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Hydraulic-Fracture-Stimulation Treatment of Well Baca 23,

Geothermal Reservoir Well-Stimulation Program

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I. SUMMARY

Well Stimulation Experiment No. 5 of the Department of Energy-sponsored Geothermal Reservoir Well Stimulation Program (GRWSP) was performed on March 22, 1981 in Baca 23, located in Union's Redondo Creek Project Area in Sandoval County, New Mexico. The treatment selected was a large hydraulic fracture job designed specifically for, and utilizing frac materials chosen for, the high temperature geothermal environment. The well selection, fracture treatment, experiment evaluation, and summary of the job costs are presented herein.

The GRWSP was initiated in February 1979 to pursue industry interest in geothermal well stimulation work and to develop technical expertise in areas directly related to geothermal well stimulation activities. Republic Geothermal, Inc. and its principal subcontractors (Maurer Engineering, Inc. and Vetter Research) have now completed six field experiments in various types of formations and in reservoir conditions ranging from low to high temperature.

The Baca reservoir lies within the Jemez Crater, Valles Caldera, and is composed of fractured volcanic tuffs. In the Redondo Creek area, wells have encountered a high temperature (550°F), liquid-dominated resource; but several wells have not been of commercial capacity, primarily because of the absence of productive natural fractures at the wellbore. Baca 23 was selected for this stimulation treatment from three candidate wells offered by Union Geothermal Company of New Mexico. The well was recompleted to isolate an interval from 3,300 feet to 3,531 feet.

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. The stimulation treatment consisted of a 3,600 bbl water pre-pad followed by 4,000 bbl of gelled water frac fluid carrying the proppant. The 20/40-mesh proppant material was about 180,000 lb of a mix of sintered bauxite and resin-coated sand. Finely ground calcium carbonate and 100-mesh sand were used as the fluid-loss additives.

The total field cost to the GRWSP of the fracture stimulation treatment and evaluation was $409,900. Of this total, $288,500 was for fracturing materials and services; $73,000 was for the rig and related equipment; and $48,400 was for other materials and services. By prior agreement, Union bore the cost of recompleting the well, rig mobilization, and a share of the production testing. Los Alamos National Laboratory contributed fracture mapping services, and Denver Research Institute and Sandia National Laboratories provided temperature logging equipment and services.

During the fracture treatment, Los Alamos National Laboratory performed a fracture mapping experiment using Baca 6 as an observation well. Using a triaxial geophone system and techniques developed for the Hot Dry Rock Project, microseismic activity caused by the fracture job was mapped. The discrete seismic events observed indicated a NE-SW trending activity in a zone roughly 2,300 feet in length. Calculations

of the dynamic 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. The temperature surveys obtained by Denver Research Institute indicated a zone cooled by the frac fluids to be more than 300 feet in height at the wellbore.

After the post-frac temperature survey was obtained, the well was circulated with aerated water and allowed to flow to be sure that the production of proppant into the wellbore would not interfere with subsequent testing. These operations confirmed that an artificial fracture had been created and that communication had been established with the reservoir system. The well was then completed with a pre-perforated liner in the treatment interval.

RGI and Union performed four separate production tests on Baca 23 to evaluate the frac job and to determine the well's productivity. A modified drillstem test performed immediately after the frac job yielded pressure data which indicated a reservoir permeability-thickness of about 2,500 md-ft. A 49-hour flow test 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 last two production tests showed that the long-term mass flow rate had dropped to about 73,000 lb/hr with a wellhead pressure of 37 psig and a steam fraction of about 50 percent. Pressure and temperature surveys indicated that two-phase flow conditions were occurring far back in the formation. The probable cause of the decline in flow rate is the reduction in relative permeability due to two-phase flow in the formation. The ability of the well to produce is limited partly because of the subhydrostatic reservoir pressure, and perhaps by the inability of the natural fracture system to feed the induced propped fracture at a higher rate. Although the well is capable of substantial producing rates at low wellhead pressures, the well will not produce at the flowline design pressure of the Baca power plant and is noncommercial under those conditions.

II. INTRODUCTION

The U.S. Department of Energy-sponsored Geothermal Reservoir Well Stimulation Program (GRWSP) was initiated in February 1979 to pursue industry interest in geothermal well stimulation work and to develop technical expertise in areas directly related to geothermal well stimulation activities. Republic Geothermal, Inc. (RGI) and its principal subcontractors (Maurer Engineering, Inc. and Vetter Research) have completed six field experiments. Two experiments have been performed in the low temperature reservoir at Raft River, Idaho (Morris, et al., 1980); two experiments in the moderate temperature reservoir at East Mesa, California (Campbell, et al., 1981); one experiment in the high temperature, vapor-dominated reservoir at The Geysers; and one experiment (reported herein) in the high temperature reservoir at Baca, New Mexico.

The Redondo Creek Project Area was selected as a well stimulation site after an extensive review of various geothermal fields throughout the western United States. Details of the selection process may be found in the GRWSP report "Reservoir Selection Task" of November 1979. The 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 Co. of New Mexico (Union). Several wells have not been of commercial capacity, primarily because of the absence of natural fractures at the wellbore which communicate with the reservoir. It is believed that a hydraulic fracture treatment can create the propped fractures required to connect the natural fracture system with the wellbore and, thereby, make these wells commercial and be an attractive alternative to redrilling. Several other factors favor the selection of Baca for a stimulation experiment. The Valles Caldera area has been the subject of several detailed studies by the U.S. Geologic Survey and other organizations. The relatively low reservoir fluid total dissolved solids content of 6,000 ppm was not expected to chemically interfere with the stimulation fluids or tracers. The high reservoir temperature and relatively shallow depth (3,000 feet to the top of the geothermal reservoir) also made it a good candidate for a field experiment (No. 5) in the evaluation of geothermal stimulation techniques, fracture fluids, proppants, and mechanical equipment.

The natural fracture system at Redondo Creek appears to be composed of a high-angle (deep) "ring-fracture" primary system associated with caldera formation and subsequent collapse during eruption of the tuff and a stress-strain or tension-relief secondary system about 90° to the "ring" system. A particularly well-developed fracture zone appears to pass through the central portion of the caldera as evidenced by higher well productivities. A detailed evaluation of the complex fracture system is limited by lack of correlation data between existing wells.

Of the wells drilled in the Redondo Creek area by Union, ten wells (Baca 5A, 12, 14, 16, 18, 19, 20, 21, 22, and 23) were completed in areas where the low productivity is suspected to be related either to the absence of sufficient temperature or absence of a communicating fracture system with the reservoir at the wellbore. For the purpose of a geothermal well stimulation field experiment, Union offered three similar candidate wells (Baca 18, 19, and 23) to the GRWSP group. The discussion which follows provides an overview of the Redondo Creek Project Area history and reservoir properties, a description of the stimulation experiment, a description of the treatment evaluation, and a summary of the experiment costs.

III. RESERVOIR DESCRIPTION

A. Regional Geology

The Valles Caldera is a prominent geological structure located in North Central New Mexico in the Jemez Mountains about 55 miles north of Albuquerque and 40 miles northwest of Santa Fe (Figure 1). Dondanville (1978) describes the caldera as a complex volcanic highland of Pliocene and Pleistocene age. Two major geologic features intersect in the Jemez Mountains. One is the eastern rim of the Colorado Plateau, along which a number of volcanic fields have developed (e.g., White Mountains, Datil, Mt. Taylor, Jemez, and San Juan). The other is the Rio Grande depression, a down-dropped block or graben that extends several hundred miles north-northeasterly through New Mexico into Colorado. The volcanic highlands are mainly composed of basalt, andesite, and dacite, with more recent rhyolitic ash flows covering portions of older lava flows.

B. Valles Caldera Geology

Dondanville (1978) described the Valles Caldera as a subcircular depression, 12 to 15 miles in diameter, with sides rising from a few hundred feet to more than 2,000 feet above the floor. A central structural dome, Redondo Peak, near the center of the caldera, has a relief of nearly 3,000 feet and maximum elevation of 11,254 feet. Redondo Peak is surrounded by a series of lower mountains which are rhyolitic volcanoes.

Smith and Bailey (1968) describe the events in the formation of the Valles Caldera. The caldera represents the latest stage of a volcanic sequence which began in late Miocene or early Pliocene time with a series of eruptions of basalt-rhyolitic tuff, and climaxed in mid-Pleistocene time with two huge pyroclastic eruptions (Dondanville, 1978). The last eruptions, about 1.4 and 1.1 million years ago, produced the Bandelier Tuff, a deposit of rhyolitic tuff with pumice in the basal intervals. Simultaneously, the roof of the magma chamber collapsed along a ring-fracture system, creating first the Toledo Caldera and secondly the Valles Caldera. As a result of the simultaneous eruption-collapse, the Bandelier Tuff is over 6,000 feet thick within the caldera and 1,000 feet thick locally outside the caldera. The Valles Caldera overlapped and partially destroyed the earlier Toledo Caldera located to the northwest.

A lake formed in the caldera and was later displaced over the south-western rim by the uplifting of a central dome, now known as Redondo Peak. This uplifting was accompanied by radial fracturing and formation of a longitudinal graben which today is identified by the Redondo and Jaramillo Creeks (Figure 2).

The volcanic activity continued with a number of rhyolitic eruptions along a chain of domes around the ring fracture system during the past million years. The more recent eruptions are on the south and west portions of the caldera, the youngest being about 100,000 years old.

The Redondo Creek geothermal area occupies a graben structure which developed as a longitudinal collapse feature across the resurgent dome near the center of the Valles Caldera. The graben structure is important to the productivity of the geothermal system because the graben faults and associated fractures probably act as permeable conduits. As such, they not only can form the producing intervals in the wells, but also can act as channels draining geothermal fluids from deeper formations.

C. Geophysical Studies

The USGS and Union have extensively surveyed the Valles Caldera. In addition to shallow temperature gradient holes, there are gravity, aeromagnetic, thermal infrared, microearthquake, seismic ground-noise, electrical resistivity, electromagnetic, magnetotelluric, and telluric profiling surveys.

The northwestern half of the caldera is an area of high temperature gradient with the highest temperatures found in the areas of active surface alteration. Dondanville (1978) points out that above average temperature gradients extend beyond the ring-fracture system. Blair et al. (1976) have shown that high subsurface temperatures are found to the west of the caldera. High subsurface temperatures extend over 50 square miles within the Valles Caldera as shown by gradient hole temperature surveys.

Gravity surveys have detected a negative gravity anomaly of about 25 milligals coincident with the Toledo-Valles Calderas. A negative gravity anomaly in geothermal areas is often interpreted as evidence of a granitic batholith. However, as pointed out by Dondanville (1978), because the basement rock in the Jemez Mountains is Precambrian granite, it is unlikely that a younger intrusion of similar density granite would be able to create so significant a gravity anomaly. The Valles Caldera gravity anomaly has therefore been interpreted to reflect a great subsidence during caldera formation and accumulation of low density rocks within the caldera. A geothermal implication would be that the Valles Caldera has been filled with a vast quantity of geothermal fluid-bearing rock.

D. Surface Geothermal Activity

There are several occurrences of active or recently active surface hydrothermal alteration distributed over an area of about 15 square miles in the northwestern half of the caldera (Dondanville, 1978). This area is characterized by white, kaolinized rocks formed by reaction of rocks with strongly acid fumaroles, hot springs, and gas seeps.

Fumarole activity is concentrated at Sulphur Springs (Figure 2). The Sulphur Springs area also has a few hot springs with small flows of water. These springs are sulfate-rich with negligible chloride content and acidic (pH=2) water. White et al. (1971) have suggested that acid, sulfate-rich springs are indicative of a vapor-dominated hydrothermal system or may be evidence of a deep liquid-dominated geothermal system which does not outcrop at the surface.

Gas seeps of carbon dioxide and hydrogen sulfide are found in numerous localities in the area of active alteration. The gas seeps are manifested most commonly as bubbles in ponds along creeks, but the odor of hydrogen sulfide on some hill slopes indicates that gas emissions may have a wider but less noticed distribution (Dodanville, 1978).

Several hot springs are also present around the western perimeter of the caldera and southwest of the caldera at Soda Dam Springs and Jemez Springs. Dondanville (1978) notes that with the exception of Soda Dam Springs and Jemez Springs, the springs are of relatively low temperature, dilute waters with little apparent contribution from the deeper geothermal system.

E. Subsurface Geothermal Activity

The wells drilled by Union have penetrated the Bandelier Tuff (Figures 3, 4, 5, and 6) which ranges from 4,000-6,000 feet in thickness in the Redondo Creek area. The tuff consists of welded and nonwelded ash flow deposits of rhyolite ash and pumice. Nearly all geothermal production in the Redondo Creek area appears to come from fractures in the lower 3,000-foot portion of the Bandelier Tuff. Measurements of the matrix tuff core from Baca wells 4, 13, and 17 show an interstitial permeability of less than 1 md with an associated porosity of 4-19% (Hartz, 1976 and Van Buskirk et al., 1979). The upper portion of the tuff is thought to be highly silicified, forming the caprock for the reservoir (Figure 6).

Hartz (1976) has suggested that the deeper, higher pressured water production from the Bandelier Tuff appears to be connected with a more extensive reservoir (the extent of which is undetermined). Below the tuff, several wells have also penetrated 1,000-2,000 feet of the Paliza Canyon Andesite (Figures 4 and 5). The andesite contains some fractures, but there appears to be considerable clay alteration and mineralization filling the fracture system. Cores of the andesite from Baca 13 show matrix porosities of 6-16%, but very low permeabilities of .1 to 1.5 md (Hartz, 1976).

Baca 10, 11, and 16 encountered Tertiary sands beneath the andesite. These sands are at least 400 feet thick as indicated by Baca 14 and are fine grained and unconsolidated. Slodowski (1976) has noted that these sands are not present around Baca 13. They may extend under Redondo Border to Sulphur Creek since they were penetrated below 2,400 feet in the Baca 2 well in the Sulphur Creek area.

At the maximum depths drilled to date, Baca 12 and 13 penetrated the top of the Permian Redbeds (Figure 5), which consist of interbedded red sands and shale. Little is known of the potential of these formations as reservoir rock (Hartz, 1976). Based upon the stratigraphy in the Sulphur Creek area, a Pennsylvania limestone and sandstone occur below the Permian Redbeds which are thought to lie upon Precambrian Granite.

The most promising zone of well productivity appears to be in the highly fractured portions of the Bandelier Tuff. As discussed earlier, this fracturing appears to be associated with the collapsed caldera faulting and resurgent dome faulting running longitudinally northeast to southwest and is bounded by Redondo Peak and the Redondo Border.

IV. RESERVOIR EVALUATION

A. Summary of Well Tests

Baca 4, 6, 11, 13, 15, 19, and 20 are all wells capable of producing steam and hot water (Atkinson, 1980a). The tests performed on these wells were two-phase separator tests with pressure buildup and drawdown measurements, along with chemical analyses of produced water, steam condensate, and noncondensable gases. Table 1 presents a tabulation of some of the production tests performed in the Baca field.

Union noted that the pit-flow production tests run on the Baca wells were subject to several difficulties affecting the reliability of formation property estimates (Hartz, 1976). A major problem was the tendency of a well to unload its wellbore fluid and fluid from the fracture system surrounding the wellbore during the early phase of the tests, giving rise to higher estimates of flow under unstable conditions. In ten wells, Baca 5A, 12, 14, 16, 18, 19, 20, 21, 22, and 23, the lack of production was thought to be related to the absence of a high conductivity fracture system. Three of the nonproductive wells (Baca 5A, 12, and 14) have been converted to water disposal wells. Data from Baca 16 suggest that the limited fractures encountered in the wellbore were filled by secondary cementation.

Testing through a separator of Wells 4, 6, 11, and 13 has permitted measurement of steam enthalpy and quality, along with detailed chemical analyses, liquid flow, and pressure transient measurements. The Productivity Indexes (PI's) of these wells range from 220 to 400 lb/hr/psi for stabilized flow rates. On the basis of bottomhole pressure calculations, Union suspects flashing is occurring which would tend to restrict the flow of fluids through the fracture system toward the wellbore, thus reducing the well productivity values measured in long-term flow tests (Hartz, 1976). Union has also noted that the reservoir fluid transmissivity (kh/μ) appears to be higher when only a single phase is present in the reservoir than when two phases are present. The tests have also demonstrated a high production rate decline during the first few days of testing. Much of this decline is thought to be the result of unloading the wellbore and fracture system. Table 2 presents much of the productivity and pressure buildup data obtained from well tests.

Pressure buildup and/or drawdown tests on Baca 4, 6, 10, 11, 13, 15, and 19 are tabulated in Table 3. The wide variation of skin effect (from +42 to -4) among the wells reflects the variability of the reservoir's fracture system. Figure 7 is an iso-kh map which suggests a correlation of the fracture system and productivity with the isothermal contours as measured by Union (Figure 8). This potential interrelationship may be a result of the hot fluids filling the fracture system.

The large number of wells with an apparent positive skin factor suggests:

1. Formation damage which could be caused by:

   a. drilling fluid

   b. scale build-up in the formation at the wellbore and the resultant plugging of the formation during the production test

2. Flashing of steam in the formation system and the resultant restriction of fluid movement by relative permeability effects in a two-phase system

3. High steam saturation (storage effects) surrounding the wellbore, or

4. Partial penetration of the well into the producing geothermal reservoir and thus restriction of flow through convergence.

B. Interference Test

In 1975, Union performed an interference test to determine the extent and nature of the reservoir permeability-porosity relationship and continuity of the reservoir. Producers chosen for the test were Baca 6, 11, and 13. The observation wells selected for the test were Baca 4, 10, 15, and 16. Baca 5A, 12, and 14 were used as water disposal wells for the test.

The test was initiated 10/3/75 and completed 3/11/76. Total production from all wells during the test was 2.24×10^9 lb (total mass) and about 1.21×10^9 lb were injected into the reservoir. Table 4 lists the production/injection data for each well. The quantity of reinjected fluids was about 54 percent of the total mass production.

During the test, a noticeable decline was recorded for all three producers. Union also noted that the productivity of the Redondo Creek wells appears to depend primarily on encountering fractures in the Bandelier Tuff. If, as suggested by Union, the Tertiary sands are the primary geothermal reservoir, the production decline would continue until steady-state conditions were reached between the primary reservoir and the fracture system of the Bandelier Tuff. Flashing and possible scale deposition within the fracture system appear to complicate and mask the actual decline rate.

During this test, the pressure interference data showed communication between Baca 6, 10, 11, 12, 13, and 14. Measurements of downhole pressure at Baca 10 indicated that it was affected by both the injection and production and was in communication with the primary reservoir. Lack of a measureable pressure response at Baca 4, 15, and 16 confirmed the presence of some lateral permeability barriers in the field.

