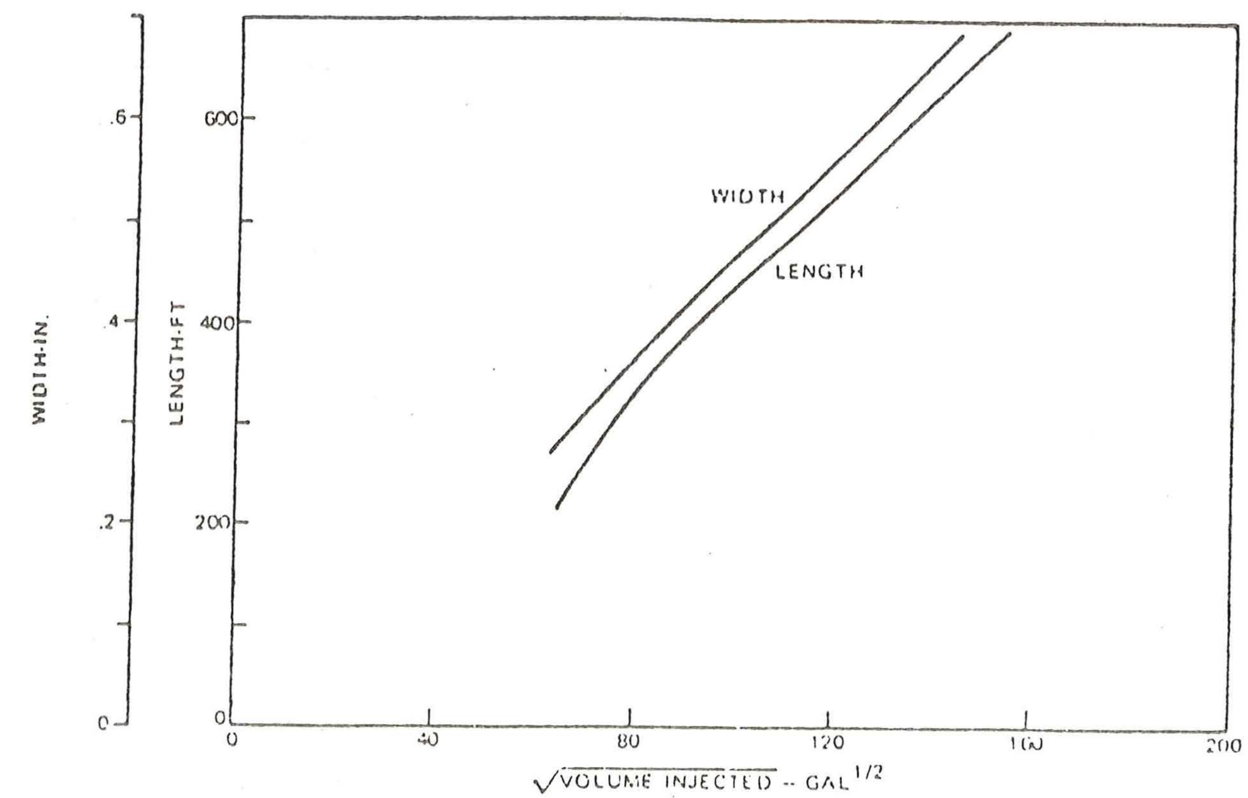


Figure III-8. Effect of Job Size on Fracture Geometry

Reservoir and Fluid Properties

In addition to the controllable variables just discussed, fluid efficiency and fracture geometry are affected by reservoir rock and fluid parameters that cannot be controlled. Fluid lost from the fracture must displace fluid from the reservoir. Thus, any parameter that makes reservoir fluid move easily, such as low viscosity, high permeability, high porosity, and high reservoir fluid compressibility, will tend to give low fluid efficiency. On the other hand, factors such as high reservoir fluid viscosity and low permeability will restrict fluid loss and tend to increase fluid efficiency.

The sonic travel time for a formation provides a direct measure of the formation elastic properties. The higher the sonic travel time, the easier a rock will fracture and the wider the fracture will be. In general, sandstones show the highest sonic travel times ranging from 75 to 95 μ-sec/ft while dolomites show the lowest, 45 to 65 μ-sec/ft. Sonic travel times for limestones generally fall in between those for sandstones and dolomites.

Earth stresses, formation depth, and rock elastic properties all influence the bottom-hole pressure necessary to create vertical fractures. The minimum bottom-hole pressure at which a fracture can be induced equals the fracture gradient times the formation depth. Fracture gradients range from 0.6 to 1.0 psi per foot and are generally lower for sandstones and higher for dolomites. Compass orientation of vertical fractures are governed by local tectonic forces not by the type of rock. A couple of generalities about fracture direction have been observed in the field. In the Gulf Coast area, fractures tend to parallel the coast line, while in the Mid-Continent area, fractures are predominantly oriented in a general northeasterly direction.

Factors Affecting the Sand Pack

Once formed, a fracture must be packed with a permeable material, generally sand, to keep it open after the fluid pressure is reduced. Some of the factors that influence the geometry of the sand bank in a fracture and the conductivity of the packed fracture will be discussed briefly.

The height and length of the sand bank is determined by fracture fluid viscosity, injection rate, sand size and the total amount of sand injected. The sand bank height is less for higher viscosity fluids, as shown in Table 1 which compares sand bank geometry for fluids with viscosities of 5, 50, and 500 cp. High fluid viscosities carry the sand further along the fracture and give a greater length to height ratio for the sand bank. For the 500 cp fluid, the sand bank height remains nearly constant and the length increases almost in proportion to the amount of sand injected. The sand bank height and length both increase as sand volume increases with a 50 cp fluid. In the case of the 5 cp fluid, the sand bank length remains constant until bank height reaches the top of the fracture. This suggests that a high viscosity fluid is needed to prop open a long fracture.

In addition to its height and length, the effectiveness of a fracture is dependent on the conductivity of the sand bank. It is extremely important to have the fracture propped open near the wellbore. For this reason, we strongly urge that the job be terminated before all of the sand has entered the fracture to prevent the sand from being overflushed into the fracture. The permeability of the proppant depends on the size and type of sand used, and is extremely dependent on the closure stress. Closure stress is the difference

TABLE 1

EFFECT OF VISCOSITY ON SANDBANK FORMATION

Formation Properties

Depth	5000 ft
Thickness	50 ft
Fracture Gradient	0.75
Formation Permeability	2.0 md
Formation Porosity	0.2
Injection Rate	10 bbl/min
Sand Concentration	3 lb/gal
Sand Size	8-12 mesh

Sandbank Profile

Fracture Fluid Viscosity, cp	Wt of Sand Injected, lb	Fracture Width, in	Sandbank Height (at well), ft	Sandbank Length, ft
5	6,850	0.33	28.0	70
	12,400	0.36	40.7	70
	18,000	0.38	49.0	70
	23,500	0.41	49.1	93
50	6,850	0.41	16.8	90
	12,400	0.44	21.7	135
	18,000	0.46	26.0	146
	23,500	0.48	30.3	150
500	6,850	0.60	11.0	70
	12,400	0.63	11.7	120
	18,000	0.67	12.4	155
	23,500	0.71	13.1	190

between reservoir pressure and the minimum pressure required to produce a fracture.

The reduction of permeability with increased closure stress is well known and documented for various sizes of proppants. Although larger sand sizes provide higher permeabilities at low temperatures at closure stresses below 4,000 psi, no benefit is

obtained from larger sands at higher closure stresses. Higher temperatures degrade both sand and glass beads. Glass beads have been found to not be cost effective and have been discontinued. While new proppants like Super Sand (a resin coated sand) and sintered bauxite pellets are cost effective whenever sand starts to crush or when elevated temperatures are encountered.

Fracturing Fluids

Fracturing Fluid Characteristics

The fracturing fluid system (liquid plus chemical and solid additives) plays a very important role in the success or failure of the overall fracturing treatment. Frac fluids being used include water, slick water, gelled water, super gels, oil-water emulsions (polymulsions), low-viscosity oils, gelled oils and high-viscosity oil fluids. Each of these fluids will be discussed in some detail later in this section. An ideal fracturing fluid should have the following characteristics:

- Adequate Fluid-Loss Control
- Low Tubular Friction Loss
- High Fracture Friction Loss
- Good Sand-Carrying Capacity
- Low Formation Permeability Damage
- Low Fracture Permeability Damage
- Low Cost
- Safe and Easy to Handle.

Fluid-Loss Control

Adequate control of fluid loss from the fracture is an important property of the fracturing fluid, since fluid that enters the fracture must maintain a wedging effect to propagate the fracture. To accomplish this, a reasonable percentage of the fluid entering the fracture must stay there. The smaller the percentage of fluid lost, the more efficient the system becomes, thereby creating more fracture per unit volume of fluid injected.

The rate of fluid loss from a fracture depends on reservoir properties, reservoir fluid characteristics, and the viscosity and wall-building characteristics of the fracturing fluid. If formation characteristics are such that fracturing fluid viscosity does not give adequate fluid-loss control, we can achieve control by adding finely ground solids to the fluid. These solids cover or bridge pore openings and restrict fluid flow from the fracture into the formation. As a result relatively large fractures can be generated with moderate volumes of fracturing fluid.

The most commonly used fluid-loss additive in water-base fluids is silica flour (ground sand) combined with a fluid-gelling agent; other additives are fine calcium carbonate or powdered limestone. For crude and refined oils, Adomite Mark II, a powdered lime coated with an oil-soluble soap or sulfonate is normally used.

Recently, oil-soluble polymers such as Inkovar 145 and Halliburton FL-3 have been introduced for use in water-base fluids. These additives have the advantage that they dissolve in produced oil and thus do not reduce fracture permeability;

they are not so effective in fluid-loss control, however, and must be used in 3-5 times the required concentration of silica flour. Because high concentrations of these expensive additives are required, the common additives are generally preferred. Many times all fluid loss control additives can be deleted.

Tubular Friction Loss

It is desirable to minimize the friction pressure drop in the tubular goods in order to limit the pump horsepower required and to allow high injection rates within the pressure limitations of the tubulars. Prediction of the friction pressure loss for fluids such as water and oil is simple since these fluids are Newtonian (i.e., their viscosity is independent of shear rate). However, the properties and flow behavior of these simple fluids can be significantly altered by adding certain chemicals (generally polymers) to give a slick, viscous, or gel-like texture to the fluid. These altered fluids are non-Newtonian, i.e., the viscosity varies with shear rate. In general, most non-Newtonian fluids used are shear thinning; that is, the faster they are sheared, pumped, or agitated, the lower the apparent viscosity. Friction loss of these fluids is difficult to predict and is primarily derived from experimental data.

The patented Superfrac process provides a means for injecting a viscous oil through tubing at high rates without suffering a high pressure loss. Water is injected along with the heavy oil to form a water film on the inside surface of the tubing which lubricates the oil along the tubing. Using this system, retined oils with viscosities up to 2000 cp have been injected as easily as an equal volume of water. The oil is saturated with water (about one-third by volume) which contains surfactants to aid in mixing and enhance the flow properties. More recently it has been demonstrated that heavy oils slightly over saturated with water can be pumped easily under some conditions without separately injecting water.

Friction Pressure Drop in the Fracture

The force that determines the fracture length-to-width ratio is the difference between the pressure of fluid entering the fracture and the minimum fracture pressure for the formation. This pressure difference is created by the fluid flowing in the fracture. Since this flowing pressure drop is proportional to fluid viscosity, wider fractures are generated by more viscous fluids. Although gelled water appears to be viscous, it has a low friction loss within the fracture (as in the tubing) and produces a narrow fracture. Typical fracture widths that can be generated by various types of fluids are shown in Table 2. Table 2 pertains to fractures in fairly deep wells (7,000 to 10,000 ft). Much wider fractures can be generated in shallower wells.

TABLE 2

TYPICAL FRACTURE WIDTH

Gelled Water	-	0.10" - 0.2"
Water	-	0.15" - 0.25"
Low-Viscosity Oil	-	0.2" - 0.3"
Viscous Oils	-	0.3" - 0.5"
Polymulsion	-	0.3" - 0.6"
Super Gel	-	0.4" - 0.7"

Sand-Carrying Capacity

Not only must a fracturing fluid be capable of creating a fracture of desired geometry, but it must suspend proppant and carry it through the surface equipment, down the well, and into the fracture. Settling velocity is a function of particle diameter, particle density, fluid density, and fluid viscosity.

Figure III-9 illustrates the relative settling rate of sand in various Newtonian fluids; this figure shows why a viscous fluid or a gelled fluid (which has a large apparent viscosity) can carry larger sand through surface equipment.

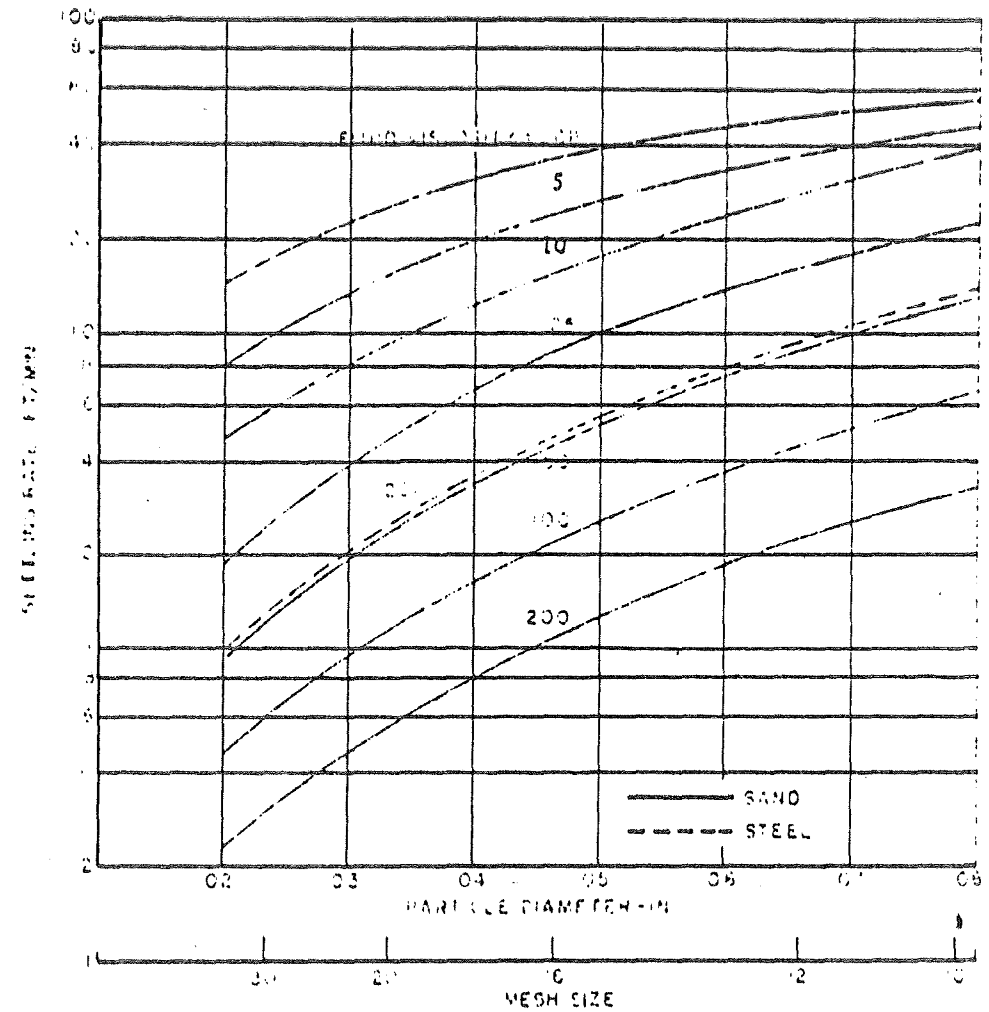


Figure III-9. Single Particle Settling Velocity versus Particle Diameter

Maximum sand concentrations and sand sizes normally pumped with various fluids are shown in Table 3.

