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Geothermal-Reservoir Well-Stimulation Program

Program Status Report

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By

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DISCLAIMER

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I. SUMMARY

Republic Geothermal, Inc., and its subcontractors have planned and executed seven experimental fracture stimulation treatments under the U.S. Department of Energy-funded Geothermal Reservoir Well Stimulation Program. The program, begun in February 1979, is ultimately to include at least eight full-scale field hydraulic and chemical stimulation experiments in geothermal wells. This report describes the seven treatments completed to date and the laboratory work performed to develop the stimulation technology.

Two stimulation experiments were performed at Raft River, Idaho, in late 1979. This is a naturally fractured, hard rock reservoir with a relatively low geothermal resource temperature (290°F). A planar hydraulic fracture job was performed in Well RRGP-5 and a dendritic, or reverse flow, technique was utilized in Well RRGP-4.

In mid-1980, two stimulation experiments were performed at East Mesa, California. The stimulation of Well 58-30 provided the first geothermal well fracturing experience in a moderate temperature (350°F) reservoir with matrix-type rock properties. The two treatments consisted of a hydraulic fracture of a deep, low-permeability zone and a dendritic fracture treatment of a shallow, high-permeability mud/cement-damaged zone in the same well.

In January 1981, an acid etching stimulation treatment was performed in the Ottoboni State 22 well located in The Geysers geothermal area of California. The treatment involved the injection of 476 bbl of a 10% HF-5% HCl acid solution behind a 476 bbl slug of high viscosity crosslinked gel fluid. This technique was intended to take advantage of the fluid mobility differences to etch discrete flow channels, or fingers, in the fracture faces.

A 7,600 bbl hydraulic fracture treatment was also performed in early 1981 in the Baca 23 well of the Redondo Creek area of New Mexico. The stimulation interval was in the upper part of the Bandelier Tuff, a 450°F interval in which the well had not encountered productive natural fractures. This treatment utilized a large cooling water prepad, a high viscosity frac fluid, and temperature resistant proppants, i.e., sintered bauxite and resin-coated sand.

The seventh treatment was conducted in Baca 20 on October 5, 1981, again utilizing a large cooling water prepad followed by a high viscosity frac fluid carrying only sintered bauxite as the proppant. The 8,735 bbl hydraulic fracture job was performed in a deep interval with a temperature of about 540°F, which gave Baca 20 the distinction of being the hottest well to be fracture stimulated in the United States to date.

A discussion of the pre-stimulation and post-stimulation data and their evaluation is provided for each experiment in this report. Six of the seven stimulation experiments were at least technically successful in stimulating the wells. The two fracture treatments in East Mesa 58-30 more than doubled the producing rate of the previously marginal producer. The two fracture treatments in Raft River and the two in Baca were all successful in obtaining significant production from previously nonproductive intervals. However, these treatments failed to establish commercial production due to deficiencies in either fluid temperature or flow rate. The acid etching treatment in the well at The Geysers did not have any material effect on producing rate. Evaluations of the field experiments to date have suggested improvements in treatment design and treatment interval selection which offer substantial encouragement for future stimulation work.

In addition, the individual activities of the subcontractors, Maurer Engineering Inc., Vetter Research, Petroleum Training and Technical Services, and Terra Tek, Inc., are summarized herein. The Phase I theoretical and laboratory studies were performed to provide the basic stimulation technology needed to design and evaluate geothermal well stimulation treatments. All of the Phase I basic studies have been completed. The Phase II site-specific laboratory and design work required for each field experiment are performed by Maurer Engineering, Vetter Research, and Terra Tek as needed.

Several potential wellsites for Experiment No. 8 (the last field experiment under the current contract) are being evaluated. The experiment is expected to be a chemical-type stimulation treatment to evaluate this technology in the geothermal environment. Chemical stimulation treatments have application to many common production (and injection) well problems, such as near-wellbore mud damage, and could significantly improve the economics of geothermal resource development.

II. PROGRAM OVERVIEW

A. Objectives

The Geothermal Reservoir Well Stimulation Program (GRWSP) is proceeding into its fourth year of activity with significant progress made in the area of promoting industry interest in geothermal well stimulation work and in pursuing technical areas directly related to the stimulation activities. The ultimate objective was to demonstrate that geothermal well stimulation in many cases is a technically viable alternative to additional well drilling and redrilling for productivity (or injectivity) enhancement which can substantially reduce development costs. Republic Geothermal, Inc. (RGI) and its subcontractors have formulated a development plan which will lead to the completion of eight full-scale geothermal well stimulation experiments by July 1982. The project was initially organized into two phases. Phase I consisted principally of studies (literature and theoretical), laboratory investigations, and numerical work. The main purpose of this phase was to establish the technological base for geothermal well stimulation treatments. This work was essentially completed in 1981 with the submission of final reports by the subcontractors. The primary objectives of Phase II were to plan, execute, and evaluate eight well stimulation treatments (the contract was modified in 1981 to increase the number of field experiments from six to eight) which utilized the technology developed or recommended by the Phase I activities. Different types of geothermal well stimulation techniques were to be used in appropriate reservoirs offered by the industry. To date, seven of the proposed eight field experiments have been completed.

In selecting candidate reservoirs and wells, the program was influenced by many contributing factors. In addition to the obvious technical considerations, the program evaluated cost-sharing arrangements provided by the well owner to conserve program funds and the potential impact that effective stimulation could have on the future commercial development of the field. This latter consideration played a strong role in the selection of the Raft River and Baca Project areas for performing four well stimulation treatments. Raft River was selected at the request of DOE Headquarters to support brine production activities required for the upcoming 5 MW geothermal power plant. Although Baca was of tremendous technical importance to the program because of its very high reservoir temperature, the fact that it was part of a DOE/Union/PNM Demonstration Plant Project considerably enhanced its priority status. The importance of The Geysers as the world's largest commercial electric generating geothermal field, along with the cost-sharing benefits offered by Union, was also instrumental in its selection for a well stimulation treatment. While each of these sites proved to be an excellent choice from a technical standpoint, it did result in five of the seven field stimulation treatments being performed in fracture dominated reservoirs. Only the two treatments at East Mesa addressed the very significant problems associated with low permeability regions in matrix-type producing formations, including well skin damage resulting from drilling and completion operations.

A description of each of the stimulation experiments completed to date is provided in the next section and summarized in Table 1. Six of the seven field treatments were at least technically successful in stimulating the wells under extremely hostile reservoir environment conditions. Evaluations of these field experiments have suggested improvements in treatment design and treatment interval selection which offer substantial encouragement for future well stimulation work in both production and injection wells. A list of GRWSP reports is given in Table 2. These reports are available from the U.S. DOE Technical Information Center.

B. Subcontractors

The subcontractors involved in the program have changed during the course of the work as the emphasis of the program shifted from the Phase I theoretical and laboratory studies to the Phase II field experiments. Originally, Maurer Engineering Inc. (MEI), Vetter Research (VR), and Petroleum Training and Technical Services (PTTS) comprised the subcontractor team. With the modification of the contract in July 1981, Terra Tek, Inc. (TTI) was added as a subcontractor for the laboratory flow test work required to support the design of field experiments. In addition, PTTS has completed its contract tasks and is no longer participating in the program. The following sections detail the specific activities of the primary subcontractors MEI, VR, PTTS, and TTI. It should be noted that all of the subcontractors were involved in varying degrees in the field experiments as well as their individual tasks and that these efforts represent a considerable part of the GRWSP accomplishments to date. The current organization chart for the program is shown in Figure 1.

C. Future Plans

The present GRWSP contract is scheduled to end in September 1982. Major tasks remaining to be completed include the proposed acid cleanout of the Baca 20 well (a continuation of Experiment No. 7) and performing Experiment No. 8.

The proposal to acid treat the Baca 20 well was completed and sent to DOE for approval in December 1981. The treatment would utilize approximately 30,000 gal of a 15 percent HCl solution to remove calcium carbonate fluid-loss additive from the propped fracture created during the hydraulic fracture experiment of October 5, 1981. The job is estimated to cost a total of $86,200 (cost-shared with Union Geothermal of New Mexico). Approval for the job is expected in May 1982 with the job completion planned for June 1982.

Several potential wellsites for Experiment No. 8 are currently being evaluated. Republic has discussed the program with several interested geothermal resource operators and a proposal for this last field experiment will probably be completed in May 1982. This experiment is expected to be a chemical-type treatment which is designed to overcome near-wellbore impairment caused by drilling mud, cement invasion, particulate matter from the formation, or scale accumulation. The intent is to provide a technically balanced approach to geothermal well stimulation with specific field results that are representative of developing resources, the best high-temperature materials available, and the most modern field techniques. Chemical stimulation treatments have application to many problems encountered in both production and injection wells and could significantly improve the economics of geothermal resource development.

III. TECHNICAL REVIEW OF TASKS

A. Field Experiments

In early 1979, geothermal resource developers were contacted and requested to participate in the stimulation program. The subsequent response indicated that nine reservoirs would be available as possible stimulation experiment sites. These reservoirs were evaluated, using available nonproprietary resource data, and a program schedule was formulated based on the selection process described in the GRWSP report "Reservoir Selection Task." In mid-1979 the proposed sequence of field tests was altered at the request of DOE to include two field experiments at Raft River. However, after these experiments were completed, the field experiment schedule has progressed approximately as planned from moderate-temperature, less hostile reservoirs to high-temperature, severe reservoir conditions. In addition, these treatments have utilized high-temperature stimulation technology in a variety of geologic settings representative of geothermal resources. The following section describes the seven field experiments completed to date.

1. Raft River Field (Experiments Nos. 1 and 2)

Raft River, Idaho, is a low-temperature (260-290°F) hydrothermal resource. Wells RRGE-1 and RRGE-2 are the best producing wells in the field and appear to intersect a natural fracture zone in the quartz monzonite reservoir. These fractures have high transmissibility, with a permeability-thickness (kh) of greater than 50,000 md-ft. Wells RRGE-3, RRGP-4, and RRGP-5 are less productive and were all considered for stimulation. Wells RRGP-4 and RRGP-5 were chosen as the best two candidates for stimulation because RRGE-3 is farther from the best producing wells and its mechanical configuration is very complex. Figure 2 is a map of the field showing the wells and the surface traces of the two major faults.

Before stimulation, RRGP-4 was essentially nonproductive. RRGP-5, however, was capable of flowing at a stabilized rate of 66,000 lb/hr and produced more than 283,000 lb/hr with a pump. This is adequate productivity, but the production came from the upper portion of the completion interval, and the produced fluid temperature of 255°F was undesirably low. Based on the performance of the better wells in the field and the proximity of Wells RRGP-4 and RRGP-5 to the Bridge and Narrows Faults, it was considered likely that highly productive fractures existed near the wells. Hydraulic fracture treatments in the deeper intervals were chosen as the best means to connect the wells with major productive fractures and to achieve the desired produced fluid temperatures of 270°F or greater. Although on the upper temperature margins of conventional oil field fracturing technology, no special techniques or materials were thought to be necessary for Raft River.