Through the use of a reservoir simulation model to match production and injection data, Union has suggested the following (Hartz, 1976):

1. The original total mass of fluid in the reservoir is at least 4.6×10^{12} lb.

2. The reservoir has an average kh of 6,000 md-ft and a ϕh of 90 feet.

3. The reservoir boundaries are a considerable distance from the tested wells; therefore, the reservoir could be considered as the "infinite" type.

4. The geothermal fluid within the reservoir is distributed areally (covering an area of approximately 36 square miles) rather than vertically.

The basic assumptions made by Union for this model which led to the above conclusions were:

1. The reservoir fluid exists in a single, hot water phase.

2. The reservoir fluids lie within a confined aquifer.

3. There is no steam/hot water interface in the reservoir.

4. The computations also assume a horizontal, isotropic, and porous reservoir. It is recognized that a volcanic reservoir has a much greater latitude of variation than a sedimentary model, so all such computations are generalizations of the whole model rather than microscopic projections of portions of the model.

Dondanville's (1978) calculations estimated a value of 40 square miles for the aquifer which closely matches the 36 square miles reported by Hartz (1976) based upon pressure interference test data.

C. Geothermal Fluid Composition

Table 5 summarizes the chemistry of the produced water, noncondensable gases, and condensate. The dissolved solids in the produced water consist primarily of sodium, potassium, calcium, silica, and chloride. The steam condensate generally had small amounts of dissolved solids. The fluids possessed about 3 percent (by weight) noncondensable gases. Approximately 99 percent of this gas is carbon dioxide (CO_2) with small amounts of hydrogen sulfide, nitrogen, hydrogen, methane, and ethane. These gases present corrosion problems and their evolution contributes to scaling.

V. SELECTION OF WELL STIMULATION CANDIDATE

Union originally offered two candidate wells to the GRWSP for the field stimulation experiment. These wells, Baca 18 and 19, were considered by Union to be prime candidates for redrills in search of productive fractures if stimulation was unsuccessful. Baca 18 was originally chosen over Baca 19 as the prime candidate because it had a larger location, more suitable for assembling the fracturing equipment, and its lower elevation made it more accessible in the winter. The original plan was that the drilling rig would move to Baca 18 to prepare it for stimulation after the completion of Baca 23. Upon completion, however, Baca 23 was found to be noncommercial and Union offered it to the GRWSP as an alternate candidate to Baca 18.

Several factors favored Baca 23 as the best candidate for stimulation. First, a drilling rig was already on the well and the slotted liner had not been installed in the openhole interval. These factors simplified the recompletion work considerably. Second, productive fractures had been encountered in Baca 10 a few hundred feet away. This production had been lost in Baca 10 however, due to mechanical problems. Third, Baca 6, located within 1,500 feet of Baca 23, was available as an observation well for fracture mapping.

VI. STIMULATION EXPERIMENT FOR BACA 23

A. Well Recompletion

Baca 23 was originally completed as shown in Figure 9A with a 9-5/8" liner cemented at 3,057 feet and 8-3/4" openhole to 5,700 feet. The well was tested at that time and would not sustain flow. An interval from about 3,300 feet to 3,500 feet was selected for fracture stimulation. Good production had previously been encountered near this depth approximately 200 feet away in Baca 10. The interval is now cemented off behind casing 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 lower temperature formations 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. This recompletion is shown in Figure 9B. The treatment interval was totally nonproductive after being isolated for the stimulation treatment. Operational details of the recompletion, treatment, and preliminary testing are given in Appendix A.

B. Fracture Treatment

Maurer Engineering designed a hydraulic fracture treatment for the well consisting of 8,000 bbl of fluid and 197,000 lb of 20/40-mesh proppant. Although the job was basically a conventional hydraulic fracture treatment, a high-formation temperature (450°F) dictated special design and materials selection requirements. Because of the temperature, the first 4,000 bbl of fluid was dedicated to wellbore and fracture pre-cooling, while the final 4,000 bbl constituted the pad and proppant transport. While frac fluids are known to degrade rapidly in 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 (GRWSP report "Geothermal Fracture Stimulation Technology"). Both resin-coated sand and sintered bauxite were mixed in approximately equal proportions by weight. The treatment was designed to create a propped fracture approximately 300 feet in height, and 400 feet in length from the wellbore. The planned and actual treatment volumes are summarized in Table 6.

Fluid used for pre-cooling the formation (Stage 1 in Table 6) was produced geothermal water from a pit located nearby. A frac blender at the pit pumped water through an 8" line to four frac tanks on the well location near the main blender. The main blender drew the water from these four frac tanks and delivered it to the frac units. The 3,582 bbl water pre-pad was pumped at an average rate of 38 BPM. The job design called for 4,000 bbl of pre-pad pumped at maximum possible rates up to 80 BPM. Pre-pad volume was slightly less than designed because the capacity of the pit was underestimated. The rate was limited by the capacity of the pit blender pumping uphill to the well location.

However, the pre-pad portion of the treatment was substantially overdesigned and it is believed that the pre-pad adequately cooled the formation.

Pad and proppant transport fluid was a 60 lb per 1,000 gal hydroxypropyl guar (HP guar) polymer gel (commercially available from Halliburton Services), pre-mixed in eleven 400 bbl frac tanks using fresh water (Stages 2-7). The gel was crosslinked as it was pumped. The job was pumped in eight stages which are summarized in Table 6. After the pre-pad, the schedule was followed closely with the exception that the proppant concentration was slightly less than designed. During the treatment the difficulty of controlling the delivery rates of two different proppants resulted in a slightly higher proportion of bauxite being injected. Approximately 15,000-17,500 lb of the planned 98,700 lb of resin-coated sand were left in the proppant storage unit at the end of the treatment. All 98,700 lb of sintered bauxite were pumped.

Finely ground calcium carbonate was used as a fluid-loss additive (FLA) in Stages 1-4. It was added at the blender at a concentration of 25 lb per 1,000 gallons of frac fluid. About 5,400 lb of the fine fluid-loss additive were used during the job. A larger mesh fluid-loss additive was chosen to slow leaks into the natural fractures of the formation; for this material, 100-mesh sand was chosen. About 42,000 lb of 100-mesh sand was pumped in Stage 3 of the treatment.

The estimated horsepower required was 5,880 hhp, assuming an 80 BPM pumping rate and 3,000 psig wellhead pressure. Actual hydraulic horsepower used was close to 6,400 hhp because of higher than expected frac pressures. 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 9B. The frac string was necessary to isolate liner laps in the well from the treating pressure. The packer used was a prototype steam packer developed by Otis Engineering Corporation. It was equipped with ethylene propylene diene methylene terpolymer (EPDM) elements and metal backup rings above and below the elements to prevent extrusion at high temperature and pressure. The particular EPDM compound, designated Y267, was developed by L'Garde, Inc. under contract to the U.S. Department of Energy (Hirasuna, 1981). The packer was also equipped with a sliding mandrel which provided nearly 20 feet of vertical movement of the tubing string. This design allowed the tubing string to thermally contract during the treatment without the problem of tubing movement at the surface. The packer performed well in all respects. Setting and unsetting operations were normal and there was no leakage.

The pad and proppant transport (Stages 2-7) were pumped at an average rate of 66 BPM and an average surface pressure of 3,300 psig. The pressure-rate history is shown in Figure 10. As shown in the figure, soon after the beginning of Stage 2, there was a drop in surface pressure coincident with a rise in pumping rate. This is a result of the friction reducing qualities of the polymer gel. The pre-pad water contained no friction reducer. Another significant feature is the rise in pressure coincident with the drop in rate during Stage 3. This is apparently a result of the 100-mesh sand reaching the formation and plugging small natural fractures. There were two unscheduled shutdowns during the treatment. The first was eight minutes into the job due to air in the suction lines from the pre-pad water tanks. The problem was corrected and the job was restarted in about one minute. The second was a 9-1/2 minute shutdown, 70 minutes into the job, due to a false indication of a tubing or packer leak. In this case there was a flow of water from the well annulus which was later discovered to be water from the rig mud system coming through the kill line to the well which was left open by mistake.

Pertinent information can be gained from looking at surface pressure readings immediately after a shutdown. At the first shutdown the instantaneous shut-in pressure was 1,300 psig. By using Equation 1, a frac gradient of 0.83 psi/ft was calculated at that point.

$$\text{Frac Gradient} = \frac{\text{ISIP} + \text{Hydrostatic Head}}{\text{Depth}} \qquad (1)$$

where

Frac Gradient = Breakdown fracture gradient (psi/ft)

ISIP = Instantaneous Shut-In Pressure with No Flow (psig)

Hydrostatic Head = Head from column of water in frac string and casing (psi)

Halfway through the treatment the second shutdown gave an ISIP of 1,600 psig or a frac gradient from Equation 1 of 0.92 psi/ft. Finally, at the end of the job, the ISIP was 2,450 psig which gave a frac gradient of 1.175 psi/ft. The reason for the buildup in frac gradient is unknown, but nonetheless should be noted for future treatments.

As part of the fracture treatment evaluation program, several chemical tracers were added to frac fluids. These chemical tracers (radioactive tracers and ammonium nitrate were not used at Union's request) were selected to perform several functions and the injection sequence was as follows:

Stage	Cum. Injection BBL	Tracer
1	3582	methanol (218 gal)
2	4084	methanol (29 gal) butyl cellusolve (50 gal) ethanol (50 gal) Tinopal CBS-X (70 lb)
3-6	7017	methanol (172 gal) isobutanol (50 gal) ethanol (50 gal)

In general, the tracers were to be used to determine if the job proceeded as planned and to monitor the frac fluid return during production tests. Representative solid and fluid samples of all frac materials were also obtained during the experiment for quality control checks. As a result of this procedure, the subsequent analysis of the injected frac fluid (samples were taken downstream of the blender) showed that the titanium crosslinker (an organic complex of titanium dissolved in isopropanol) for the gelled polymer was not added to the solution until Stage 7. This was determined by analyzing the samples for titanium and isopropanol which are two readily identifiable components of the crosslinker solution. The injected frac fluid was therefore less viscous than called for in the treatment design. However, the frac fluid was sufficiently viscous to carry the proppant into the formation, which is its primary function, and no harmful effects appear to have resulted. The original treatment design assumed that the polymer would degrade rapidly at the high formation temperature and an adequate margin of safety was provided in the polymer concentration used.

C. <u>Experiment Costs</u>

Field costs for recompletion, stimulation, and testing were originally estimated to be $884,000 of which $524,000 was the estimated GRWSP share. The actual total of the field costs to the GRWSP was $409,900. Of this total, $288,500 was for fracturing materials and services; $73,000 was for the rig and related equipment; and $48,400 was for other materials and services. The actual cost was less than the original estimate because the stimulation work was accomplished in seven rig days instead of the nine originally estimated, and an abbreviated well testing program was performed. The original estimate provided for a relatively large test facility to be moved in at GRWSP expense after the rig moved off. However, the testing was done with a smaller test unit which Union installed at their expense. A summary of the field experiment costs is given in Table 7.

Other services which were provided at no cost to the GRWSP and which were not included in the original $884,000 field cost estimate were the fracture mapping work provided by Los Alamos National Laboratory (LANL) and temperature logging provided by Denver Research Institute (DRI) using Sandia National Laboratories' logging equipment.

VII. TEST RESULTS AND ANALYSES

During the fracture treatment of Baca 23, LANL 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 Geothermal Energy Program (Albright and Pearson, 1980), microseismic activity caused by the fracture job was mapped. Releases of microseismic activity (and therefore, rock failure) during the hydraulic fracture stimulation of Baca 23 were observed and plotted in Figures 11 and 12 (Albright, 1981). The 14 discrete seismic events analyzed indicate NE-SW trending (geomagnetic orientation) activity in a zone having roughly a length of 2,300 feet, width of 650 feet, and height of 1,300 feet. The rock failure occurred in a broad zone. Each mapped event location is probably known within 150 feet in relation to other failure locations, and thus clearly suggests the stimulation did not result in the creation of a singular monolithic fracture. That detectable rock failure was infrequent during the stimulation of Baca 23 implies that comparatively little total energy was expended in the creation of new fractures. An alternative interpretation could be that horizontal stresses in the reservoir may not be so dissimilar as to allow the accumulation of strain in the formation. However, the appearance of an elongated zone of seismicity presumably striking normal to the least confining stress in the rock appears to contradict this explanation. The microseismic events would be expected to proceed in advance of any significantly widened fracture and would not necessarily define a propped flow path to the wellbore at Baca 23.

As previously discussed, the 231-foot interval isolated for stimulation was nonproductive prior to the treatment. This indicated that no significant natural fractures intersected the wellbore. The pre-frac temperature survey obtained by DRI is shown in Figure 13 along with a post-frac temperature survey obtained 12 hours after the frac job. A comparison of these temperature profiles shows that a zone, more than 300 feet in height at the wellbore, was cooled by the frac fluids. The top of the fracture is indicated to be at a depth of 3,230 feet, 70 feet above the 7" liner shoe. The vertical fracture extent below 3,531 feet could not be determined because of the cement plug in the wellbore.

Calculations indicate that sufficient fracture volume was generated to put in over 2,500 cubic feet of proppant and additives into the formation. Using a 300-foot fracture height, an estimate of the length of the dynamic fracture wing could be from 429 to 579 feet with proppant carried 300 to 500 feet away from the wellbore. Appendix B shows the predicted dynamic fracture geometry for two cases which attempt to determine the effect of using two frac fluids. Since the job was done using two distinct fluids, Case 1 is a superposition of two separate cases using the computer model. In Stage 1, it was assumed that only a 200-foot high fracture and a relatively low fluid efficiency was obtained since the frac fluid was water. After about 90 minutes of low viscosity fluid injection (Stage 1), a small fracture only a few hundredths of an inch wide and less than 200 feet in length was created. However, 150 feet or more away from the wellbore, low temperature conditions exist in the fracture because of the large volume of cool fluid injected. Next, Stage 2 fluid entered the fracture and a viscous fluid was injected for the next 60 minutes. At this point the fracture widened, the rate increased, and the frac height was assumed to increase to 300 feet. By superimposing the first frac length, about 150 feet was added to the calculated length and the calculated volume was estimated to increase by 10 percent. Utilizing these assumptions, the final frac length is predicted to be 579 feet in length and the fracture volume at the end of the job is 6,336 cubic feet. Case 2 assumed the pre-pad fluid generated a negligible fracture volume or length. The calculated Case 2 dynamic frac length is therefore 429 feet.

After the post-frac temperature survey was obtained, the frac string was pulled and a bit was run to check for proppant fill and to clean out the well. On two separate occasions, March 23 and 24, the well was circulated with aerated water and allowed to flow to be sure that production of proppant into the wellbore would not interfere with subsequent testing (Appendix A). During the first flow, the well produced for 1.7 hours at an average rate of 177,000 lb/hr. On March 24 the well produced for 5.7 hours at an average rate of 168,000 lb/hr. No significant amount of proppant was produced into the wellbore after the frac job.

At this time it was determined that the well was worthy of final completion and further testing. A 5-1/2" pre-perforated liner was installed in the treatment interval as shown in Figure 9C. Between March 26, 1981 and May 12, 1981, RGI and Union performed four separate production tests to evaluate the stimulation job.

On March 26, 1981, a 6-hour production test through drillpipe was performed. The procedure was a combination of conventional drill stem test (DST) methods 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. This unique testing method was utilized to overcome the downhole data acquisition problems commonly associated with flowing a high volume, geothermal well. In addition, past Baca experience had shown that large diameter casing, combined with the low reservoir pressure, can result in wellbore storage effects which obscure all meaningful reservoir data. The DST method overcomes the wellbore storage problem to a large extent. During the DST, a relatively low, steady flow rate (illustrated in Figure 14) of about 21,000 lb/hr was obtained. Rates were measured by gauging the flow into the rig's mud tanks. Transient pressure and temperature data were obtained downhole during the production period and the subsequent pressure buildup period. The maximum recorded temperature at 2,987 feet was 342°F and indicated that the near-wellbore area had not recovered from the injection of cold frac fluids.

Conventional transient pressure analysis techniques were used to analyze the data given in Table 8. Horner analysis of the pressure buildup data (Figure 15) yielded a reservoir permeability-thickness of about 2,500 md-ft and a skin factor of -4.0. This analysis was influenced by the limited duration of the test (i.e., the transient pressure responded only to a small area of the reservoir surrounding the well), the changing fluid properties as the temperature increased, and the presence of the propped fracture. The calculated permeability-thickness is lower than the values obtained for most of the other wells in the area by Union (Hartz, 1976) but the negative skin factor indicates wellbore stimulation. The PI measured during this test was about 520 lb/hr/psi. This PI value suggests that the well should be relatively productive. Table 2 shows that the range of PI's in other Baca wells is 220-400 lb/hr/psi. The length of the fracture was calculated from the pressure data (using the pressure vs $[\Delta t]^{1/2}$ plot) to be about 200 feet, which is less than the dynamic fracture length calculations. This may reflect the approximate point at which the hydraulically created fracture intersects the natural fracture system and linear flow no longer dominates. Fracture conductivity calculations also suggest the artificially created fracture has relatively high conductivity comparable to that expected for 20/40-mesh proppant.

Following the modified DST, a 49-hour flow test (test No. 2 using Union's sequence number) was performed to determine the well's productive capacity. A 12" pipeline was installed between the Baca 23 wellhead and the nearby sump. The flow rate was calculated using a single orifice plate method to measure the two-phase flow conditions. Only the fourth production test utilized a "mini-separator" to measure the steam fraction (a slipstream sample is taken with an isokinetic sampler and passed through a small separator). The results, illustrated in Figure 16, showed that the well could produce approximately 120,000 lb/hr total mass flow at a wellhead pressure of 45 psig (assuming a 40 percent steam fraction). This test was terminated on March 30, 1981 so that the rig could be moved off the site and production test facilities installed for a long-term flow test.

Union performed two flow tests on the well during April-May, 1981. The flow rates for these tests are illustrated in Figures 17 and 18. A static temperature profile of the well prior to test No. 3 showed that the bottomhole temperature still remained low (401°F). Well temperature and pressure surveys run on April 21, 1981, recorded a maximum pressure of 120 psig and a temperature of 344°F at 3,500 feet (temperature survey shown in Figure 13). Therefore, two-phase flow was occurring in the formation. The formation cooling seen in the April 21, 1981 temperature survey (Figure 13) was apparently a result of the temperature drop associated with brine flashing in the formation. The steam fraction measured at the wellhead using a "mini-separator" was about 50 percent.