TABLE 3

MAXIMUM SAND CONCENTRATION IN VARIOUS FLUIDS

Fluid Type	Max. Sand Conc. Lb/Gal	Sand Size
Water	2 - 3	20 - 40
Slick Water	2	20 - 40 or 10 - 20
Gelled Water	4 - 5	20 - 40 or 10 - 20
Super Gel	5 - 6	10 - 20 or 8 - 12
Polymulsion	4 - 5	10 - 20
Moderate Viscosity Lease Crude	4 - 5	20 - 40 or 10 - 20
High-Viscosity Oils	5 - 6	10 - 20 or 8 - 12
High-Viscosity Gelled Oils	5 - 6	10 - 20 or 8 - 12

Besides carrying the sand through the surface equipment, the fracturing fluid should not allow proppant to settle too soon in the fracture. In general, low-gel concentrations (20 lbs/1000 gals. or less) and low-viscosity oils allow too rapid settling of proppant particles within the fracutre. This produces rapid fracture fillup near the wellbore with very slow growth in length as more sand is injected (see Table 1). High-viscosity gelled water (40 lbs/1000 gals. or more) and high-viscosity oils restrict proppant settling and give a slower rate of fracture fillup, therefore producing a long bank which grows vertically with time.

High-viscosity oils (μ > 300 cp), cross-linked polymer gels, and polymer emulsions can carry proppant long distances along a fracture, threby giving a long sand bank that will fill only a fraction of the total fracture height or more realistically

will form a very thin monolayer of proppant throughout the fracture system. This very small fracture width after the frac job is called the static width. It is a small percentage of the dynamic width created by the fluid. An estimate of this final frac width as a percent of the dynamic frac width can be made by dividing the average sand concentration in lb/gal by 15. For example, if the average sand concentration was 1 lb/gal, then the final frac width would be only 1/15 or 6-2/3% of the calculated dynamic width. This is not sufficient and should be avoided for geothermal wells or wells with high flow rates.

Formation Permeability Damage

Damage to the formation may be caused by fluid-loss additives, a brine incompatible with a formation, precipitation of salts within a formation, or plugging by waxes or asphaltenes present in oils.

Laboratory tests have shown that formation damage from fluid-loss additives can cause permeability reductions of up to 60 percent in the reservoir near the fracture face.

Damage from salt precipitation and brine incompatibility is difficult to predict; however, in some instances, the damage can be severe. In extremely water-sensitive formations, a water-based fracture treatment should not be attempted. In moderately sensitive sands, a treated high calcium or potassium content brine can generally be used with heavy oil to give a successful Super Frac job. In extremely water-sensitive areas, a Super Frac job will require a saturated calcium chloride or potassium chloride brine.

If a residual refinery oil is to be used as a fracture fluid, it should have low wax and low asphaltene content. Either wax or asphaltene might form a filter cake which is very impermeable and insoluble in reservoir fluids, thereby drastically reducing the degree of stimulation produced by the treatment.

Fortunately, a reduction in matrix permeability adjacent to the fracture face does not restrict production nearly as much as a similar reduction in a radial flow system. In a radial system, permeability reduction of 90 percent (k = 0.1 times native permeability) to a depth of only 6 inches at the wellbore results in a productivity reduction of more than 50 percent. However, the same degree and depth of damage experienced in a fractured system where flow is linear, reduces productivity by only 3 percent.

Because of the linear flow into a fracture, only extreme formation damage or damage extremely deep into the reservoir can appreciably alter productivity in a fractured well. Of the four mechanisms previously mentioned, only injection of a high wax or asphaltene content oil, or injection of fresh water into a water-sensitive formation, can give damage this severe. Therefore, we must remember to check for formation sensitivity to the water and for wax or asphaltene content of oils before selecting a fracturing fluid.

Fracture Permeability Damage

Fluid-loss additives are chosen for their ability to plug a formation and restrict fluid flow from a fracture to the formation. Their plugging characteristics can also reduce the fracture permeability when the well is returned to production. On the basis of laboratory tests, the following recommendations are made:

1. If fluid-loss additives (Adomite Aqua, Adomite Mark II and silica flour) must be used with 20-40 mesh, the following precaution should be taken. After fracturing, the well should be produced at a low rate to maintain the closure stress below 1,000 psi unitl the produced fluid volume equals the volume of fluid injected in the treatment.

2. If fluid-loss additives are used with 10-20 mesh or larger sand, maintain the closure stress at or below 3,000 psi during well cleanup.

Fluid Cost

Fluids should be compared on a cost per unit volume of fracture created, rather than on a cost per unit volume of fluid injected, in order to take fluid efficiency into account. Typical costs for various types of fracture fluids will be discussed later. Also, small jobs cost less money and sometimes can be quite cost effective relative to the results.

Safety

All water-base and most oil-base fracturing fluids are considered safe to handle; however, caution should be exercised when pumping volatile oils such as unweathered crudes, condensates, or gelled condensate.

Types of Fracturing Fluids

The earliest fracturing jobs used napalm or crude oil for the fracturing fluid, but currently most fracture jobs are done with water-based fluids. Low cost and ease of handling are the two biggest advantages of water-base fluids. However, water-base fluids should be avoided in formations containing clays that might swell on contact with water. Water-base fluids vary from plain water to super gels and oil-base fluids vary from plain crude oil to heavy refined oils and gelled oils. In addition, emulsions containing oil and water are used. Still another group of frac fluids, acids, are discussed later. The commonly used fluids are defined below:

Water. Plain water is seldom used as a frac fluid because it has high fluid loss and poor sand-carrying properties. However, in some very low permeability, high-pressure formations, and for special or small jobs, plain water can be successfully used.

Slick Water. Slick water is made by adding synthetic, long-chain polymers to fresh or salty water. The addition of very small amounts of polymer results in the maximum benefit in terms of friction loss. For example, water containing the optimum concentration of 6 lb/1000 gal has less friction pressure loss than a gelled water containing 40 lb/1000 gal. The only advantage to slick water is the reduction in friction pressure loss in the tubing. Sand-carrying ability is little better than plain water, and it will not create a wide fracture.

Gelled Water. Fresh or salt water can be gelled by adding relatively large amounts of polymer, of the order of 20 to 40 lb/1000 gal. Three types of polymers are commonly used: (1) Guar gum is the most widely used. It is a natural product of the Guar plant. (2) Polyacrylamide is a synthetic polymer which has some desirable properties. (3) Hydroxyethyl Cellulose (HEC) is a straight-chain polymer with better high-temperature properties. Guar gum is most effective at temperatures below 200°F, while polyacrylamide and HEC can be used at somewhat higher temperatures. A chemical "breaker" is generally added to reduce the fluid viscosity in the reservoir after a few hours. Fluid-loss agents are also used. Gelled water is by far the most widely used fracture fluid because of its low cost where suitable water is available. A formation sample should be tested for the presence of swelling clays before gelled water is used.

Crosslinked Polymer Gels. Very high viscosity gelled water, commonly called super gels, can be produced by crosslinking the polymer molecules in the gelled waters

described on the previous page. Crosslinking is accomplished by adding certain metal or borate ions. Super gels are now offered by all the service companies. Although the super gels appear to be pseudosolids, they can be pumped through tubing with friction loss less than that for plain water. No fluid-loss additives are usually required, and the super gels are capable of creating very side fractures and have excellent sand-carrying qualities. This is the only type of fluid that can routinely carry large proppant sizes. For temperatures in excess of 200°F, polyacrylamides have slightly better properties than Guar gum and should be considered despite their higher costs. Despite their high potential, super gels are not always best. Their use has been somewhat limited due to the high cost compared to gelled water and also the concern for quick cleanup with no damage.

Polymer Emulsions. A polymer emulsion (Exxon Patent) is a fracturing fluid made by emulsifying oil and treated water. The addition of lease crude oil and an emulsifier to gelled water will form an oil-in-water emulsion. This fluid has much higher viscosity than gelled water and is much cheaper than a super gel. The emulsion is broken by salt water or by degradation of the polymer. Polymer emulsions are available from all service companies.

Low-Viscosity Oils and Gelled Oils. Crude oil, when used as a frac fluid, will not damage water-sensitive formations (if the oil is not waxy). Oil can also create wider fractures than most water-base fluids and has fairly good sand-carrying properties. High friction loss in tubing limits the use of oil to shallow or medium depth wells except for deep, low-permeability wells where high injection rates are not required to prevent screenouts. Fluid-loss agents are generally used and a polymer is often added to gel the oil. Gelled oils give reduced friction pressure in the tubing and better sand-carrying characteristics.. Refined oils are used more often than crude for gelled oil frac fluid.

B. Thermal

Summary

Thermal methods of stimulation are attractive when a heavy oil reservoir is fairly shallow. When heated, the viscous oil loses one half its viscosity for every 10°F rise in temperature; therefore, at a given reservoir pressure the flow rates will increase or be stimulated. Water viscosity is reduced by a factor of 10 when heated to 500°F or 260°C. In a sense the geothermal well has already been thermally stimulated since thermal effects from a large heat source such as magma or volcanic activity has heated the water from its normal temperature to a much higher one.

Full-scale, man-made thermal methods require large amounts of energy. With escalating energy costs today, fewer oil wells can qualify for thermal stimulation. Periodic treatments of hot solvents are effective in older oil wells with certain types of problems like paraffin or asphaltenes.

It should be noted that similar treatments of superheated water may have applicability to remove wellbore damage due to precipitation and scale deposits in geothermal wells and fields.

Introduction to Thermal Methods

Large volumes of oil previously considered unrecoverable--or at least uneconomic to recover--are now considered as candidates for the three main thermal processes: *steam displacement*, *steam stimulation*, and *in situ combustion*. Although expensive, these processes are particularly attractive because the heavy crude reserves for which they are suitable are already discovered and well defined. In North America at least, the conventional reserve-production ratio has gone down in the past few years, so the recovery of these heavy crude reserves will be imperative.

Thermal methods can be divided into two rather general categories: drive and stimulation. The *drive processes*, steam displacement and in situ combustion, are those which may lead to increased recovery over that which can be obtained from primary production. *Stimulation processes* are those which increase the rate of production from individual wells, although stimulation may also lead to increased recovery by extending the economic life of the wells.

This discussion will be limited to the major *stimulation* technique, cyclic steam injection (huff-and-puff). In this process, large volumes of steam are injected into a well, after which it is placed back on production, or is shut in for a few days ("soaking") before being returned to production. For example, in a typical huff-and-puff process in California, 6000 to 10,000 bbls of water as steam are injected over a period of 5 to 8 days in a well that was making 10 BPD. After injection of the steam, the well is shut in for a few days and then put back on pump. After producing water for five to ten days, oil production may soon reach 100 BPD and then decline to its original 10 BPD in four or five months.

In the following paragraphs, we will discuss the way in which stimulation is obtained from steam injection, criteria for the selection of wells to be stimulated, and some of the practical considerations in designing steam stimulation projects.

Principles of Steam Stimulation

The concept of thermal stimulation originated from the observed effect of temperature on the viscosity of crude oils. As temperature is increased, the viscosity of a crude oil may be markedly reduced and, as shown in Figure III-10, the reduction is much greater for low-gravity crude oils. This explains why thermal stimulation is presently being applied primarily in

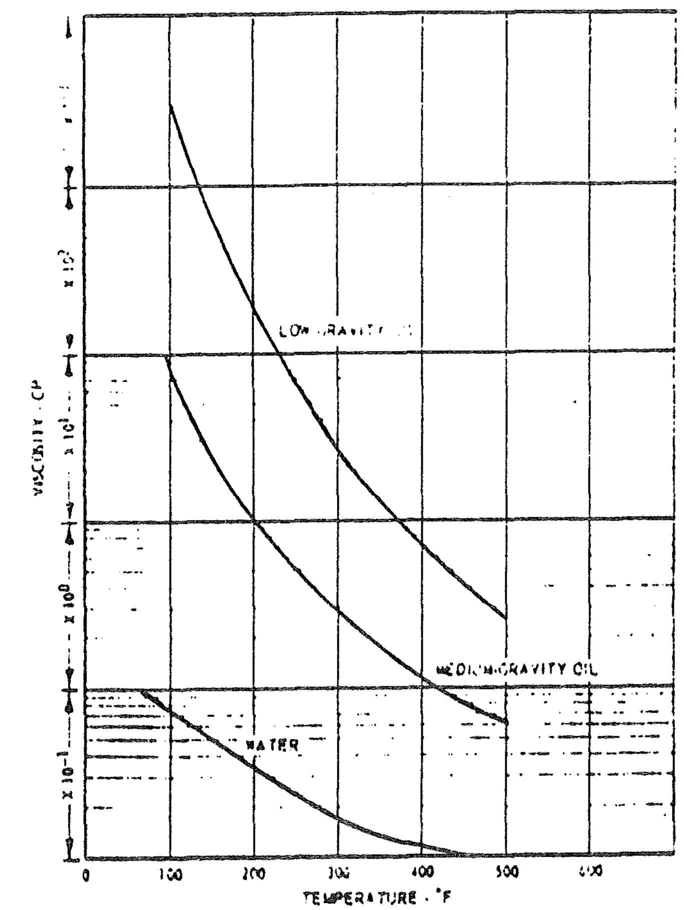


Figure III-10. Effect of Temperature on Liquid Viscosity

reservoirs producing low-gravity crudes. Since productivity of a well is inversely proportional to oil viscosity, any reduction in viscosity will result in an increase in the well's production rate. The primary object in a thermal stimulation process, therefore, is to get thermal energy into the formation and allow the rock to act as a heat exchanger and permit storage of the injected heat. This heat may then be used effectively to lower the viscosity of the oil flowing through the heated region.

Besides the benefit obtained from reduced viscosity, an additional amount of stimulation is often produced because of the removal of certain types of near-wellbore damage, such as fine solids, asphaltic deposits, and paraffinic deposits. As with other stimulation techniques, the removal of this damage often causes productivity increases much higher than those attainable by "basic stimulation" which, in thermal stimulation, is caused by the reduction in oil viscosity.

Thermal Stimulation and Damage Removal.

We can illustrate the separate and combined effect of thermal stimulation and damage removal with the help of the simplified radial flow model shown in Figure III-11. This model is similar to the one discussed in the well testing and acidizing lectures, in that it contains a zone of damage (radius r_d, permeability k_d) near the wellbore, and an unaltered zone (radius r_e, permeability k) extending to the drainage radius, but in addition it contains a third zone (radius r_h, permeability k) which has been heated to some uniform temperature higher than the remainder of the reservoir. The permeability of the oil in the "cold" region, μ_{oc}. Calculation of the amount of stimulation, assuming that the heat reduced the oil

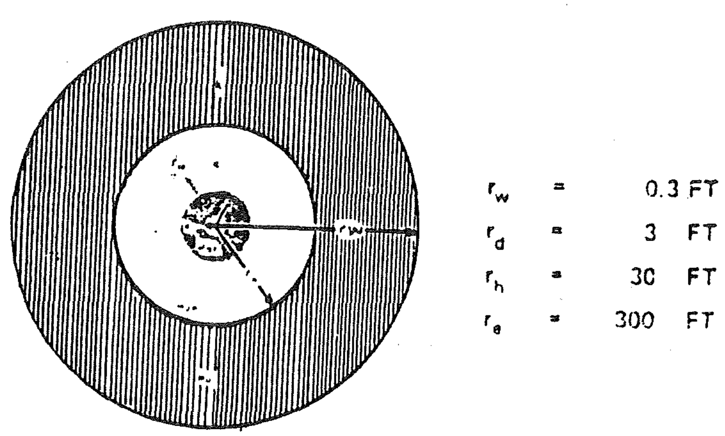


Figure III-11. Simplified Radial Flow Model for Thermal Stimulation Calculations

viscosity 100-fold in the heated zone, illustrates the following points:

1. Under the assumed conditions, which represent reasonable field values, a three-fold stimulation ratio is the maximum that can be expected due to a viscosity reduction alone in an *undamaged* reservoir for a 100-fold viscosity reduction.

