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CHEMICAL STIMULATION TREATMENT,
THE GEYSERS:
OTTOBONI STATE 22.
GEOTHERMAL-RESERVOIR WELL-STIMULATION PROGRAM

February 1981

DOE/AL/10563--T11

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MASTER

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For

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I. SUMMARY

Republic Geothermal, Inc. and its subcontractors performed Experiment No. 6 of the Geothermal Reservoir Well Stimulation Program (GRWSP) at The Geysers Field in Sonoma County, California. The reservoir matrix, composed principally of graywacke-type rock, has a primary flow system for geothermal fluids through natural fractures. The vapor-dominated hydrothermal system with a reservoir temperature of about 460°F presented a challenge for stimulation technology in a significant geothermal development area.

Ottoboni State 22 (OS-22), selected for this stimulation experiment, was offered by Union Oil Company (Union) on a cost sharing basis. This well had low productivity (46,000 lb/hr), probably because it did not intersect the primary natural fracture system of the reservoir. Surrounding production wells are considered to be good wells with an average flow rate of about 100,000 lb/hr. OS-22 was completed open-hole (common in The Geysers geothermal wells) to 8,373 feet with the desired stimulation zone located just below the casing shoe. Therefore, no extensive well work except for plugging back was needed to isolate the 1,000-foot unproductive treatment zone between 4,600 feet and 5,600 feet.

The stimulation technique selected was an acid etching treatment (Halliburton Services' MY-T-ACID®). A small water prepad was used to provide tubular cooling and fluid loss control. Following the water prepad were 500-750 bbl of high viscosity crosslinked gel fluid and 400-500 bbl of a hydrofluoric-hydrochloric (HF-HCl) acid solution. The frac fluids were expected to enter only a single or limited fracture zone within the open interval. Frac rates of 20-40 BPM and surface pressures of 3,000 psig were estimated for this treatment. During the job, however, no significant surface pressure was recorded, and all fluids flowed easily into the interval. Subsequent evaluation of the well performance showed that no noticeable stimulation had been achieved even though the frac fluids were properly injected. Temperature and gamma ray surveys along with tracer studies indicated that the frac fluids entered natural fracture channels over a 650-foot zone of the open interval, which probably prevented the staged acid etching treatment from functioning as designed.

There is no evidence to suggest that the acid etch technique will not work in The Geysers reservoir. The technique needs to be attempted again in a shorter interval and/or with a larger treatment volume for proper evaluation.

II. INTRODUCTION

A. Geology

The Geysers steam field is located in the upper Mesozoic Franciscan Complex and the Great Valley Formation. Magmatic activity is expressed in the area with Quaternary volcanic rocks distributed throughout. The general trend of the structure in the area is northwest-southeast and is well defined by the Collayomi Fault Zone which separates the Franciscan Complex from the Great Valley Formation.

The Franciscan Complex is the reservoir rock for most of the production in The Geysers. The rock types found in this complex consist of graywacke, shale, ultramafic igneous rocks, volcanics, chert, serpentinite, and metamorphic rocks. Relic sedimentary structure is often completely destroyed due to the intense folding and faulting which occurred during its chaotic history. The permeability of these rocks is very low and all production is believed to come from fractures. The predominant rock type is graywacke, which is well indurated and usually highly fractured. The fractures are commonly filled with calcite and/or quartz; however, the fractures which are not completely sealed provide permeability for the steam reservoir.

Faulting in The Geysers is parallel with the strong northwest-southeast structural trend which is prominent throughout most of the northern coastal belt of the Franciscan Complex. The northwest-southeast right lateral movement of the San Andreas Fault Zone has undoubtedly played an important role in developing this structure. Unfortunately, the complexity of faulting and fracturing in The Geysers has made it difficult to develop the steam field. Production fractures have never been correlated with surface features, and the horizontal projection of production zones in subsurface maps is usually not possible.

B. Field Development

The Geysers geothermal area is currently the world's largest producer of electrical energy from a geothermal source (908 MW from fifteen units). Over 200 wells have been drilled in the area, and it represents one of the few known vapor-dominated hydrothermal systems. Early wells were drilled adjacent to natural steam vents, tapping the vapor-dominated reservoir at depths of less than 1,000 feet. Steam production from these wells ranged from 40,000 to 80,000 lb/hr. Higher flow rates and greater pressures are now being attained from wells penetrating steam zones between 4,900 and 9,800 feet. Maximum well depths reach approximately 11,000 feet.¹

Dry steam is produced from near-vertical fractures occurring in a hard, dense sandstone of the Franciscan formation. The average initial per-well production is 150,000 lb of 465°F steam per hour with a static bottomhole pressure in the 450-500 psig range.