The low productivity obtained from the well during these last tests is of concern. The mass flow rate dropped to about 70,000 lb/hr with a wellhead pressure of 37 psig. This two-phase flow rate appeared to be stable during the last few days of test No. 4. At the end of the test, the well died when the wellhead back pressure was increased by a few psi. Thus it was concluded that the well would not produce at the 100+ psig design flowline pressure of the Baca power plant. The well recovers productivity following a shut-in period and then exhibits the same flow rate decline again; therefore, the cause of the flow rate decline is probably not scaling in the formation. Partial closing of the fractures with pressure drawdown is possible, but there is no evidence to indicate that this is occurring and no proppant has been observed in the produced fluid. The probable cause of the low productivity is the relative permeability reduction associated with two-phase flow effects in the formation. This, in turn, probably results from restricted inflow because of the low permeability formation surrounding the propped fracture. The permeability-thickness calculated from the pressure buildup data obtained following test No. 4 was 4,600 md-ft.

The large pressure drawdown leading to flashing flow in the formation is partly the result of the low initial reservoir energy (i.e., the reservoir fluid pressure and temperature are too low to sustain high flow rates to the surface). Two-phase flow in the formation and a rapid early decline in flow rate have been observed in most of the other wells in the field. Calculations of the wellbore flow conditions at Baca suggest that in this subhydrostatic-pressured reservoir as temperatures decrease to 450-480°F, the wells cannot flow.

During the first two production tests, numerous liquid-phase fluid samples were taken from the flow line and analyzed to define both the qualitative and quantitative aspects of the chemical tracer and frac fluid return. Sampling was discontinued when the methanol and total organic carbon content had decreased to a concentration that was less than ten percent of the highest concentration observed in any produced sample. At this point, the end of production test No. 2, approximately 2.1 times more fluid had been produced back than had been injected. In addition, several samples were analyzed for potassium and lithium, both of which were found to be suitable natural tracers. The chemical data are summarized in Tables 9 through 13. Figures 19 through 22 show this data plotted versus the cumulative production.

The most notable results obtained from the chemical data are: 1) the general mixing of all the tracers in the return fluids; 2) the low total quantities of alcohol tracer returned; 3) the high level of fluorescence in all samples; 4) the early appearance of reservoir fluid; and 5) the rapid thermal degradation of the polymer. The mixing of the tracers in the return fluids and the early appearance of reservoir fluid support the conclusion that the artificially created fracture did communicate with the naturally fractured reservoir system which resulted in the complex tracer pattern. The low total quantities of tracers and polymer material return can be attributed to several possible causes; 1) the relative retention of the various organic tracers in the formation, 2) dilution by the reservoir fluid, and 3) precipitation of the material as an insoluble reaction product with other injected materials such as the polymer. The data from this experiment is not sufficient to quantify the reasons for the variations in organic tracer return which ranged from 27 percent to 7 percent. The Tinopal CBS-X provided a clear visual indication of the frac fluid return even in relatively low concentrations.

It is interesting to note that the polymer content (HP guar), as shown by the relative amount of organic material present, drops rapidly. This indicates a rapid thermal degradation of the material due to exposure to high temperature. The less rapid fall-off in the total organic carbon material is consistent with the conversion of the polymer to a soluble nonpolymeric organic material. The total polymer return accounted for by these two material measurements is 46 percent. Laboratory experiments have shown that the heating of the gelled water solution results in the formation of highly insoluble titanium oxide; therefore, it was not surprising that titanium was not found in the production samples.

VIII. CONCLUSIONS AND RECOMMENDATION

As a result of the stimulation experiment performed on Baca 23, the conclusions and recommendation are as follows:

A. Conclusions

1. A large hydraulic fracture treatment was successfully performed on Baca 23 with 450°F bottomhole conditions. Production tests indicated an artificial fracture was created in a previously

nonproductive interval and communication with the reservoir system was established.

2. The productivity of the well declines rapidly with continued production to a subcommercial, stable rate. The probable cause of this decline is the relative permeability reduction associated with two-phase flow effects in the formation. The ability of the well to produce without a large pressure drawdown is limited partly because of the subhydrostatic reservoir pressure and perhaps by the inability of the natural fracture system to feed the high conductivity, propped fracture at a higher rate.

3. Although the stimulation treatment did not result in a commercial well at Baca 23, the hydraulic fracturing technique shows promise for future stimulation operations and for being a valid alternative to redrilling.

B. Recommendation

Another well stimulation experiment in the Redondo Creek area is appropriate. A deeper, hotter interval should be selected to achieve high productivity at high wellhead pressures. Consideration should also be given to the utilization of larger fluid treatment volumes and larger proppants.

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TABLES AND FIGURES

TABLE 1

BACA WELL TEST SUMMARY

(Data from Hartz 1976 and Unpublished Union Records)

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW LB/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR TEMPERATURE BASED ON ENTHALPY °F	
B-4-1	8/13-22/73	228	204	175	26.0	145,800	569.5 516-569	566 523-566	@ 228 hrs range
B-4-2	9/10-11/13/73	1538	120	113	27.5	172,500	566.1 526-566	556 532-563	@ 1538 hrs range
B-6-1	10/08-15/72	166	137	92	24.4	153,500	517 513-534	524 521-538	@ 165 hrs range
B-6-2	10/25-11/4/72	190	92	69.5	27.6	146,900	530.9 527-538	536 532-541	@ 189 hrs range
B-6-3	11/6/72-1/16/73	1700	51.5	37.75	30.7	147,700	532.2 518-581	536 525-574	@ 1700 hrs range
B-6-4	6/5-24/75	428	58	--	30.0 (est.)	248,000 (est.)	--	--	2-phase test
B-6-5	7/3-21/75	428	53	--	30.3 (est.)	240,000 (est.)	--	--	2-phase test
B-6-6	7/25-8/19/75	584	107.5	100.5	22.8	175,000	500.9 493-513	510 504-521	@ 584 hrs range
B-10-1	8/26-9/3/75	215	31	--	34.1 (est.)	126,000	--	--	2-phase test
B-11-1	1/8-9/74	24	--	140	33.4	480,500	619.9	602	@ 24 hrs

Table 1 (continued)

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW LB/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR TEMPERATURE BASED ON ENTHALPY °F	
B-11-2*	1/11-25/74	311	121	105	49.6	205,000	746.6 744-806	676 674-696	@ 310 hrs range
B-11-3	1/29-30/74	27	143			No Data			
B-11-4	2/01-24/74	546	131	115	41.1	271,400	675.9 668-734	638 634-669	@ 546 hrs range
B-11-5	6/26-9/25/74	2182	138 127 129	126.5 114 124	35.6 32.9 26.9	267,100 252,000 164,300	633.1 604 526-671	611 591 532-635	@ 745 hrs @ 1440 hrs @ 2182 hrs range
B-11-6	11/8-17/74	243	120	101	39.0	305,900	651	623	@ 217 hrs
B-13-1	11/30/74-1/06/75	792	62	--	29.6 (est.)	300,000	--	--	2-phase test
B-13-2	1/10-2/25/75	1103	124	115	25.4	303,700	537.8 522-561	541 533-559	@ 1100 hrs range
B-13-3	5/14-6/6/75	471	110	92.5	31.6	257,200	581 549-588	575 550-580	@ 471 hrs range
B-13-4	6/13-20/75	163	110	87	27.0	273,200	537 536-539	540 539-542	@ 115 hrs range
	2nd rate		190	33	20.5	161,000	432	453	@ 159 hrs
B-15-1	6/27-7/14/75	429	63	--	70.0 (est.)	169,400	--	--	2-phase test
B-1			65	--	95	85,000	--	338 (1,500 ft)	
B-3			--	--	11	--	--	390 (1,800 ft)	

Table 1 (continued)

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW LB/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR TEMPERATURE BASED ON ENTHALPY °F	
B-18	3/12/79	3	5	--	50 (est.)	56,000	--	--	Test did not stabilize
B-18	4/24/79	8.5	--	--	--	--	--	--	Flow died
B-18	6/29/79	4	21	--	60	50,000	--	210(WHT)	Flow died
B-19-1	11/15/79	12	--	--	30	38,000 to 215,000 (120,000 avg)	--	213	4-6 hour cycles
B-20	9/16-17/80	27.7	125	117	62	81,600	865	704	@ 27.5 hrs
B-20	9/24/80-1/6/81	2520	116	75	56.5	56,100	793	--	Avg data for last 4 days

* Sand buildup in water line makes H_2O data suspect.

TABLE 2

TRANSMISSIVITY VALUES FROM PRODUCTIVITY AND PRESSURE BUILDUP DATA

(After Hartz, 1976)

WELL	TEST NUMBER	PI lbs/hr/psi	PI TRANSMISSIVITY $\frac{kh,\ md\text{-}ft}{\mu\ \ \ cp}$	BUILDUP TRANSMISSIVITY $\frac{kh,\ md\text{-}ft}{\mu\ \ \ cp}$
Baca 4	2	263	22,400	42,100
Baca 6	1	274	24,900	48,500
Baca 6	2	241	21,900	46,400
Baca 6	3	221	20,300	46,700
Baca 6	6	316	29,100	64,000
Baca 11	4	318	29,300	No Buildup
Baca 11	6	400*	36,800*	34,600
Baca 13	2	427**	39,300**	26,400
Baca 13	3	329**	30,300**	No Buildup
Baca 13	Interference Test	243**	22,400**	20,300

* Well may not have been stable.

** Baca 13 rates and pressure fluctuate; therefore, PI's may not be representative of stabilized conditions.

TABLE 3

RESULTS OF PRESSURE BUILDUP TESTS

(After Hartz, 1976)

WELL	TEST NO.	DATE	kh md-ft		SKIN S	FINAL STATIC BUILDUP Press., psig	MEASURED DEPTH ft
Baca 4	2	11/13/73	4207		+14.7	1686	6350
Baca 6	1	10/15/72	4849		+ 7.9	959	3690
Baca 6	2	11/03/72	4641		+ 8.0	984	3690
Baca 6	3	1/16/73	4666		+ 8.8	985	3690
Baca 6 (After Deepening)	6	8/19/75	6401		+ 9.7	1004	3830
Baca 10	1 (Two-phase Test)	9/03/75	5151		+42.9	1761	5959
Baca 11	6	11/17/74	3457		- 3.9	1811	6630
Baca 13	2	2/25/75	2638	2332 Avg.	- 1.9	2310	8176
Baca 13	Interference Test	4/19/76	2025		+ 4.3	2288	8100
Baca 15	1 (Two-phase Test)	7/14/75	8630*		- 2.9	911	5500

Average of all tests (except Baca 15) — 4310 md-ft (using average for B-13 and value from B-6 test 6)

* Assumes drainage area contains steam only.

TABLE 4

BACA PRODUCTION TESTS

(After Hartz, 1976)

WELL	DAYS ON PROD.	TOTAL MASS $x\ 10^6$ lbs	TOTAL STEAM $x\ 10^6$ lbs	AVERAGE RATES, MLB/HR TOTAL MASS	STEAM
B-6	63	256	66	170	44
B-11	170	899	425	220	104
B-13	207	1089	302	219	61
TOTAL		2244	793	609	209

INJECTION

B-5	140
B-12	575
B-14	499
TOTAL	1214

TABLE 5

BACA WATER CHEMICAL COMPOSITION

(After Hartz, 1976)

WELL	AVG. TDS IN BRINE (ppm)	AVG. TDS IN CONDENSATE (ppm)	SILICA (ppm) IN BRINE	NONCONDENSABLE GAS % BY WT.	H_2S CONCENTRATION (ppm)		AVERAGE	
					NONCONDENSABLE	TOTAL STEAM	FLASH %	FLOW RATE lb/hr TOTAL
Baca 4	5100	28	302 (167-701)	3.16	165 (150-180)	165 (117-213)	26.8	171,400
Baca 6	6018 (5800-6230)	23 (3-65)	453 (160-600)	1.33 (1.27-1.38)	61 (60-61)	99 (69-257)	27.8	163,700
Baca 11	6895 (6056-7593)	59 (7-105)	740 (640-835)	3.76 (2.30-5.94)	365 (222-564)	477 (290-867)	39.7	227,100
Baca 13	6477 (5500-8684)	13 (7-25)	786 (556-963)	2.93 (1.93-3.94)	81 (57-96)	149 (8.63-205)	28.4	284,600

NOTE: 1. Some samples from Baca 4 were diluted prior to analysis. The results from these analyses are not included in the above.

2. Left out values obtained from low rate of two-rate test on Baca 13.

TABLE 6

BACA 23 WELL TREATING SCHEDULE

Stage No.	Planned Size (bbl)	Actual Size (bbl)	Proppant (lb/gal)	Proppant (Size)	Fluid
1	4,000	3,582	0	-	Produced water with Fluid Loss Additive (FLA) 40 BPM rate
2	500	502	0	-	Crosslinked HP Guar 60 lb/1000 gal with FLA; 60 to 70 BPM rate
3	500	502	2	100-mesh	Crosslinked HP Guar 60 lb/1000 gal with FLA; 60 to 70 BPM
4	500	526	0	-	Crosslinked HP Guar 60 lb/1000 gal with FLA; 60 to 70 BPM rate
5	900	905	1	20/40-mesh	Crosslinked HP Guar 60 lb/1000 gal with no FLA; 65 to 75 BPM rate
6	1,000	1,000	2	20/40-mesh	Crosslinked HP Guar 60 lb/1000 gal with no FLA; 65 to 75 BPM rate
7	600	562	3	20/40-mesh	Crosslinked HP Guar 60 lb/1000 gal with no FLA; 65 to 75 BPM rate
8	58	62	0	-	Flush with produced pit water
	8,058	7,641			

TABLE 7

ACTUAL DIRECT COSTS TO GRWSP
FOR STIMULATION AND EVALUATION
BACA 23

Fracturing Materials and Service	
Fluids and proppants	$ 167,067
Pumping service, transportation, etc.	83,377
Water and water hauling	6,121
Frac tanks	18,855
Misc. service	13,036
	288,456
Rig daywork	52,798
Rig fuel	5,463
Equipment rentals	
Compressors	7,036
Drilling equipment	6,154
Other	1,565
	14,755
Expendable materials	5,297
Misc. services	
Packers	4,567
Nitrogen and coil tubing	6,214
Pressure testing	3,671
Pressure and temperature instruments	3,698
Tubing inspection	2,922
Crane and tractors	14,408
Other	3,835
	39,315
Transportation of tubing and misc. equipment	3,818
Total	$ 409,902

TABLE 8

BACA 23 PRESSURE BUILDUP DATA
DRILLSTEM TEST

3-26-81

P_{ws} (psig)	Δt(hrs)	$\frac{t+\Delta t}{\Delta t}$	$(P_{ws} - P_{wf})$ (psi)	$(\Delta t)^{1/2}$
668	.008	709.4	0	.0894
675	.017	334.4	7	.13
682	.033	172.7	14	.182
684	.08	71.8	16	.293
685	.16	36.4	17	.400
687	.25	23.7	19	.500
688	.33	18.2	20	.574
689	.42	14.5	21	.648
691	.75	8.56	23	.866
692	1.0	6.67	24	1
693	1.01	6.61	25	-
695	2.0	3.83	27	1.414
696	2.67	3.12	28	1.63
697	3.0	2.89	29	1.73
698	4.0	2.42	30	2.0
699	5.0	2.13	31	2.24
699	6.0	1.94	31	2.45
700	7.0	1.81	32	2.65
701	8.0	1.71	33	2.83

t_p = 5.66 hrs.

Q = 1433 BPD (measured water rate)

m = 14 psi/cycle (from Horner plot)

TABLE 8 (continued)

$$kh = \frac{(162.5)\ [Q]\ (B)\ (\mu)}{m}$$

$$= \frac{(162.5)\ [(1433)(1.23)](1.23)(.1)}{14}$$

$$= 2500 \text{ md-ft}$$

$$s = 1.151 \left\{ \frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{kh}{\phi\mu C_t h\ r_w^2}\right) + 3.23 \right\}$$

$$= 1.151 \left\{ \frac{692 - 668}{14} - \log\left(\frac{2500}{(.2)(.1)(231)(15 \times 10^{-6})(.36)^2}\right) + 3.23 \right\}$$

$$= -4.0$$

TABLE 9

INJECTED FLUIDS SAMPLED DURING TREATMENT
March 22, 1981 - BACA 23

VR Code	Stage	Cumulative Injection (bbl)	Appearance	Tracer (Amount)
7603-7607	1 (prepad)	3,582	Thin	Methanol (218 gal)
7608-7612	2	4,084	Thin	Methanol (29 gal) Butyl Cellusolve (50 gal) Ethanol (50 gal) Tinopal CBBS-X (70 lbs)
77613-7616	3-6	7,017	Slightly Viscous	Methanol (172 gal)
7617-7621	7	7,579	Very Viscous	Methanol (33 gal) Isobutanol (50 gal) Ethanol (50 gal)
-	8 (flush)	7,641	Slightly Viscous to Thin	None Added
-	Various Post Treatment Additions of Mud Tank or Pit Water to Well Prior to or During Production Testing	10,565	-	None Added

TABLE 10

AVERAGE COMPOSITION OF INJECTED FLUIDS
(March 22, 1981-BACA 23)

VR CODE	STAGE	TRACER (AMOUNT)	METHANOL[a]	ETHANOL[a]	ISOBUTANOL[a]	BUTYL[a] CELLUSOLVE	FLUORESCENSE[b]	ISOPROPANOL[a]	TITANIUM[a]	POLYMER[a]	TOTAL ORGANIC[a] CARBON (CORRECT)
7603-7607	1(Prepad)	Methanol (218 gal)	273	<1.0	<1.0	<1.0	Negative	<1.0	<0.002	<1	<1
7608-7612	2	Methanol (29 gal) Butyl Cellusolve (50 gal) Ethanol (50 gal) Tinopal CBS - X (70 lbs)	275	<1.0	<1.0	<1.0	Moderate	<1.0	<0.002	3144	1589
7613-7616	3-6	Methanol ()172 gal)	441	211	<1.0	149	Intense	<1.0	<0.002	5435	2780
7617-7621	7	Methanol (33 gal) Isobutanol (50 gal) Ethanol (50 gal)	562	1886	1739	<1.0	Intense	118	44	8032	5087

a. Value expressed as mg/l (i.e., ppm).

b. Relative intensity of the sample fluorescence under a black light.

c. Total Organic Carbon remaining after correcting for the carbon content of the tracers.