To isolate the deep interval of Well RRGP-4 for the fracture treatment, a 7" liner was cemented through the upper portion of the openhole interval (Figure 3). This isolated a 195-foot openhole interval (4,705-4,900 feet) near the bottom of the well for the hydraulic fracture treatment. The technique employed was a four-stage dendritic fracture treatment. It was chosen because, if dendritic fracturing was achieved, it offered the best chance of intersecting major natural fractures. The main concern was that a single, planar fracture might only parallel and not intersect the principal natural fractures. The dendritic, or reverse flow, fracturing technique is designed to create branching or diversion of the fracture wings by downhole stress modification. Multiple stages or pumping periods are used with each stage utilizing a low-viscosity fluid, sand slugs, and two brief flow-back periods. High pumping rates are used in these treatments to offset fluid leakoff into natural fractures and to enhance erosion in the fracture faces by the proppant and fine sand.

The 7,900 bbl treatment was pumped at a high rate (50 BPM) and utilized a low viscosity polymer gel frac fluid (HP guar) carrying relatively low concentrations of proppant. The treatment included 50,400 lb of 100-mesh sand added for leakoff control and 58,000 lb of 20/40-mesh sand proppant. Use of both sand and HP guar was considered acceptable here because of the relatively low temperature.

Following the treatment, the U.S. Geological Survey (USGS) ran their high temperature acoustic borehole televiewer and observed that the created fracture extended the full 195-foot height of the open interval and was oriented approximately east-west, parallel to the nearby Narrows Fault (Figure 2). A section of the fracture is shown in Figure 4. In the post-stimulation flow test, the well produced at a stabilized rate of 28,300 lb/hr with a downhole fluid temperature of 270°F. This rate represented at least a five-fold increase over the pre-stimulation rate; but even with an estimated pumped rate capability of more than 100,000 lb/hr, the well was still subcommercial. The produced fluid temperature is significantly higher than past measurements. This fact suggests that the new artificial fracture is producing fluid from a deep zone not open in the original hole. The chemical data further support this interpretation in that the extent of polymer degradation determined chemically is consistent with fluid exposed to higher temperatures.

Conventional fracture-type curve analysis (log-log plot) yields a fracture length of approximately 335 feet and a permeability-thickness (kh) of 800 md-ft. The Horner plot of the same pressure buildup data has two straight line segments after the fracture dominated period, one during early time (less than 15 hours) and one during later time (greater than 15 hours). These two segments give kh values of 1,070 md-ft and 85,000 md-ft, and suggest the presence of more than one permeability zone in the vicinity of the wellbore. Also, a negative skin factor (minus 6.0) indicates a stimulated zone close to the wellbore.

Well RRGP-5 originally had good productivity from the upper portion of the completion interval. The goal of the treatment for this well was a similar or higher productivity, but from a deeper, hotter interval. The well was recompleted similar to RRGP-4, as shown in Figure 5, in preparation for this stimulation treatment. The recompletion consisted of cementing a 7" liner through the upper portion of the openhole interval which sealed off the existing producing interval and left a 216-foot openhole interval near the bottom of the well. A large fracture treatment designed to create a single planar propped fracture was selected for RRGP-5. The treatment consisted of 7,600 bbl of a relatively low viscosity polymer gel (HP guar) with 84,000 lb of 100-mesh sand for leakoff control and 347,000 lb of 20/40-mesh sand proppant. Near the end of the treatment, the pumping rate was gradually reduced in an effort to sand the well out and leave the fracture propped near the wellbore with an open, high-conductivity channel near the top. As the rate approached zero, the wellhead pressure dropped to zero psig indicating that communication with the natural fracture system had been achieved. Also, a significant pressure response was noted in RRGE-1 during the frac job.

Following the treatment, the USGS borehole televiewer showed that the created fracture spanned the upper 135 feet of the open interval (possibly through the original wellbore). The fracture was oriented northeast-southwest, parallel to the nearby Bridge Fault (Figure 2). In the post-stimulation production test, the well stabilized very rapidly at a 94,300 lb/hr rate with a 30 psia wellhead pressure. The produced fluid temperature was unchanged from the pre-stimulation flow condition. Following the natural flow test, a pump was installed in the well and it produced more than 307,000 lb/hr. Chemical analysis of the produced fluid indicated a relatively low rate of polymer degradation in the reservoir, confirming that the frac fluid traveled upward into a cooler portion of the reservoir.

Pressure buildup and temperature data also suggest strongly that the fracture treatment went upward to the original producing interval (possibly through the original wellbore). The Horner plot of the pressure buildup data shows only a short transition phase between the fracture dominated period and the late time constant pressure period. Estimates of the late time formation kh were large--greater than 100,000 md-ft. The Horner analysis indicates a very large positive skin factor. This skin factor is probably not due to formation damage but rather to the limited entry nature of the completion.

2. East Mesa Field (Experiments Nos. 3 and 4)

The East Mesa field, in the Imperial Valley of California, is a moderate-temperature reservoir producing from a sandstone and siltstone matrix. Several features of East Mesa made it an excellent choice for the second set of field experiments. The reservoir is known in more detail than most other geothermal reservoirs and this in-depth knowledge provides a sound basis for designing and evaluating stimulation treatments. The moderate temperature range (320°-350°F) was the next logical step from Raft River conditions in the evaluation of fracture fluids, proppants, and mechanical equipment. The selection of a matrix-type reservoir was also important at this stage of the program. Fracture geometry has been successfully predicted in matrix-type reservoirs in the petroleum industry, and the existing interpretive techniques should transfer to geothermal reservoirs. Furthermore, the reservoir fluids, with a total dissolved solids content of less than 2,000 mg/l, were not expected to chemically interfere with the stimulation fluids or tracers.

Well 58-30, selected for these experiments, is ideally suited mechanically. Unlike many other geothermal wells at East Mesa and elsewhere, it is completed with a cemented, jet perforated liner (Figure 6). This afforded an opportunity to easily and cheaply isolate zones of a size that can be effectively treated and evaluated. The first treatment was a planar-type hydraulic fracture of a 250-foot, low-permeability sandstone interval (6,587-6,834 feet) near the bottom of the well. This zone has good sand development, but the permeability has been severely reduced because of authigenic cementation by carbonate minerals. Porosity is still high enough, however, to provide good storage capacity. A fracture treatment of this zone was intended to create a high conductivity linear flow channel in the low permeability area surrounding the well, thereby enhancing the flow capacity. The treatment consisted of 2,800 bbl of a viscous crosslinked polymer frac fluid (HP guar) and 163,000 lb of sand. The fluid was pumped at an average rate of 40 BPM during the treatment.

The second treatment was a dendritic-type fracture treatment in a shallower, higher permeability, 300-foot interval (4,952-5,256 feet) of the same well. This cooler upper zone, drilled with a predominantly bentonitic mud system, has good sands (high porosity and permeability) which show permeability impairment near the wellbore. The staged treatment was designed to create multiple short fractures through the damaged zone around the wellbore. The treatment consisted of 10,300 bbl of low viscosity frac fluid (HP guar) and 44,000 lb of 100-mesh sand pumped in five stages at an average rate of 48 BPM. The 100-mesh sand was injected in slugs as a fluid-loss control agent in the 50 md permeability sandstone, as a diverter for succeeding stages of the treatment, and to erode flow channels in the fracture faces.

From July 25 to August 2, 1980, the well was production tested to evaluate the fracture experiment on the upper zone. The lower section of the well, from 6,547 feet to TD, was sanded back to prevent flow from the lower frac zone. The well flowed an average of 132,000 lb/hr. Reservoir pressure buildup data show the total open interval permeability-thickness was 9,427 md-ft, or approximately a 108 percent increase in kh for the upper frac zone. This analysis indicates the shallow hydraulic stimulation treatment of the high permeability, upper interval was very successful. The upper zone treatment to correct near-wellbore damage is of particular importance because such mud and cement damage is believed to be a common cause of impairment in Imperial Valley geothermal wells.

Well cleanout operations were initiated in August to remove the sand covering the lower frac zone. The coil tubing being used to lift sand out of the well parted and left approximately 5,170 feet of tubing in the hole. Following the fishing and cleanout operations, the entire wellbore was opened for a flow test and the well achieved a total flow rate of about 198,000 lb/hr. The lower zone, stimulated with a small hydraulic fracture treatment, showed a 19 percent increase in kh but an 84 percent increase in fluid production. In addition, the overall fluid production temperature increased by 5°F. Higher temperatures reduce the hydraulic head in the wellbore (lower flash point) and thereby increase the natural flow rate more than would be expected from the kh increase alone.

In summary, Well 58-30 was successfully stimulated by the two fracture treatments. Although some of the improvement in the upper interval was lost during workover operations, the overall productivity of the well had been increased 114 percent and the kh had been increased 38 percent.

3. The Geysers Field (Experiment No. 6)

The fifth experiment was performed at The Geysers geothermal area in Sonoma County, California, and was cost-shared with the well operator, Union Geothermal Company. The well chosen for this chemical stimulation treatment was Ottoboni State No. 22. This well is completed openhole from 4,600 feet to 8,360 feet in naturally fractured graywacke. The reservoir temperature is about 460°F. The well was plugged back to 5,600 feet to isolate the upper 1,000 feet of openhole interval for the treatment.

The stimulation technique employed was an acid etching treatment (Halliburton Services MY-T-ACID®). A 476 bbl low viscosity prepad was pumped to provide cooling of the tubulars and formation. Following the prepad were 476 bbl of high viscosity crosslinked gel fluid (HP guar) and 476 bbl of 10% HF-5% HCl acid solution with corrosion inhibitors and friction reducer. After the acid, an additional 445 bbl of low viscosity fluid were injected as displacement and overflush.

Fracture fluid pump rates of 20-40 BPM and a surface pressure of 3,000 psig were estimated for this stimulation job. However, no significant surface pressure was recorded and all fluids easily flowed into the interval. Subsequent evaluation of well performance showed that no noticeable stimulation had been achieved. Temperature and radioactive tracer surveys, shown in Figure 7, indicated that the fracture fluids entered natural, pre-existing fracture channels in the lower 650 feet of the 1,000-foot openhole interval. In addition, chemical tracers injected sequentially with the frac fluids returned in a highly mixed fashion. The small fluid volume employed and widespread entry interval probably resulted in shallow penetration of the formation.

After the job the well was cleaned out to total depth and returned to its pre-stimulation condition. The final steam flow rate was 41,200 lb/hr which is similar to the rate recorded before the stimulation job. This confirmed the fact that the acid etching treatment did not create any new, high conductivity flow paths to the main reservoir system. There is no evidence to suggest, however, that the acid etching technique will not work, and the technique needs to be attempted again in a shorter treatment interval or with larger fluid volumes.