Available subsurface data indicate that steam production in The Geysers region is largely from nonhomogeneous fracture zones in Franciscan graywacke. Given the presence of suitable reservoir rocks at any of several levels, the structural conditions determining the presence of steam would appear to depend upon: (1) the presence of channel ways such as faults, fractures, or bedding planes that provide an adequate fluid conductivity for the system; (2) the presence of structural traps for steam accumulation; and (3) a potent heat source.

At The Geysers, drilling site preparation costs are high because of the rough terrain. This has led to the practice of drilling multiple deviated wells from a common site. Experience at The Geysers has indicated that five wells can be drilled from a common location. However,

some wells drilled as close as 100-130 feet from a commercial producer have failed to encounter sufficient fractures for commercial production.²

III. SELECTION OF CANDIDATE WELL

Union offered the OS-22 well (Figure 1) as a stimulation candidate to the GRWSP. This well is located in the production area of Units 7 and 8 and is surrounded by good production wells, as indicated in the following tables and figures. Halliburton Services had been actively working with Union on the stimulation treatment design for this well since 1974, including laboratory studies of the formation and treatment materials. They recommended a chemical stimulation program, discussed later, which was intended to increase well productivity in excess of conventional hydraulic fracturing techniques. The GRWSP contract specifically calls for the field testing of exotic-type stimulation techniques, such as the acid etching treatment, for geothermal applications. The cost sharing of the experiment with Union offered a unique opportunity to take advantage of over six years of work by Union and Halliburton Services.

OS-22 was a good candidate because all the surrounding wells encountered fractures at or above the depth that the stimulation treatment was attempted. Another factor in the selection of OS-22 was the need to isolate the desired interval from the remaining wellbore. Since the desired stimulation zone in OS-22 was just below the casing shoe, this interval was isolated by sanding off the bottom of the well and using a casing packer (Figure 2). In wells where the top of the stimulation interval is in open hole, the interval must be isolated from above by installing a casing string or by using an openhole packer. Either technique increases the cost of the job, and the use of an openhole packer introduces an added risk of mechanical failure during the stimulation job.

In addition, OS-22 was selected as the most favorable candidate for the acid etching treatment for the following reasons:

1. Existing steam entries in OS-22 were safely excluded because they are all below the interval to be treated.
2. Surface location was large enough to accommodate the required equipment and tankage.
3. Being one of the poorer producers, the potential loss of OS-22 due to unforeseen circumstances would not create an immediate curtailment situation for Union's operations.

Figures 3 through 5 show the areal and subsurface location of OS-22 relative to the surrounding wells. The nonproductive interval isolated for treatment (the top 1,000 feet of openhole) is marked. This interval is 300 feet horizontally from a major entry in the original hole of Well A, and 250 feet horizontally from a minor entry in Well J. Both of these entries are above the interval isolated for treatment in OS-22. Depending on the azimuth and dip of these fractures, they could be very

FIGURE 1
DIAGRAMMATIC SKETCH OTTOBONI STATE 4596 WELL No. 22
THE GEYSERS

DATE SPUDDED: 5-10-75
 DATE COMPLETED: 6-23-75

KELLY BUSHING +24'
 GROUND LEVEL 2952'

RCI 2637

FIGURE 2
UNION OS-22 COMPLETION DIAGRAMS

FIGURE 3
WELL LOCATION AND CROSS SECTION LINE MAP
THE GEYSERS

ACT 2545

7

FIGURE 5
CROSS SECTION THROUGH LINE F-F'
THE GEYSERS

close to OS-22. Vertical perspectives along lines E-E' and F-F' of Figure 3 are provided by cross sections in Figures 4 and 5. Figures 4 and 5 show that the frac interval is 1,000 feet or more below the top of the reservoir. The geologist's log for OS-22 is given in Figure 6.

OS-22 has always been a poor producer compared with surrounding wells. Rig test rates measured soon after drilling are given in Table 1.

TABLE 1

RIG RATE TESTS

<u>Well</u>	<u>Rate (lb/hr)</u>	<u>Wellhead Pressure (psig)</u>	<u>Date</u>
F	368,000	115	8/71
D	215,000	72	2/71
J	170,000	110	10/69
A	162,000	124	5/75
G	120,000	71	2/73
OS-22	90,000	137	6/75

Well G, north of OS-22, was abandoned in 1975 due to casing failure. Production rates of the other wells as of March 30, 1978 are given in Table 2.

FIGURE 6

UNION

GEOTHERMAL DIVISION

GEOLOGIST'S LOG

COMPANY Union Oil Co. of Calif.
 FIELD Seaford
 WELL Offshore Seaford
 COUNTY San Diego
 STATE Calif.
 LOCATION 724 N. ...
...