TABLE 11

PRODUCED FLUIDS SAMPLED DURING PRODUCTION
(March 23-30, 1981 - BACA 23)

VR Code	Date (Time)	Sampling Frequency	Cumulative Production (M lbs.)	Solids Production	Comments
7793-7796	3/23/81 (19:00-20:30)	30 min	Not Available	Heavy	Clay (Montmorrillonite)
7797-7799	3/23/81 (21:00-22:00)	30 min	318	Light	Clay (Montmorrillonite)
7800-7811	3/24/81	30 min	1181	Light	Bauxite (major); Sand and Supersand (moderate), Clay (moderate)
7813-7818	3/26/81 (04:00-08:00)	60 min	1314	Light	Clay (Montmorillonite)
7918-7926	3/28/81	15 min	1695	Light	Clay (Montmorillonite) Sand, Bauxite
7927-7935	3/28/81	30 min	2319	Light	Clay (Montmorillonite) Sand, Bauxite
7833-7835, 7973-7975	3/28/81 thru 3/30/81	Variable	7779	Light	--

TABLE 12

COMPOSITION OF PRODUCED FLUIDS[a]

(March 23-30, 1981 - Baca 23)

VR CODE	CUMULATIVE PRODUCTION (Mlbs)	METHANOL	ETHANOL	ISO-BUTANOL	BUTYL CELLU-SOLVE	FLUOR-ESCENCE[b]	POLY-MER	TOTAL ORGANIC CARBON (CORRECTED)[c]
7793	N/A	26.3	<1.00	<1.00	<1.00	none	122.	120.
7794	N/A	25.0	<1.00	<1.00	<1.00	none	143.	140.
7795	N/A	25.6	<1.00	<1.00	<1.00	none	137.	186.
7796	N/A	38.8	<1.00	<1.00	<1.00	none	152.	166.
7797	90	333.	109.	44.9	15.6	light	472.	693.
7798	180	306.	105.	26.5	22.7	light	430.	866.
7799	318	454.	386.	26.5	22.0	light	382.	592.
7800	335	411.	337.	32.2	15.2	light	444.	521.
7801	434	280.	84.9	16.4	19.7	light	318.	718.
7802	473	315.	82.9	13.1	16.8	light	251.	809.
7803	611	361.	61.8	14.1	19.2	light	233.	708.
7804	714	310.	86.1	7.10	23.7	medium	61.0	546.
7805	771	175.	50.1	10.9	21.1	medium	102.	682.
7806	882	228.	37.9	4.50	17.0	medium	87.4	547.
7807	941	209.	34.2	21.3	15.6	medium	77.1	482.
7808	988	119.	43.2	45.0	15.0	medium	63.3	543.
7809	1055	104.	41.0	25.2	16.9	medium	44.9	543.
7810	1138	139.	42.1	4.50	20.1	medium	38.0	385.
7811	1181	104.	27.2	5.30	18.7	medium	42.6	501.
7813	1211	107.	26.1	4.50	12.0	medium	240.	454.
7814	1228	166.	43.2	9.90	13.7	medium	200.	456.
7815	1251	141.	55.1	10.9	16.5	medium	107.	455.
7816	1272	156.	36.0	13.1	17.0	medium	65.6	454.
7817	1290	166.	48.9	8.90	18.1	medium	57.5	458.
7818	1314	139.	47.7	6.20	18.4	medium	49.5	459.
7918	1347	85.0	28.0	3.00	17.1	medium	27.3	395.
7919	1380	98.0	28.0	3.00	9.00	medium	28.1	385.
7920	1447	235.	62.9	9.00	18.2	medium	17.5	273.
7921	1507	69.0	23.0	3.00	6.90	medium	20.1	480.
7922	1553	77.0	21.0	9.00	9.30	medium	20.2	468.
7923	1588	79.0	18.0	9.00	5.20	medium	18.9	436.
7924	1623	45.0	16.0	9.00	5.40	medium	19.2	460.
7925	1658	47.0	16.0	1.00	5.80	medium	18.5	448.
7926	1695	46.0	15.0	1.00	5.60	medium	17.1	431.
7927	1766	53.0	16.0	1.00	5.60	medium	15.3	369.
7928	1837	55.0	20.0	1.00	11.2	medium	14.5	386.
7929	1908	51.0	15.0	1.00	6.50	medium	13.6	371.
7930	1979	47.0	15.0	1.00	5.50	medium	12.3	350.
7931	2047	37.0	14.0	1.00	4.70	medium	12.0	345.
7932	2115	53.0	19.0	1.00	4.30	medium	11.1	314.
7933	2183	31.0	14.0	1.00	4.70	medium	11.4	321.
7934	2251	46.0	14.0	1.00	4.60	medium	10.7	304.
7935	2319	62.0	19.0	1.00	3.20	medium	10.4	272.

TABLE 12 (continued)
COMPOSITION OF PRODUCED FLUIDS[a]

(March 23-30, 1981 - Baca 23)

VR CODE	CUMULATIVE PRODUCTION (Mlbs)	METHANOL	ETHANOL	ISO-BUTANOL	BUTYL CELLU-SOLVE	FLUOR-ESCENCE[b]	POLY-MER	TOTAL ORGANIC CARBON (CORRECTED)[c]
7833	2917	34.6	47.7	6.20	3.80	medium	<1.00	417.
7834	3437	34.6	<1.00	20.0	3.80	medium	<1.00	415.
7835	3957	34.6	<1.00	20.0	3.30	medium	<1.00	389.
7973	4477	15.0	<1.00	<1.00	2.00	medium	3.47	89.0
7974	6509	19.0	<1.00	<1.00	1.50	medium	5.09	113.
7975	7779	12.0	<1.00	<1.00	1.50	medium	6.84	87.0

a. Value expressed as mg/l (i.e. ppm). The analytical uncertainty is plus or minus 5% with the exception of the organic carbon which is plus or minus 2%.
b. Relative intensity of sample fluorescence under a black light.
c. Total Organic Content remaining after correcting for carbon content of the tracers.

TABLE 13

Average Potassium and Lithium Concentrations of Injected and Produced Fluids

INJECTED FLUID

VR CODE	SAMPLE	POTASSIUM*	LITHIUM*
7603-7	Stage 1 (Prepad)	81	5.3
7613-16	Stage 3-6	25	0.25
7617-20	Stage 7	22	0.1

PRODUCED FLUID

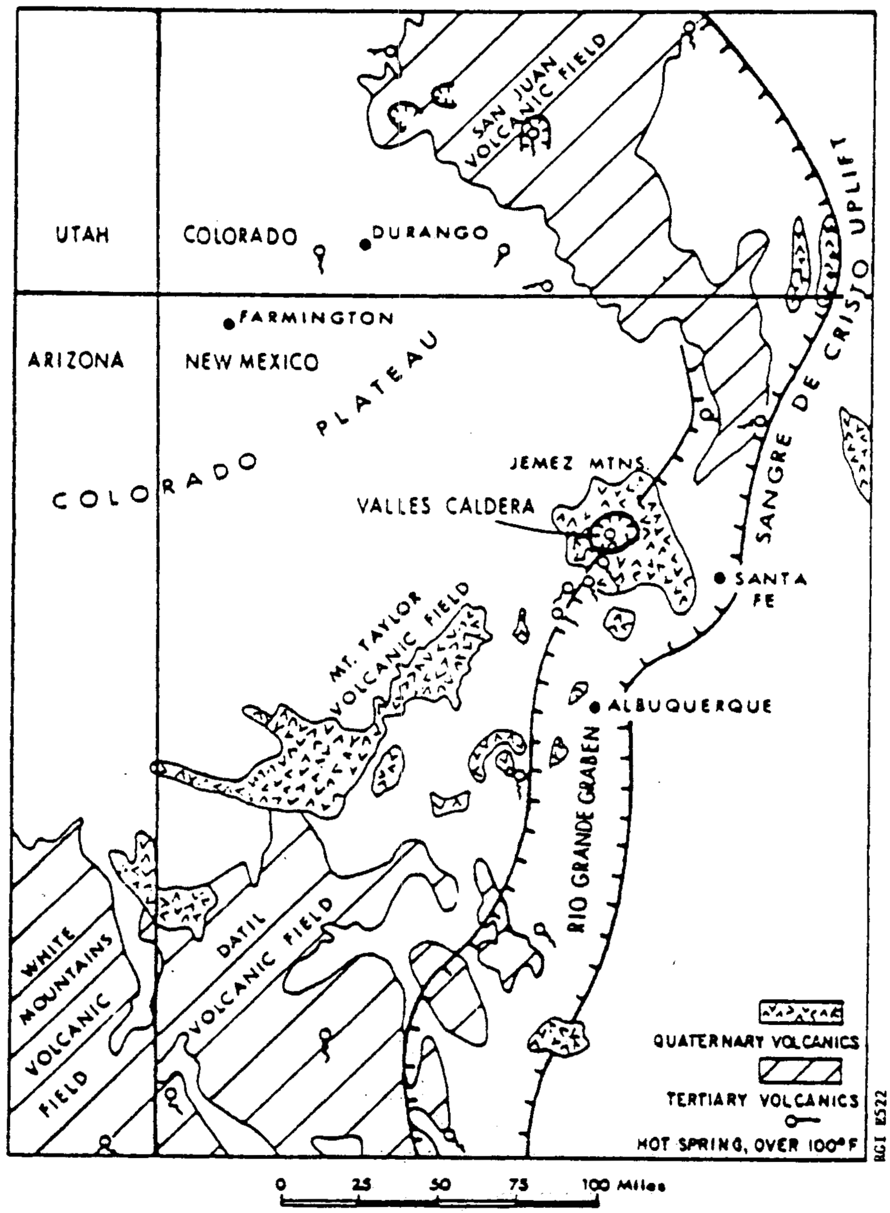
VR CODE	CUMULATIVE PRODUCTION (LBS)	POTASSIUM*	LITHIUM*
7804-6	750,000	220	16
7931	2,000,000	192	19
7935	2,500,000	189	19
7975	7,800,000	241	25

* Results expressed in mg/l or ppm. The analytical uncertainty is ± 5%.

FIGURES

FIGURE 1

REGIONAL GEOLOGIC SETTING OF VALLES CALDERA



(After Dondanville, 1978, p. 157)

FIGURE 2
GEOTHERMAL FEATURES OF THE JEMEZ MOUNTAINS, NEW MEXICO

(After Hartz, 1976)

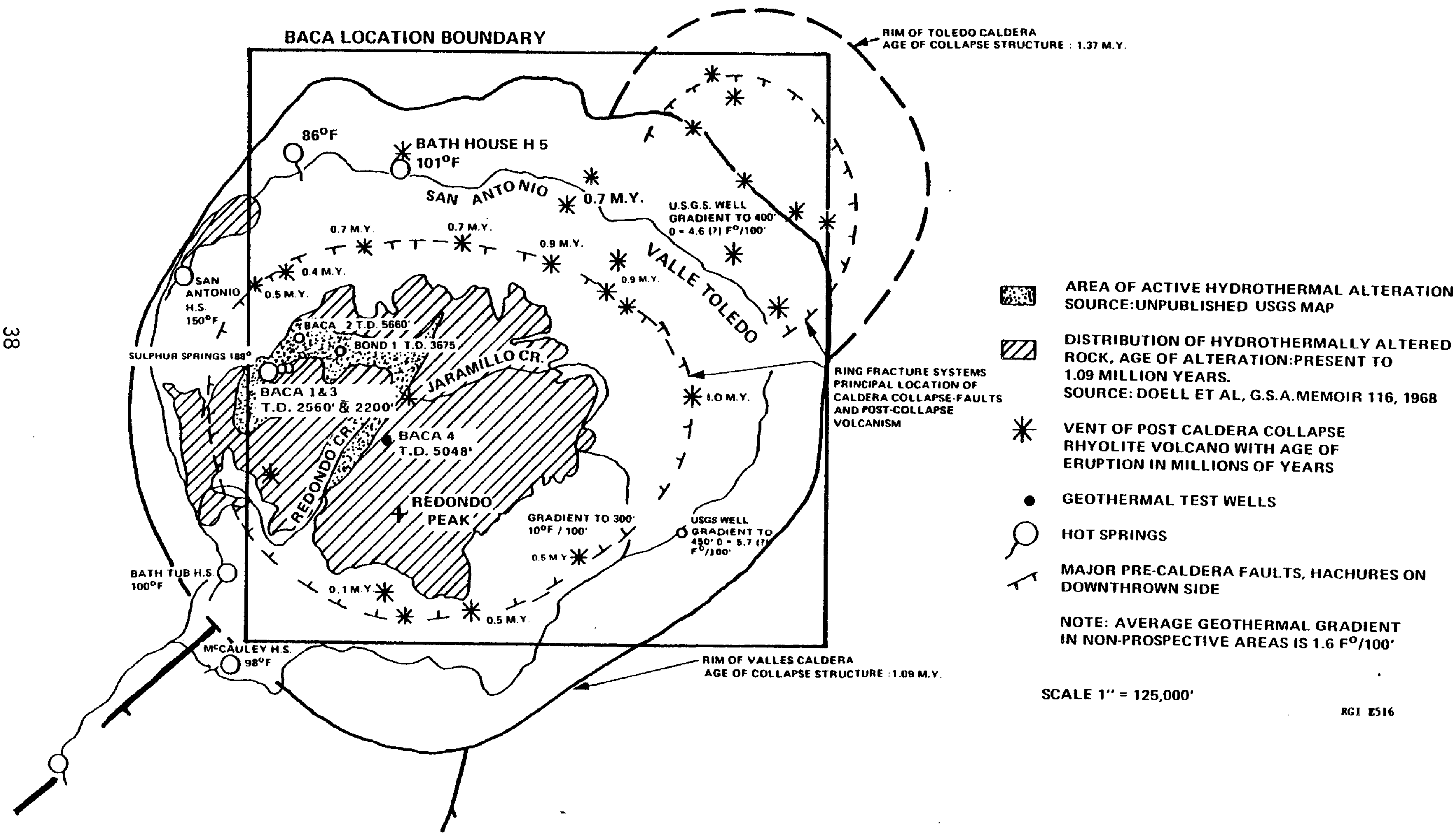


FIGURE 3

CONTOURS ON BASE OF THE BANDELIER TUFF

(After Hartz, 1976)

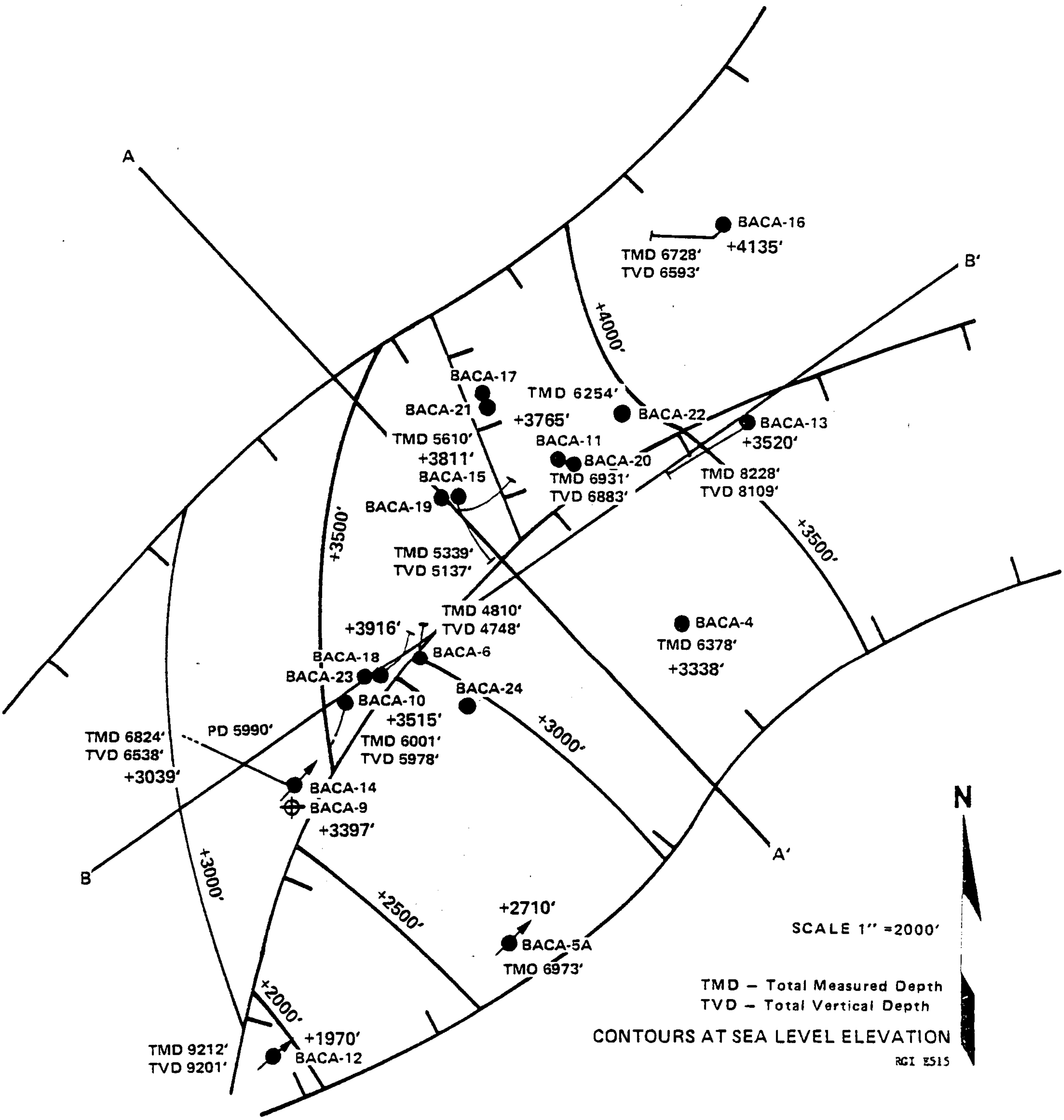


FIGURE 4

NW–SE CROSS SECTION THROUGH THE REDONDO CREEK AREA

(After Hartz, 1976)