4. Baca Field (Experiments Nos. 5 and 7)

The Baca reservoir lies within the Jemez Crater, Valles Caldera, and is defined by more than 20 wells completed to date in the Redondo Creek area by Union Geothermal Company of New Mexico. The main reservoir, 4,000 to 6,000 feet in thickness, is composed of volcanic tuffs with low permeability and a primary flow system of open fracture channels. In the Redondo Creek area, wells have encountered a high temperature (550°F) liquid-dominated reservoir, but several wells have not been of commercial capacity, primarily because of the absence of productive natural fractures at the wellbore.

After considering several candidate wells, RGI and Union agreed that Baca 23 and subsequently Baca 20 were the best sites for the fracture treatments. These wells, shown in Figures 8 and 9, were selected because: (1) they were poor producers; (2) the fracture system is present in the area as proven by the surrounding wells; (3) the wells could be recompleted to isolate the stimulation interval; (4) observation wells were available within 1,500 feet; (5) the wellsite was large enough for the frac equipment; and (6) in the case of Baca 23 the rig was already on location. The experiments were cost-shared by Union and the GRWSP.

Baca 23 was originally completed as shown in Figure 8A with a 9-5/8" liner cemented at 3,057 feet and 8-3/4" openhole to 5,700 feet. The well was flow tested and at that time would not sustain flow. An interval from 3,300 feet to 3,500 feet was selected for fracture stimulation. Productive fractures had previously been encountered near this depth approximately 200 feet away in Baca 10. Fracturing a more shallow interval, immediately below the shoe of the 9-5/8" casing, was considered to have a substantial risk of communication with the lower temperature formation above. The temperature in the zone selected was approximately 450°F.

Since the top of the selected interval was deeper than the existing 9-5/8" liner, a 7" liner was cemented to a depth of 3,300 feet to exclude the interval above. The lower portion of the hole was sanded back to 3,800 feet and plugged with cement to 3,531 feet to contain the treatment in the desired interval. The treatment interval was totally nonproductive after being isolated for the stimulation treatment.

A large hydraulic fracture treatment was performed on the well consisting of 7,641 bbl of fluid and 180,000 lb of 20/40-mesh proppant pumped in eight stages. A 3,600 bbl cold water prepad was pumped at an average rate of 38 BPM. The frac fluid consisted of 4,000 bbl of crosslinked polymer gel (HP guar) pumped at an average rate of 66 BPM and an average surface pressure of 3,300 psig. The final displacement volume was 66 bbl of water. The treatment was pumped through a 4-1/2" tubing frac string with a packer set near the top of the 7" liner as shown in Figure 8B. Although the job was basically a conventional hydraulic fracture treatment, the high formation temperature (450°F) dictated special design and materials selection requirements. Therefore, the large water prepad was dedicated to wellbore and fracture pre-cooling with the frac fluid used to place the proppant. While frac fluid properties are known to degrade rapidly at high temperature, these effects were minimized by pre-cooling, by pumping at high rates (up to 75 BPM), and by limiting the frac interval to 231 feet. Proppants were selected for their insensitivity to the high temperature. Both resin-coated sand and sintered bauxite were used. The two proppants were mixed in near equal proportions by weight.

During the fracture treatment, Los Alamos National Laboratory performed a fracture mapping experiment using Baca 6 as an observation well. A triaxial geophone system was placed in the well, and using techniques developed for the Hot Dry Rock Project, microseismic activity caused by the fracture job was mapped. The 14 discrete seismic events indicate northeast trending activity in a zone roughly 2,300 feet long, 650 feet wide, and 1,300 feet high. The rock failure, therefore, occurred in a broad zone and suggests the stimulation did not result in the creation of a singular monolithic fracture. These microseismic events would be expected to proceed in advance of any significantly widened, artificially created fracture and would not necessarily define a final propped flow path to the wellbore at Baca 23. Calculations of the theoretical fracture length were made assuming a 300-foot high fracture. The results suggest a fracture wing of 430 to 580 feet in length may have been created, depending on the assumptions utilized for the frac fluid, fluid efficiency, and fracture width.

As discussed above, the 231-foot interval isolated for stimulation was nonproductive prior to the treatment. This indicated that no significant natural fractures intersected the wellbore. Twelve hours after the frac job, a temperature survey was obtained by Denver Research Institute. This survey showed a zone cooled by the frac fluids estimated to be more than 300 feet in height at the wellbore.

On March 26, 1981, a six-hour production test through drillpipe was performed in which transient, downhole pressure and temperature measurements were obtained. A unique testing method was utilized to overcome the data gathering problems usually associated with flow testing a geothermal well. The procedure was a combination of conventional drillstem test (DST) methods (to eliminate large wellbore storage effects) and gas lift to maintain steady, single-phase flow to the wellbore. The gas lift was provided by injecting nitrogen gas at depth through coil tubing inside the drillpipe. As a result of this procedure, the well flowed at a low, steady rate (about 21,000 lb/hr) and the transient pressure data obtained downhole provided an indication of wellbore storage effects, fracture flow effects, and reservoir transmissivity.

A conventional Horner analysis of the pressure buildup data yielded an average reservoir permeability-thickness of 2,500 md-ft. This compares closely with results from other non-commercial wells in the area. Although the linear flow indicators were weak, the length of the fracture was calculated to be about 300 feet using the pressure versus square root of time analysis. A skin factor of -3.9 was also calculated. The maximum recorded temperature was 342°F which indicated that the near wellbore area had not recovered from the injection of cold fluids.

Following the modified DST, a 49-hour flow test was performed to determine the well's productive capacity. The results showed that the well could produce approximately 120,000 lb/hr total mass flow at a wellhead pressure of 45 psig, although the rate was continuing to decline. The chemical tracer data showed that the frac fluid stages were thoroughly mixed together in the return fluids and the frac polymer had thermally degraded by the end of this test.

Union performed a long-term flow test on the well during April-May 1981. A temperature profile of the well prior to this test showed that the bottomhole temperature still remained low (401°F). Temperature and pressure surveys run on April 21 recorded a maximum temperature of 344°F and a maximum pressure of 120 psig at 3,500 feet. Therefore, two-phase flow was occurring in the formation, with the steam fraction estimated at more than 50 percent. This two-phase flow condition has been observed in other wells in the field.

Of greater concern is the low productivity observed during this last test. The mass flow rate had dropped to 73,000 lb/hr (about 50 percent steam) with a wellhead pressure of 37 psig in May 1981. Since the well recovers productivity following each shut-in period and then exhibits the same decline again, the cause of the rate decline is probably not due to scaling in the formation. Partial closing of the fracture is possible because of the pressure drawdown. The most probable explanation, however, is that the productivity loss is the result of relative permeability reduction associated with two-phase flow effects in the formation. The relatively low formation temperature in the completion interval also contributes to the well's poor productivity.

Baca 20 was originally completed as shown in Figure 9A with a 9-5/8" liner cemented at 2,505 feet and a 7" slotted liner hung at 2,390 feet with the shoe at 5,812 feet. The 7" slotted liner was pulled, lost circulation zones cured using cement plugs, and then a 7" blank liner was cemented in place at 4,880 feet in order to isolate the desired treatment interval. Since the frac interval was to be from 4,880 feet to 5,120 feet, a sand plug was placed from 5,827 feet total depth to 5,400 feet and then capped with cement to 5,120 feet. This particular 240-foot interval was chosen primarily because the best production in the area has been found near the bottom of the Bandelier Tuff and because of its high reservoir temperature (540°F).

The hydraulic fracture treatment was accomplished in the eleven stages using a total fluid volume of 8,700 bbl. The high formation temperature (540°F) once again dictated special treatment design and materials selection. The treatment was pumped through a 4-1/2" tubing string with a packer set at 2,412 feet, just below the 7" liner hanger. A 3,000 bbl fresh water prepad was used to cool the wellbore and fracture. The proppant selected was 119,700 lb of 16/20-mesh sintered bauxite, followed by 119,700 lb of 12/20-mesh sintered bauxite. The proppant was carried by a 60 lb/1,000 gal hydroxypropyl guar polymer gel mixed in 5,700 bbl of fresh water. This fluid was a new high-pH crosslinked HP guar system having better stability at high temperature. The gel was crosslinked as it was being pumped. Chemical tracers were added to the injected fluid to monitor fluid returns.

In an effort to stop leakage into the small natural fractures, approximately 4,200 lb of 200-mesh calcium carbonate and 42,000 lb of 100-mesh calcium carbonate were pumped as fluid-loss additives. The 100-mesh material was injected in "slugs" to enhance its chances of bridging on the fractures. This material was used in lieu of sand as in the Baca 23 job. The majority of the treatment fluid was pumped at approximately 80 BPM. Minor variations in the planned pumping schedule occurred during the treatment, but all fluids and proppants were injected into the formation and the desired goal of ending the treatment at a relatively high proppant concentration was achieved.

During the fracture treatment, Los Alamos National Laboratory again performed a fracture mapping experiment using Baca 22 as an observation well. A triaxial geophone system was placed in the well at a depth of approximately 3,000 feet, and the microseismic activity caused by the fracturing job was mapped. A large number of discrete events (38) were recorded during the job; however, the orientation measurement of the tool was lost. Again the activity occurred in a broad zone which was roughly 2,000 feet long, 1,600 feet wide, and 1,700 feet high. Theoretical calculations of the artificially created fracture length yielded 340-800 feet for a homogeneous matrix material, depending on the assumptions utilized for the frac fluid, fluid efficiency, and fracture height. These calculations were based on the injected fluid and proppant volumes in a single, vertical fracture.

As discussed above, the 240-foot interval was nonproductive prior to the treatment, although there was a small rate of fluid loss during the well completion operations. This indicated that at least one lost circulation zone existed in the wellbore. Approximately 12 hours after the frac job, the first of several temperature surveys was obtained in the well. These temperature surveys showed a zone cooled by the frac fluids, estimated to be less than 100 feet in height, near the bottom of the open interval. In addition, the zone located behind the 7" liner casing at approximately 4,720 feet also indicated some cooling. This zone was apparently cooled by the workover fluids and possibly by the fracturing fluids; however, the communication between this zone and the open interval (if it exists) appears to be at some distance away from the wellbore. Electric log surveys were run in the open interval following the frac job. No significant new fracture zones (or high porosity) were observed.

On October 10-11, 1981, a 6-hour production test through drillpipe was performed in the same manner as the drillstem test at Baca 23. A steady rate of about 21,000 lb/hr single-phase flow was maintained to the wellbore. Transient pressure and temperature data were obtained downhole during the DST. A conventional Horner analysis of the pressure buildup data yielded an average reservoir permeability-thickness of 1,000 md-ft. Evaluation of these data also indicated small wellbore storage effects and fracture (linear) flow near the wellbore. Although the indicators of linear flow were weak, the length of the fracture was calculated to be about 160 feet from the pressure data. A skin factor of -4.8 was also calculated. Numerical simulation of a high conductivity fracture in a low permeability formation supports this interpretation, although the solution is not unique. The maximum recorded temperature during the test was 320°F and indicated that the near wellbore area had not recovered from the injection of cold fluids.