TOTAL DEPTH 9346'
 SPUD DATE 1/15/55
 COMPLETION DATE 6/21/55
 DRILLING CONTRACTOR Hoover & Co.
 ENGINEER ...
 GEOLOGIST ...

CASING RECORD

30" 55'
24" 55'
21" 415'
 ...
 ...

DRILLING
 RE - NEW BIT
 RPB - REPAIR BIT
 CB - CORE BIT
 LC - LAST CIRCULATION
 DEV - DEVIATION
 DST - DRILL STEM TEST

ROCK
 S - SHALE
 SL - SLTSTONE
 SD - SANDSTONE
 CS - CONGLOMERATE
 L - LIMESTONE
 D - DOLOMITE
 G - GYP. ANHYD.

EXPLANATION

MINERALS
 C - CALCITE
 CHL - CHLORITE
 I - INFUSIVE
 CL - CLAYS
 S - SODIUM
 E - EPIDOTE
 F - FELDSPAR

PHYSICAL - CHEMICAL
 SM - SOFT MUD
 S - SOFT MUD
 FL - FLOW LINE
 T - TEMPERATURE
 P - PRESSURE
 FC - FINE SAND CIRCULATION
 M - MUD HEAD

DEPTH	PENETRATION DATA		LITHOLOGY	
	FEET	INCHES	PRIMARY LITHO	DESCRIPTION
4500				
4510				
4520				
4530				
4540				
4550				
4560				
4570				
4580				
4590				
4600				
4610				
4620				
4630				
4640				
4650				
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5940				
5950				
5960				
5970				
5980				
5990				
6000				

TABLE 2
MARCH 1978 PRODUCTION RATES

<u>Well</u>	<u>Rate (lb/hr)</u>	<u>Wellhead Pressure (psig)</u>
F	137,500	158
D	102,500	125
A	100,000	126
J	90,500	124
OS-22	55,500	124

Later prestimulation production data obtained while the wells were on-line to the power plant are listed in Table 3.

TABLE 3
1980 PRODUCTION RATES

<u>Well</u>	<u>Date</u>	<u>Wellhead Pressure Rate (lb/hr)</u>	<u>(psig)</u>	<u>Completion Date</u>
J	9/22/80	76,500	128	10/69
D	9/22/80	100,000	129	2/71
F	10/8/80	141,000	131	8/71
A	10/8/80	80,000	128	5/75
OS-22	10/8/80	46,000	127	6/75

Note:

1. Producing wellhead temperature on OS-22 was 348°F during the 10/8/80 readings.

2. A static temperature and pressure survey was run in OS-22 on July 1, 1975. The readings are shown in the attached Table 4.
3. Chemical analyses of The Geysers area produced gases and solids are given in Table 5.

IV. STIMULATION TREATMENT DESIGN

Computer programs were run by Halliburton Services to design a MY-T-ACID® frac treatment (an acid etching fracture treatment) at pump rates of 20 and 40 BPM and a fracture height of 50-100 feet. The results, using data in Appendix A, show that to acid etch a fracture 394 feet long, a 4,200 to 4,700 gal viscous preflush and an 8,000 to 9,000 gal acid solution are required. The core material, described in Appendix B, showed practically no matrix permeability, but natural fractures were known to exist. Because of this, high fluid loss was considered to be a potential problem. For this reason, the fluid volumes from the computer designs were increased substantially. Because The Geysers reservoir is a vapor-dominated system, the frac fluids injected into the well were expected to enter a single or limited fracture zone near the bottom of the open interval.

At lower temperatures HF acid reacts slowly with sandstone, but activation energy calculations indicated that there should be an adequate reaction of HF acid on sandstone at 460°F. Acid etched fracture flow capacity tests run at 400°F substantiate these data (Appendix A). Laboratory tests showed that HF acid would dissolve the graywacke material in a smooth surface pattern. The smooth surface pattern resulting from a conventional acid etch yields a low conductivity fracture, as shown in Appendix A. For this reason, a MY-T-ACID® technique was recommended. This technique utilizes a high viscosity gel solution injected into the fracture in front of the acid solution. The mobility contrast between the two solutions causes the acid solution to finger through the viscous gel along a limited number of paths. The gel degrades after exposure to high temperature, leaving the acid to react with the formation material. The etched paths, held open by the unetched rock in between, form high conductivity flow paths to the wellbore. Appendix C summarizes the lab work on the polymer selection and characterization.

To ensure a higher reactivity of the HF acid with the rock, the acid solution should be in contact with the rock as long as possible and the temperature kept as high as possible. This would entail using a moderate pump rate for pumping the acid solution and using a relatively small water prepad. Application of corrosion test criteria showed that the 10% HF-5% HCl acid solution could be controlled within acceptable corrosion limits using available inhibitors and additives.