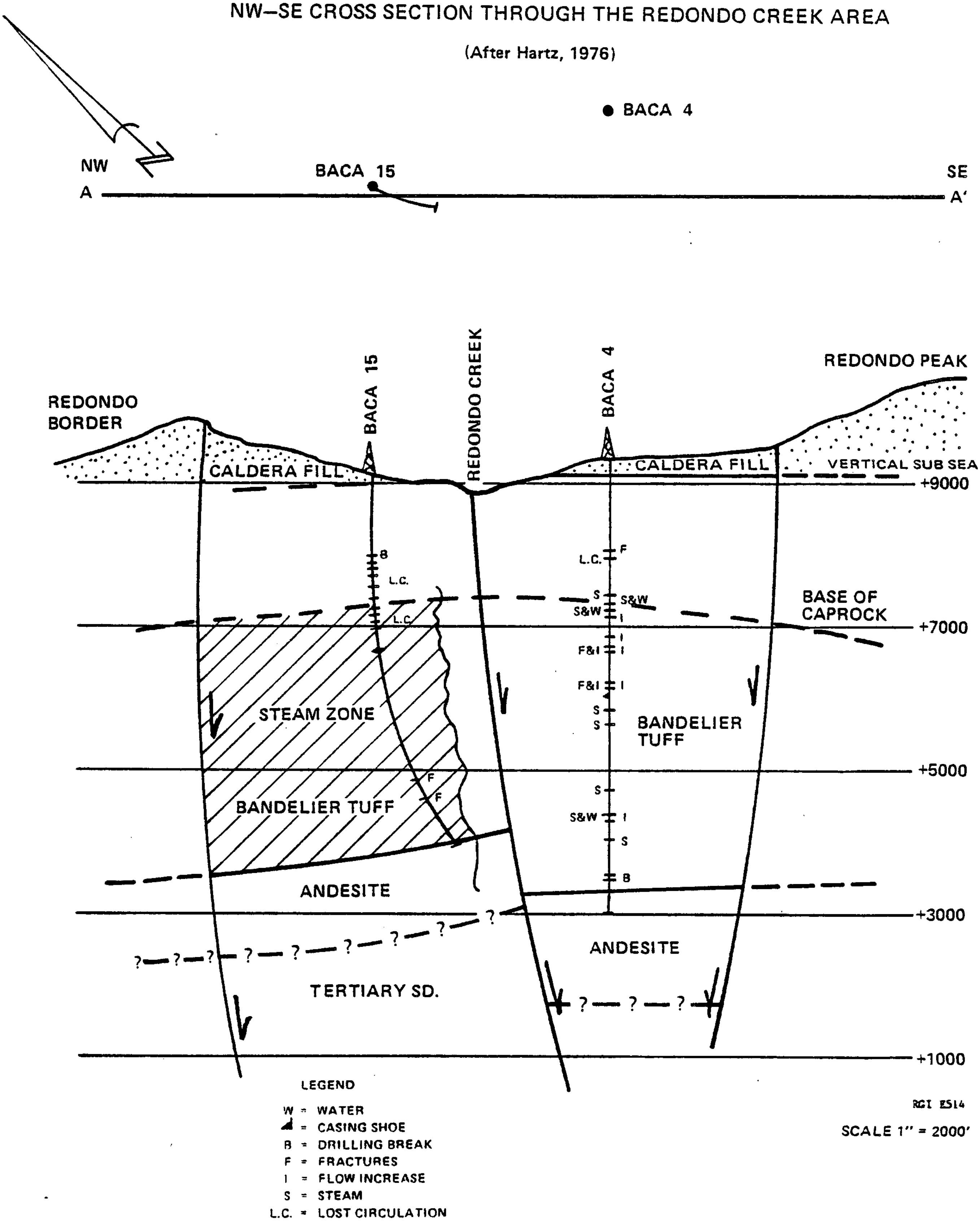
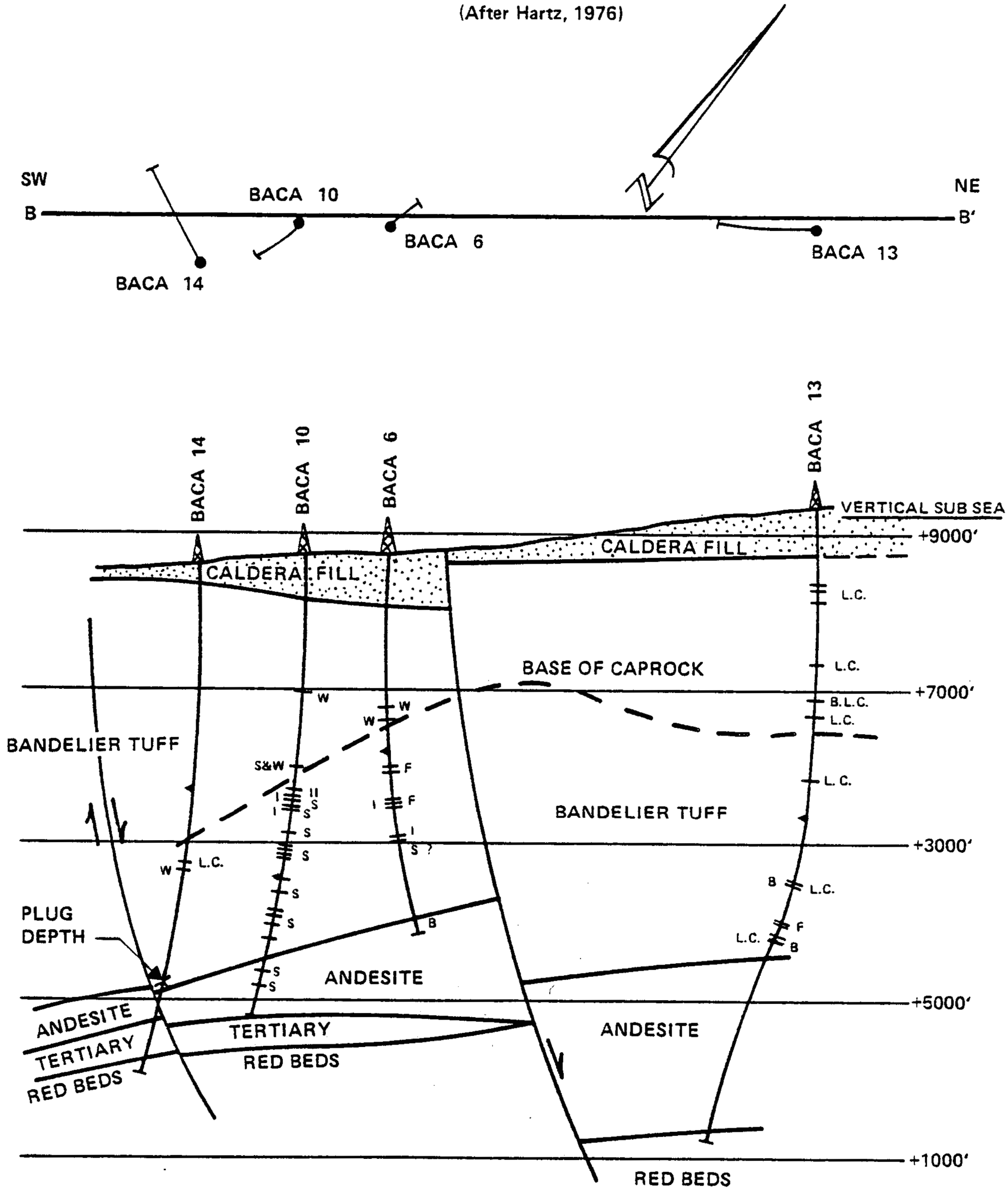


FIGURE 5

SW—NE CROSS SECTION THROUGH THE REDONDO CREEK AREA

(After Hartz, 1976)



LEGEND

- = CASING SHOE
- B = DRILLING BREAK
- F = FRACTURES
- I = FLOW INCREASE
- S = STEAM
- W = WATER
- L.C. = LOST CIRCULATION

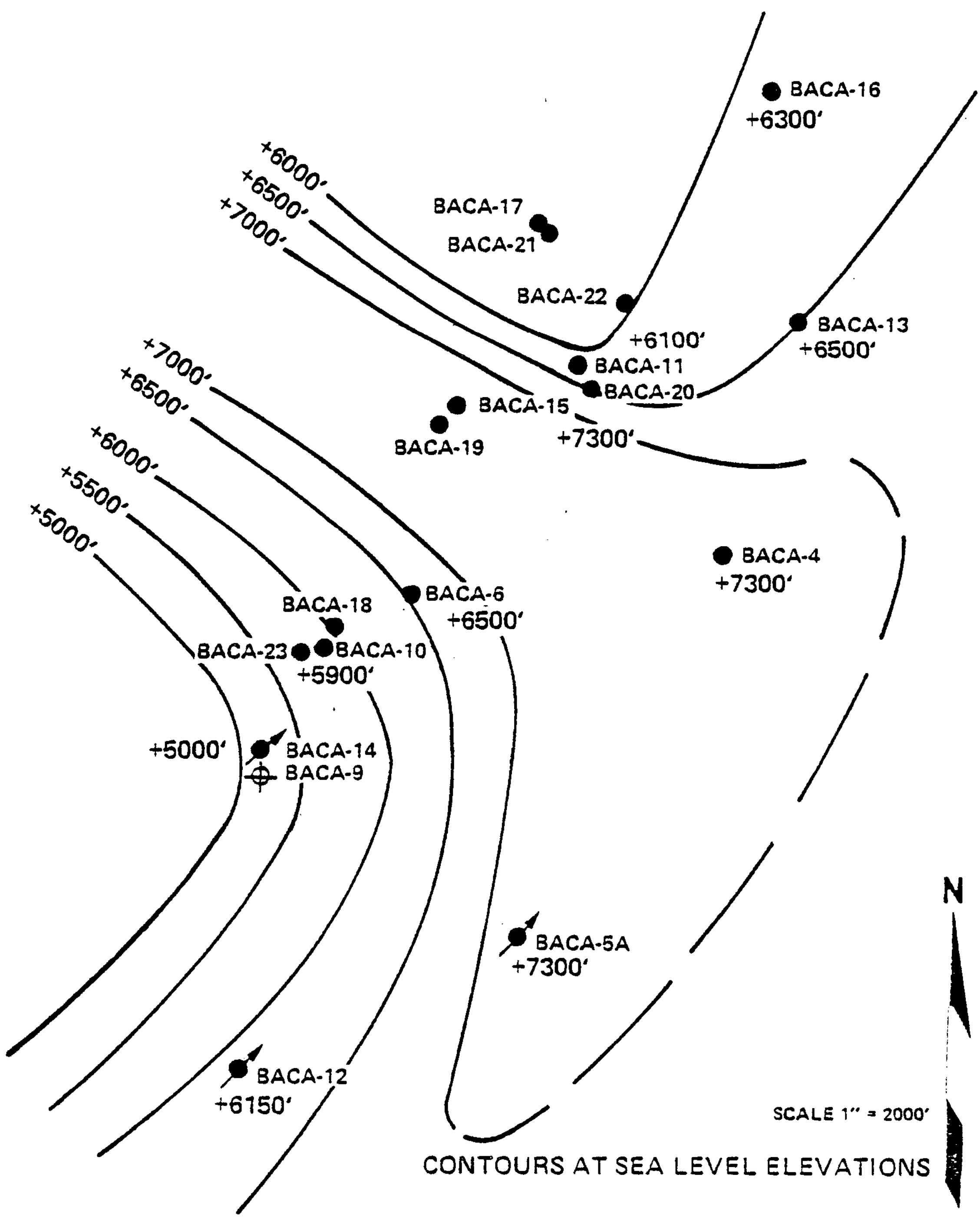
RGI E513

SCALE 1" = 2000'

FIGURE 6

CONTOUR MAP ON THE BASE OF THE CAPROCK

(After Hartz , 1976)



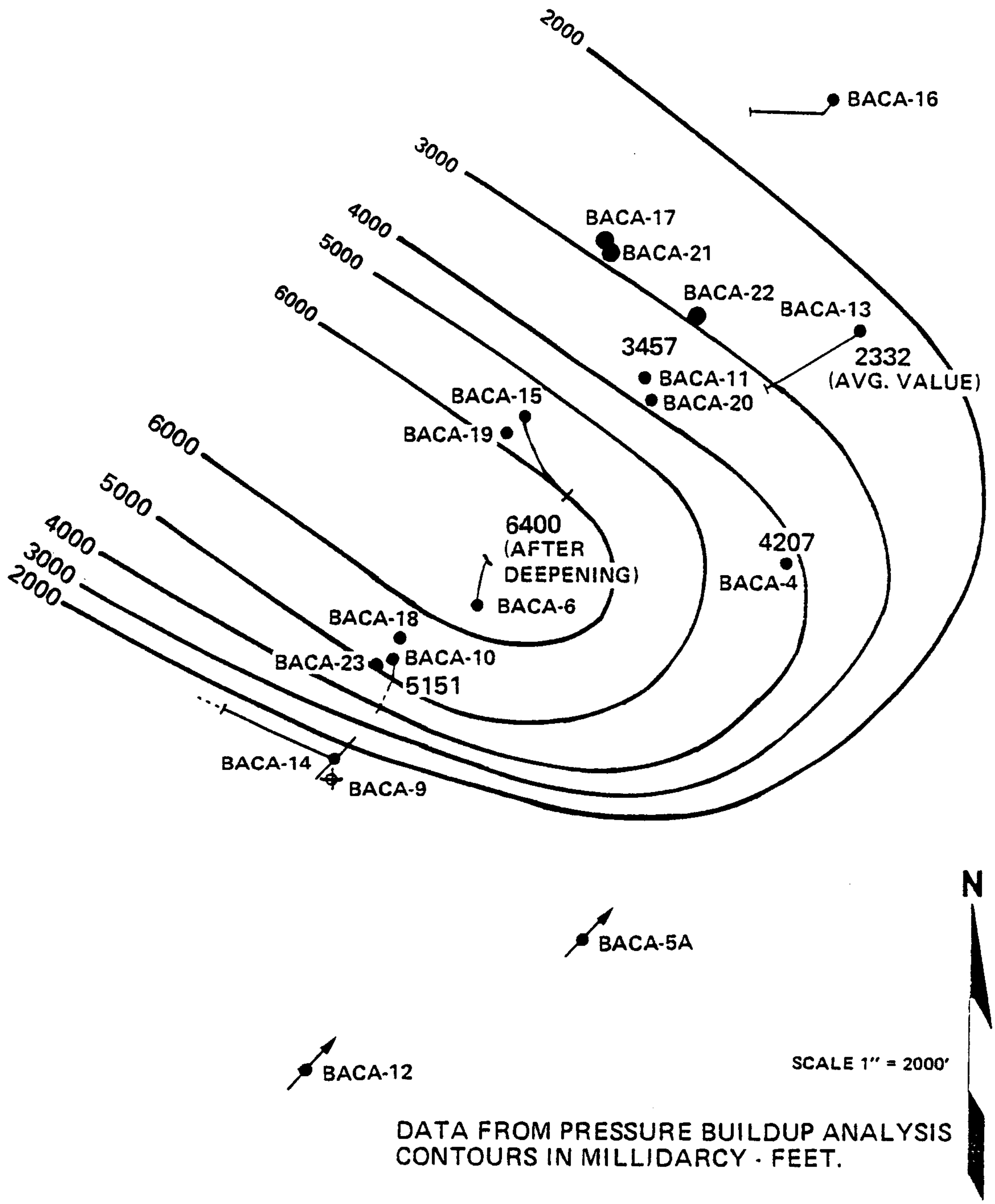
CONTOURS AT SEA LEVEL ELEVATIONS

BGI 2520

FIGURE 7

ISOPERMEABILITY—THICKNESS MAP, BACA, NEW MEXICO

(After Hartz, 1976)



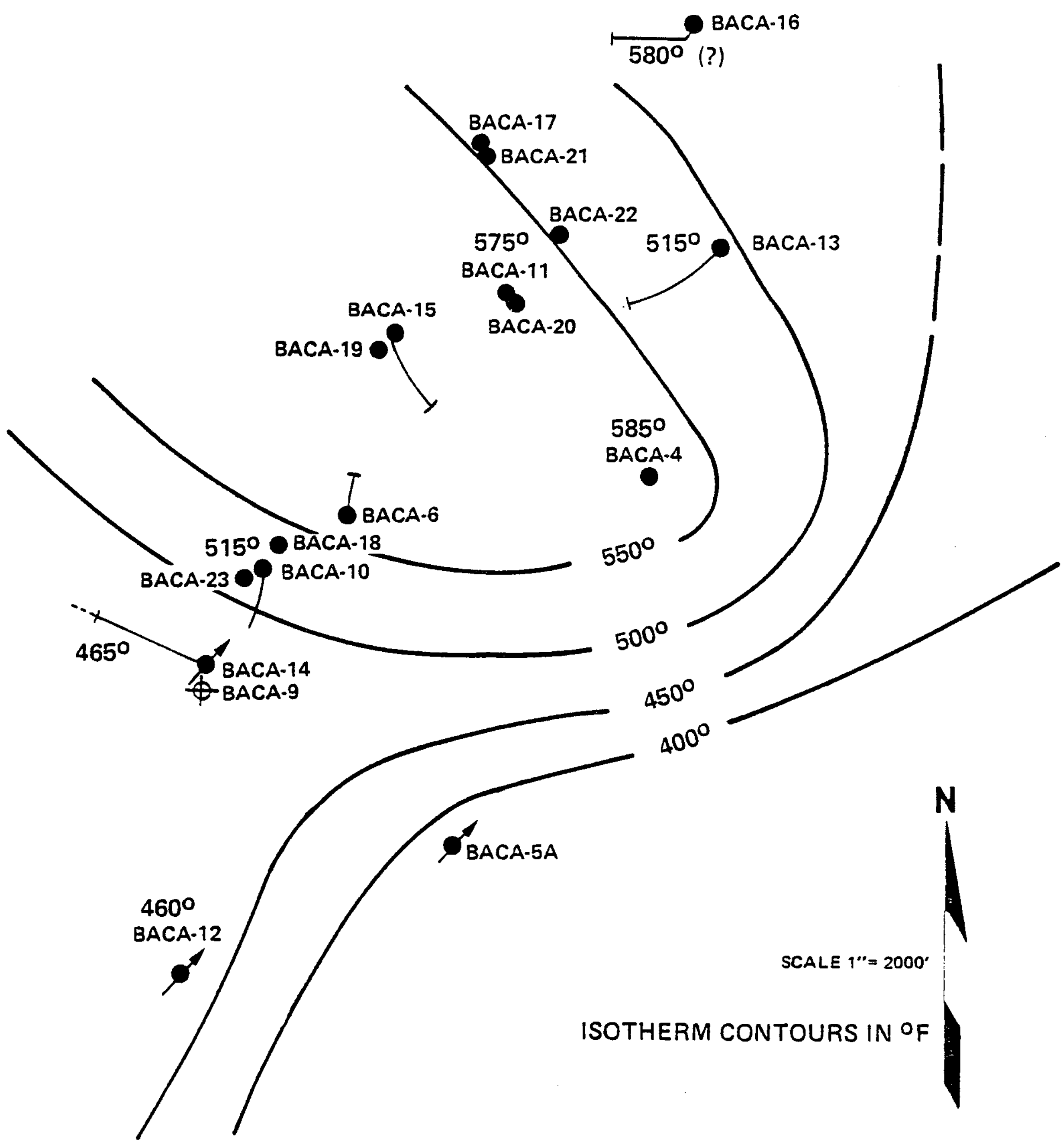
DATA FROM PRESSURE BUILDUP ANALYSIS
CONTOURS IN MILLIDARCY - FEET.