Following the modified DST, a 14-day flow test was performed to determine the well's productive capacity. The well produced approximately 120,000 lb/hr total mass flow initially, but declined rapidly to a final stabilized rate of approximately 50,000 lb/hr (wellhead pressure of 25 psig) under two-phase flow conditions in the formation.

Because of the poor performance of the well, it was decided to perform an acid cleanout of the fracture. As indicated above, calcium carbonate was used as the fluid-loss additive during the hydraulic fracture treatment. This material was used with the expressed intent of performing an acid cleanout should the fracture conductivity show damage. The possibility of such damage with insoluble fluid-loss additives (e.g., 100-mesh sand) has been a concern in prior stimulation experiments. Although the pressure data does not indicate that the fracture conductivity has been damaged, it does not preclude the possibility that the calcium carbonate has plugged the natural fractures and flow paths in the formation which intersect the artificial fracture.

To summarize, large hydraulic fracture treatments were successfully performed on both Baca 23 and Baca 20. Production tests indicated that high conductivity fractures were propped near the wellbore and communication with the reservoir system was established. The productivities of Baca 23 and Baca 20 have declined to noncommercial levels since the fracture treatments. The probable cause is relative permeability reduction associated with two-phase flow effects in the formation. The ability of Baca 23 to produce substantial quantities of fluid at a high wellhead pressure is limited because of the low formation temperature in the shallow treatment interval. The productivity of Baca 20 is severely restricted because of the low permeability formation surrounding the artificially created fracture.

B. Maurer Engineering Inc.

1. Field Experiments

Maurer Engineering Inc. was directly involved in the planning, supervision, execution, and evaluation of all the field experiments completed to date. Its primary functions were to design and supervise the hydraulic fracturing treatments and provide an on-going link with the service companies and stimulation materials suppliers participating in the field experiments. These tasks were a significant part of the overall program and allowed the utilization of the most advanced stimulation technology available.

2. Laboratory Studies

MEI was also responsible for several tasks of the Phase I portion of the program to develop new technology for geothermal well stimulation. These tasks have been completed. Laboratory studies were performed on proppants, frac fluids, and additives to evaluate the limits on each material's potential for use in a hostile geothermal environment. Some significant results were found during this work.

Available data in the literature on proppants give only properties and strengths under triaxial stress at low temperatures. Data were obtained using a proppant tester constructed for this program, to evaluate proppant materials at elevated temperatures up to 500°F. Both short-term and long-term test results showed that most proppants are temperature sensitive. Sand was found to degrade severely if subjected to both closure stress and temperature above 300°F. These results were reported in "Geothermal Fracture Stimulation Technology - High-Temperature Proppant Testing," Volume II, July 1980 and "Geothermal Fracture Stimulation Technology - Proppant Analysis at Geothermal Conditions," Volume IV, January 1981.

Physical strength and crush measurements were carried out on many potential geothermal proppant materials. Proppant materials with desirable properties at elevated temperature include:

aluminum oxide, garnet, resin-coated materials (sand, bauxite, etc.), and sintered bauxite. While there are limits to the use of these proppants, they are generally resistant to the crushing loads and geothermal waters.

Fluid-loss additives (e.g., silica flour, sand, calcium carbonate, etc.) were evaluated at high-temperature under static test conditions. These materials work by bridging and plugging the exposed formation to enhance frac fluid efficiency and fracture growth. No significant differences in results were found in these tests for the different materials; however, calcium carbonate was easily dissolved in low pH fluids, and therefore was a preferred choice in several of the field experiments to avoid possible permeability damage to the propped fracture.

Fracturing fluids were compared and evaluated with several different laboratory tests which include: polymer degradation in Baroid test cells at high-temperature, apparent viscosity measurements in high-temperature form viscometers, and proppant carrying capacity in a high-temperature falling ball viscometer. These results are reported in "Geothermal Fracture Stimulation Technology - Geothermal Fracture Fluids," Volume III, January 1981. Degradation of even the best polymer solutions starts around 300°F. This degradation continues at higher temperatures with time even if stabilizers or other high-temperature additives are included. The physical properties of these fluids, especially the crosslinked polymer systems, are quite complex since they depend on temperature, time, shear rate, shear history, and concentration. In the higher temperature environment, frac fluid stability problems can be overcome by utilizing special treatment procedures (e.g., high injection rates, pre-cooling the formation, short treatments, etc.).

C. Vetter Research

Under the terms of the GRWSP contract, the services supplied by Vetter Research (VR) as a subcontractor fell under two general categories. The areas were field experiments and laboratory efforts.

1. Field Experiments

In five of the stimulation experiments, VR personnel were directly involved in the treatment design and at the field site with quality control and sampling of injected and produced fluids. For all the jobs, Vetter Research supplied the quantitative chemical analyses needed by the program.

Tracer materials, both radioactive and chemical, were used in the stimulation experiments to help in the post-stimulation diagnostics. It was anticipated that if a stimulation procedure was successful in placing the fracture fluids and proppants, then some fraction of the fluid that was injected into a well should be returned to the surface in the post-stimulation flow test.

Quantitatively measuring the return of fracture fluid is useful in understanding the injected fluid behavior under the hostile geothermal environment and in designing future stimulation jobs.

As part of the tracer studies, laboratory techniques were developed which allowed the polymer material in the fracture fluid to be used as an effective tracer. In addition, other chemical tracers, such as alcohol and Tinopal CBS-X®, have been shown to be useful in monitoring the fluid behavior. These tracers provide an indication of the frac fluid mixing taking place in the formation and a quantitative material balance on the amount of injected fluid returned to the surface. Radioactive tracers have been found to be less desirable from an economic and logistical standpoint.

In addition, VR has performed static and dynamic laboratory experiments in order to define the chemical compatibility and possible reactions of the frac fluids and materials in the geothermal environment. These studies are a necessary part of the preliminary experimental stimulation technique design.

2. Laboratory Studies

The laboratory efforts on the chemical aspects of the GRWSP consisted of three parts: fracturing fluid evaluation, acid work, and scale inhibitor tests. The object of the fracturing fluid evaluation was to characterize by chemical methods, the temperature/time degradation behavior of polymer-based fluids that may be used in stimulating geothermal wells. The organic polymers tested were hydroxypropyl guar, hydroxyethylcellulose, carboxymethylcellulose, and xanthan gum. Also, two commercially available crosslinked hydroxypropyl guar systems were investigated.

The report titled "Geothermal Reservoir Well Stimulation Program - Fracturing Fluid Evaluation (Laboratory Work)," presents the development of analytical techniques for characterizing the polymers and the results of static and dynamic high-temperature aging of the polymers in various salt water environments. The fluids were tested at 302, 392 and 482°F. Also covered are the implications of these results based on the time/temperature degradation of the polymers and the relative ease of flushing the degraded polymer from a sandpack.

The significant results of this laboratory work on fracturing fluid contained in the report are:

a. Analytical techniques and test procedures were developed for examining the high-temperature static and dynamic degradation of water soluble polymers. The techniques perfected were carbohydrate and total organic carbon analysis. Attempts were made at using high-pressure liquid chromotography to characterize the degradation of the polymers. However, insufficient time was available to fully explore this promising technique.

b. Laboratory data showed that overall, the crosslinked fracturing fluid systems that are commercially available have as good chemical stability and cleanup characteristics as the "pure" polymer fluids. Of the commercial fluids, hydroxypropyl guar systems gave the most satisfactory results. For the "pure" polymer solutions, hydroxyethylcellulose had the best stability and cleanup features.

c. All of the water-based polymers had good chemical stability up to 302°F, but only the commercial fracturing fluids had good displacement characteristics. None of the fluids were found to be stable at 482°F.

d. The effect of the salts on stabilizing the polymer degradation was found to be very dependent on the particular polymer and test temperature. No general conclusions could be reached on the salt effect on polymer degradation.

The report "Geothermal Reservoir Well Stimulation Program - Acidification of Geothermal Wells (Laboratory Experiments)" contains the results of the acid studies and scale inhibitor tests. In particular, this report describes the laboratory testing of the reactions of acetic, formic, hydrochloric, and hydrofluoric acids with calcium carbonate, kaolin, sepiolite, and two formation materials at temperatures of 347 and 437°F.

A test procedure was developed which provided information regarding the relative reactivities of selected minerals or formation materials with three of the four acids investigated. Tests with hydrochloric acid were complicated by reactions of the acid with the test vessel materials, and therefore, only limited work could be done with this acid at the desired temperatures. In spite of these difficulties, information regarding the amount of soluble material in the various acids was obtained. From this information, an approximate value for the percent dissolution of the minerals under the different reaction conditions was calculated. Additional information regarding the formation of solid secondary reaction products upon cooling of the reacted acid was also obtained. The implications of the mineral reactivities with the different acids and the formation of secondary solids on geothermal acidizing operations were discussed.

Significant conclusions derived from the acid work are:

a. Acetic acid, at elevated geothermal temperatures dissolves calcium carbonate in approximately stoichiometric quantities.

b. Hydrofluoric acid dissolved considerably more sepiolite and formation materials than acetic or formic acids. Formic acid, however, dissolved more kaolin than hydrofluoric or acetic acids. The rate and quantity of mineral dissolution generally increased with increasing temperature.

c. Selective leaching of aluminum by formic acid was noted. It was also found that acetic acid selectively leached calcium and hydrofluoric acid selectively leached silica.

d. Secondary deposits were found adhering to the formation materials after the completion of each test, except for the HCl-treated Desert Peak material. This result points out that care must be taken to ensure that an acid system chosen for a stimulation treatment is compatible with the formation material and reservoir fluid.

The report on the acidification also contained data on the hydrothermal stability of several commercially available scale inhibitors (for calcium carbonate). Their efficiency in inhibiting the formation of calcium carbonate scale before and after aging at 500°F was measured. The significant conclusion reached, as a result of this laboratory work, was that all commercially available scale inhibitors are thermally unstable (as a function of time) at 500°F in their acidic forms. If the inhibitor is acidic, then it should be neutralized for better thermal stability.

D. Petroleum Training and Technical Services

Under the initial two-year GRWSP contract, PTTS was assigned specific tasks and responsibilities summarized below. In addition, PTTS assisted in the planning and evaluation of the first four field experiments called for in the GRWSP Phase II effort. PTTS was primarily involved in three tasks:

1. Technology Transfer - The objective of this task was to assess the stimulation technology developed for the oil and gas industry and to evaluate it as to applicability to the geothermal industry. A detailed analysis was made in the following areas: (a) stimulation process variables, (b) frac fluid interactions, (c) fracturing problems, (d) temperature effects in fracture design, (e) fracture evaluation, and (f) stimulation case histories.