Using HF acid in an acid etching treatment was expected to provide an adequate stimulation. However, drawbacks existed and were as follows:

TABLE 4*

STATIC PRESSURE AND TEMPERATURE SURVEY

OTTOBONI STATE 22

JULY 1, 1975

<u>DEPTH (FT)</u>	<u>PRESSURE (PSIG)</u>	<u>TEMPERATURE (°F)</u>
50	336.45	409.0
1000	341.12	415.5
2000	347.20	439.0
3000	353.14	439.8
4000	359.81	440.4
4500	362.15	440.7
5000	365.42	441.2
5500	368.69	451.0
6000	371.50	450.8
6500	374.77	450.8
7000	377.57	450.8
7500	383.64	451.0
8000	508.92	474.8
8340	606.10	481.3

*Data provided by Union Oil Company.

TABLE 5

GASES AND SOLIDS IN GEYSERS AREA STEAM (PPM)

<u>COMPONENT</u>	<u>GEYSERS RANGE OF CONC. MEASURED</u>		<u>GEYSERS AVERAGE</u>	<u>OTTOBONI STATE WELLS</u>	<u>CASTLE ROCK SPRINGS</u>
	<u>Low</u>	<u>High</u>			
CO ₂	290	30600	3260	4123	216
H ₂ S	5	1600	222	277	96
CH ₄	13	1447	194	146	3.6
NH ₃	9.4	1060	194	176	140
N ₂	6	638	52	47	2.2
H ₂	11	218	56	57	1.0
C ₂ H ₆	3	19	NEG		
C ₃ H ₈					0.03
AS	0.002	0.050	0.019		0.06
B	2.1	39	16		
HG	0.00031	0.018	0.005		

1. When HF acid reacts with silicious rock, one of the reaction products is fluosilicic acid (H_2SiF_6) which will react with any sodium ion to form a secondary precipitate of sodium fluosilicate (Na_2SiF_6). Also, HF acid will react with calcium carbonate in the formation rocks to form a precipitate of calcium fluoride (CaF_2). These precipitates can plug small fractures or pore spaces and restrict production if there is sufficient calcium carbonate present.
2. The success of any acid etching treatment depends upon the ability to develop a fracture system. If the well is naturally fractured, fluid loss must be controlled in order to obtain deep etching of the fracture. If fluid loss cannot be controlled, then a very short etched fracture will be developed.
3. The VERSAGEL 1525[®] gel properties used in the computer calculations were all extrapolated from lower temperature data (300-350°F). If the gel is not stable or does not have adequate viscosity at 460°F, then no viscous fingering will occur and little fracture flow capacity will be developed.

A. Stimulation Procedure

The treatment was performed on January 15, 1981 using 3,000 hydraulic horsepower and one 100 BPM blender supplied from four 500 bbl frac tanks (Figure 7). The treatment was designed to be pumped at 20 to 40 BPM in four distinct stages as described below:

Stage No.

1. Inject 20,000 gal of water containing 15 lb/1,000 gal WG-11[®] plus 55 gal of ethanol and 55 gal of isopropanol as tracers.
2. Inject 20,000 gal of viscous crosslinked gel solution (VERSAGEL[®] 1600 - 60 lb/1,000 gal).
3. Inject 20,000 gal of 10% HF-5% HCl acid containing 15 lb/1,000 gal WG-11[®].
4. Displace with 9,000 gal of low viscosity fluid and add 3 lb of radioactive sand (coated with iridium 192, total 10 millicuries) before the last 3,000 gal. Overflush with 9,000 gal of low viscosity fluid. A total of 20,000 gal of displacement and overflush water was mixed with 15 lb/1,000 gal WG-11[®] plus 55 gal of n-butanol and 55 gal of isobutanol as tracers.

The treatment schedule was followed very closely except that the pumping rate had to be reduced near the end of Stages 2 and 3 in order to withdraw the last few barrels from each tank without entrained air.

FIGURE 7
STIMULATION EQUIPMENT LAYOUT
FOR EXPERIMENT NO. 6, ACID ETCHING TREATMENT

RG1 2758

The treating record is shown in Appendix D and Table 6. Ethanol and isopropanol were injected as tracers in the prepad while n-butanol and isobutanol were injected in the displacement fluid as tracers. As indicated by the treating record, no significant surface pressure buildup was observed and all fluids flowed easily into the interval.

V. POST-STIMULATION EVALUATION

A. Well Log Surveys

After the treatment, temperature and gamma ray surveys were run to locate the frac fluid entry points and to find the radioactive sand. Figure 8 shows the temperature log which indicates that the bottom 650 feet of open interval accepted fluid. Since the steam is low pressure and low density, it is reasonable to find the cold fluid entry as deep as possible in the isolated zone.