RGI E512

FIGURE 8

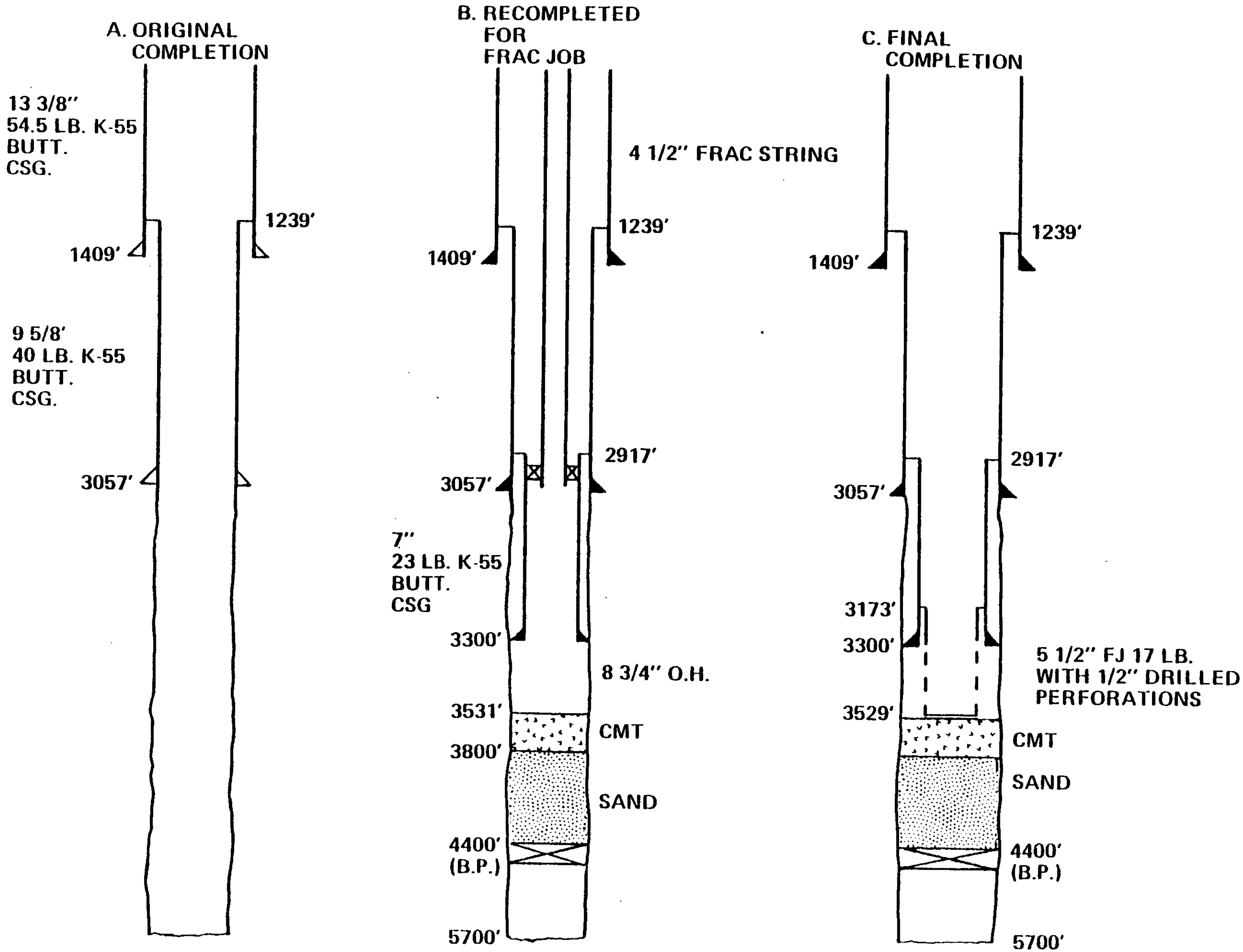
ISOTHERMS AT 3000' ABOVE SEA LEVEL, BACA, NEW MEXICO

(After Hartz, 1976)



RGI E517

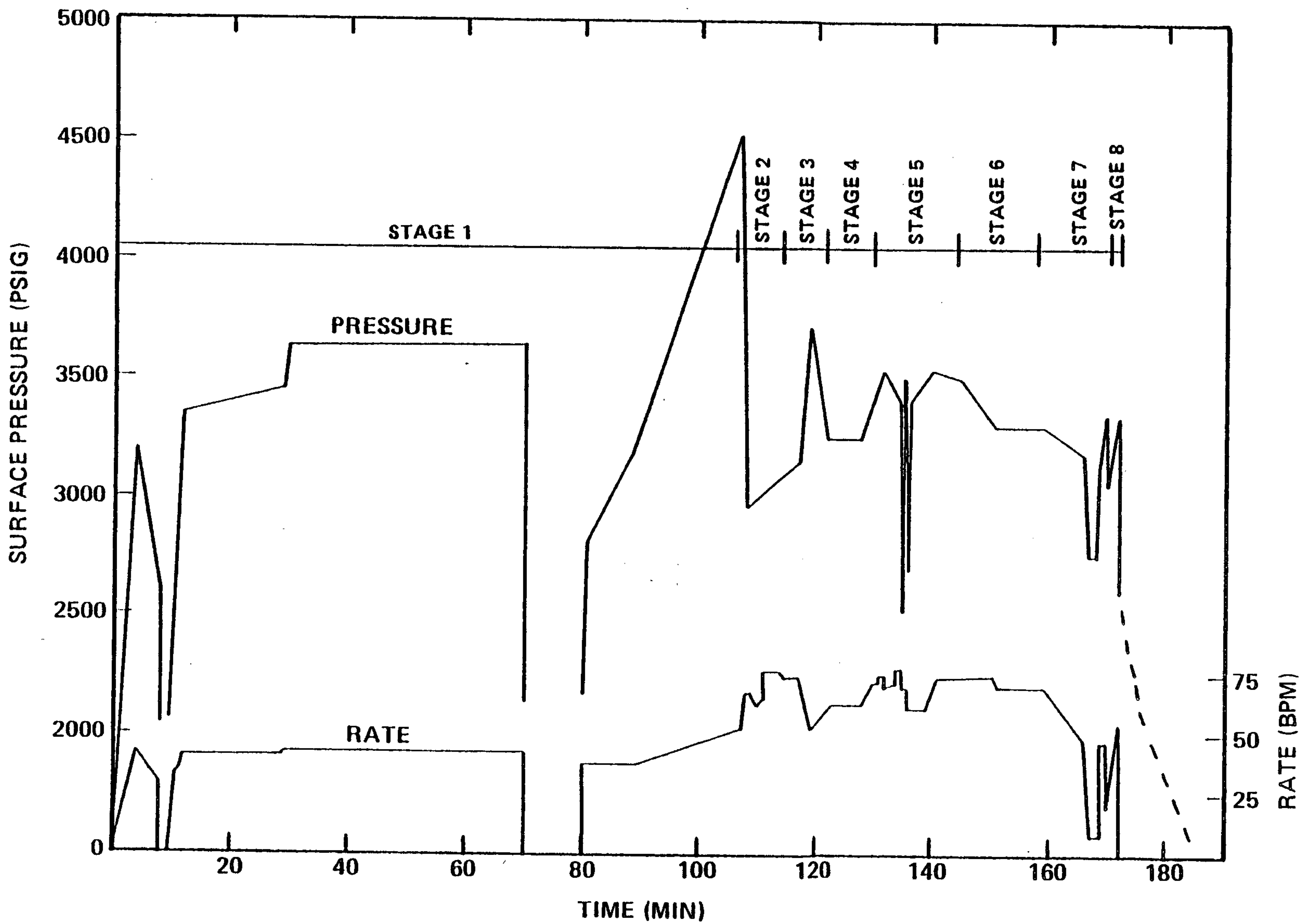
FIGURE 9
BACA 23 COMPLETION DETAILS



RGI E876

FIGURE 10

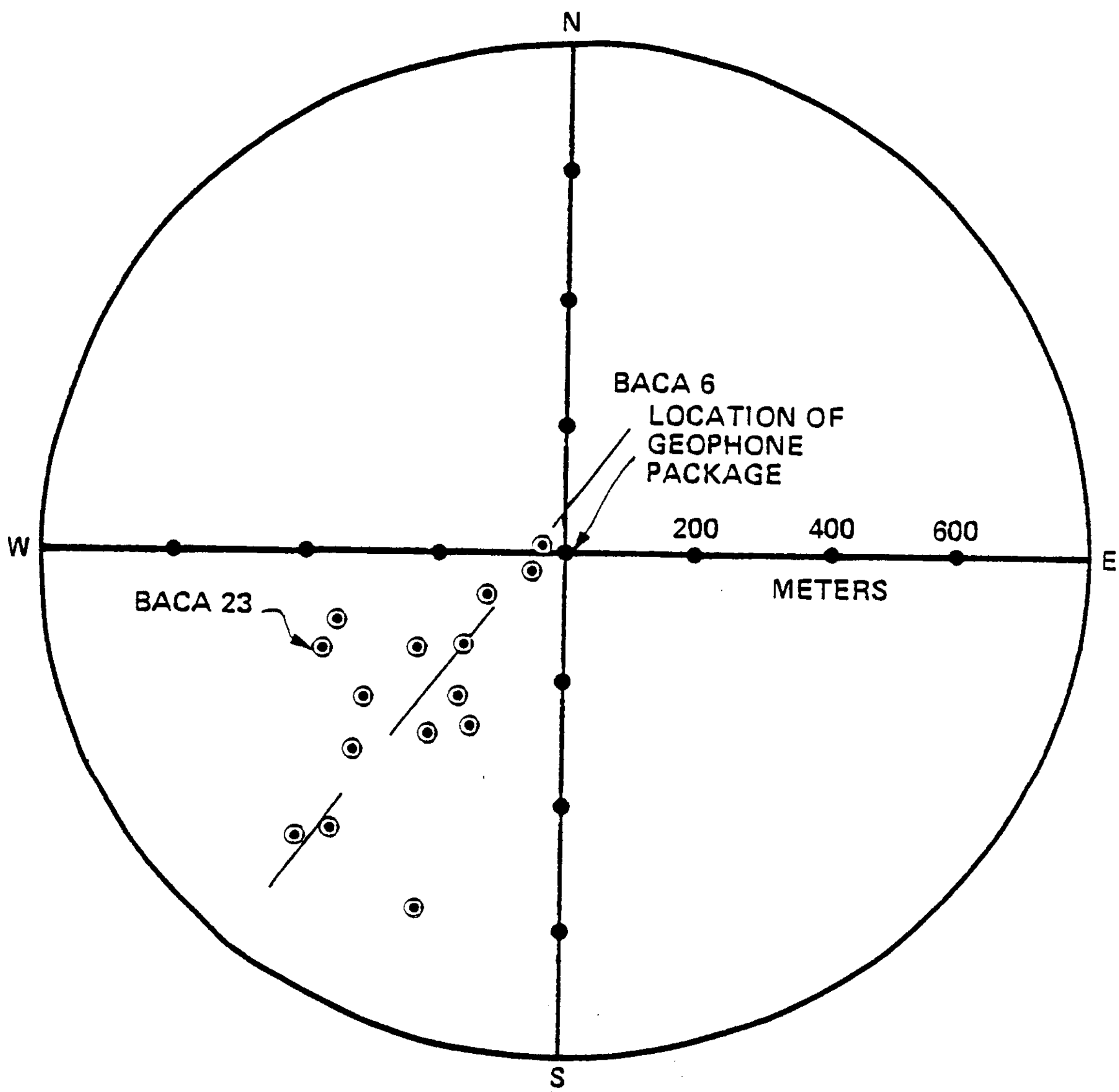
UNION BACA 23
FRACTURE STIMULATION PRESSURE/RATE HISTORY



RGL E881

FIGURE 11

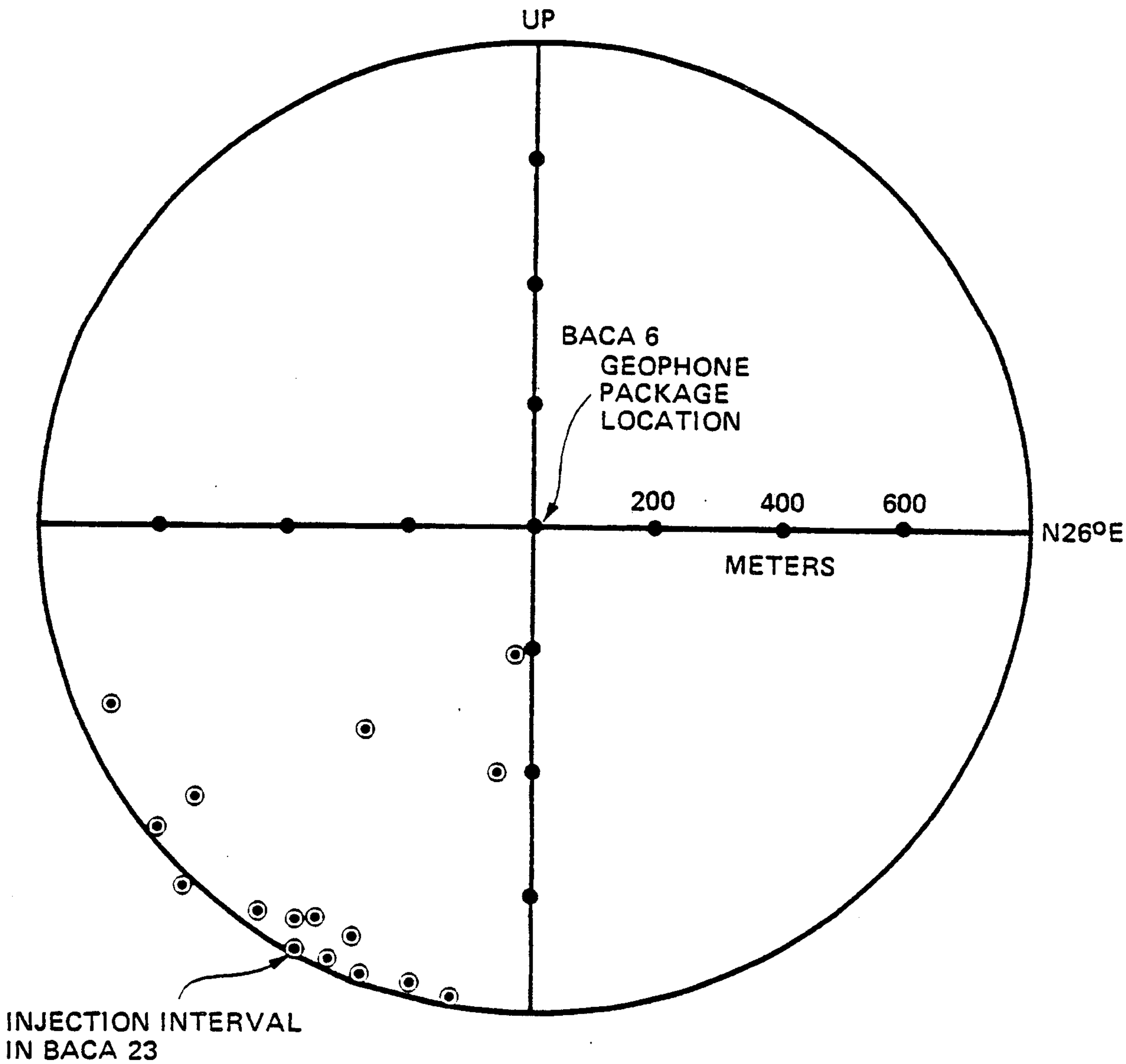
MICROSEISMIC EVENT LOCATIONS SHOWN IN PLAN VIEW
(GEOMAGNETIC ORIENTATION)



RGI E933

FIGURE 12

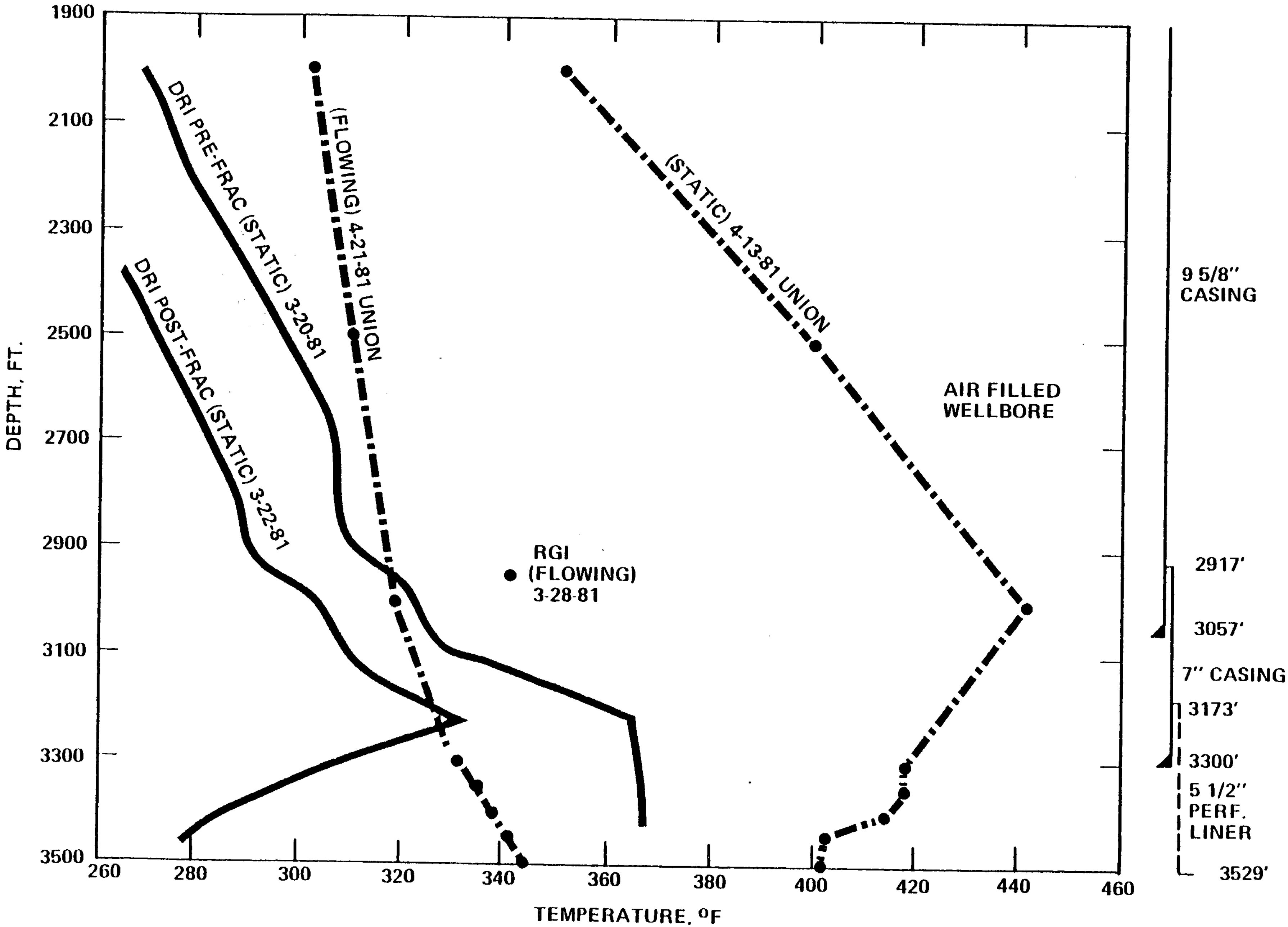
MICROSEISMIC EVENT LOCATIONS SHOWN PROJECTED TO A VERTICAL PLANE STRIKING 26°E OF N (GEOMAGNETIC ORIENTATION).