   An integral part of the analysis involved a breakdown of each stimulation report to quantify the efficiency of various treatments and design criteria in a more objective fashion to provide an ordered ranking according to productivity increase. The results of this phase are summarized in a final report on Technology Transfer issued in May 1980.

2. Numerical Modeling - Development and conversion of computer codes for use in contract projects. PTTS was involved in the development and/or modification of the following five computer codes:

a. Interactive Fracture Design Program - This program was developed by combining the following functional elements:

   WELTEM - a wellbore temperature model GERTSM - a fracture parameter model, and a fracture fluid temperature model.

   PTTS modified the GERTSM model provided by Maurer Engineering Inc. to accommodate a variation in input fluid temperature at the upstream end of the model and a time-distance dependent temperature profile in the fracture. The temperature effects in the fracture can be determined by several published techniques, i.e., Sinclair (constant leakoff at a given time); or Whitsitt-Dysart (variable leakoff); or by a prescribed leakoff rate as a function of distance into the fracture. A technical report, "Interactive Fracture Design Model," was issued in May 1980.

b. WELTEM: This code is based on a Romero-Juarez publication ("A Simplified Method for Calculating Temperature Changes in Deep Wells," SPE Journal of Petroleum Technology, June 1979). PTTS modified the code to include any arbitrary wellbore size, tubular goods, and pumping time by using a regression analysis on the independent variables. The model can now determine any bottomhole temperature for any geometry at any given time. Secondly, the WELTEM code was integrated into the interactive fracture design program to allow a realistic determination of the downhole temperature at the sandface during the fracture job.

c. GEOTEMP: This code was developed by ENERTECH under contract to Sandia National Laboratories. It simulated heat flow in and around the wellbore. PTTS removed all machine dependent codes and modified the software to generalize the fluid properties allowed, removed limitation and tubular goods geometry, and added interactive graphic capability.

d. DIFFUS: This program was obtained from the Department of Energy Morgantown Energy Technology Center. It is a comprehensive model capable of three-dimensional flow simulation within a fractured system, but was not fully operational as received. PTTS segmented and modified the program to simulate a system with a single fracture. A technical report, "Modification and Implementation of the M.E.T.C. Simpac Program," was issued in May 1980.

e. SHAFT78: This program was obtained from Lawrence Berkeley Laboratory. The code could not be made operational and work was terminated on its conversion.

3. Symposium on Geothermal Stimulation - Organization and delivery of a one-day symposium on the results of the first year's work. PTTS assisted RGI in the organization and delivery of a symposium on Geothermal Reservoir Well Stimulation to facilitate the interchange of information on geothermal well stimulation technology. This symposium took place in San Francisco on February 7, 1980. Proceedings of the conference were published as a GRWSP report.

E. Terra Tek, Inc.

As part of the GRWSP contract modification of 1981, Terra Tek, Inc. was added as a subcontractor and assigned the task of performing laboratory flow tests to provide design and evaluation data for the stimulation experiments. To date, TTI has only assisted in the work associated with Experiment No. 7 (Baca 20).

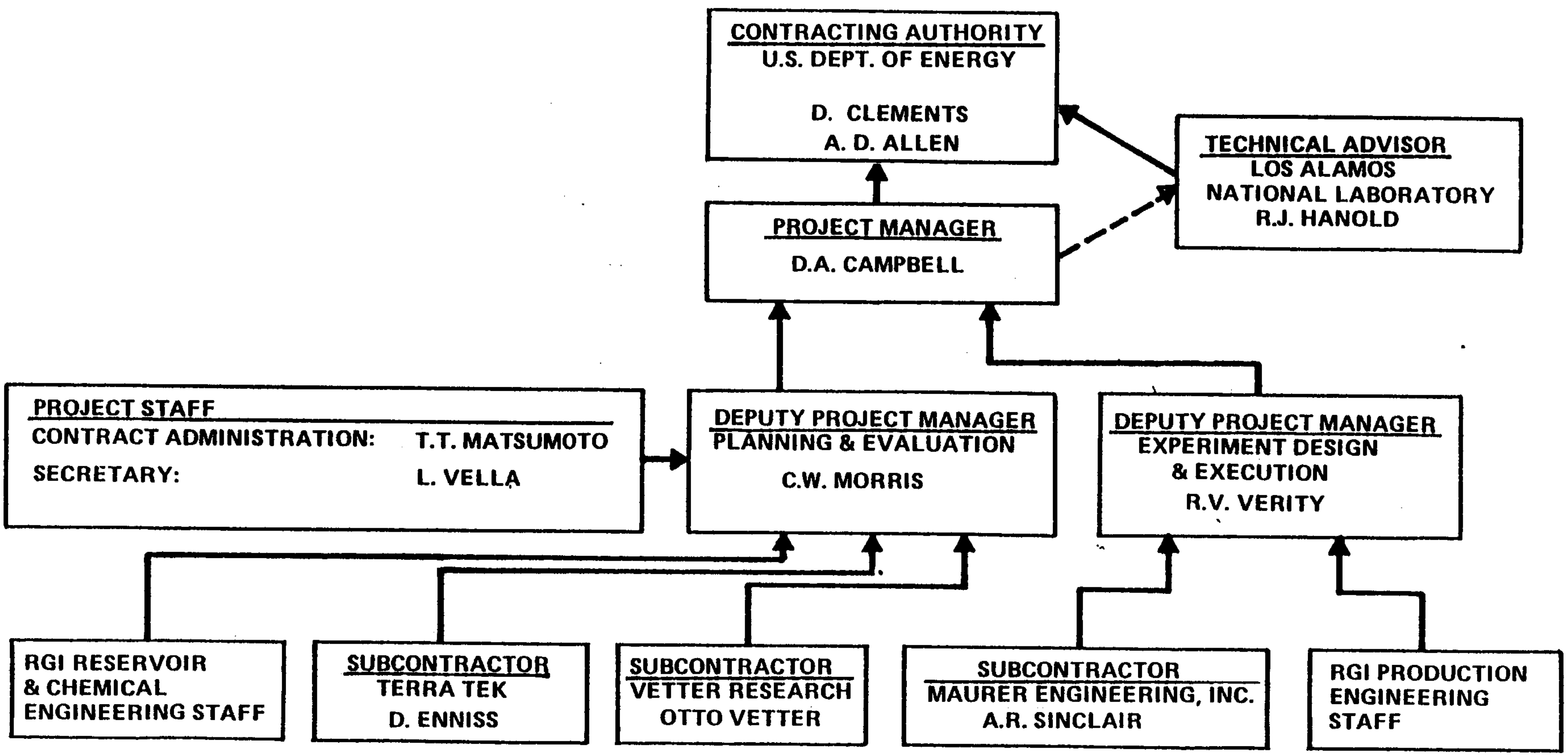
Because of the extremely hostile reservoir conditions at Baca 20, a laboratory test was performed to evaluate the effectiveness of the frac fluid under in-situ conditions. This test utilized the actual Baca formation material (Bandelier Tuff), the frac fluid (crosslinked HP guar gum polymer), and the 16/20 bauxite proppant in a synthetic Baca brine to determine the possible damage to the proppant pack caused by the thermal degradation of the polymer. By measuring fluid conductivity prior to and immediately after the flow of the frac fluid through a vertically fractured core under the simulated in-situ conditions of the Baca reservoir, the extent of conductivity impairment was quantitatively obtained. The test results indicated that the frac fluid would not cause conductivity damage because of polymer residue or proppant embedment; therefore, the hydraulic fracture treatment of Baca 20 was performed as designed.

FIGURE 1

PROJECT ORGANIZATION
GEOTHERMAL RESERVOIR WELL STIMULATION PROGRAM

REPUBLIC GEOTHERMAL, INC.