In the 214 bbl of displacement fluid, three pounds of radioactively tagged sand were injected. This sand was picked up by the gamma ray survey, also shown in Figure 8, and indicates that the highest counts of radioactivity also correspond to the lower 650 feet of open hole.

B. Fracture Length Calculations

Since the temperature and gamma ray surveys show a 650-foot interval which accepted the frac fluids and because surface pressure was extremely low, natural fractures are interpreted to be open in the 650-foot interval. If the total effective width of all the natural fractures are added together, a realistic fracture width estimate of 1/4- to 1/2-inch can be made. This might include as many as 50 fractures cutting through the wellbore that are only 0.0025 to 0.005 inches wide. With 500 bbl (21,000 gal) of VERSAGEL® solution and 500 bbl of the HF and HCl solution, the total fluid volume to fill a fracture is 1,000 bbl or 5,610 cu ft. Using Eq. (1) below, an effective length of acid penetration can be calculated assuming that the acid fingers to the tip of the VERSAGEL® fluids.

$$L = \frac{6(\text{Frac Volume})}{(\text{Frac Height})(\text{Frac Width})} \quad (1)$$

In this case, assume that the frac volume is the total injected fluid volume (5,610 ft³) and the frac height is 650 feet. Using a total effective width of all the natural fractures of 1/2 inch, Eq. (1) yields an effective frac length of 103.5 feet.

This calculation assumes a 100 percent fracturing fluid efficiency. Because of the high formation temperatures, this is not realistic. Some of the injected fluids are vaporized or leaked off perpendicular to the main direction of the fracture. Assuming a 50 percent leakoff volume (fluid efficiency), the effective fracture length will be reduced by one half. Equation (2) includes the fluid efficiency term and gives a more realistic fracture length.

TABLE 6
UNION OS-22 ACID ETCH TREATMENT

STAGE	VOLUME (GAL)	FLUID	RATE (BPM)	SURFACE PRESSURE (PSI)
1. (PREPAD)	19,992	LOW VISCOSITY POLYMER GEL	32	30
2.	19,992	HIGH VISCOSITY CROSSLINKED POLYMER GEL	32	70
3.	19,992	10% HF-5% HCL ACID WITH CORROSION INHIBITORS AND FRICTION REDUCER	INITIAL: 33.5 FINAL: 20	110 0
4a. (DISPLACEMENT)	8,988	LOW VISCOSITY POLYMER GEL	20	10
4b. (OVERFLUSH)	9,702	LOW VISCOSITY POLYMER GEL	20	10

FIGURE 8

TEMPERATURE AND GAMMA RAY SURVEY OTTOBONI STATE 22

● FLUID ENTRY POINTS AS INDICATED BY R/A TRACER.

AGI 2754

$$L = \frac{6(\text{Frac Volume})(\text{Fluid Efficiency})}{(\text{Frac Height})(\text{Frac Width})} \quad (2)$$

where

L	=	effective fracture length, ft
Frac Volume	=	total fracture volume, ft ³
Fluid Efficiency	=	fraction between 0 and 1.0
Frac Height	=	fracture height, ft
Frac Width	=	fracture width, in

For the case described above, the effective length is 51.7 feet.

C. Tracer Tests

The alcohol tracers injected with the tracer fluids were returned to the surface as the well was flow tested. Table 7 lists the concentration of each alcohol tracer returned as a function of time. The notable trend in the table is the general mixing and diminishing concentration of all alcohols with time. This is somewhat contrary to the way the alcohols were expected to return. It appears that at least part of the ethanol and isopropanol-rich prepad went into the naturally fractured voids near the wellbore. When the well was returned to production, these voids emptied rapidly to give high concentrations at early times. Also these fluids mixed with those that were in the artificially created fractures at the bottom of the open interval. The general mixing of the tracers suggests that a single fracture was not created, but that all the injected treatment stages became thoroughly mixed in the formation fracture system or were not displaced as slugs.

D. Pressure Tests

Forty-eight hours after the fracture stimulation treatment, a flow test was performed. During the initial flow, the pressure drawdown as measured at the wellhead flow was severe. Flow through the orifice plate was essentially zero after the well was opened to flow for 30 minutes. Figure 9 shows the pressure drawdown as a function of time. The data is essentially meaningless and it appears that the post-stimulation flow consists only of fluid injected during the treatment. After one hour of flow, the wellhead pressure was nearly zero. Table 8 lists the wellhead pressure and time data.

After the well was cleaned out to total depth and returned to its pre-stimulation condition, the flow rate was measured at 41,200 lb/hr. Table 9 summarizes other recent tests for comparison and shows that the stimulation treatment had no effect on the production from the well.