RCI E934

FIGURE 13

BACA 23 TEMPERATURE SURVEYS



RGI E882

FIGURE 14

BACA 23 PRODUCTION TEST
DST 3-26-81

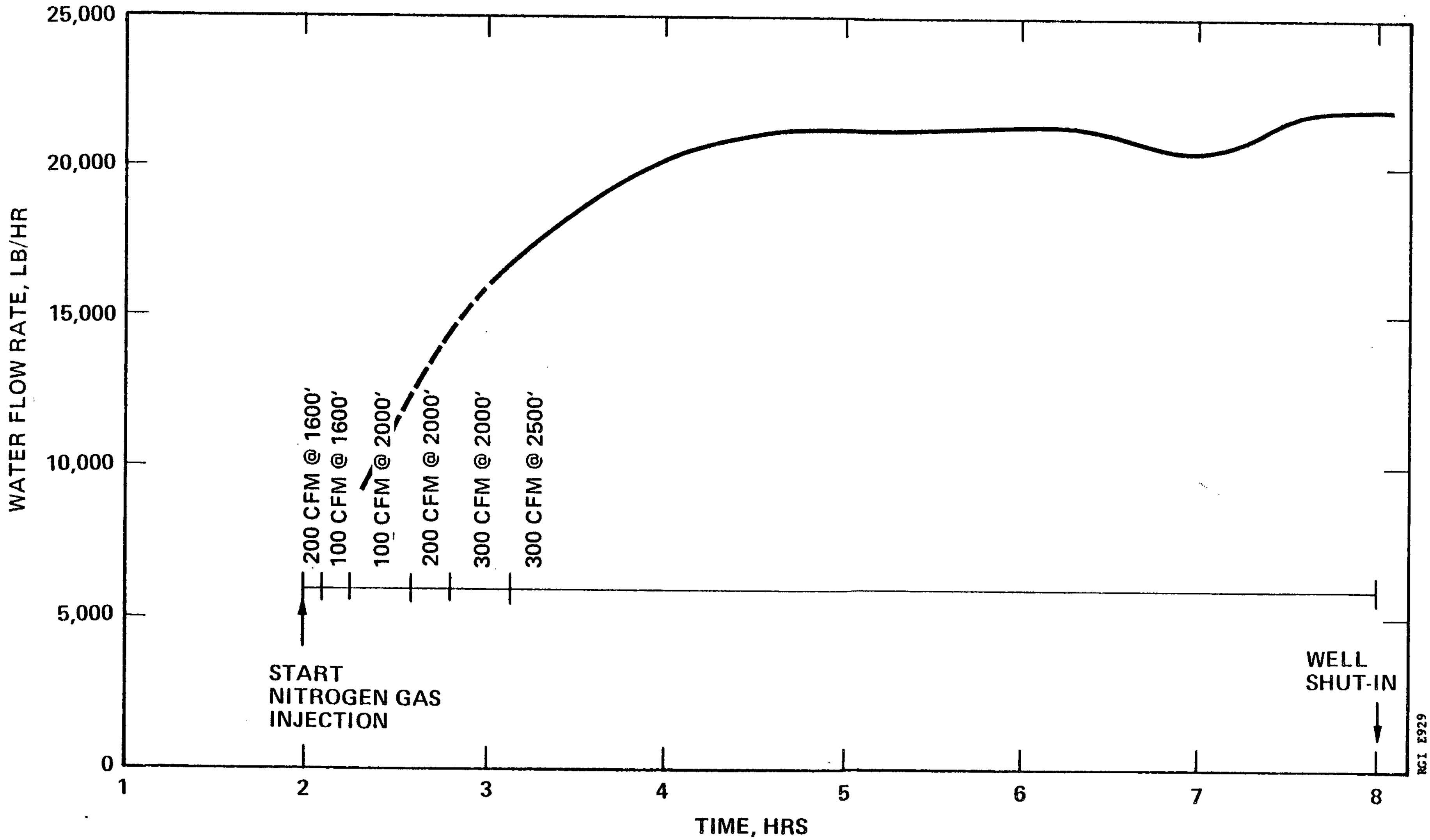


FIGURE 15

BACA 23 PRESSURE BUILDUP DATA
3-26-81

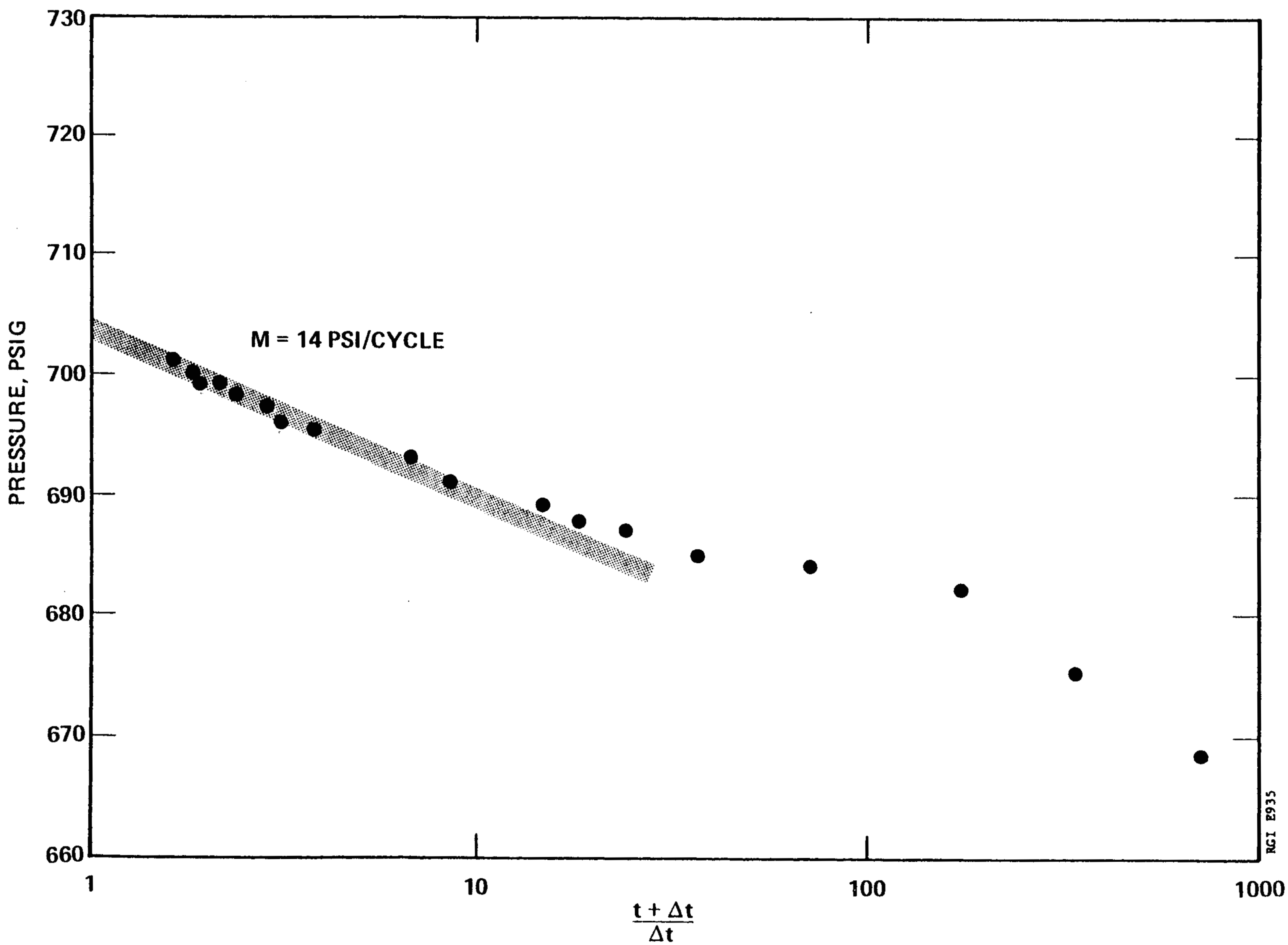
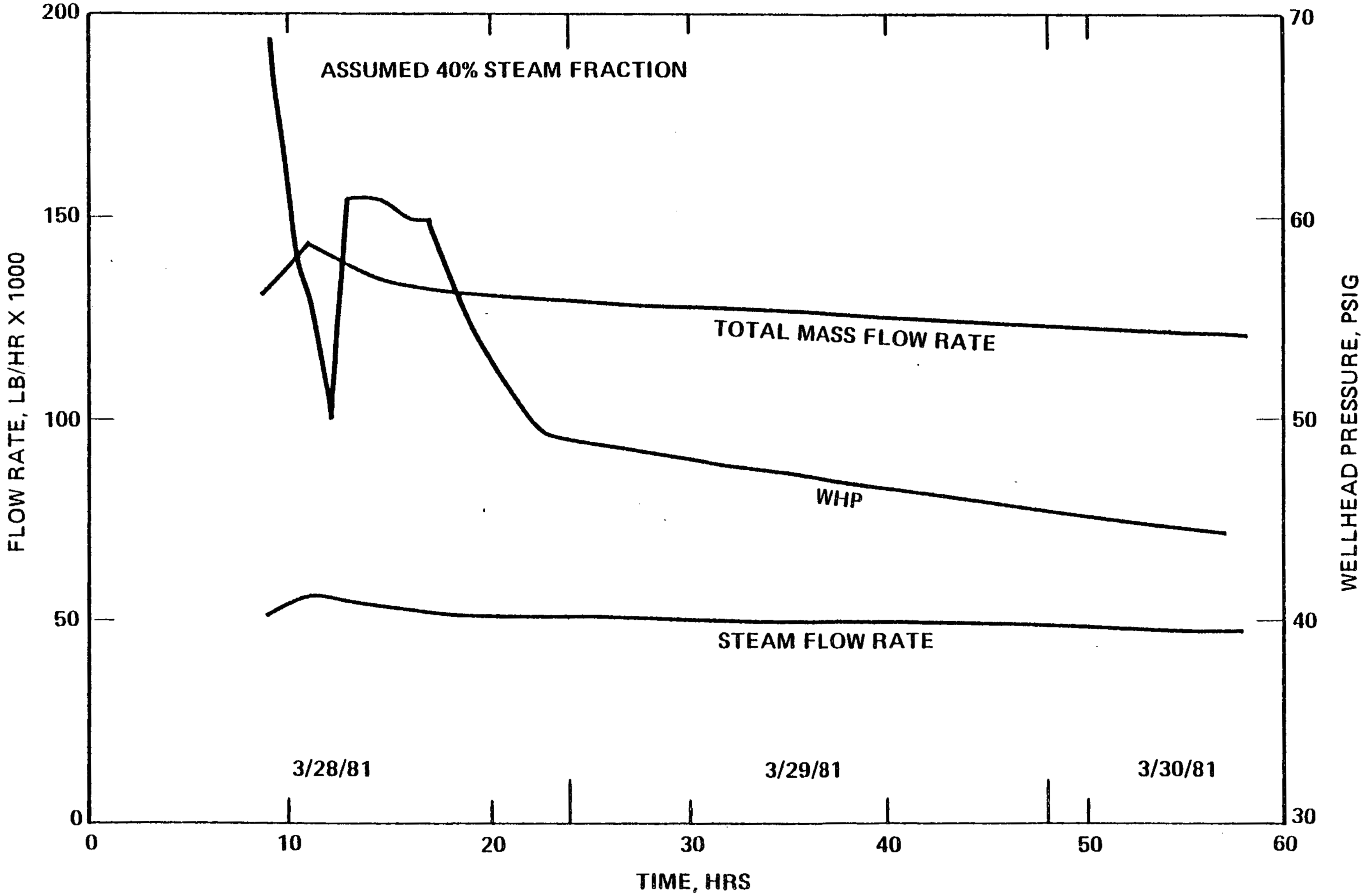


FIGURE 16

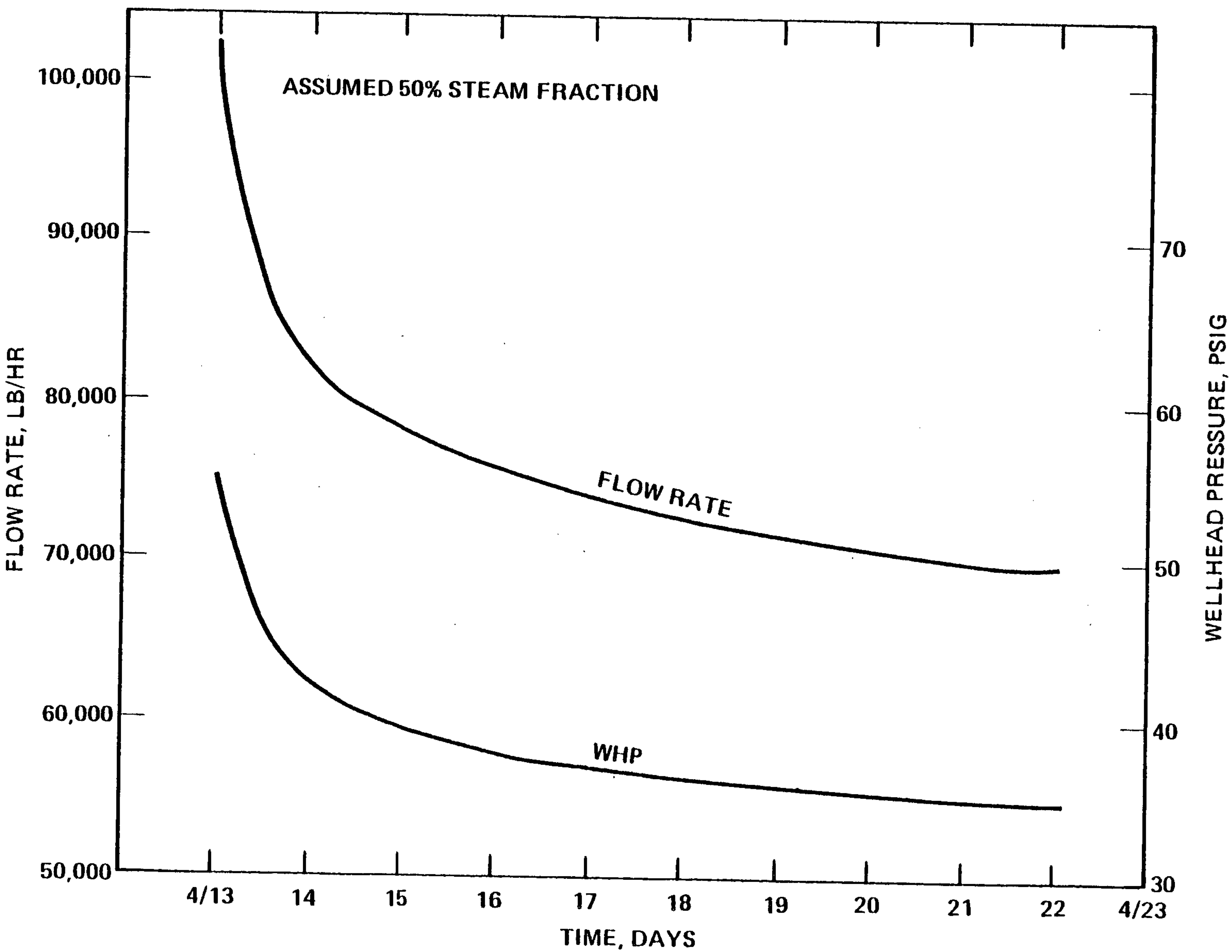
BACA 23 PRODUCTION TEST NO.2
3-28-81 TO 3-30-81