2. In a *damaged* reservoir, the maximum stimulation obtainable is the product of the stimulation ratios obtainable for heat alone and damage removal alone. For example, for a moderately damaged well the stimulation ratio can be 11.8 (4.0 x 2.94). Even if the damage is not removed, the stimulation ratio is nearly as high (10.3). It should be noted, however, that although the peak stimulated rate may be only slightly lower than for the case where the damage is removed, the decline is more rapid, and the rate returns to its pre-stimulation value as the reservoir cools.

Duration of Improvement.

The productivity improvement resulting from a thermal stimulation process is only temporary, since the heated region is cooled in time by conduction to the surroundings and by heat removed with the produced fluids. As the temperature drops, oil viscosity increases, and the stimulation effect is diminished. The stimulation process may be repeated to maintain the overall production rate at a higher level than its pre-stimulation value but the stimulation benefits from succeeding treatments will decrease. Much of the field evidence accumulated to date indicates these reduced benefits result from declining reservoir pressure and an increase in the water saturation in the wellbore region. The maximum number of treatments which may be successfully applied varies from one field to another. In some California fields where steam stimulation was successful, six to ten stimulation cycles have generally been run before a well can no longer be used.

<u>Calculations Are Used to Predict Results</u>.

The thermal stimulation process is not applicable to all reservoirs containing heavy oils. The effects of a great many other variables must be evaluated when considering the application to a particular well. A calculation procedure which makes it possible to study the effect of each variable on the expected behavior of the stimulated well is presented in the references. Though a simplification of physical reality, this method has a sound theoretical foundation and employs heat transfer and fluid flow theory to form a comprehensive analysis.

The heat transfer model accounts for cooling of the region heated around the wellbore by both vertical and radial conduction of heat to unproductive strata. These heat losses are calculated for the injection, shut-in, and production phases of an individual cycle. Heat losses can be calculated for any number of productive sands separated by unproductive rock.

The oil production rate increase which occurs due to heating is calculated by radial flow equations which account for viscosity reduction in the heated area. The response of succeeding cycles of steam injection after the first can also be calculated with this method. Heat left in the formation at the termination of

the previous cycle reduces heat losses during succeeding cycles.

Many factors to be considered when selecting a thermal stimulation project, such as fuel costs, water treating, market price of the oil, and equipment requirements, lend themselves readily to economic analysis. Many other processes and reservoir parameters, which are not so readily evaluated, have been studied using this calculation method. The results are presented in Figures III-12 through 16 (the reservoir and injection data used for these figures are given in Tables 4 and 5). The *incremental oil/steam ratio* was selected as the primary dependent variable for these studies since it can be directly related to the economics of the process. The incremental oil/steam ratio is defined as the ratio of the increased oil production to the amount of the steam injected expressed as barrels of water. The oil/steam ratios referred to in the following discussion are the cumulative values which occur when the oil production rate has returned to its pre-stimulation value

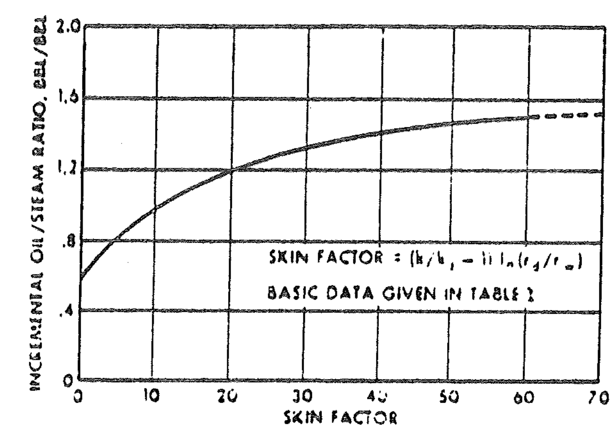


Figure III-12. Effect of Skin Factor on Calculated Incremental Oil/Steam Ratio

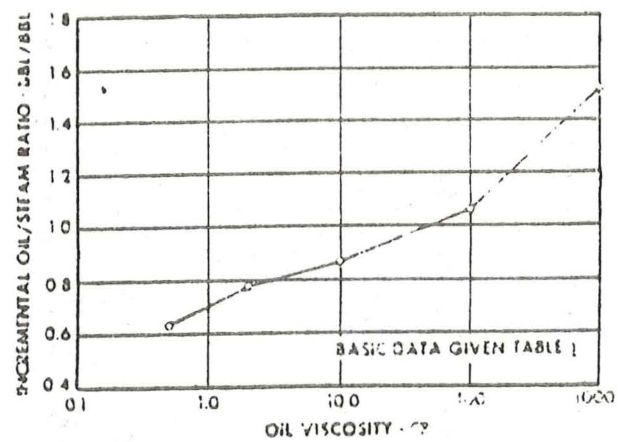


Figure III-13. Effect of Initial Viscosity on Incremental Oil/Steam Ratio

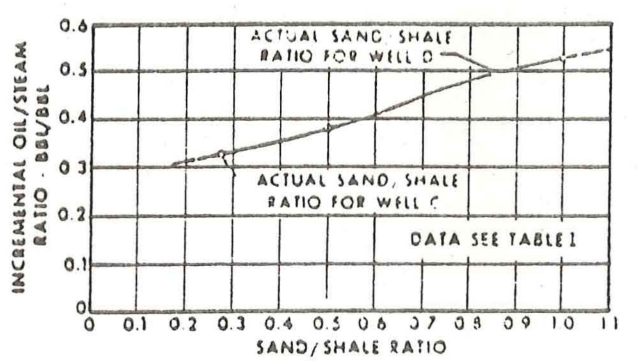


Figure III-14. Calculated Effect of Sand/Shale Ratio on Incremental Oil/Steam Ratio

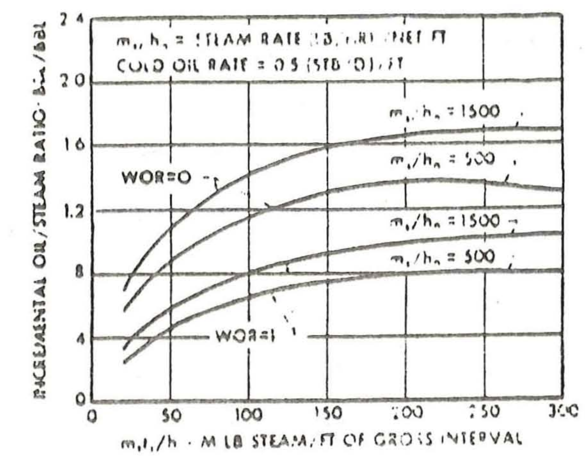


Figure III-15. Theoretical Prediction of Incremental Oil/Steam Ratio vs. Steam Injected

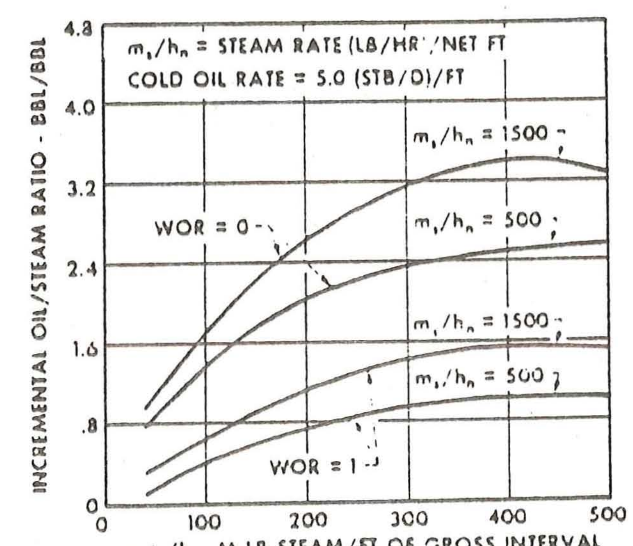


Figure III-16. Theoretical Prediction of Incremental Oil/Steam Ratio vs. Steam Injected

TABLE 4

STEAM STIMULATION TEST AND CALCULATION DATA

Reservoir Characteristics	Well A (Fig. III-3)	Well B (Fig. III-4)	Well C (Fig. III-5)
Depth, ft	1250	3000	3740
Section Thickness, ft	400	200	1088
Net Sand Thickness, ft	400	67	234
Number of Sands	1	6	18
Reservoir Temperature, °F	100	100	120
Oil Viscosity, cp			
at TR	2000	0.5-1000	133
at 300°F	9	0.08-6	8
Skin Factor	0-100	0-5	0
Effective Well Radius, ft*	0.181	0.00176	0.00176
Prestimulation			
Oil Rate, B/D	10	300	99
Oil Productivity Index, bpd/psi	0.1	1.0	0.3
WOR, bbl/bbl	0.029	1.0	0.57
GOR, scf/bbl	63	1000	600
Stimulation			
Steam Injected, MM lb	3.0	40.	16.6
Wellhead Injection Surface Conditions:			
Pressure, psig	290	780	770
Temperature, °F	420	520	5.8
Steam Quality, dim	0.8	0.95	0.95
Injection Time, days	7	80	55
Shut-in Time, days	3	4	5

TABLE 5

CALCULATION BASES FOR FIGURES III-12 THROUGH III-16

Original Reservoir Temperature, °F	125
Original Reservoir Oil Viscosity, cp	70
Oil Gravity, °API	16.5
Oil Specific Heat, Btu/lb °F	0.482
Formation Thermal Diffusivity, ft^2/D	0.632
Formation Thermal Conductivity, Btu/D/ft °F	24.0
Sand/Shale Ratio	0.5
Average Individual Sand Thickness, ft	13
Formation Depth/Section Thickness RAtio	14.6
Effective Well Radius, ft	0.25
Effective Drainage Radius, ft	1000
Normal Producing Bottom-Hole Pressure, psia	300
Static Formation Pressure, psia	1000
Producing Gas-Oil Raio, scf/bbl	500
Shut-in Time Following Injection, days	3

Effect of Skin Damage

As already illustrated in Figure III-12, it is apparent that the amount of *skin damage* present in a well prior to stimulation can have a tremendous effect on the production response of the well when it is steam stimulated. This is true even if no damage removal is obtained, although the stimulation benefits are greater when the damage is removed.

Figure III-14 shows the effect of skin damage on the incremental oil/steam ratio for a stimulation cycle for a typical California well (Well A). These results are based on the assumptions that no damage was removed by the steam. Calculations were made assuming skin factors ranging from o to 60. Figure III-16 shows that the calculated incremental oil/steam ratio increases significantly as skin factor increases over this range.

Effect of Cold Oil Viscosity

For a given temperature rise, the *viscosity reduction* of a low viscosity oil is much less than for a high viscosity crude. Thus, the increase in peak oil rates following steam injection will be smaller, the lower the original oil viscostiy. The effect of cold oil viscosity on the incremental oil/steam ratio is shown in Figure III-13. The results show more than a two-fold increase in incremental oil recovered for a 1000 cp oil as compared with a 1 cp oil for the same amount of steam.

Effect of Sand/Shale Ratio

The effect of the *sand/shale ratio* on the incremental oil/steam ratio for a cycle is depicted in Figure III-14. The net sand thickness and number of sands was held constant in these

calculations, and the gross section thickness was varied in order to vary the sand/shale ratio. The decline in the incremental oil/steam ratio as the sand/shale ratio decreases is the result of increased heat losses to the interbedded shales. The incremental oil/steam ratios for stimulation jobs on two wells in the same reservoir are shown in Figure III-14. The wells are similar except for their sand/shale ratios (data for Well C is shown in Table 4). The sand/shale ratio for Well D was much higher than that for Well C which largely explains the more favorable response by Well D.

A low sand/shale ratio is probably the explanation for the economic failure of some steam stimulation projects, although the conclusions about sand/shale ratio hold only if the sand and shale beds are interspersed throughout the entire production section. For example, a well that had two 100-ft sands separated by 800 ft of shale would respond to steam stimulation more favorably than a well that had twenty sands each averaging 10-ft thick separated by 42 ft of shale even though both wells would have the same gross and net sand thickness and the same overall sand/shale ratio. The two sands would lose much less than the twenty sands because of less contact area between sand and shale.

Effect of Pre-stimulation Water/Oil Ratio, Oil Production Rate and Rate of Steam Injection

The effects of *pre-stimulation water/oil ratio, oil production rate and rate of steam injection* are shown in Figures III-15 and III-16 (data are given in Table 5). Oil production rates and steam injection volumes are shown on a per foot of gross thickness basis. The effect of a high pre-stimulation water/oil ratio is greatest at the higher oil producing rates. This can be seen by comparing Figure III-16 with Figure III-15. The incremental oil/steam ratio also shows a much more rapid increase with increasing rate of steam injected per foot of gross interval for higher oil production rates. An explanation for the better response for higher oil rate wells is that for higher production rates and a given energy input, cycle times are shorter and a greater fraction of the energy injected goes to heating the produced oil and less is lost to the shales and produced water. Since the heat capacity of water is approximately twice that of the crude oil, a high water/oil ratio results in a high rate of energy removal as fluids are produced from the formation.

Effect of Process Control Variables

The *steam injection rate* should be as high as possible while keeping pressure within equipment limitation and below the fracture level. High rates provide two benefits: first, wellbore heat losses as a percentage of total heat injected are reduced, and second, a given amount of energy can be injected in a shorter period of time, thus minimizing the production loss while the well is being steamed. The latter benefit is magnified in higher producing rate wells.

It should be noted in Figures III-13 and III-14 that as the *cumulative steam input* is increased, the incremental oil/steam ratio curves pass through a maximum and begin to decline. Thus, there appears to be an optimum level of steam input for a given set of operating conditions. The incremental oil/steam ratio falls off at high steam injection levels because of the following factors: (1) increased heat losses associated with the larger heated radius and longer cycle times resulting from higher energy inputs, (2) increased lost production as the

length of the injection period is increased, (3) a lower rate of increase of the heated radius with energy injected as the heated radius becomes relatively large, and (4) a diminishing incremental benefit to the productivity index by further increasing the heated radius.

The *back-pressuring* of a well early in the production phase of a stimulation cycle can theoretically result in substantial increases in the cumulative oil produced at cycle end. Back-pressuring prevents or minimizes the flashing of produced water to steam which wastes large quantities of heat. A pumping well can be back-pressured by one of two methods. First, the annulus pressure can be controlled manually while the well is pumped off. Second, the well can be back-pressured more or less automatically by the column of liquid that will exist above the pump when pump capacities are rate limiting.

Theoretically, the optimum program of back-pressuring a well would be one in which the producing bottom-hole pressure is maintained slightly above the saturation pressure for steam at the existing bottom-hole temperature. This would provide the maximum drawdown possible without flashing a large fraction of the produced water to steam.

Evaluating Steam Stimulation Prospects

A set of criteria for selecting steam stimulation candidates has evolved from mathematical studies, such as those referred to above, and from the field performance of thermally-stimulated wells. These criteria are useful for initial screening, but must be supplemented by a more careful study of the physical reservoir and fluid parameters and their probable behavior during and after the stimulation.

The optimum criteria are:

1. *Crude gravity less than 15° API.* Steam stimulation has been applied to oils ranging from 10 to 40° API; the lower limit is due to the difficulty of moving heavy crude through the cold portion of the reservoir. The upper limit is due to the less significant effects of heat on viscosity.

2. *Oil saturation of at least 1200 bbl/acre-ft.* Reservoirs being stimulated at present range from 600 to 2000 bbl/acre ft.

3. *Reservoir porosity from 10-30%.* The greater the porosity the greater the transfer of heat to the oil-in-place.