TABLE 7

POST-STIMULATION TRACER PRODUCTION
OTTOBONI STATE 4596, WELL NO. 22
THE GEYSERS

<u>Time (hours)</u>	<u>ETOH</u>	<u>IPA</u>	<u>NBOH</u>	<u>IBOH</u>
0.25	36.2	18.9	5.6	4.8
4.75	12.9	8.1	5.6	2.9
9.25	25.4	6.8	11.1	3.8
22.25	10.8	5.9	4.4	2.9
27.25	28.4	41.6	29.9	34.2
33.75	19.9	28.1	31.1	27.6
38.75	24.8	19.9	27.8	21.9
44.75	5.4	6.5	9.9	6.7
52.25	4.0	5.9	4.4	5.7
60.75	4.0	5.9	5.6	4.0
70.75	4.0	8.1	8.9	7.6

Values expressed in parts per million

ETOH = ethanol
IPA = isopropyl alcohol
NBOH = n-butane
IBOH = isobutanol

FIGURE 9
POST-STIMULATION PRESSURE DRAWDOWN, OTTOBONI STATE
THE GEYSERS

TABLE 8

POST-STIMULATION DRAWDOWN DATA
OTTOBONI STATE 4596 WELL NO. 22
THE GEYSERS

<u>t (hours)</u>	<u>P (psia)</u>
0	235.0
.0055	228.8
.0139	221.1
.0222	214.2
.0277	210.0
.0361	203.6
.0416	177.3
.0472	146.9
.0555	110.2
.0639	79.4
.0694	61.9
.0750	46.1
.1139	56.7
.1416	54.0
.1583	51.3
.1750	50.1
.2083	48.1
.2416	45.7
.3750	41.1
.5416	35.3
.7083	31.6
.8750	28.4
1.5160	21.3

TABLE 9

SUMMARY OF PRE- AND POST-STIMULATION FLOW TESTS

<u>Date</u>	<u>Steam Flow (lb/hr)</u>	<u>Wellhead Pressure (psig)</u>
Pre-Stimulation		
10/08/80	46,500	127
11/26/80	49,500	134
12/17/80	40,500	159
Post-Stimulation		
2/27/81	44,108	130
3/03/81	41,200	135

These data confirm the fact that the acid etch treatment did not create any new high conductivity flow paths to the main reservoir system and that the well now produces at the same rate as before the stimulation treatment.

VI. EXPERIMENT COSTS

The total cost of rig work and fracturing services for this experiment (excluding Republic's and program subcontractors' labor) was \$333,755. Under the cost sharing agreement with Union Oil Company, the GRWSP portion of these expenses was \$227,638.

VII. CONCLUSIONS

From the results of this experiment, the following conclusions are drawn:

1. From the examination of the temperature and gamma ray logs, the frac fluids went into the open interval and entered a zone over 650 feet in height. This is contrary to the original plan of opening a single fracture interval of small height at the bottom of the open interval.
2. Tracer studies along with the temperature and gamma ray surveys indicate that the fracture system in the treated interval is made up of a number of natural fracture channels rather than one large fracture. These small natural fractures resulted in a high fluid leak-off rate and probably prevented the acid etching treatment from functioning as designed.
3. The rapid drawdown of the well after it was returned to production indicates that the treatment was ineffective in creating high conductivity fractures connected with the main fracture system responsible for steam production in other wells. Returning the entire well to flow indicated that

essentially no damage occurred to the well because of the stimulation experiment.

Recommendations based on the experience gained in this project are:

1. Due to the extensive and varied natural fracture system that exists even in nonproductive intervals, in The Geysers reservoir, smaller treatment intervals and/or larger volume treatments are required.
2. Bottomhole treating pressures which are useful for post-mortem analysis of the treatment could not be inferred from the near-zero surface treating pressures. Downhole pressure measurements are recommended for any future stimulation experiment.
3. A continuous temperature log should be run at several different times after the stimulation treatment. This may result in the identification of individual stimulated zones. Selective, rapid heat-up of a small zone in the treated interval may be indicative of establishment of a link with the productive, main fracture system.

VIII. REFERENCES

1. The Geothermal Resource, published by Petroleum Information Corporation, 1979.
2. H. L. Overton and R. J. Hanold, "Geothermal Reservoir Categorization and Stimulation Study," Los Alamos Scientific Laboratory, LA-6889-MS, July 1977.