MAY 1982



RGI E572

FIGURE 2

MAP OF RAFT RIVER FIELD

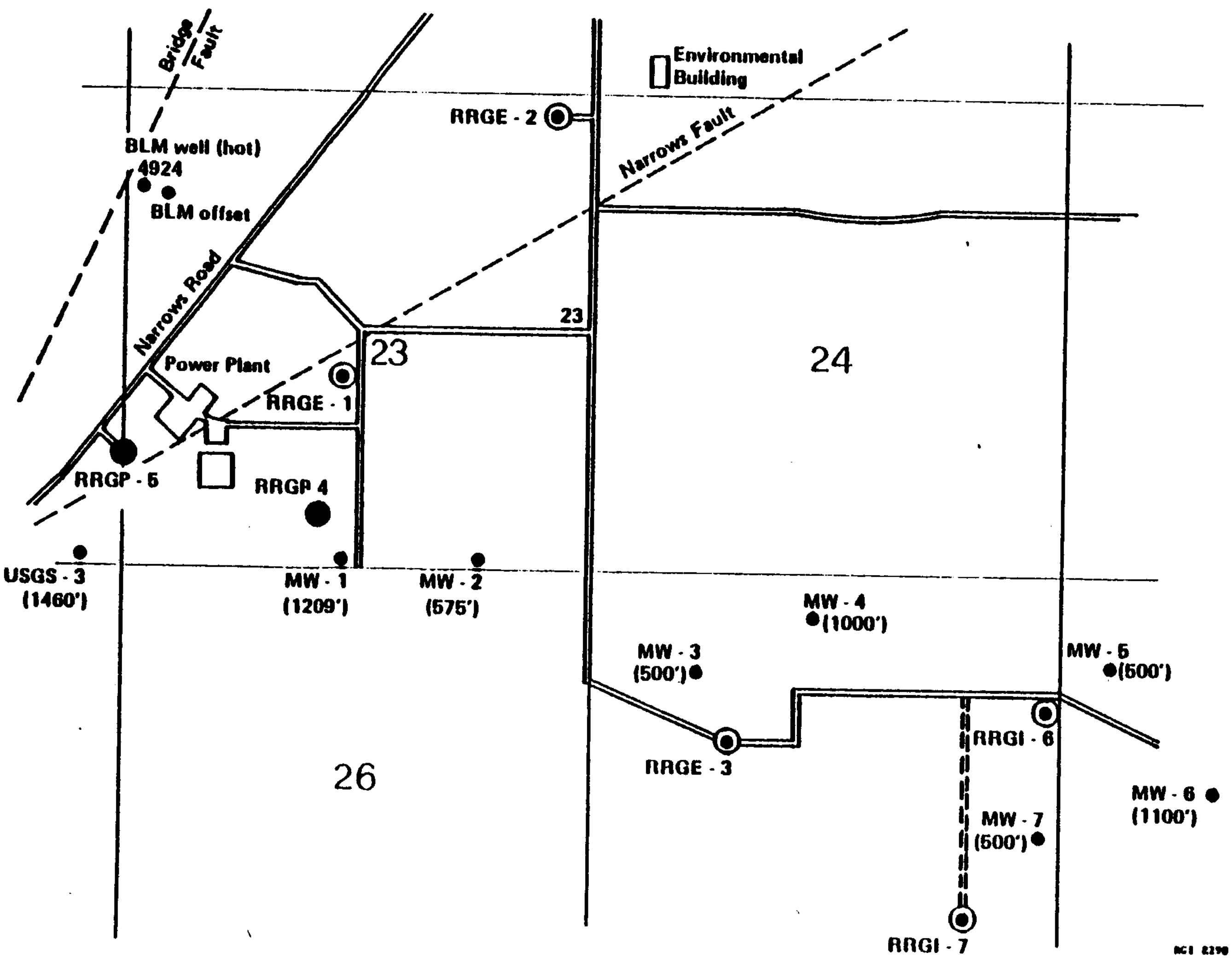


FIGURE 3

SCHEMATIC OF RAFT RIVER RRGP-4

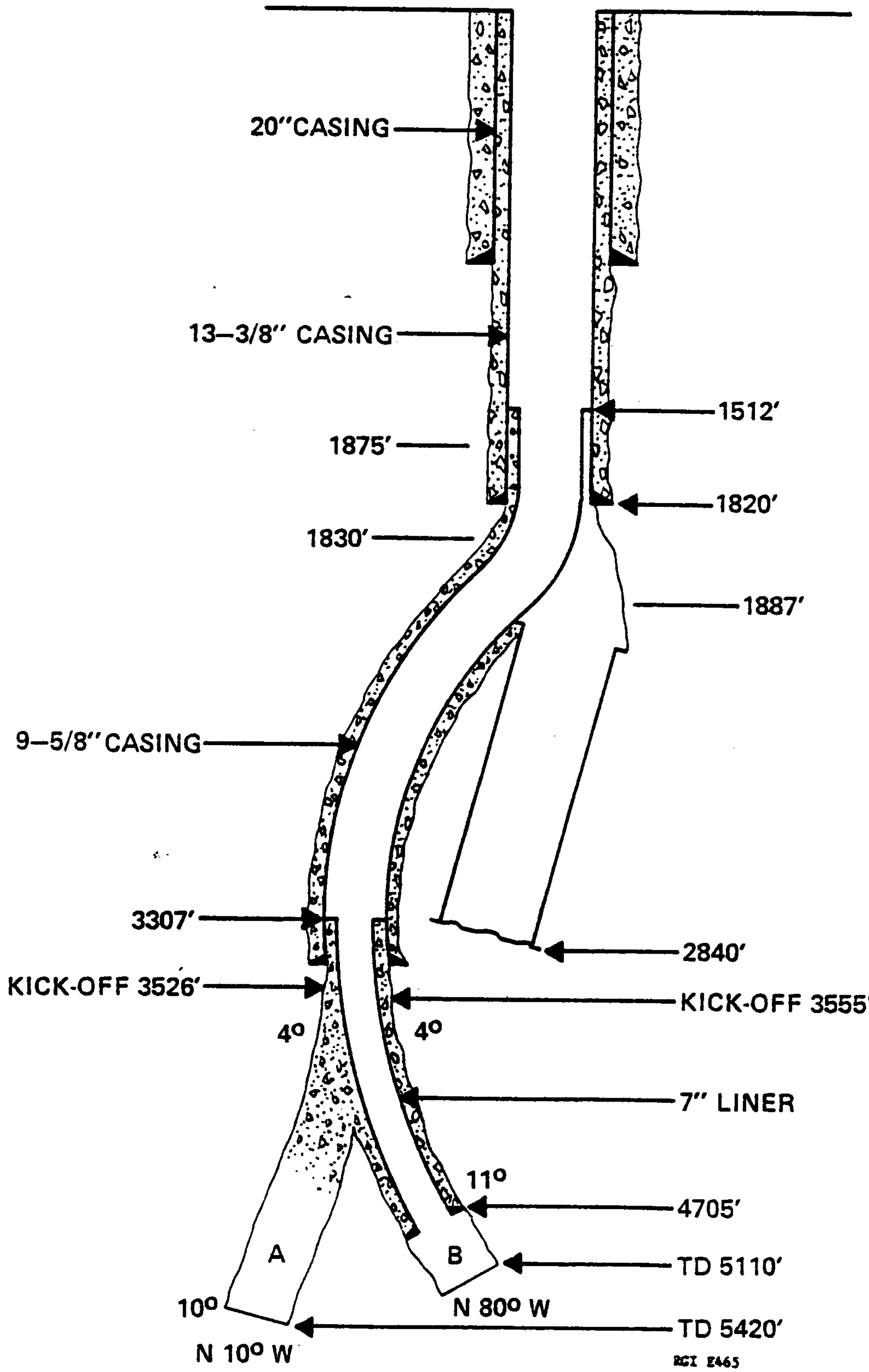
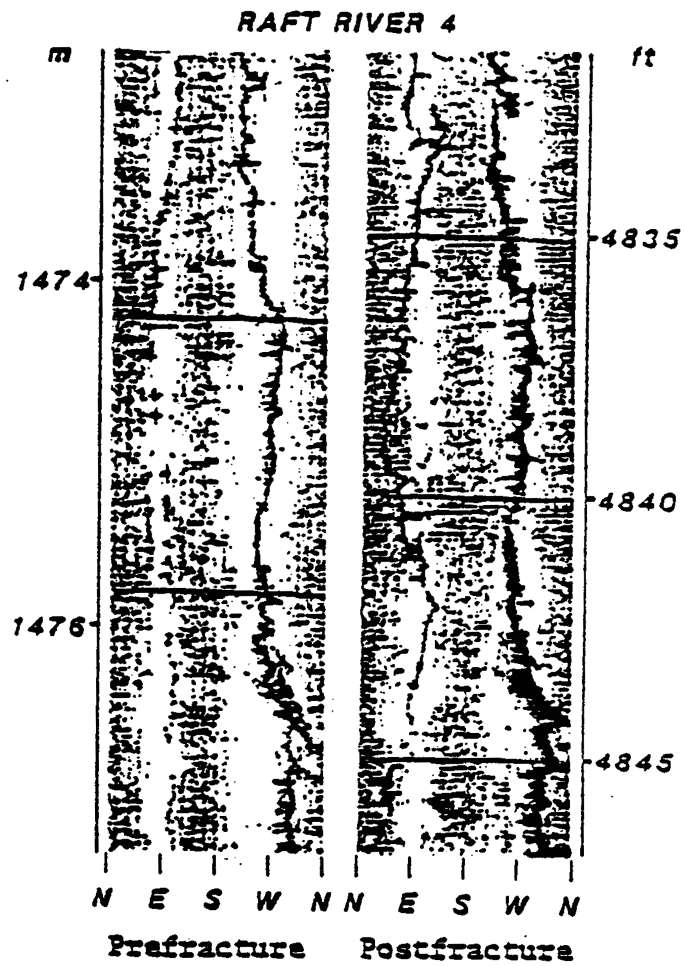