4. *Net sand thickness of at least 50 feet.* With thicker sands, the ratio of surface area across which vertical heat transfer and heat losses occur is less. Accompanying this criteria is the preference for a high sand/shale to minimize heat losses to the shale. Excessive stratification can be a severe problem.

5. *Reservoir depth less than 3000 feet.* Reservoirs from 40 to 8000 feet deep have been thermally stimulated. The limiting factor at shallow depths is the pressure which may be applied without causing fractures. The limiting factors for deep wells are wellbore heat losses and high injection pressures. The critical pressure for steam is 3211 psig, above which saturated steam cannot exist and superheat temperatures become extremely high, requiring special equipment.

6. *Low producing water-oil ratio.* Because of its high heat capacity, water can use up much of the thermal energy which would otherwise be contributing to the reduction of oil viscosity.

7. *Sufficient reservoir pressure.* An obvious, but sometimes overlooked, fact is that steam stimulation, like all stimulation techniques, does not create any new reservoir pressure; "dead" reservoirs cannot be stimulated.

8. *High pre-stimulation production rate.* Injection cycles are shorter and heat losses to shales are less for higher rate wells.

9. *Large skin factor.* As previously discussed, stimulation of damaged wells can result in dramatic productivity increases even if the damage is not removed. If damage is removed, the well will produce at rates above the pre-steam rate even after the heat has dissipated.

10. *Good mechanical condition of the well.* Tubing, casing, and cement must be in top mechanical condition to withstand high temperatures. Screen, gravel pack, or other provisions must be made in some fields to stop accelerated sand production.

Water Supply and Treatment

A successful and economical steam recovery project needs an adequate water supply that does not require excessive treating. Before planning a large steam generator, the economics and feasibility of treating the available water by filtration, and deaeration, as well as with saoftening agents and pH adjusting chemicals should be studied to be sure that this is a viable system.

Steam Generators

A once-through or forced circulation steam generator is preferred because, since only about 80% of the water is vaporized, the feedwater can contain a relatively high soluble solids content. Also, the once-through units do not use separator drums and therefore do not need level controls and do not require blowdown. Most common sizes now being used are in the 10,000,000 to 22,000,000 BTU/hour range. Recently, several units of 100,000,000 BTU/hour and even larger have been set in the field. These larger units provide lower cost steam.

Fuel Supply and Burners

Both natural gas and oil are being used to fire once-through steam generators. Residual fuel oil may be brought in by pipeline or tank truck, or lease crude may be used. Although oil is cheaper on a BTU basis in most places, gas requires a lower equipment investment and less maintenance. Gas does not require storage tanks, fuel preheaters, fuel atomizers or start-up air compressors, and controls are simpler. The cost of oil burners and auxiliaries runs about 10-15% more than gas burners.

Surface Transmission Lines

Lines must be sized and insulated to minimize both heat loss and pressure drop of the high-pressure, high-temperature steam. Expansion loops and/or joints will be required.

Wellheads and Wellhead Connections

The following special provisions must be made in regard to wellheads:

1. Unless all devices to compensate for pipe expansion are placed downhole, wellheads must contain sliding seals for pipe movement.

2. Flow lines or steam injection lines must be flexible at the Christmas tree connection.

3. Allowance must be made for pressure capacity reduction of the metal because of temperature.

4. Well workovers require special high-temperature blowout preventers.

Downhole Equipment and Heat Losses

Two factors deserving serious consideration in the design of well completions for use in a steam injection operation are *wellbore heat losses* and *casing temperatures*. Obviously, the heat losses between the surface and the injection interval can have a tremendous influence on the efficiency of a steam injection process. Casing failure resulting from an excessive temperature increase has been one of the major problems associated with the steam stimulation process.

The calculation of the wellbore heat losses and casing temperatures for different types of well completions requires a knowledge of the pressure and temperature distribution in the wellbore for specified injection conditions. Various methods are available for the estimation of wellbore heat losses. The results of heat loss calculations for various wellbore conditions and for a wide range of injection rates and times are summarized below:

1. Significant pressure drops can occur during steam injection down a wellbore.

2. Heat losses decrease rapidly during the first few days of steam injection but decline slowly thereafter (Figure III-17).

3. The instantaneous percent heat loss increases rapidly with decreasing injection rates (Figure III-18).

4. Significant reductions in both the heat losses and casing temperatures can be achieved by using a tubing packer and dry annulus and by aluminum-painting the tubing (Figure III-19).

Failures of casing have occurred mostly in old wells where deteriorated casing or poor cement jobs were present. In addition to setting tubing packers to reduce casing pressure and temperature, the best preventive measures are (a) recementing old wells, if casing condition and formation characteristics indicate a chance for success at reasonable cost, (b) proper cementing of new wells with high-tempereature cement, and (c) proper provision for expansion and contraction.

Tubing failures are rare because tubing is usually run in good condition and provision is made for expansion, either by a downhole expansion joint or a sliding wellhead seal. High temperature thread compound is used.

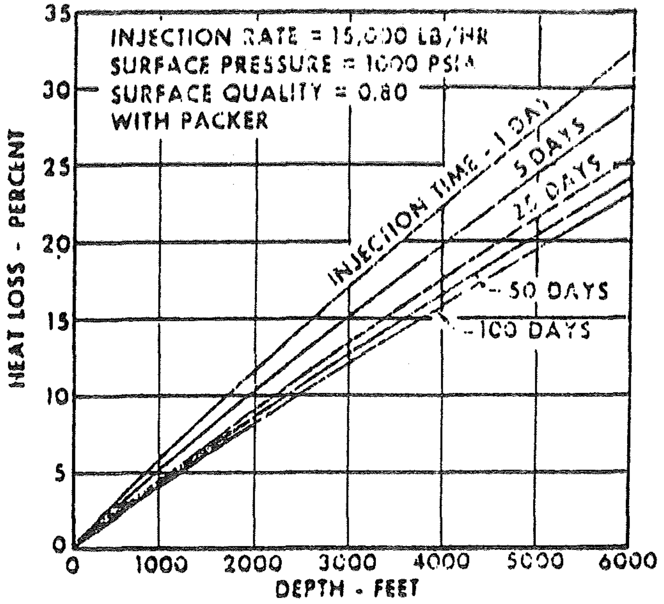


Figure III-17. Effect of Injection Time and Depth on Percent Heat Loss

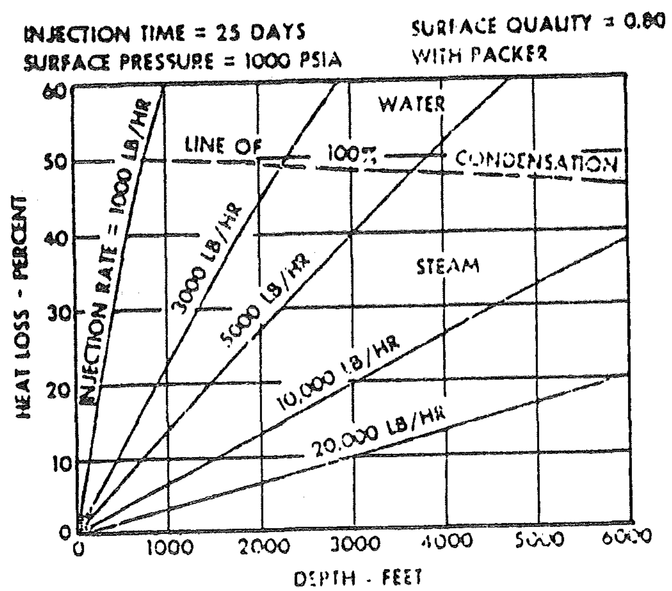


Figure III-18. Effect of Injection Rate and Depth on Percent Heat Loss

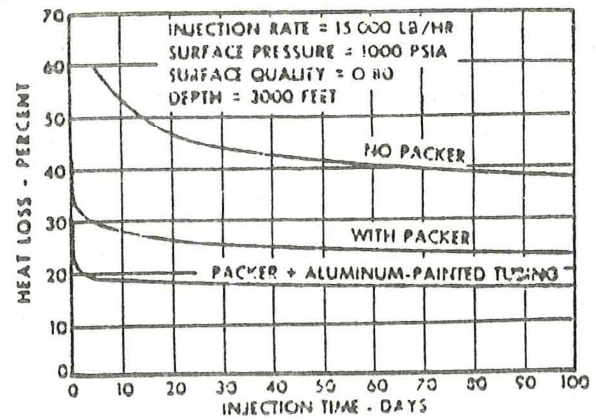


Figure III-19. Effect of Well Completion Method and Inejction Time on Percent Heat Loss

Sand Problems, Plugging, Emulsions and Corrosion

Some thermal recovery projects have been abandoned because of serious damage to the well from *sand production*. A resin-coated sand, called Super Sand, now provides permanent protection from sand production and largely replaces slotted liners, gravel packing, and ceramic screens which have been used with partial success in the past.

Steam stimulation has been reported to be unsuccessful in formations containing swellable clays because of plugging; at present there is no remedy for this problem.

The mixing of viscous crude with high-temperature steam in the producing zone creates *emulsions* that are difficult to break in many cases. These emulsions should be broken and residues discarded upstream from the production storage and handling facilities. The type of emulsion produced varies with the type of crude, so emulsion breaking equipment or chemical should be selected for each specific case after pilot runs have established the characteristics of the emulsion.

All of the *corrosion* problems normally experienced in oilfield production will be aggravated because of the increased temperatures; inhibitor treatment and careful alloy selection is required to minimize deterioration of downhole equipment.

Safety

Steam stimulation is an operation for which oil field supervisory personnel and labor are not normally trained and which involves equipment that can explode or cause burns. Adherence to pressure vessel codes, steam codes, and the services of a competent safety engineer are essential.

Special training should be provided for the handling of hot metals, hot oil, and hot water. All wells should be considered as flowing wells, since a pumping well under high temperature may flow ahead of hot fluid at any time. Steam lines subject to rapid change in flow rates and temperatures may buckle and break. Steam lines not buried should be tied down securely. Special blowout preventers and an adjustable-height working platform on each well will be required.

C. Mechanical, Jetting, and Drainhole Drilling

Summary

There are many mechanical devices that are run to unclog tubing and perforations. Early patent literature shows the gradual development of scratchers, wires, and brushes into hydraulically assisted treating tools. One of the tools widely used today for well plugging and scale deposition is a swab and drop tool which puts a suction on the formation, then a pressure surge. Another way to treat the perforations and the near-wellbore region is with a jetting tool which squirts high-pressure water or acid at the perforations or in an open hole section. Another mechanical treatment possible for a geothermal well is to use drainhole or sidetracked drilling methods near the producing formation. This may be effective when scale deposition and high near-wellbore pressure drop has lowered the production rate to an unacceptable level. It may also preclude the need for drilling a new geothermal well.

Swab-and-Drop

Swab-and-drop is a novel method for removing plugging materials from wells. The technique employs a casing swab run on tubing. The tubing is reciprocated to alternately apply a vacuum and a pressure surge to the producing interval. Fluid is produced out of the annulus as the string is being hoisted. A circulating valve is provided for periodically reverse circulating to remove the plugging materials loosened during the vacuum-pressure surge cycles.

The tool, which is illustrated in Figure III-20, can be fabricated from stock items. Although originally designed for

water-injection wells, the swab-and-drop technique should work on production wells that have skin damage.

The main operational points to be considered are:

1. Extremely high-pressure surges can be generated during the treatment. In fact, a fracture network is probably created in the vicinity of the wellbore.

2. The rate of reciprocation will be governed by the rate of influx of reservoir fluids. This rate is established at the outset of the treatment and should be fast enough to create a low pressure below the swab. The tubing is held in the "up" position long enough to allow fluid to accumulate below the swab to give a good pressure surge on the drop cycle.

3. The tensile limitations of the tubing should be considered at all times.

4. The service rig should be capable of dropping the pipe rapidly; parachutes at tubing joints slow the descent of the tubing after it contacts the wellbore fluid which aids in producing the pressure surge.

5. The wellbore should be circulated clean before starting to reciprocate and after ten or twelve swab-and-drop cycles as experience dictates. The fluid returns should be checked for the amount and nature of the plugging materials. The treatment is continued until the returns are relatively clean.

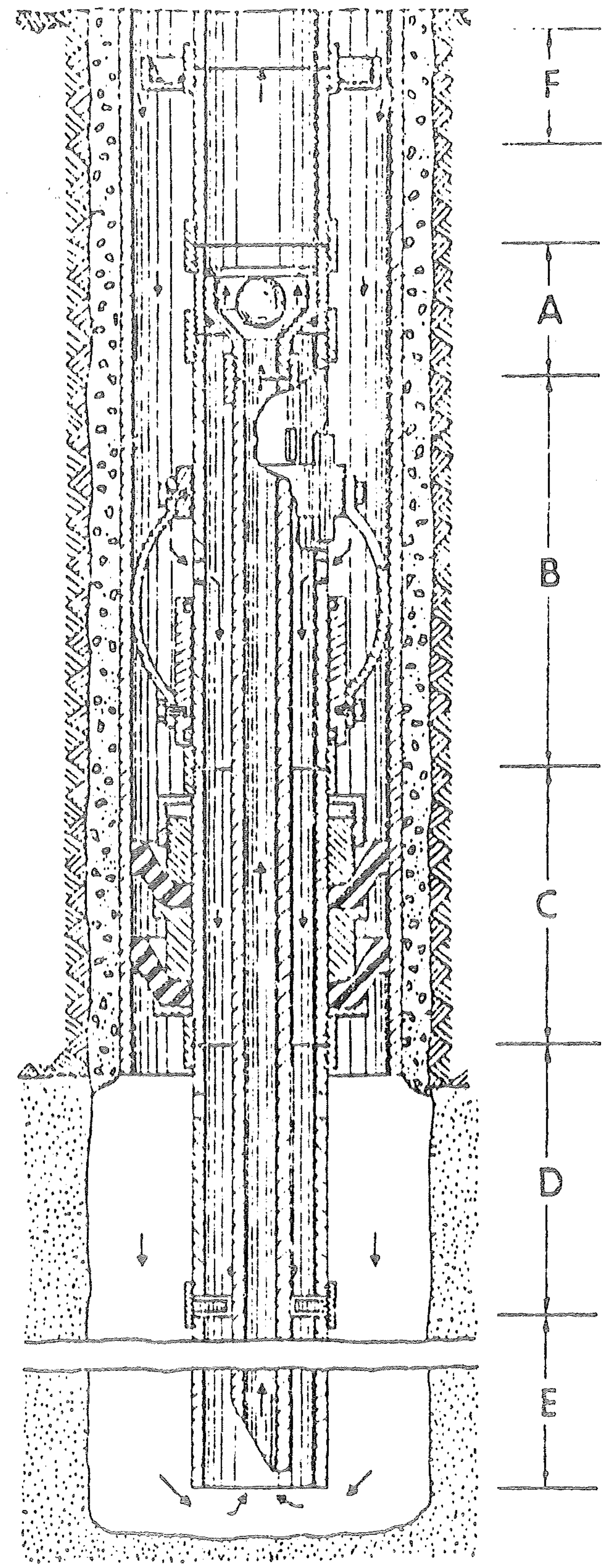


Figure III-20. Swab-and-Drop Device

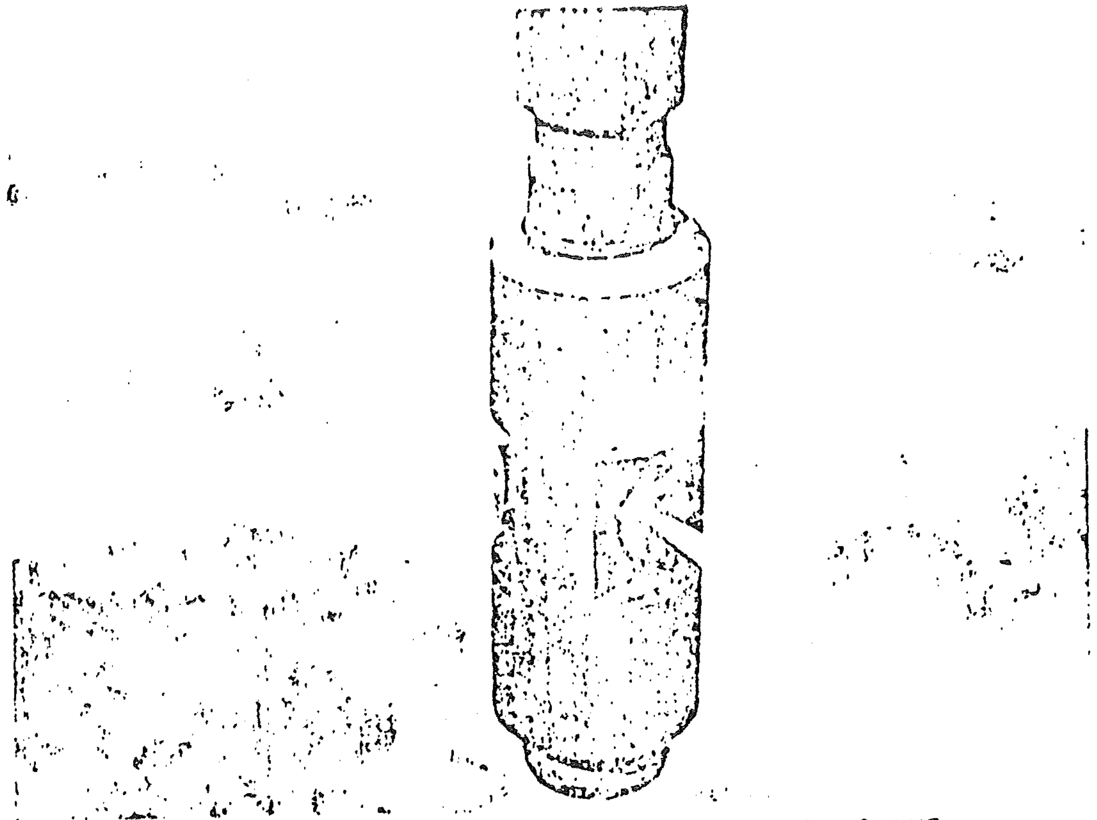
6. Swab-and-drop treatments should be attempted only when the available data indicate a particle plugging problem exists.