APPENDIX A

ACID ETCHED FRACTURE FLOW CAPACITY TESTS

Conditions: Temperature = 400°F
 Closure Pressure = 1667 psi

<u>Acid Solution</u>	<u>Contact Time (Min)</u>	<u>Fracture Flow Capacity (md-ft)</u>		<u>Amount Removed and Crushed (Inch)</u>
		<u>MY-T-ACID®¹</u>	<u>Conventional²</u>	
(10% HF-5% HCl)	20	6,744	908	0.006
	40	13,488	0	0.006

¹Fracture conductivity that could result from a MY-T-ACID® treatment. When a viscous preflush is used ahead of acid, viscous fingering can occur. Any treatment where viscous fingering is anticipated is described as a MY-T-ACID® treatment. When viscous fingering occurs, the acid contacts only a portion of the fracture resulting in differential etching and usually much higher fracture conductivity.

²Fracture conductivity measured under closure pressure. This is the fracture conductivity that would be expected from a conventional fracture acidizing treatment.

FORMULATION FOR 1000 GAL 10% HF-5% HCl

118 gal 70% liquid HF acid
 141 gal 20° Be' HCl
 741 gal water

CORROSION TESTS

Test Time ----- 2 hours
 Test Temperature ----- 400°F
 Test Pressure ----- 500 psig
 Metal Type ----- N-80 Tubing Steel
 Surface Area to Volume Ratio ----- 50 cc/in²

<u>Acid</u>	<u>Inhibitor</u>	<u>Additive</u>	<u>Corrosion Loss in lb/ft²</u>
10% HF-5% HCl	2.0% HAI-75	100 lbs/1000 gals HII-124S	0.017
10% HF-5% HCl	2.0% HAI-75	100 lbs/1000 gals HII-124B	0.054

*Data provided by Halliburton Services.

APPENDIX B

CORE ANALYSIS DATA

UNION WELL DX-11, THE GEYSERS

Immersion Tests

Effects of immersion under vacuum at 115°F for one hour in the following:

<u>Depth (feet)</u>	<u>Fresh Water</u>	<u>10% NaCl</u>	<u>2% KCl</u>	<u>2% Clay-Fix</u>	<u>7 1/2% MCA</u>	<u>6% HF</u>	<u>Kerosene</u>
4609-30	NFR	NFR	NFR	NFR	V-SAF	V-SAF	NFR

NFR = No fines released.

V-SAF = Very small amount fines.

X-Ray Diffraction Analysis

	<u>Bulk Sample</u>	<u>White Sample</u>	<u>Shale Sample</u>
Quartz	major 36%	very small	major
Feldspar	moderate 21%	-	small
Calcite	-	major	-
Dolomite	-	-	-
Kaolinite	small 12%	-	moderate
Illite	small 14%	-	moderate
Montmorillonite	-	-	-
Mixed Layer Clay	moderate 17%	-	moderate
Chlorite	small	-	small

Solubility (by weight loss):

(a)	5%	(15% HCl at 75°F)
(b)	26%	(HF-Acid for 1 hour at 75°F)
(c)	54%	(HF-Acid for 24 hours at 75°F)

(continued on following page)

APPENDIX B (continued)

Mechanical Rock Properties

<u>Core Orientation</u>	<u>Poisson's Ratio</u>	<u>Young's Modulus of Elasticity (psi)</u>
Vertical	0.14	5.3×10^6
Horizontal	0.13	4.7×10^6

Bulk Density

Bulk density = 2.72 grams per cc

Conclusions

The submitted core was primarily sandstone with white streaks and nodules of calcite and dark streaks of a shaley appearance. The rock also contained a few small vugs and natural fractures. The rock properties and bulk densities were comparable to hydrocarbon producing sandstones.

*Data provided by Halliburton Services

APPENDIX C

LABORATORY TESTS

A. Stimulation Fluids

Four different fluids were used to run the MY-T-ACID® stimulation treatment. As labeled in Section IV of the text, Stage 1 was the prepad of slick water containing 15 lb/1,000 gals of HP guar. It was tested at room temperature and found to have 7 cp of viscosity. It was used to provide low tubular friction and to precool the near wellbore region. Table C-1 shows the viscosities at various shear rates which occur as the fluid is mixed, pumped into the well, and flows in the fractures.

Stage 2 is the crosslinked HP guar or VERSAGEL® (60 lb/1,000 gal) that is used to provide a viscous bank for the acid to finger through. Its uncrosslinked apparent viscosity at room temperature was 62 cp, which is well within the range of acceptability. Upon crosslinking, the viscosity will increase to several thousand centipoise of non-Newtonian fluid gel. The VERSAGEL® viscosity shear rate behavior is shown for the uncrosslinked fluid in Table C-1. A typical response of the viscosity of the crosslinked VERSAGEL® to temperature is shown in Table C-2. The uncrosslinked viscosity of the VERSAGEL® fluid versus temperature 170 sec^{-1} is shown in Figure C-1.

Stage 3 is the fingering acid slug of 10% HF and 5% HCl. It is a Newtonian fluid with a viscosity of 1 cp at room temperature.