FIGURE 4

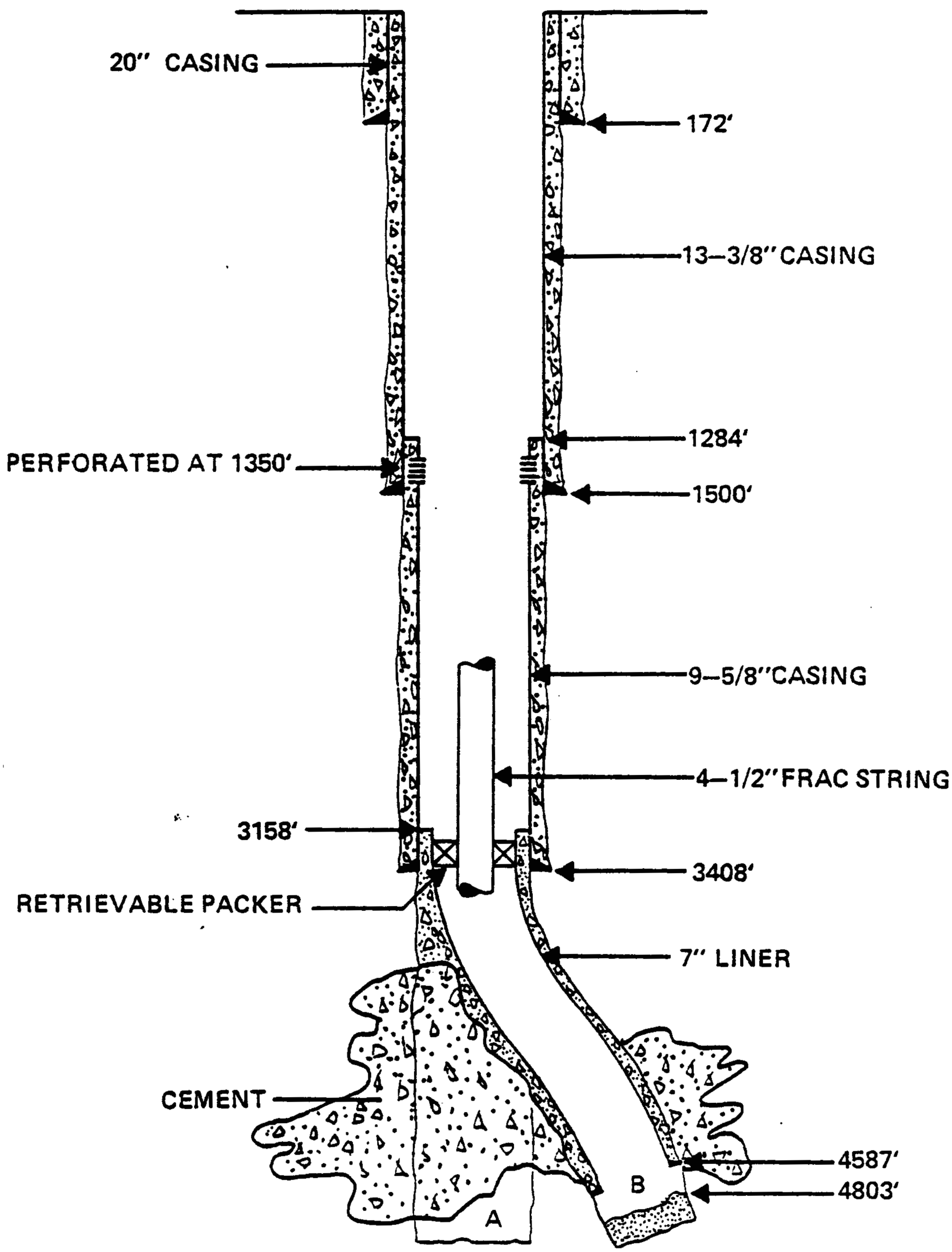
PRE-EXISTING AND PROPPED FRACTURES IN RAFT RIVER RRGP-4



EGI E1199

FIGURE 5

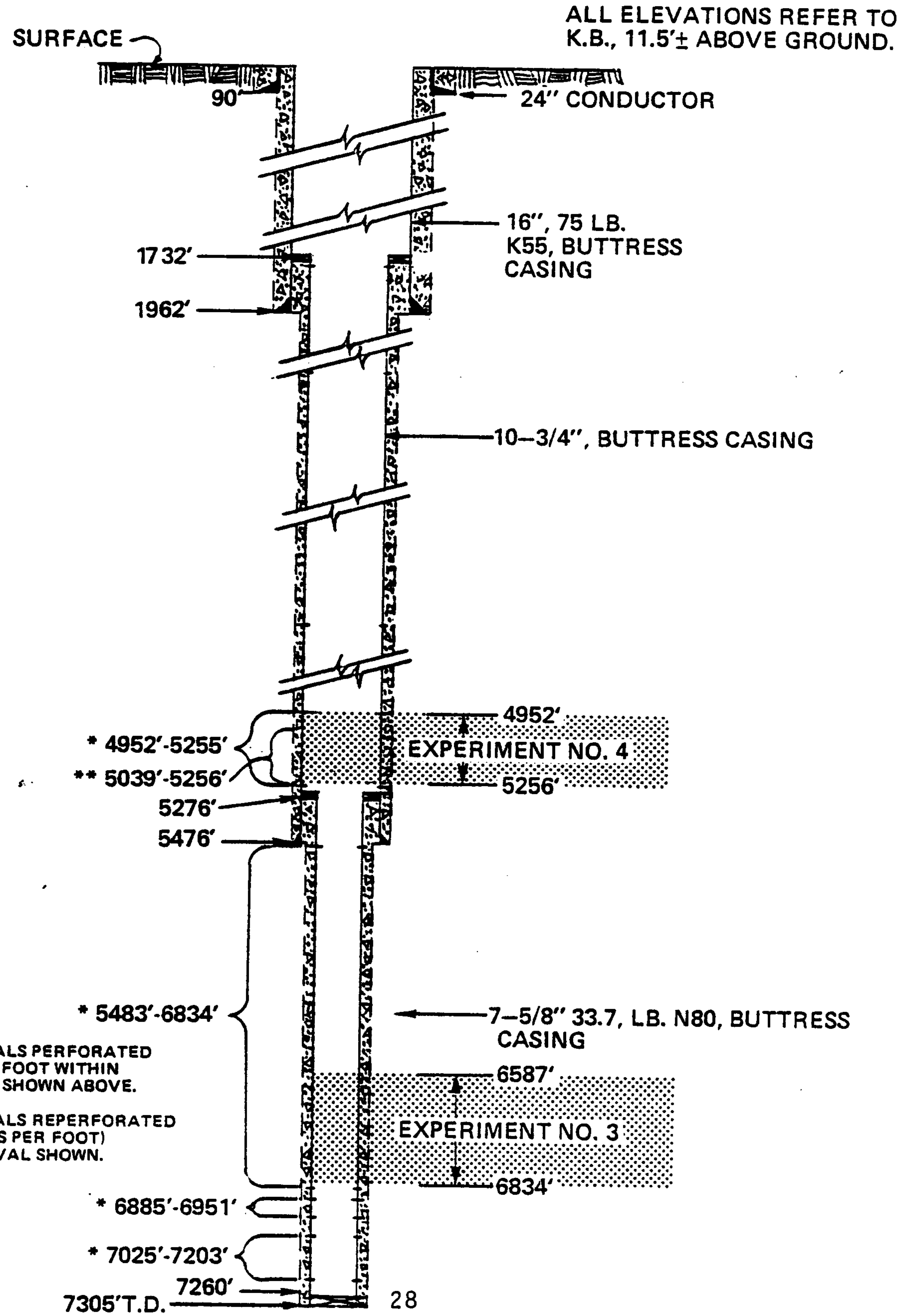
SCHEMATIC OF RAFT RIVER RRGP-5



RGI E476

FIGURE 6

COMPLETION DETAIL
EAST MESA 58-30



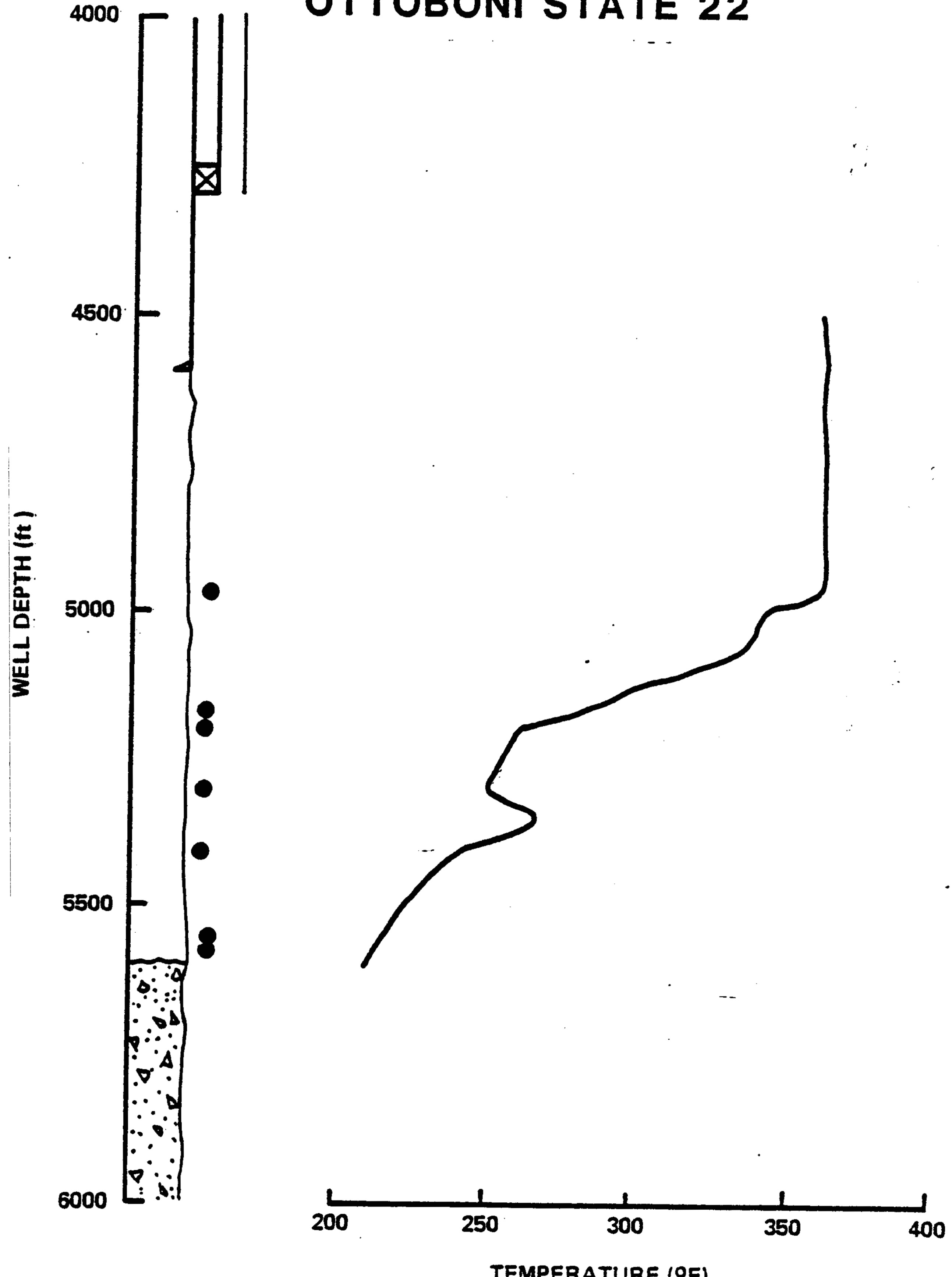
- SELECTED INTERVALS PERFORATED W/4 JET SHOTS PER FOOT WITHIN MAJOR INTERVALS SHOWN ABOVE.