Jet Cleaning and Acidizing

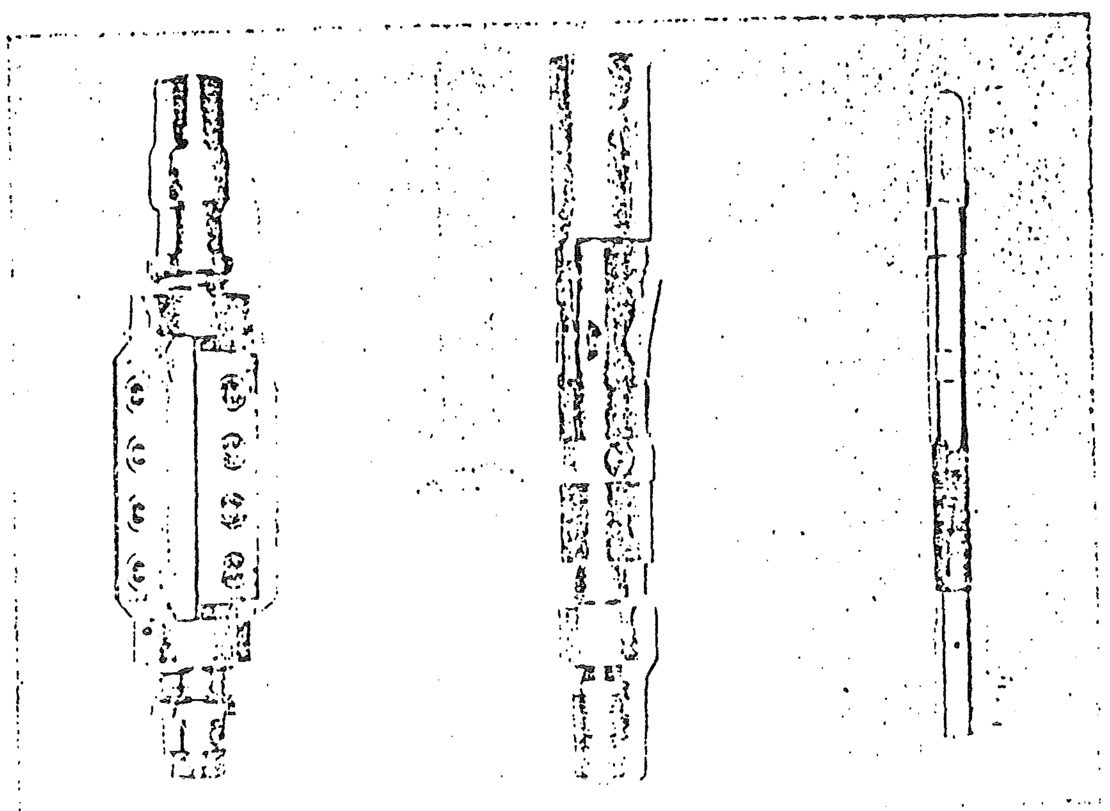
Jetting techniques can assist wellbore clean up by a combination of hydraulic and chemical action. As most chemical reactions are accelerated by agitation, the jetting technique can be applied to practically all chemical well treatments. Treatments have been conducted with acids, scale and mud removal solutions, paraffin solvents, and surfactants in oil-base or water-base carriers.

The tool is generally run on tubing with two or three jets oriented radially in one or two planes. After it is run in, a ball is dropped that seats in the bottom of the tool. Generally, a feed rate through the jets is established and the treatment is then scheduled for a given interval of time at different levels in the wellbore. Figure III-21 illustrates the jetting gun, a rotating hold-down for maintaining a fixed position when cutting a horizontal notch, a mechanical collar locater, and a pump down gun which will seat in a nipple located at the bottom of tubing.

When possible, the intervals to be treated should be determined on the basis of a log or core analysis. Depth control can be obtained by tubing tally, measuring wireline inside the tubing, mechanical collar locator, or by tagging bottom and picking up.



SINGLE-STAGE GUN WITH JETS IN ONE HORIZONTAL PLANE



ROTATING HOLD-DOWN

COLLAR LOCATOR

PUMP – DOWN GUN

Figure III-21

A horizontal plane can be jetted by rotating the tubing with power tongs or a vertical plane can be jetted by lowering the pipe in short increments. As discussed in the chapter on perforating, sand can be introduced into the treating fluid to cut holes through casing, cement, or formation.

Acid jetting is a good method of cleaning up open-hole intervals after original completion and for removing scale deposits. The hydraulic action loosens the insoluble materials and the fluid used, either acids, surfactants in a carrier, or solvents, chemically removes the soluble material.

Abrasijet and *Hydra-jet* are the respective Dowell and Halliburton trade names of their tools. For single, moderate-volume treatments, jetting tools can be frabricated at a small cost and left on the tubing to avoid an extra tubing trip.

Drainhole Drilling

Horizontal drainholes have been drilled in producing wells to stimulate production. Several electrolytic model studies have been presented describing the effects of drainholes on well productivity. Partial results of one such study are illustrated in Figure III-22. Note that for drainhole lengths of 10 to 20 percent of the draining radius, productivity will be approximately doubled if 2 to 4 drainholes are drilled.

Special directional drilling techniques and equipment are used for drainhole drilling. The unique aspect is a flexible drill collar fabricated by cutting a drill collar circumferentially in a cloverleaf pattern every eight to twelve inches, Figure III-23.

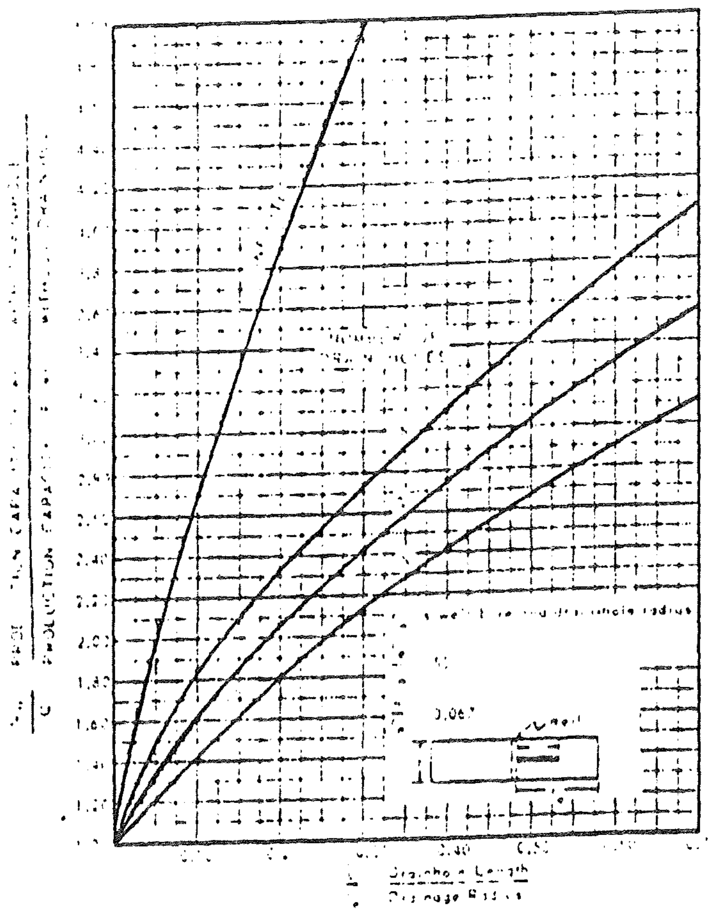


Figure III-22. Effect of Drain-hole Drilling on Production Capacity

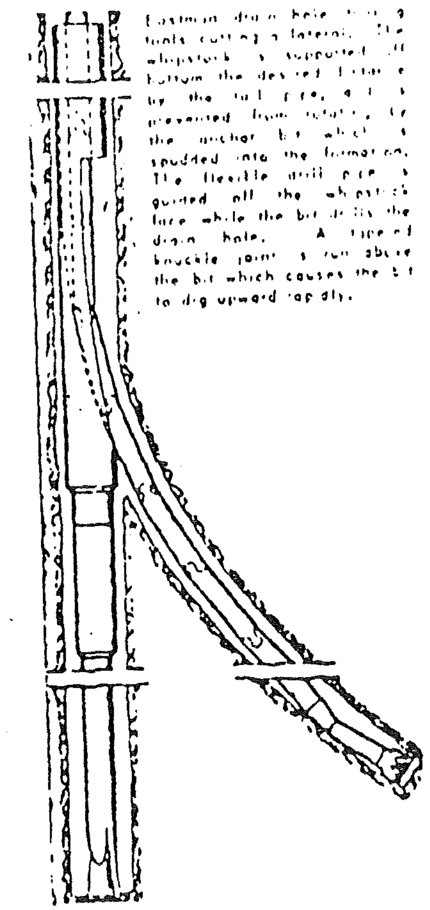


Figure III-23

The cuts are beveled to prevent the pipe from parting laterally. Circulation is maintained through a rubber hose inside the drill collar. Deviation as high as 90° can be reached within 20 ft, after which the borehole is extended horizontally as far as 100 ft.

This type of completion has had limited use in California, West Texas, Venezuela, Western Canada, and Sicily. The service is offered by the Eastman Oil Well Servicing Company; Continental Laboratory Inc., Billings, Montana; and Oilwell Drainhole Drilling Company, Long Beach, California.

When drainhole drilling is being considered, an experienced, reputable company should be employed. Drilling must be carried out at low rotary speed and bit weight to avoid twisting off or sticking the flexible pipe. The equipment is extremely difficult to fish. Twisting off and sticking problems are more pronounced in naturally-fractured, hard-rock reservoirs.

Other methods for drainhole drilling have been proposed recently where turbodrills and mud motors are used for quick deviated drilling. These methods no longer require low weights and speeds with the state-of-the-art advances in downhole motors.

D. Explosive and Implosive

Summary

Wells do not respond to explosives unless you are in "hard rock" stripper wells in the Appalachain region. Explosives can shock and sometimes demolish the tubing, formation, and the cement job with the results usually negative. For geothermal, this is an extremely poor choice for stimulation since it is difficult to produce high flow rates from a rubblized zone.

Better luck has been obtained with an implosive tool where the tool loosens and removes particles and some plugging. This method has disadvantages, but in combination with other devices and treatments, there are some possible applications of implosion treatments for geothermal wells.

Explosive Stimulation

Shooting a well involves loading and firing an explosive charge placed in the wellbore opposite a section of oil-bearing or gas-bearing rock. The purpose of shooting is to increase production by enlarging the wellbore and creating a zone of fracturing in the reservoir rock around the wellbore.

The original use of explosives in wells is credited to Col. E. R. Roberts, who made application for a patent in 1864. The first treatments were done with a black powder which was replaced by liquid nitroglycerin in the 1870's. Liquid nitroglycerin is still used although solidified nitroglycerin, nitroglycerin gelatins, and 60 percent ammonia gelatin dynamite are also used. More recently, the use of nuclear explosives have been used experimentally in thick, low permeability gas reservoirs. The Talley-Frac process is sometimes used where a viscous liquid explosive is pumped into the rock matrix and detonated to form a fracture network. Presumably, the rock will be sufficiently pulverized to prop itself. Usually the fines generated are more of a nuisance than any actual stimulation that might be gained.

Explosives are credited with the economic development of numerous low-permeability reservoirs. Although the use of explosives declined with the advent of acid treating in the early 1930's and hydraulic fracturing in the late 1940's, it is still the prime method of stimulating "hard rock" stripper wells in the Appalachian area.

Considerable effort has been expended to relate explosives technology to rock mechanics and to fluid flow in a porous media. Several theoretical treatments of the subject have been presented and a number of expirical correlations have been made to aid in designing a treatment. Despite this, treatments are largely based on local experience. The amount of nitroglycerin used has varied from 5 to 200 qts; the smaller shots are used primarily to overcome skin damage. Some shots are tamped or stemmed with sand, water, or cement, and some have been detonated untamped. Although most treatments have been conducted in open hole, some shooting has been done in casing below a cement plug.

The conditions under which explosive stimulation is most applicable are:

1. A limestone, dolomite, or extremely hard well consolidated sandstone.

2. A long open-hole completion to allow tamping within the open-hole section. It has been found from experience that if water is used for tamping, the fluid should be contained within the open-hole section to avoid damage to the casing string.

3. Service rig charges should be low enough to allow for several days' cleanout time by bailing, drilling, or swabbing.

4. Generally, treatments have been more effective where there is some evidence of skin damage.

Implosion Stimulation

Baker Oil Tools Inc. have available, as a service, a tool for loosening and removing plugging materials from the face of a producing section by implosion. The tool is called a Baker Model F Stimulation Valve and can be run on 2-3/8 inch or 2-7/8 inch tubing. The technique was developed for injection wells, but has since been used on producing wells.

The tool was developed on the principle of a drill stem tester and is essentially a fast-acting valve run on tubing in conjunction with a packer. The tubing is run in the hole, either empty or with a water cushion, the packer is set, and the valve is opened by rotating the tubing. The rapid application of a pressure differential and the resulting high-fluid velocity across the completion interval dislodge the plugging material. The wellbore can then be reverse circulated to remove the plugging material by unseating the packer. Any height of section can be isolated and treated by setting a bridge plug in the wellbore before treating.

The technique is not widely used for stimulation, but is more often used as a substitute for a swab to bring a well in.

E. Injection Methods

Summary

To get oil out of wells almost every conceivable fluid has been reinjected back into the wells. Fluids that are solvents for scale or deposition are commonly used. Also, aromatic oils and hot oils of various types are used to dissolve asphaltenes and paraffins in older wells. The most effective use of these solvents is when flow restriction (to more permeable zones) is used. Some type of solvent injection may be of benefit in geothermal wells since wellbore damage can be self-destructive and severely limit flow rates.