Stage 4 is the flush containing 15 lb/1,000 gals of HP guar. Its purpose is to clean and flush all equipment and tubing of the acid. It will also displace the acid into the fractured formation by pushing the acid through the crosslinked VERSAGEL®. Its apparent viscosity was over twice that of the Stage 1 prepad and measured 17 cp. One possible explanation for the higher viscosity is that the Stage 4 flush water tank was filled from the well's steam condensate tanks. The Stage 1 prepad was made from fresh water that was hauled to the site. The condensate contained boron ions which can sometimes complex the gel and increase its apparent viscosity.

TABLE C-1

FLUID RHEOLOGY: FANN 35A VISCOMETER

Stage 1

Fluid Sample--Pad Fluid

SHEAR RATE	VISCOSITY
(sec ⁻¹)	(cp)
5	50.0
10	25.0
170	9.0
341	8.25
511	7.0
1022	6.0

Apparent Viscosity = 7.0 cp

Stage 2

Fluid Sample--VERSAGEL® (Uncrosslinked)

SHEAR RATE	VISCOSITY
(sec ⁻¹)	(cp)
5	1060.0
10	700.0
170	139.0
341	79.5
511	62.0
1022	39.0

Apparent Viscosity = 62.0 cp

Stage 4

Fluid Sample--Displacement Fluid

SHEAR RATE	VISCOSITY
(sec ⁻¹)	(cp)
5	100.0
10	75.0
170	27.0
341	21.0
511	17.0
1022	12.5

Apparent Viscosity = 17.0 cp

FIGURE C-1
FLUID RHEOLOGY: FANN 50C VISCOMETER

TABLE C-2

TEMPERATURE EFFECTS ON
VERSAGEL® CROSSLINKED FLUID

<u>Time at</u> <u>Temperature</u> <u>(Min.)</u>	<u>Temperature, °F</u>	<u>Viscosity, (cp)</u>
0	100	990
0	125	1900
0	150	1800
0	175	1750
0	200	1300
0	225	1250
0	250	1120
0	275	1050
0	300	900
0	325	800
0	350	700
0	375	610
0	400	510
0	425	320
0	450	40
5	450	10

B. Core Material

A piece of core was analyzed by the Halliburton Research lab in preparation for acid-frac work on an Ottobani No. 22-type well.

The submitted core was primarily sandstone with white streaks and nodules of calcite and dark streaks of a shaley appearance. The rock also contained a few small vugs and natural fractures. The rock properties and bulk densities were comparable to hydrocarbon producing sandstones.

The data is presented below for a typical core analysis on this specimen:

Core Analysis--Ottobani-Type Core

<u>Depth (feet)</u>	<u>Solubility*</u> <u>%</u>	<u>Salt Content, mg.</u> <u>Salt/100 gm. Core</u>
4609-30	3.7	8.0

* This is solubility in dilute hydrochloric acid as calcium carbonate only

Immersion Tests

Effects of immersion under vacuum at 115°F for one hour in the following:

<u>Depth (feet)</u>	<u>Fresh Water</u>	<u>10% NaCl</u>	<u>2% KCL</u>	<u>2% Clay-Fix</u>	<u>7-1/2% MCA</u>	<u>6% HF</u>	<u>Kerosene</u>
4609-30	NFR	NFR	NFR	NFR	V-SAF	V-SAF	NFR

NFR = No fines released

V-SAF = Very small amount fines

X-Ray Diffraction Analysis

	<u>Bulk Sample</u>	<u>White Sample</u>	<u>Shale Sample</u>
Quartz	major	very small	major
Feldspar	moderate	-	small
Calcite	-	major	-
Dolomite	-	-	-
Kaolinite	small	-	moderate
Illite	small	-	moderate
Montmorillonite	-	-	-
Mixed Layer Clay	moderate	-	moderate
Chlorite	small	-	small

Mechanical Rock Properties

<u>Core Orientation</u>	<u>Poisson's Ratio</u>	<u>Young's Modulus of Elasticity (psi)</u>
Vertical	0.14	5.3×10^6
Horizontal	0.13	4.7×10^6

Bulk Density

Bulk density = 2.72 grams per cc

APPENDIX D
TREATING RECORD

JANUARY 15, 1981
STARTING TIME 10:38 A.M.

STAGE 1
(Prepad)

SURFACE PRESSURE = 30 psig

STAGE 2
(VERSAGEL)

SURFACE PRESSURE = 30 to 40 psig

APPENDIX D
(continued)

STAGE 3
(Acid)

SURFACE PRESSURE = 30 to 100 psig

STAGE 4

(Displacement Fluid)

SURFACE PRESSURE = 0 to 30 psig