** SELECTED INTERVALS REPERFORATED (TOTAL 8 JET SHOTS PER FOOT) WITHIN THE INTERVAL SHOWN.

RGI 2653

FIGURE 7

TEMPERATURE AND GAMMA RAY SURVEY
OTTOBONI STATE 22



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

FIGURE 8

BACA 23 COMPLETION DETAILS

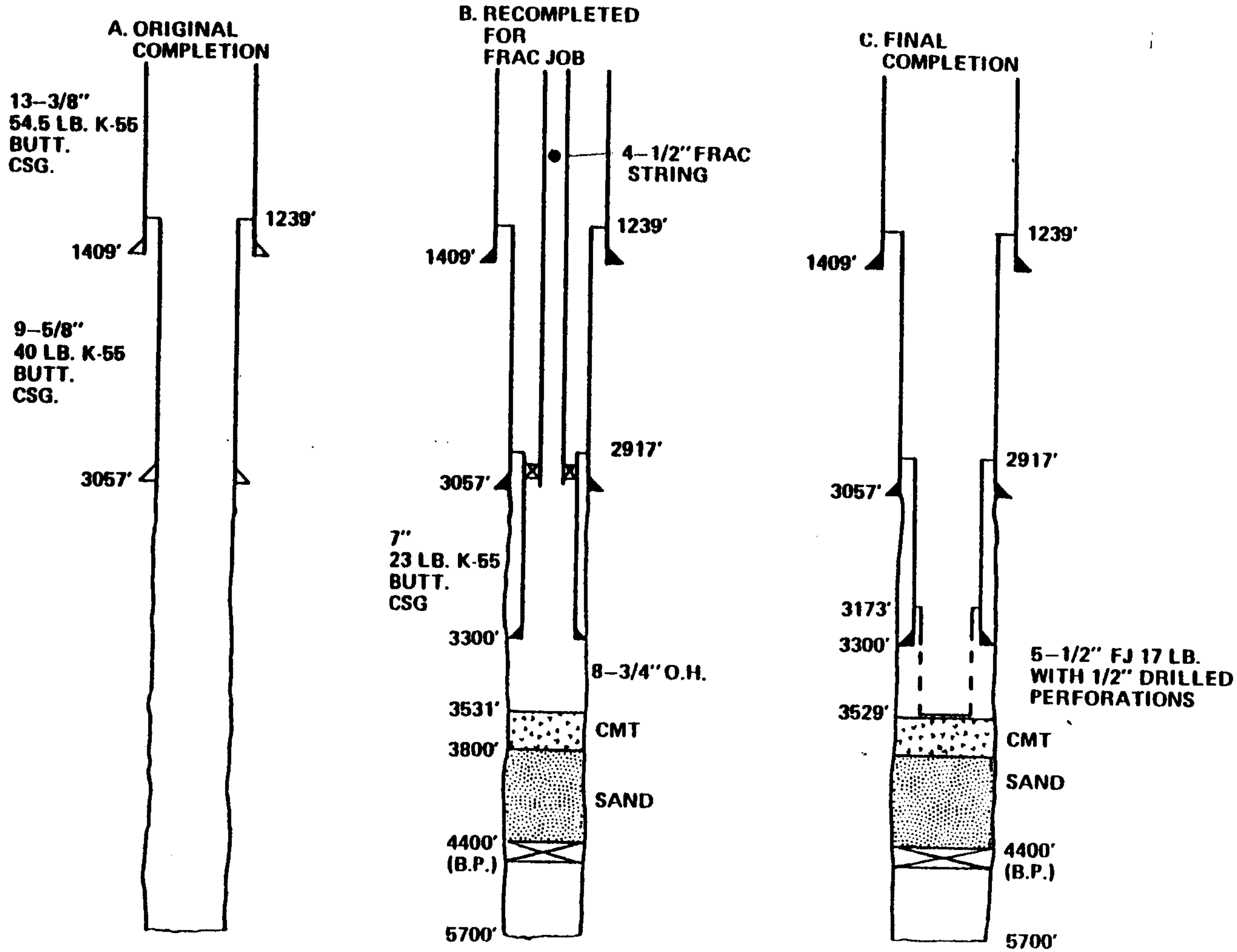
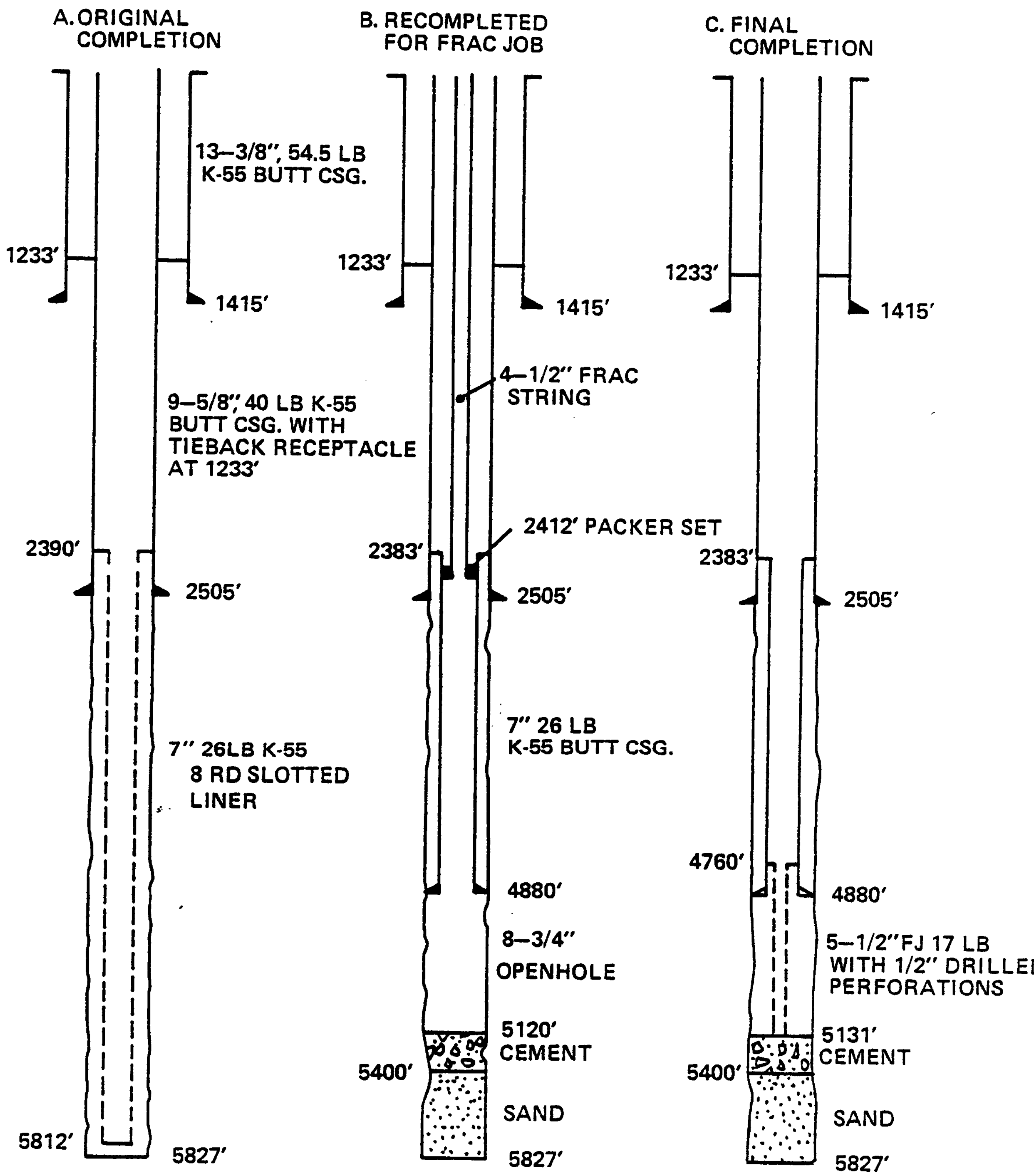


FIGURE 9

BACA 20 COMPLETION DETAILS



RGI E1103

TABLE 1

GRWSP SUMMARY OF EXPERIMENTS

Experiment	Location & Well	Res. Temp. (°F)	Reservoir Formation	Stimulation Treatment	Frac Interval Height (ft)	Frac Fluid	Proppant
1	Raft River, ID RRGP-4	290	Fractured metamorphic & intrusive rocks	Dendritic hydraulic fracture	195	7900 bbl 10 lb HP Guar/1000 gal 2 lb XC Polymer/1000 gal	Sand 50,400 lb 100-mesh* 58,000 lb 20/40-mesh
2	Raft River, ID RRGP-5	290	Fractured metamorphic & intrusive rocks	Large hydraulic fracture	216	7600 bbl 30 lb HP Guar/1000 gal	Sand 84,000 lb 100-mesh* 347,000 lb 20/40-mesh
3	East Mesa, CA 58-30	350	Deltaic sandstone & shale sequence	Hydraulic fracture	247	2800 bbl 60 lb HP Guar (Crosslinked gel)/1000 gal	Sand 44,500 lb 100-mesh* 59,200 lb 20/40-mesh Resin-coated Sand 60,000 lb 20/40-mesh
4	East Mesa, CA 58-30	320	Deltaic sandstone & shale sequence	Dendritic hydraulic fracture	304	10,300 bbl 10 lb HP Guar/1000 gal 2 lb XC Polymer/1000 gal	Sand 44,000 lb 100-mesh*
5	Baca, NM B-23	450	Fractured Bandelier tuff	Large hydraulic fracture	231	3600 bbl water pre-pad 4000 bbl 60 lb HP Guar (Crosslinked gel)/1000 gal	Sand 42,000 lb 100-mesh* Resin-coated Sand 81,500 lb 20/40-mesh Bauxite 98,500 lb 20/40-mesh
6	The Geysers, CA OS-22	460	Fractured Franciscan graywacke & greenstone	Acid etching	1000	476 bbl pre-pad 15 lb HP Guar/1000 gal 476 bbl Pad 60 lb HP Guar (Crosslinked gel)/1000 gal 476 bbl 10% HF-5% HCl 445 bbl Displacement 15 lb HP Guar/1000 gal	None -
7	Baca, NM B-20	540	Fractured Bandelier tuff	Large hydraulic fracture	240	3,000 bbl water pre-pad 5,700 bbl 60 lb HP Guar (crosslinked gel)/ 1,000 gal	Calcium carbonate 4,200 lb 200-mesh* 42,000 lb 100-mesh* Bauxite 119,700 lb 16/20-mesh 119,700 lb 12/20-mesh

*Fluid-loss additive

TABLE 2

GRWSP REPORTS

1. Part I - Contract Proposal - Geothermal Reservoir Well Stimulation Program Management - EW-78--32-0114

   Part II - Technical Proposal

   Part III - Cost Proposal

2. Management Plan for Geothermal Reservoir Well Stimulation Program Management - March 22, 1979

3. Proposal for Producing Well Hydraulic Fracture Stimulation, Raft River Field - GRWSP - June 1979

4. Geothermal Reservoir Well Stimulation Project - Reservoir Selection Task - November 1979

5. Geothermal Reservoir Well Stimulation Program - First-Year Progress Report - February 1980

6. Proposal for Producing Well Hydraulic Fracture Stimulation Treatments - East Mesa Field - GRWSP - April 1980

7. Modification and Implementation of the M.E.T.C. Simpac Program - May 1980 (PTTS)

8. Interactive Fracture Design Model - May 1980 (PTTS)

9. Volume I - Geothermal Reservoir Well Stimulation Program - Technology Transfer - May 1980 (PTTS)

   Volume II - Technology Transfer (PTTS)

   Volume III - Technology Transfer (VR)

   Volume IV - Technology Transfer (MEI)

10. Proposal for Producing Well Hydraulic Fracture Stimulation Treatment - Baca Project Area - GRWSP - November 1980

11. Raft River Well Stimulation Experiments - August 1980

12. Proceedings of the Geothermal Reservoir Well Stimulation Symposium - February 7, 1980

13. Proposal for Producing Well Chemical Stimulation Treatment - The Geysers - GRWSP - December 1980

14. Volume I - Geothermal Fracture Stimulation Technology - Fracturing Proppants and Their Properties - July 1980 (MEI)

Volume II - Geothermal Fracture Stimulation Technology - High Temperature Proppant Testing - July 1980 (MEI)

Volume III - Geothermal Fracture Stimulation Technology - Geothermal Fracture Fluids - January 1981 (MEI)

Volume IV - Geothermal Fracture Stimulation Technology - Proppant Analysis at Geothermal Conditions - January 1981 (MEI)

15. Technical Proposal - Geothermal Reservoir Well Stimulation Program Extension - June 1981

    Cost Proposal - Geothermal Reservoir Well Stimulation Program Extension - June 1981

16. Fracturing Fluid Evaluation (Laboratory Work) (Vetter Research) - January 1982
17. Acidification of Geothermal Wells-Laboratory Experiments (Vetter Research) - January 1982
18. Chemical Stimulation Treatment - The Geysers - Ottoboni State 22 Geothermal Reservoir Well Stimulation Program - (Draft)
19. Hydraulic Fracture Stimulation Treatments at East Mesa 58-30 Geothermal Reservoir Well Stimulation Program - (Draft)
20. Requirements for Downhole Equipment Used for Geothermal Well Stimulation - (Draft)
21. Hydraulic Fracture Stimulation Treatment of Well Baca 23 - (Draft)
22. A Review of Surface Equipment Requirements for Geothermal Well Stimulation - (Draft)
23. Hydraulic Fracture Stimulation Treatment of Well Baca 20 - (Draft)
24. Status Report GRWSP - April 1982
25. Experiment 8 Proposal (to be written)
26. Experiment 8 Final Report (to be written)
27. GRWSP Summary (to be written)

Note: Copies of the published GRWSP reports may be obtained from:

U.S. Department of Energy
Technical Information Center
P.O. Box 62
Oak Ridge, Tenn. 37830