Solvent or Oil Injection

There are a number of solvents commercially available that can be used to treat oil wells having productivity impairment from paraffin or asphalt deposition. An agent commonly used that is available from service companies is *carbon bisulfide;* however, this agent is highly toxic and also flammable. It is expensive unless purchased in large quantities, and when used in large quantities may be objectionable to refiners, as are carbon *tetrachloride* or *tetrachloroethylene.* If chlorinated solvents are used, production should be flared for a time after treatment because these solvents will poison some refinery catalysts if present in the crude oil.

Highly aromatic refined oils are good solvents and generally are much cheaper than the chemicals mentioned above. These materials may be variously referred to as heavy *aromatic naptha, aromatic solvent,* or *aromatic hydroformate.* Generally these solvents will readily dissolve both asphaltic and paraffinic waxes. Their effectiveness may be enhanced by heating and by addition of surfactants.

LPG and other light hydrocarbons such as butane and pentane are not recommended for treating wells for asphalt or wax plugging. The addition of these materials to crude oil can cause precipitation or asphaltenes by stripping peptizing agents from the asphaltene particles.

Crude oil has found limited use as a stimulation agent for producing wells. This technique has proved to be an effective and relatively inexpensive method for improving productivity of wells in some high permeability reservoirs. However, re-injection of crude oil into low permeability strata can cause well damage, particularly if the injected crude oil is below formation temperature.

In many areas, lease crude is used to remove accumulations of paraffin from the wellbore by circulating hot oil in the tubing and annulus. The effectiveness of such treatment depends on getting the hot oil in contact with the wax deposits downhole. It should be kept in mind that in such circulating systems the tubing and annulus constitute an extremely long counter-current heat exchanger. The annulus fluid may be either transferring heat or gaining heat from the formation and the fluid in the tubing. If the well is too deep or the fluid velocity too low, the circulating fluid may actually be dissolving wax deposits from up the hole and reprecipitating them across the productive interval when the bottom-hole temperature is below the cloud point of the oil.

One of the most severe limitations of injecting either solvents or oil to correct damage within the formation is in displacing the material into the zone of impairment. This may require the use of some zone isolation technique such as ball sealers or straddle packers. Simply "bull-heating" a solvent or

oil into the well or even spotting the fluid across the interval will not assure that the impaired zone will be treated. In such instances, the majority of the injected fluid will in all likelihood enter zones of unimpaired permeability and will be relatively ineffective in the damage zone. Zone isolation is helpful in restricting the entry of the treating fluid into the zones requiring treatment.

<u>Treatment of Clay Swelling Damage With n-Hexanol</u>

Severe permeability reductions can occur when relatively fresh water from drilling-mud filtrate or workover fluids contacts clay-containing formations. The most common clay mineral groups are montmorillonite, kaolin, chlorite, and illites. Of course, montmorillonite can cause severe permeability reductions when contacted by fresh water. In general, the lower the original permeability, the larger the percent reduction in permeability.

The presence of clay minerals can be established in a qualitative manner by X-ray diffraction. It can be argued that qualitatively establishing the presence of clay minerals does not necessarily indicate that they are distributed in the matrix in such a manner that they can be contacted by the invading water. However, if montmorillonite is present, there is a very good chance that fresh water will greatly reduce the permeability.

Laboratory and field tests have shown that n-hexonal injection can restore most of the original permeability to fresh water-damaged formations containing montmorillonite. A partially miscible solvent, n-hexanol removes the water from the swollen clay, allowing it to collapse to its original volume.

several miscible solvents, were capable of restoring only part of the original permeability.

Geothermal Wells

Many precipitants and scale can damage the geothermal hot water producing intervals. Some solvents may be particularly effective in removing these scales and precipitants; however, each type of scale will depend on the temperature and chemical makeup of the source water. Much additional work is needed in this area since it involves new technology.

IV. CURRENT STIMULATION TECHNIQUES

There are many types of stimulation techniques in use today. The majority of these techniques involve the injection of fluids to physical crack or preferentially attack the producing formation. There is a great variation in the types of fluid employed and the rates at which they are injected. The fluids may be thin like water or acid or very viscous similar to cross linked polymer fluids. Many of the techniques use proppants to retain the fracture conductively created by the high pressure fluid injection. Also some techniques employ diverting agents, fluid loss materials, fine sand, coarse sand, and other materials for specific tasks.

A. Matrix of Techniques

Table 6 lists 14 different techniques that are now used or have been used in oil and gas well stimulation. Primary emphasis is on the physical and mechanical stimulation techniques although acidizing is also mentioned. A look at Table 6 shows in the first column the generic name for the treatment and then gives a brief description of the treatment. The matrix attempts to answer several questions about the different treatments such as:

- Does it remove wellbore damage?
- Does it provide reservoir stimulation?
- What are it physical fluid properties?
- Is it used with a proppant?
- Are chemical effects important?

Table 6

Matrix of Stimulation Techniques

Potential Type of Stimulation Treatment	Brief Description Of Treatment	Removes Wellbore Damage	Provides Reservoir Stimulation	Viscosity, Sand Carrying, and Fluid Properties	Type of Proppant	Chemical Effects	Fluid Compatibility	Formation Damage	Application to Geothermal Reservoirs	Comments
Water Frao	Planar Frac with water as the fluid, sand as the proppant. Usually high rate jobs.	Yes	Slight, because fractures are too short.	Poor to Fair	Usually sand at low con-concentrations of up to 1 lb/gal.	Minimal	Water has to be compatible.	Minimal if water is com-patible w/formations.	Yes, in certain areas to overcome wellbore damage by scale and to reduce pressure drop.	Plain water will not be as widely used as gelled water since it has no limit in safety factors.
Kiel-Dendritic Frac	Pump in/Flow back multiple stages to create branched fracture in formation, uses various fluids and proppants.	Yes	Yes, Twice the average planar fracture.	Good because of sand slugs carried at high turbulent rates.	Usually fine to 20/40 mesh sand in slugs at high con-centrations 2 to 8 lb/gal.	Minimal	Water has to be compatible.	Minimal if water is com-patible w/formations.	Yes, for increased pro-duction fractures and fractured zones.	Good potential technique for fractured formations.
Pressure Cycling Fracturing	Uses low cycle fatigue of formation to enhance fracturing.	Yes	Yes	Fair to Good	Usually sand at low to medium con-centrations, maybe slugs of sand.	Minimal	Water has to be compatible.	Minimal if water is com-patible w/formations.	Yes, for increased pro-duction fractures and fractured zones.	Good potential technique for fractured formations.
Gelled Frac	Planar Frac using Polymer water and sand	Yes	Yes, Size Sensitive	Fair to Good	Sand usually at low con-centrations 1 to 3 lb/gal.	Water Analysis + Polymer Chemistry.	Water has to be compatible	Polymer debris can damage, check w/core tests.	Yes, standard method.	Good potential in general geothermal work.
Cross-linked Gel Frac	Cross-linked polymers to fully suspend sand or proppant in a planar frac.	Yes	Yes, Size Sensitive	Excellent	Sand, Super Sand or Bauxite at any con-centration to 10 lb/gal.	Water Analysis + Polymer Chemistry.	Water has to be compatible.	Check for damage, cross-link breakage, polymer break-age, residue.	Yes, but temperature sensitivity and cost may moderate or minimize use.	Fair potential in special geothermal work.
Foam Frac	Nitrogen/water mixture with a foaming agent to credit a planar fracture.	Yes	Yes, Size and rate sensitive	Excellent	Sand at low average con-centration be-cause sand only added to liquid.	Surfectants have complex chemistry	Water compatible	Minimal with water & chemistry checked.	No, cost and temperature sensitivity minimize effectiveness.	Poor potential because major attribute of quick clean up required.
Emulsion Frac	Polymer water in oil emulsion carrying sand and other proppant to make a planar frac.	Yes	Yes	Excellent Viscosity tailored to job.	Sand, Super Sand or Bauxite at any con-centration to 8 lb/gal.	Oil, Water & surfactant chemistry check	Complex compatibilities	Usually minimal if checked out thoroughly with reservoir.	No, oil is not wanted in a geothermal well.	Not under consideration for geothermal, widely used in oil and gas wells.
Cool Frac	High rate water or polymer frac to create a planar water fracture in a hot formation.	Yes	Yes	Fair to Good	Sand at low concentrations (small sand to 20/40 mesh).	Minimal short-time fractures, quick trtmt.	Water compatible	Usually minimal.	Yes, high rates give good margin for error-extend fracture into very hot reservoir.	Good potential for long planar fracs in all types of geothermal reservoirs.
Super Sand Frac	Use of a cohesive proppant to prevent sand movement and loss of fracture con-ductivity at high closure stress-uses any fluids to make a planar frac.	Yes	Yes	Good, Size sand for job	Super Sand - a cohesive proppant re-tains perme-ability under high closure.	Minimal phenolic formaldehyde resin.	Water compatible	Minimal because no fines move-ment Super Sand is good down-hole filter.	Yes, no sand flow back permanent stimulation.	Good potential in combination with cool, gelled and kiel-dendritic fractures techniques.
Bounded/Gravity Frac	Use of various densities of fluids, diverting agents, spacers, and proppant to control fracture vertical height and create a long planar frac.	Yes	Yes Height control	Fair to Good	Varies from Nylon, Plastics to sand, Super Sand to Bauxite and steel shot. Also divert-ing agents, spacers, & sealant.	Check heavy & Lt. fluids because den-sity is mod-ified chemi-cally-salts, etc.	Check any fluids used.	Intentional damage on top or bottom of fracture.	Possible, special situation.	Complex technique may be required in areas of low data input.
Matrix Acidize	Low rate acid injection	Yes	No	Poor to None	None	HCL or HF extreme	Before & After Reaction.	Possible and Temp. Effects	Possible, but not likely.	High-Temperature effects unknown.
Acid Frac	High rate acid injection to create an unpropped planar frac.	Yes	No	Poor	Usually only 100 mesh sand low con-centrations.	HCL, HF, or organic acid extreme.	Before & After reaction.	Possible and Temp. Effects.	Possible in certain applications.	High-Temperature effects unknown.
Chemical Inhibitor	Injection of special chemicals & surfactants to control corrosion, inhibit reactions and to lower surface tension.	Yes	No, unless large or com-bination treat-ments.	Fair to Poor	Sand at low con-centrations.	Each chemical might have an effect.	Check overall system for compatibility	Could have damage cap-ability, ck.	Maybe required in certain reservoir for long-term production.	Potential and need unknown at this time.
Erosion Frac	Injection of various fluids at high rates to help clean damage and fine away from wellbore. Makes a planar frac.	Yes	Yes, if also large volumes	Fair to good.	Any abrasive proppant material 1 to 4 lb/gal usual con-centration.	Minimal but check any new fluid.	Water Compatible	Minimal by high rate.	Yes, may be necessary for maximum flow con-ditions and scale removal.	Potential appears good, needs more evaluation.

- Is fluid compatibility a problem?
- Can the formation be damaged by this technique?
- Is it applicable to Geothermal reservoirs?

At the end of the table for each technique comments are made on how the technique might be applied to geothermal well stimulation. Over one-half of these techniques may be used on geothermal wells; however, many more in-depth examinations of the limits of these systems as well as further engineering data and design inputs will have to be applied before one or two of these techniques will be applied to an actual well. One item not explicitly covered by the matrix of properties is that each geothermal well will have different problems and complexities. Each well might be completed differently and the type of formations will vary considerably. For example, when the permeability is low, one type of treatment might be needed, and when high, a completely different technique will be required.

Each service companies has a different name for most of these techniques listed in Table 6. Many of their names for the techniques are quite descriptive such as "Riverfrac®," "Hyrafrac®," "Sandfrac®," Acidgel Frac and Vis-o-frac. When discussing any of the techniques listed in Table 6, you should ascertain what that particular service company calls their technique which matches more closely the concept that you are inquiring about.

B. Other Types of Stimulation

There are many other types of stimulation treatments which people talk about or suggest but are seldom if ever used. Some of these far out ideas may indeed be valuable in our consideration of geothermal wells stimulation.

1. Hot Fluid Injection

Where hot oil is injected to clean up and stimulate oil wells, very hot water or chemical solutions other than acid may do the same thing in geothermal wells. Scale, precipitants and fines could potentially be dissolved or displaced away from the wellbore without damage to the wellbore, pipe or cement. The type of fluids to be used is not known but there may be some surface chemistry advantages to either high and low rate injection of a water based system. This would be a case of using the hot water and high temperatures already there to advantage. New tools should be considered where this might be used as a generally used technique in a particular area.

2. Liquid and Solid Explosives

In desperation, explosives have been used on many oil and gas wells. They work swell in hard rock country where the rock is extremely strong and tight to gas flow and where a cave-in will not kill the well. Unfortunately, explosives have had very poor results in normal oil and gas wells which produce from sandstone, soft or medium strengths limestone or from naturally fractured formations. Usually the wellbore is blown to pieces and the well is choked completely with

debris, fines and collapsed pipe. It is normally impossible to ever get a tool back down to the formation. In almost every new energy project such as oil shale, Devonian shale gas production, and hot dry rock explosives have been tried. In the latter case rocket propellant charges were exploded in the granite, hot dry rock. The complete results gathered using quite sophisticated instrumentation (by LASL) showed no change in fracture size, length or volume. In the California geysers, explosives have been proposed and will probably be used to try and stimulate the steam wells there. If the wellbores are not damaged severely or destroyed, stimulation is possible. However the outcome, it will be closed watched by industry and the Department of Energy.

The main drawback to explosives is the fact that all the energy is expended in micro or milliseconds. Because of this, the great mass of rock that makes up the formation does not have time to move, and rock not moved will be unaffected. Near wellbore effects are devastating and pulverization of the rock is apparent. Pulverized rock is called fines and definitely is not desired near the wellbore. The energy efficiency of cracking rock by fracturing is quite high compared to exploding it since the rock cracked by a hydraulic wedge is done slowly with the rock breaking in tension. The explosive effect is very localized and is not felt usually over 10 or 20 feet away from the wellbore.

V. STIMULATION TECHNIQUES FOR GEOTHERMAL WELLS

A. Most Promising Techniques

To date the most promising techniques for general use in stimulating hot water geothermal wells are the planar frac using viscous polymer water, a proppant and fluid loss additives and the dendritic frac using higher flow rates, slick water, slugs of proppant and a shut-down, flow-back technique to stress the formation.

1. Planar Frac

The planar frac is offered by most service companies under various names based on the type of fluid to be used. The polymer fluid can be a crosslinked or an uncrosslinked system which carries the sand out into the fracture. Fluid costs will be quite important to the general use of this type of technique since large volumes may be required to stimulate one of several zones in a single geothermal well. The use of fluid loss additive will probably be needed in large sections to create a large volume fracture. The permeability of the proppant should be constant under load at reservoir temperature for extended periods (years). The use of large cooling pads of water and high flow rates will help keep the average fracture temperature well below the actual reservoir temperature. This effect is known as convective heat blockage and keeps the fluid in

the fracture cool by fluid leakoff to the formation. Since the frac job only takes a few hours to complete, it is not possible to fully reheat all of the fluid quickly (by conduction). When the well is returned to production, convection and conduction heat transfer quickly heat up the fracture zone and the temperature of the produced fluid rises quickly and approaches the reservoir temperature.

2. Dendritic Fracs

A quite different concept is used in fracturing by downhole stress modification which causes branch (dendritic) fractures, diversion and self propped fractures. The dendritic fracturing techniques.

The Kiel or Dendritic Fracture [99] is usually designed to use the highest possible flow rate that the tubular goods will allow during the treatment. A slick fluid is used to minimize the tubular friction loss. Slugs of fine and coarse sand or other proppants are used throughout the several stages of the treatment. As few as two or as many as 10 or 20 stages comprise the Kiel frac with the actual number of stages depending on the particular properties of the reservoir.

One stage consists of a pad of clear fluid then a slug of fine sand, then another pad to displace the fine sand out into the formation, then another slug of fine sand, another clear fluid pad, then a coarse sand slug, clear fluid and then a shut down-flow back period which allows the formation to close and stress or slough off spalls of formation material. After a brief rest, injection is restarted and the spalls are moved away from the wellbore to block the tip of the fracture. Again, a short shut down and possible flow back period is used to finalize one stage of the Kiel frac treatment. This sequence is repeated as many times as designed for in the particular reservoir. After the second shut down-flow back period, the second stage clear fluid pad is injected. This pad trys to reinflate the old fracture. Since the junk and spalls have been pushed to the end of the first fracture, it is effectively terminated. The new fracture is forced to go somewhere else wherever it breaks down the easiest. The new fracture may follow a minor joint (natural fracture) system or may grow in a different direction relative to the original fracture. This is possible since the first fracture changed the original downhole stress state. According to Shuck[47], the minimum horizontal stress can be changed over a distance of several thousand feet by a large injection or wedge of fluid. Unfortunately, we do not know how to predict the direction of change or exactly how to control the new direction.

Other benefits of the Kiel frac are that its frequent shut downs allow any broken equipment to

be fixed during a shut down period. Common problems are loss of suction line, leaks, valve failures, and out of fuel. In a new area many unknowns govern the optimum stimulation technique; therefore, the first treatment in a new area brings fresh information into the engineering design process and allows a more optimum treatment in the next wellbore.

B. Cost Considerations

The cost of the stimulation treatment is quite important because the technology depends on the actual cost of producing hot water. If the optimum stimulation technique costs a few tenths of a cent per increased barrel of production with little downside risk, then it will be justifiably used at every opportunity. However, if the cost is so high that no amount of increased production will pay it out then other ways must be found to keep the wells productive - or else many additional wells must be drilled.

Basically the stimulation cost can be broken down into 7 major areas which are:

- Well Preparation
- Site Preparation
- Prefrac Testing and Design
- Transportation
- Equipment Rental and Fees

- Material Costs
    - Fluids
    - Proppants
    - Additives
    - Chemicals
    - Tracers
- Testing and Evaluation

Each viable technique that we consider will be compared on the basis of equipment rental, transportation fees and material costs since the other costs are well site specific and will be added to any well workover.

One technique may be more costly but have higher potential for production increase. This must be counter weighed with a risk factor which estimates how likely a failure is to occur. High risk, high cost techniques are definitely not the first choice of this effort since the change to go forward in this area of new technology largely depends on what we learn and what we do during the initial phase of the well stimulation project.

VI. AREAS OF NEEDED INVESTIGATION

When considering the areas of needed investigation, the primary idea is what will have the most effect on stimulation of the geothermal wells. Unless we can economically interpret technology and apply it wisely to the geothermal area of energy production, a valuable energy resource could be lost or delayed from becoming a renewable resource.

Innovative thinking and unusual experiments in the lab are needed. There are several areas where the need for additional investigation is apparent. Some specific areas involve further testing both short and long term properties of all chemicals, fluids, proppants, and materials used in geothermal wells. The interactions of the physical properties versus chemical properties as affected by high temperatures is not well understood and much further testing is required.

Further field tests on wells with both similar and widely varying parameters are required in our background of knowledge. The geothermal program needs to be broad based enough to allow for a substantial number of field tests and multiple tests in areas where information can be recycled and an improved stimulation design can be optimized.

Field observation, supervision, sampling and testing are all essential so that all available information may be gleaned from the field tests. The laboratory procedures and test directions can be modified once the field results point out further unknown areas or interaction.

Finally, radical changes in drilling or completion may be indicated with todays rapid change of technology in those areas. An open mind but innovative ideas are clearly called for to help us optimize hot water, geothermal production.

VII. ENGINEERING CALCULATIONS FOR VARIOUS TECHNIQUES

In this section the tools of engineering design will be discussed and reasons given for how, why, and where these tools can be used in the design of different stimulation treatments. Various service companies will use slightly different techniques with slightly different results.

The important part of the design calculations is the actual scheduling of materials and equipment in an efficient manner to do the job intended. This makes it sound easier than it actually is since there are 12 reservoir parameters to consider and 6 controllable parameters which can be varied during the treatment. Let us first took at the controllable parameters. These are:

- Fluid Loss Control
- Flow Rate
- Fluid Viscosity
- Fluid Temperature
- Proppant Concentration
- Fluid Pressure

At any phase in the treatment these can be varied or changed. The reservoir paramters involve its permeability, porosity, Youngs Modulus, temperature, sonic travel time, type of formation, pressure, fluid viscosity, stress conditions, and other characteristics. These are relatively fixed for a given treatment and are treated as constants for conventional treatments.

In the following sections the procedures used to keep track of these variables and plan or engineer these different techniques is discussed. A general outline of a procedure is given although the specific wells may cause some slight variation in the actual engineering design.

A. Planar Fracs

Also called conventional hydraulic fracturing, planar fracs are designed with several standard programs to generate dynamic fracture geometry. These are specified as the Howard and Fast[169], Geertsma[206], or Kristianovich and Eheltov [209] solutions to a planar fracture growth in an isotropic, elastic media (rock). All the programs consider the fluid loss interaction with rock mechanics; however, only the last one evaluates the friction loss in the fracture simultaneously with the fracture growth and fluid loss.

None of the approaches allow the fluid to change temperature in the fracture. Since this always happens when injecting a cold fluid into a hot formation, it has to be considered. The Sinclair [207] and Whitsett [210] papers show the magnitude of the effect called convective heat blockage by fluid leakoff. For this project the Geertsma fracture geometry program has been combined with the Sinclair heat transfer model to given a variable frac fluid temperature. Sample printouts on this program are shown in Figure VII-1.

After several fluid viscosities and flow rates have been tried, a particular fluid is chosen to be used and a schedule of proppant addition is set up which allows for equipment breakdown and adequate pad volume to get the minimum crack width at the wellbore to allow proppant to enter.

HYDRAULIC FRACTURE DESIGN PROGRAM

USING

TEMPERATURE DEPENDENT FRACTURE FLUID PROPERTIES

FRACTURE PARAMETERS

TIME (MINS)	WIDTH (IN)	LENGTH (FT)	VOLUME CU.FT	EFF. %	AVG.FLUID TEMP. DEG.F
0.0	0.0	0.0	0.0	0.0	350.0
10.0	0.097	156.1	503.7	18.0	268.7
20.0	0.116	224.9	867.6	15.5	269.9
30.0	0.128	278.1	1190.9	14.2	270.4
40.0	0.138	323.1	1490.0	13.3	270.7
50.0	0.146	362.9	1772.2	12.6	270.9
60.0	0.154	399.0	2041.7	12.1	271.1
70.0	0.160	432.2	2300.7	11.7	271.3
80.0	0.165	463.2	2551.5	11.4	271.4
90.0	0.170	492.3	2794.9	11.1	271.5

Figure VII-1. Frac Fluid Coeff = 0.004

If an adequate fluid is not found, fluid loss material is added to existing fluids which changes the rate of fluid leakoff into the formation and all the programs are rerun until a feasible one is finally found.

Calculations are made for the amount of horsepower and equipment that will be needed and also the pressure limits on the wellhead, casing, and packers that might be used. Finally, cost analysis is made to identify high cost items and see if adjustments can be made to minimize or eliminate these.

B. Dendritic Fracs

The Kiel Frac 99 stimulation designs are based on different considerations and are designed quite differently than planar fracs. No perfect theory exists on which to base the actual dynamic geometry; therefore, certain assumptions are made as to what length of fracture is needed. This is based on the well spacing and reservoir permeability. Once this is established, then field experience and good judgment is used to decide what fluid efficiency is attainable in the particular situation. Based on the fluid used a frac width can be assumed and a frac height can be estimated from the well logs. With these parameters it is relatively easy to design a fracture treatment.

The following equation is then used to calculate the volume of each stage of maybe 5 stages.

Frac Volume = 2(Fluid Eff)(Frac Length)(Frac Width)(Frac Height)

Then the frac volume is split into even increments of pad, sand slugs, and clear fluid injection. Experience guides most of the designs into those that have a good chance of success and those which should accomplish the stimulation goals and objectives.

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IX. APPENDIX

Treating Reports on Well Stimulation of High-Temperature Oil and Gas Wells. The interviews for following wells were collected by A. R. Sinclair with various service companies.

HYDRAULIC FRAC TREATMENTS

COMPANY: Apache
AREA: Anadarko Basin (West Oklahoma, Texas)
DEPTH: 16,000 - 18,000 ft.
TEMPERATURE: 275 - 325°F
INTERVAL: 20-40 ft.
PERMEABILITY: .1 to .5 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT: 50,000 gal.
RATE: 12-15 BPM
TYPE OF FLUID: Western (Titan 3) and B.J. (Krystal)
TYPE OF PROPPANT: Sintered Bauxite and Super Sand
AMOUNT OF PROPPANT: 50,000 lbs.
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST: Simple flow test to evaluate well

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS: 2 to 4 factor improvement in production

COMMENTS:
- Fracture gradient .93-.95 psi/ft up to .97 psi/ft.
- Not using guar based fluids anymore because these fluids break down at high temperature (changed a year ago)
- Mentioned Dowell YF 400 as a new high-temperature fluid.

HYDRAULIC FRAC TREATMENTS

COMPANY: ARCO
AREA: South Texas *
DEPTH:
TEMPERATURE: 275° - 300°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID:
TYPE OF PROPPANT: Standard Halliburton Fluids
AMOUNT OF PROPPANT: Sintered Bauxite
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

- cross link gel
- delayed retardation
- methanal additive

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

* Location and details confidential.

HYDRAULIC FRAC TREATMENTS

COMPANY: Apache
AREA: Anadarko Basin (West Oklahoma, Texas)
DEPTH: 16,000 - 18,000 ft.
TEMPERATURE: 275 - 325°F
INTERVAL: 20-40 ft.
PERMEABILITY: .1 to .5 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT: 50,000 gal.
RATE: 12-15 BPM
TYPE OF FLUID: Western (Titan 3) and B.J. (Krystal)
TYPE OF PROPPANT: Sintered Bauxite and Super Sand
AMOUNT OF PROPPANT: 50,000 lbs.
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST: Simple flow test to evaluate well

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS: 2 to 4 factor improvement in production

COMMENTS:
- Fracture gradient .93-.95 psi/ft up to .97 psi/ft.
- Not using guar based fluids anymore because these fluids break down at high temperature (changed a year ago)
- Mentioned Dowell YF 400 as a new high-temperature fluid.

HYDRAULIC FRAC TREATMENTS

COMPANY: ARCO
AREA: South Texas *
DEPTH:
TEMPERATURE: 275° - 300°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID:
TYPE OF PROPPANT: Standard Halliburton Fluids
AMOUNT OF PROPPANT: Sintered Bauxite
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

- cross link gel
- delayed retardation
- methanal additive

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:
* Location and details confidential.

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Panola County, Texas (Cotton Valley Sand)

DEPTH: [Zone #1 9,128-9,286'][Zone #2 8,915-8,750']

TEMPERATURE: 242°F

INTERVAL: [Zone #1 125'] [Zone #2 300']

PERMEABILITY:

GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:	(ZONE #1)	(ZONE #2)
VOLUME OF TREATMENT:	410,000 Gal	240,000 Gal
RATE:	35 BPM	
TYPE OF FLUID:	Krystal 50 + CO2	Krystal 50 + CO2
TYPE OF PROPPANT:	20-40 Ottawa Sand	Ottawa Sand
AMOUNT OF PROPPANT:	1,000,000 lbs.	600,000 lbs
AVG (lb/gal)		
SLUGS ? (Y or N)		
HIGHEST (lb/gal)		

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

Frac Length

- Zone #1 1,000'
- Zone #2 1,000'

COMMENTS:

- 400 MCF/Day (before)
- 800 MCF/Day (after)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Freestone County, Texas (Cotton Valley Lime)

DEPTH: 11,800' - 11,590'

TEMPERATURE: 287°F

INTERVAL: 210'

PERMEABILITY:

GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:

VOLUME OF TREATMENT:

RATE: 15 BPM

TYPE OF FLUID:

TYPE OF PROPPANT:

AMOUNT OF PROPPANT:

- 220,000 gals Super Krystal 60 + 10% Methanol
- 100,000 gals Krystal 50 + 5% Methanol
- 60,000 lbs 100 Mesh
- 576,000 lbs 20-40 Ottawa Sand
- 192,000 lbs 20-40 Sintered Bauxite

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

Frac Length - 1,000'

COMMENTS:

- 200 MCF/Day (before)
- 1,100 MCF/Day (after)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Freestone County, Texas (Cotton Valley Lime)

DEPTH: 12,532 - 12,330'

TEMPERATURE: 300°F

INTERVAL: 172'

PERMEABILITY:

GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
. 140,000 gal Super Krystal 60 + 10% Methanol
. 80,000 gal Krystal 60 + 3% Methanol

VOLUME OF TREATMENT:

RATE: 12 BPM

TYPE OF FLUID:

TYPE OF PROPPANT:
. 50,000 lbs 100 Mesh Sand
. 239,000 lbs 20-40 Ottawa Sand
. 289,000 lbs 20-40 Bauxite

AMOUNT OF PROPPANT:

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

Frac Length 950'

COMMENTS:

. 1,000 MCF/Day (before)
. 4,400 MCF/Day (after)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Rusk County, Texas

DEPTH: 10,903'

TEMPERATURE: 270°F

INTERVAL: 300'

PERMEABILITY:

GAS, OIL, OR OTHER:

TYPE TREATMENT:

VOLUME OF TREATMENT:
. 120,000 gal Super Krystal 60 + CO2
. 50,000 gal Krystal 50 + CO2

RATE: 15 BPM

TYPE OF FLUID:

TYPE OF PROPPANT:
. 270,000 lbs 20-40 Ottawa Sand
. 40,000 lbs 20-40 Bauxite

AMOUNT OF PROPPANT:

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

. 1,100 psi
. 1,100 MCF/Day + 70 BBLS H20 per Day

COMMENTS:

Frac Length - 1,050'

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79
AREA: Cherokee County, Texas
DEPTH: [Zone #1, 10,801 - 10,850'][Zone #2, 10,437']
TEMPERATURE: 280°F
INTERVAL: [Zone #1 18'] [Zone #2 50']
PERMEABILITY:
GAS, OIL, OR OTHER:

	ZONE #1		ZONE #2	
TYPE TREATMENT:				
VOLUME OF TREATMENT:	40,000 gals		140,000 gals	
RATE:	15 BPM			
TYPE OF FLUID:	Super Krystal 60 + Diesel + CO2		Super Krystal 60 + Diesel + CO2	
TYPE OF PROPPANT:	20-40 Ottawa	20-40 Sintered Bauxite	20-40 Ottawa	Sintered Bauxi
AMOUNT OF PROPPANT:	102,000 lbs	15,000 lbs	470,000 lbs	5,500 lbs

AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:
Frac Length - [Zone #1, 1,800'] [Zone #2, 1,800']

HYDRAULIC FRAC TREATMENTS

COMPANY: Report By BJ Hughes 8/21/79
AREA: Freestone County, Texas (Travis Peak)
DEPTH: 10,260'
TEMPERATURE: 260°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT: 80,000 gals
RATE: 12 BPM
TYPE OF FLUID: Krystal 50
TYPE OF PROPPANT: 20-40 Ottawa Sand
AMOUNT OF PROPPANT: 160,000 lbs
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Rusk County, Texas

DEPTH: 10,355 - 10,414 '

TEMPERATURE: 262°F

INTERVAL:

PERMEABILITY:

GAS, OIL, OR OTHER:

TYPE TREATMENT: . 20,000 gal Krystal 30 + 5% Diesel

VOLUME OF TREATMENT: . 120,000 gal Super Krystal 60
. 90,000 gal Krystal 50

RATE: 14 BPM . 9,025 gal Methanol

TYPE OF FLUID: . 7,518 gal Diesel

TYPE OF PROPPANT: 20-40 Ottawa Sand

AMOUNT OF PROPPANT: 587,500 lbs

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79

AREA: Harrison County, Texas

DEPTH: 9,950 - 10,036'

TEMPERATURE: 258°F

INTERVAL:

PERMEABILITY:

GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: . 215,000 gal Super Krystal 60 + 5% Diesel + 5% Methanol

VOLUME OF TREATMENT: . 135,000 gal Krystal 60 + 5% Diesel + 5% Methanol

RATE: 20 BPM

TYPE OF FLUID:

TYPE OF PROPPANT: 20-40 Ottawa Sand

AMOUNT OF PROPPANT: 985,000 lbs

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):

TYPE OF TEST:

POST FRAC TESTING (Y or N):

TYPE OF TEST:

RESULTS:

Frac Length 1,000'

COMMENTS:

106 MCF/Day (before)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes (8/21/79)
AREA: Panola County, Texas
DEPTH: 9,353'
TEMPERATURE: 243°F
INTERVAL: 352'
PERMEABILITY:
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT: 210,000 gal
RATE: 35 BPM
TYPE OF FLUID: Krystal 50
TYPE OF PROPPANT: 20-40 Ottawa Sand
AMOUNT OF PROPPANT: 600,000 lbs
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

Frac Length 900'

COMMENTS:

- New Well
- 3,800 MCF/Day

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79
AREA: Harrison County, Texas
DEPTH: 10,034 - 10,174'
TEMPERATURE: 256°F
INTERVAL: 200'
PERMEABILITY:
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: . 20,000 gal Super Krystal 60 + Diesel
VOLUME OF TREATMENT: . 45,000 gal Krystal 50 + Diesel
RATE: 12 BPM
TYPE OF FLUID:
TYPE OF PROPPANT: 20-40 Ottawa Sand
AMOUNT OF PROPPANT: 219,400 lbs
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

Frac Length - 500'

COMMENTS:

135 MCF/Day (after)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79
AREA: Freestone County, Texas (Cotton Valley Sand)
DEPTH: 11,582 - 11,720'
TEMPERATURE: 273°F
INTERVAL: 60'
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT: 150,000 gal
RATE: 18 BPM
TYPE OF FLUID: Super Krystal 60 + Diesel
TYPE OF PROPPANT: 20=40 Ottawa Sand
AMOUNT OF PROPPANT: 300,000 lbs
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

Grac Length 1,200'

COMMENTS:

2,500 MCF/Day (after)

HYDRAULIC FRAC TREATMENTS

COMPANY: Report by BJ Hughes 8/21/79
AREA: Upshur County, Texas
DEPTH: 11,790 - 11,828'
TEMPERATURE: 290°F
INTERVAL: 17'
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT: . 20,000 gals Krystal 50
VOLUME OF TREATMENT: . 2% Sta-Live Acid
RATE: 10 BPM
TYPE OF FLUID:
TYPE OF PROPPANT: 20-40 Ottawa Sand
AMOUNT OF PROPPANT: 5,000 lbs
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Cardinal Chemical
AREA: Elk City, Oklahoma
DEPTH: 14 to 16,000 ft.
TEMPERATURE: 280°F
INTERVAL: Deep Morrow 100 + ft.
PERMEABILITY: 0.2 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Small and Large Sand Polymer Water Frac
VOLUME OF TREATMENT: Med
RATE: 10-15 BPM
TYPE OF FLUID: Gelled Water
TYPE OF PROPPANT: Small (100 mesh) and 20/40 SAnd, and Super Sand tail in (20/40)
AMOUNT OF PROPPANT:
AVG (lb/gal) 1 to 2 lb/gal
SLUGS ? (Y or N) No.
HIGHEST (lb/gal) 4 lb/gal

PRE FRAC TESTING (Y or N):
TYPE OF TEST: No

POST FRAC TESTING (Y or N):
TYPE OF TEST: No

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Cardinal Chemical
AREA: West Texas
DEPTH: 22,000 ft
TEMPERATURE: 325°F
INTERVAL: ~ 100 - 200 ft.
PERMEABILITY: 0.1 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Deep Acid Frac
VOLUME OF TREATMENT: Med
RATE: 10-15 BPM
TYPE OF FLUID: HCC
TYPE OF PROPPANT: None
AMOUNT OF PROPPANT:
AVG (lb/gal) 0.0
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST: N/A

POST FRAC TESTING (Y or N):
TYPE OF TEST: N/A

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Coastal States Gas
AREA: Anadarko Basin
DEPTH: 15,273 ft.
TEMPERATURE: 260°F
INTERVAL:
PERMEABILITY: Morrow Sandstone
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT: 60,000 gal.
RATE: 13 BPM (9,500 psi pump pressure)
TYPE OF FLUID: geled kerosene
TYPE OF PROPPANT: 20-40 sand
AMOUNT OF PROPPANT: 56,000 lbs.
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

Significant improvement.

COMMENTS:

Treatment corrected skin damage problems.

HYDRAULIC FRAC TREATMENTS

COMPANY: Conoco
AREA: Ellenburger (West Texas)
DEPTH: 20,000 ft
TEMPERATURE: 350° - 400°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT: Acid Frac
VOLUME OF TREATMENT: 40,000 gal
RATE:
TYPE OF FLUID: Acid
TYPE OF PROPPANT: None
AMOUNT OF PROPPANT:
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

Limestone Formation

COMPANY: Conoco
AREA: Corpus Christi (Webb County)
DEPTH:
TEMPERATURE: 250°F (highest)
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID: Cross Link Gel (poly sacharide derivative)
TYPE OF PROPPANT: 20 - 40 mesh
AMOUNT OF PROPPANT:
AVG (lb/gal) 4 lb/gal
SLUGS ? (Y or N)
HIGHEST (lb/gal) 6 - 8 lb/gal

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

* Not doing too many frac jobs.

COMPANY: Dowell
AREA:
DEPTH:
TEMPERATURE: 400°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID: YF 400 Stratafrac
TYPE OF PROPPANT:
AMOUNT OF PROPPANT:
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

* Type of fluid depends on formation condition and permeability.
* Water might be adequate in tight formation.
* Mentioned earlier meeting with project team.

HYDRAULIC FRAC TREATMENTS

COMPANY: Exxon
AREA: E. Texas Division - Hainesville Lime, Cotton Valley Lime
DEPTH: 12,000 ft
TEMPERATURE: 290°F
INTERVAL: 100 ft. gross pay
PERMEABILITY: 0.3 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Versagel Polymer Water Planar Frac
VOLUME OF TREATMENT: 100.000 gal
RATE: 12 BPM
TYPE OF FLUID: Various Polymer/water solution (Versagel 14, 15 or Klean 160)
TYPE OF PROPPANT: Bauxite
AMOUNT OF PROPPANT:
- AVG (lb/gal) 1 to 3 lb/gal
- SLUGS ? (Y or N) No
- HIGHEST (lb/gal) 7 lb/gal

PRE FRAC TESTING (Y or N): Yes, Production Tests
TYPE OF TEST:

POST FRAC TESTING (Y or N): Yes, Production Tests & Temperature
TYPE OF TEST: Logging

RESULTS: Good results w/Hydraulic Fracturing, Acid Fracs would not work here. Results are independent of the amount of bauxite used.

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Forest Oil
AREA: McAllen Ranch. Y Field
DEPTH: 13,000 ft.
TEMPERATURE: 380 - 400°F (estimated from logging runs)
INTERVAL: 100 ft (min) to 400 ft (max) gross; 160 ft net
PERMEABILITY: .05 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT: 375,000 gal
RATE: 12 BPM (11,000 psi pump pressure)
TYPE OF FLUID: Versi gel*
TYPE OF PROPPANT: Bauxite*
AMOUNT OF PROPPANT:
- AVG (lb/gal)
- SLUGS ? (Y or N)
- HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS: Very good results.

COMMENTS:

*Started with Halliburton high gel and 20-40 Brady sand; later switched to versi gel and bauxite.

HYDRAULIC FRAC TREATMENTS

COMPANY: Gulf Oil Company
AREA: South Texas
DEPTH: 12,000 ft.
TEMPERATURE: 300°F
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER:

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID: Stand high-temperature fluid supplied by service companies
TYPE OF PROPPANT: Sand (20-40) -
AMOUNT OF PROPPANT:
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

- Length of fracture about 600 ft.

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Houston Natural Gas
AREA: Harris Co. - Wilcox
DEPTH: 13,000 ft.
TEMPERATURE: 320°F
INTERVAL: 2.
PERMEABILITY: 0 to 2 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Kiel Frac
VOLUME OF TREATMENT: 3,500 bbls (2,200 to 2,500 bbl into formation)
RATE: 11 to 12 BPM
TYPE OF FLUID: 12#/1000 gal - Guar + XC (5 to 1)
TYPE OF PROPPANT: 100 mesh sand
AMOUNT OF PROPPANT: 100,000 lb.
AVG (lb/gal) 8 #/gal slugs
SLUGS ? (Y or N) Yes
HIGHEST (lb/gal) + 12 lb/gal sand out at end

PRE FRAC TESTING (Y or N): Y
TYPE OF TEST: Build up Data 22 day shut in 3,835 psi BHP @ 22 days

POST FRAC TESTING (Y or N): Y
TYPE OF TEST: Prod. Test

RESULTS: 0 → 1 mmcfd
158 mcfd → 1.6 mmcfd

COMMENTS: Good Well, Cleanup very important

HYDRAULIC FRAC TREATMENTS

COMPANY: Miami Oil
AREA: Zapata Co., Tex-Wilcox
DEPTH: 11,500 ft.
TEMPERATURE: 350°F
INTERVAL: 100 ft.
PERMEABILITY: ~20 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Kiel Frac (5 to 6 stages)
VOLUME OF TREATMENT: 2,500 BBLS
RATE: 11 to 13 BPM
TYPE OF FLUID: 12#/1,000 gal Guar + XC (5 to 1)
TYPE OF PROPPANT: 100 mesh sand
AMOUNT OF PROPPANT: 100,000 lbs.
AVG (lb/gal)
SLUGS ? (Y or N) Yes!
HIGHEST (lb/gal) 8#/gal

PRE FRAC TESTING (Y or N): N
TYPE OF TEST: Wildcat Well

POST FRAC TESTING (Y or N): Y
TYPE OF TEST: Long-Term Production Test

RESULTS: 1 mmcfd Gas Well

COMMENTS: Clean up very important because of high pressure.

HYDRAULIC FRAC TREATMENTS

COMPANY: Monsanto
AREA: Madden, Wyoming - Mesa Verde
DEPTH: 16,000 feet
TEMPERATURE: 310°F
INTERVAL: 100 to 500 ft
PERMEABILITY: Low
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT:
RATE:
TYPE OF FLUID: POTENTIAL WELLS
TYPE OF PROPPANT: NOT YET FRACED.
AMOUNT OF PROPPANT:
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Shell
FRAC GRADIENT: 1.0 psi/ft
AREA: S. Texas
SURFACE PRESSURE: 12,000 - 14,000 psi
DEPTH: 12 to 13,000 ft
TEMPERATURE: 300 to 320°F
INTERVAL: Gross 300 - 400 ft, Net 100 ft.
PERMEABILITY: 0.2 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: 20% prepad KCL, 30-35% pad, staggered gel concentration 16-100 Versagel
VOLUME OF TREATMENT: 130,000 gal
RATE: 12-15 BPM
TYPE OF FLUID: Versagel
TYPE OF PROPPANT: Sand 250,000 lb 20/40 ottawa
AMOUNT OF PROPPANT:

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal) 5 to 6

PRE FRAC TESTING (Y or N):
TYPE OF TEST: Buildup Test

POST FRAC TESTING (Y or N):
TYPE OF TEST: Temp Logs

RESULTS:

COMMENTS:

HYDRAULIC FRAC TREATMENTS

COMPANY: Southport Exploration
AREA: Custer County (West Oklahoma)
DEPTH: 10,500 ft.
TEMPERATURE: 150 - 160°F (Standard Temperature Gradient)
INTERVAL:
PERMEABILITY:
GAS, OIL, OR OTHER: Condensate Well (500 BPD and 5 MCFD)

TYPE TREATMENT:
VOLUME OF TREATMENT: 75,000 gal
RATE: 15 BPM (6,000 psi pump pressure)
TYPE OF FLUID: Western (Polaris Gel)*
TYPE OF PROPPANT: 20-40 Sand
AMOUNT OF PROPPANT: 120,000 lbs.

AVG (lb/gal)

SLUGS ? (Y or N)

HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST: Tight; No Production

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS:

COMMENTS:

* Cross link polymer gel standard for this area.

• Got to fracture in this area because formation won't give up a thing.

HYDRAULIC FRAC TREATMENTS

COMPANY: Southport Exploration
AREA: Roger Hill County (West Oklahoma)
DEPTH: 14,000 ft.
TEMPERATURE: 250°F
INTERVAL: 40 ft (Total 80 ft)
PERMEABILITY:
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT:
VOLUME OF TREATMENT: 2,400 Barrels
RATE: 10 BPM (1300 psi pump pressure)
TYPE OF FLUID: Western (Polaris Gel)
TYPE OF PROPPANT: Super Sand
AMOUNT OF PROPPANT: 120,000 lbs.
AVG (lb/gal)
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST:

POST FRAC TESTING (Y or N):
TYPE OF TEST:

RESULTS: .5 MCFD (before)

3 MCFD (after)

COMMENTS:

- Super Sand worked okay.
- Two stage job; total interval was 80 ft.

HYDRAULIC FRAC TREATMENTS

COMPANY: Texas Int'l Petroleum (multiple treatments reported)
AREA: Glen Rose Lime - Walker Co., Texas
DEPTH: 12,700 + 14,831'
TEMPERATURE: 280°F - 360°F
INTERVAL: 50' plus fractured zones
PERMEABILITY: 0.10 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Conventional Fracture (e.g. Western's West Pad 8)
VOLUME OF TREATMENT: 100,000 gals
RATE: 15 BPM to 17 BPM
TYPE OF FLUID: Super Thick Fluids of various type ISIP = 3625 psi
TYPE OF PROPPANT: Sand usually 20/40 mesh
AMOUNT OF PROPPANT: 136,000 lb
AVG (lb/gal) 1 to 1.4 lb/gal
SLUGS ? (Y or N) N
HIGHEST (lb/gal) 2 to 4 lb/gal

PRE FRAC TESTING (Y or N):
TYPE OF TEST: Production Test

POST FRAC TESTING (Y or N): Y
TYPE OF TEST: Production Test

RESULTS: Not well defined - very poor wells to poor wells
Other problems usually caused a masking of results

COMMENTS: Sand crushing maybe a severe problem.

HYDRAULIC FRAC TREATMENTS

COMPANY: Western Co.
AREA: Ellenberger Formation - West Texas
DEPTH: 20,000+ ft.
TEMPERATURE: 405°F
INTERVAL: 200+ ft.
PERMEABILITY: <0.01 md
GAS, OIL, OR OTHER: Gas

TYPE TREATMENT: Frac Job
VOLUME OF TREATMENT: Medium Size
RATE: 10 to 15 BPM
TYPE OF FLUID: Gelled Water
TYPE OF PROPPANT: None
AMOUNT OF PROPPANT:
AVG (lb/gal) 0.0
SLUGS ? (Y or N)
HIGHEST (lb/gal)

PRE FRAC TESTING (Y or N):
TYPE OF TEST: N/A

POST FRAC TESTING (Y or N):
TYPE OF TEST: N/A

RESULTS:

COMMENTS:

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