RGI E928

FIGURE 17

BACA 23 PRODUCTION TEST NO.3
4-13-81 TO 4-23-81



RGI E931

FIGURE 18

BACA 23 PRODUCTION TEST NO.4
5-1-81 TO 5-12-81

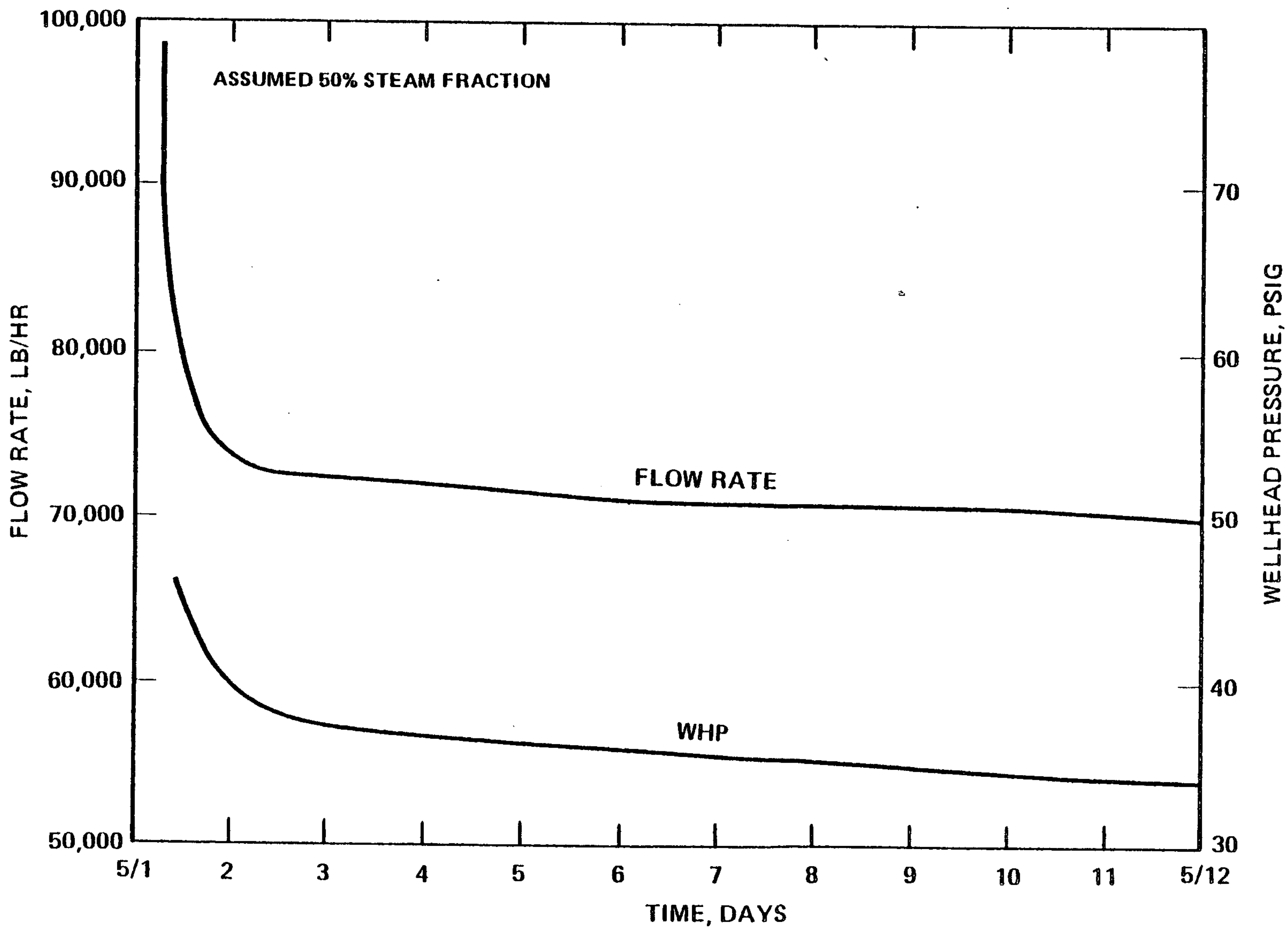


FIGURE 19

BUTYL CELLUSOLVE AND ISOBUTANOL TRACER CONCENTRATION IN BACA 23 PRODUCED FLUID

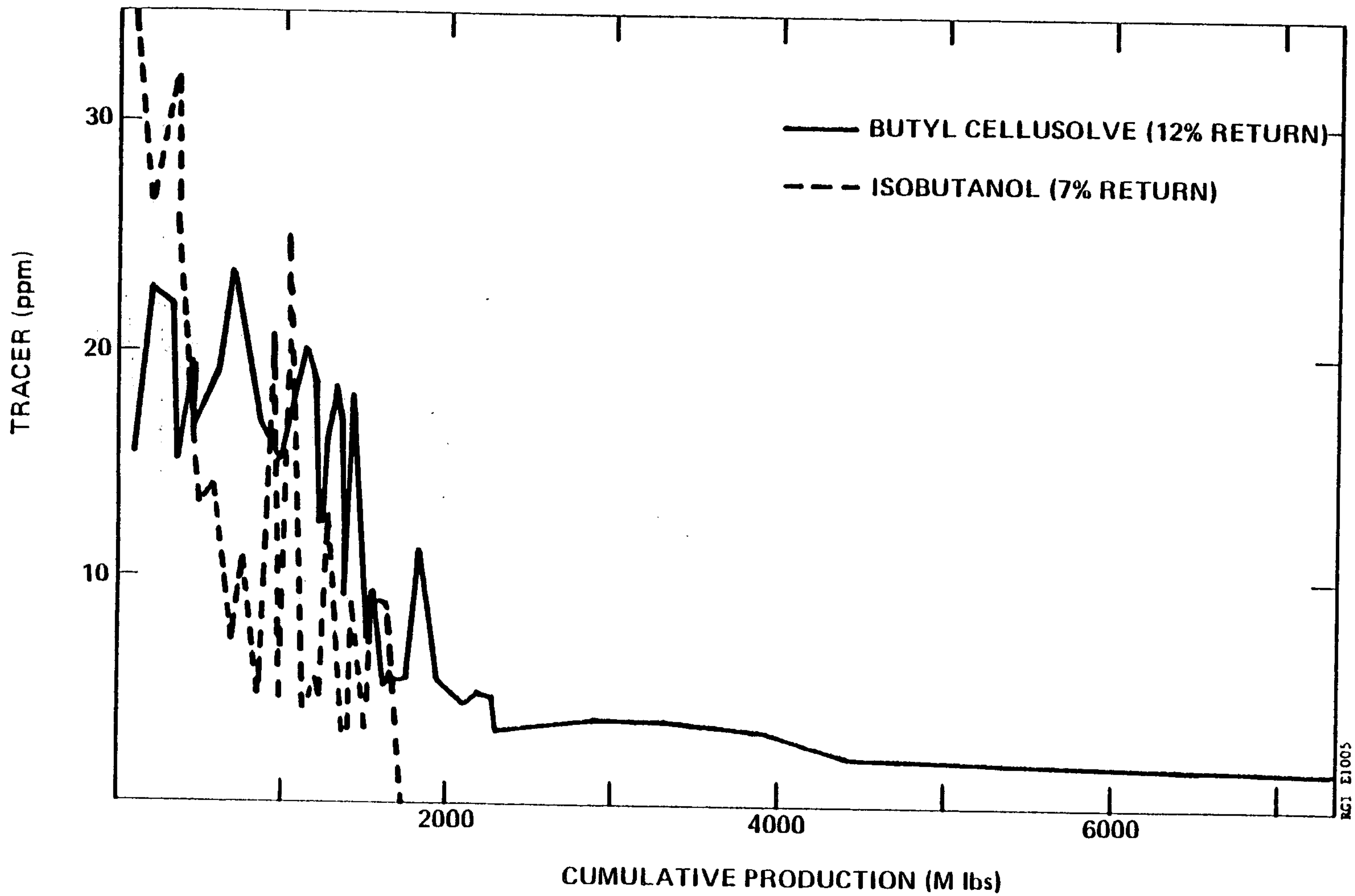


FIGURE 20

ETHANOL TRACER CONCENTRATION IN BACA 23 PRODUCED FLUID

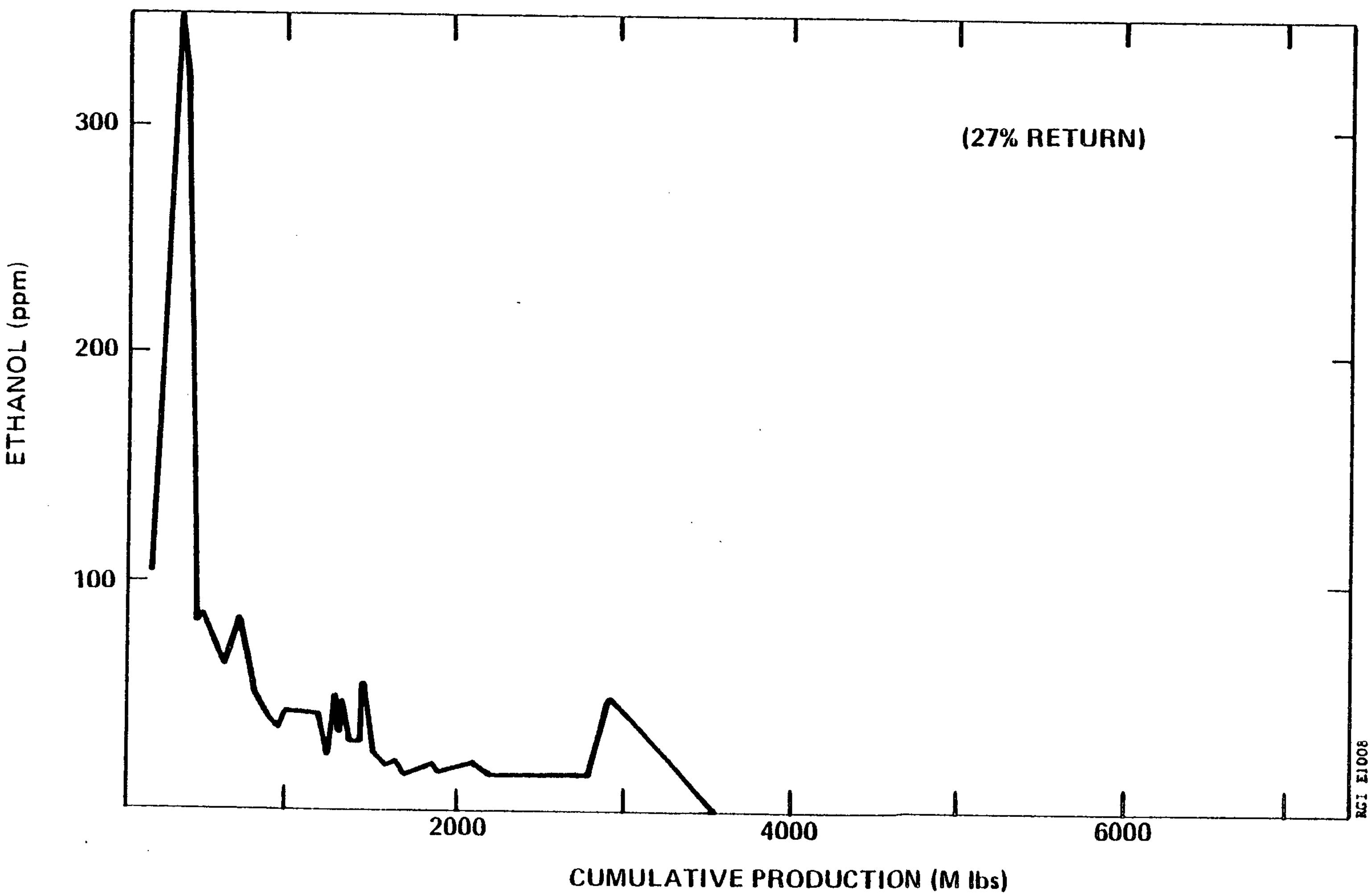


FIGURE 21

METHANOL TRACER CONCENTRATION IN BACA 23 PRODUCED FLUID

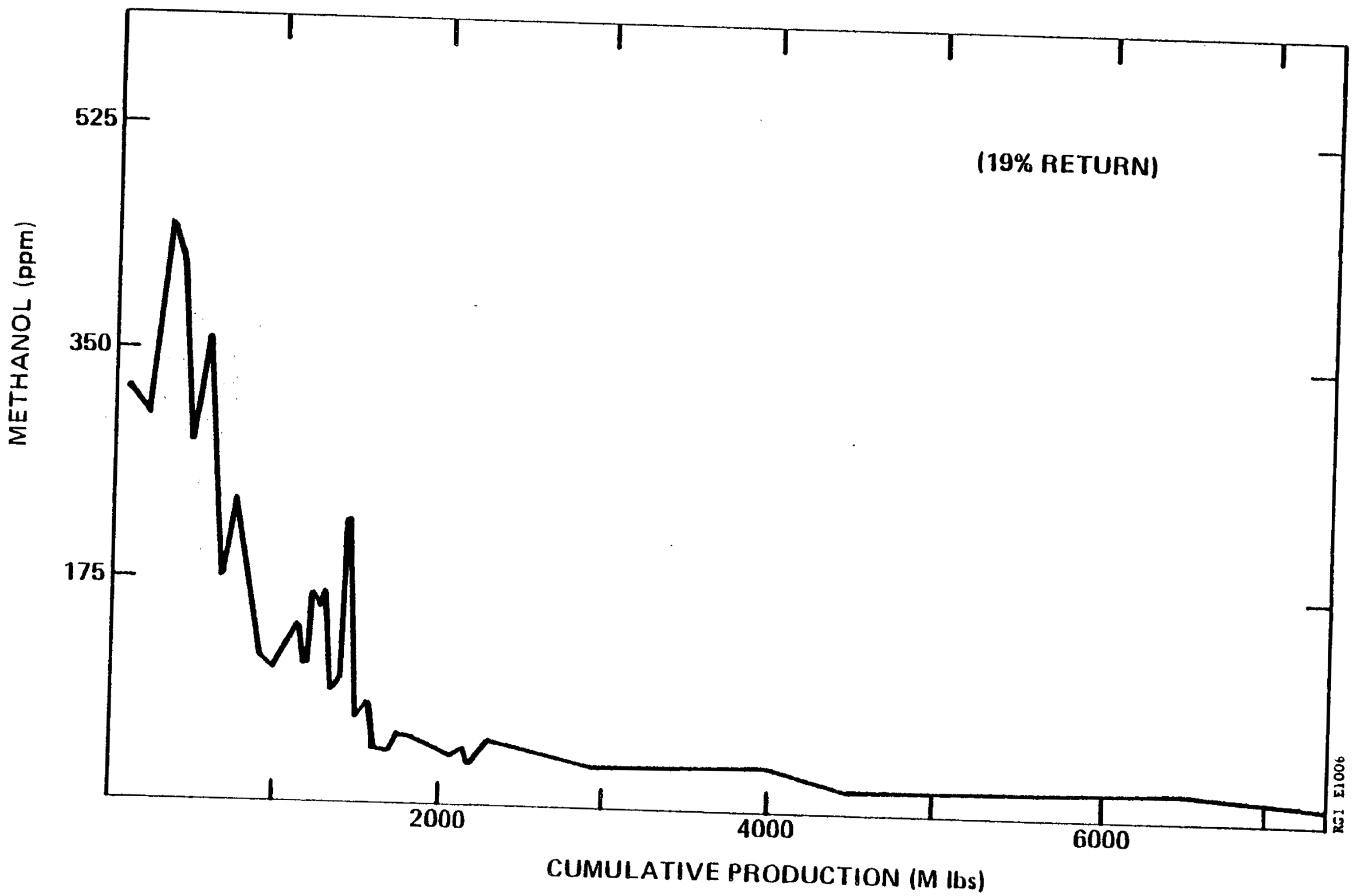
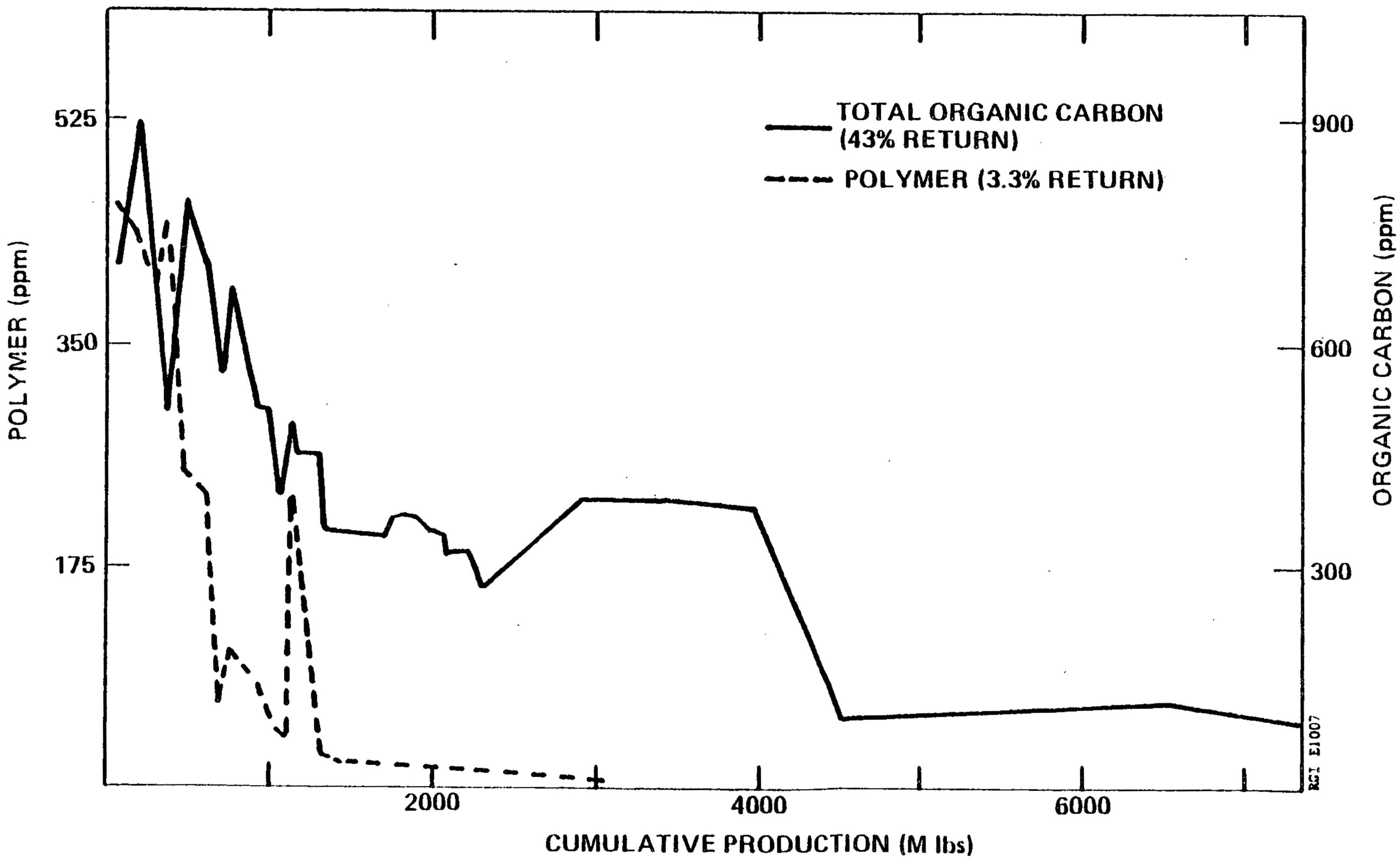


FIGURE 22

TOTAL ORGANIC AND POLYMER CONCENTRATION IN BACA 23 PRODUCED FLUID



APPENDIX A

BACA 23
HISTORY OF RIG OPERATIONS
AND STIMULATION TREATMENT

March 17-26, 1981

Tuesday
March 17, 1981

Reamed and drilled with 8-1/2" bit to 3,305 feet. POH, made up 7", 23 ppf liner and RIH. Cemented liner with top of hanger at 2,917 feet and shoe at 3,300 feet. While WOC picked up 102 joints of 4-1/2" tubing frac string, made up with hydraulic tongs and stood back in derrick in triples. ODECO truck arrived and spotted 13 frac tanks on location. Halliburton crew arrived and began rigging up manifolding for supply of pre-pad water from pit.

Wednesday
March 18, 1981

RIH with 9-5/8" RTTS packer to pressure test 7" liner lap. Pressure test OK. POH with packer, LD 34 stands of 4-1/2" drillpipe, leaving about 2,800 feet of 4-1/2" DP in derrick. Moved east set of pipe racks to edge of location. CJC began filling frac tanks with fresh water. Halliburton rigging up piping to deliver pit water for frac pre-pad.

Thursday
March 19, 1981

Picked up 6-1/8" bit and 3-1/2" DP stinger. RIH and tagged cement at 3,012 feet. Drilled cement and cleaned out sand to 3,531 feet. GRWSP began paying for rig at 1930 hours on 3/19. Moved Sandia logging trailer onto location in preparation for running pre-frac temperature log.

Friday
March 20, 1981

Killed well, made four-stand short trip and POH. Checked and replaced pipe rams in lower BOP. DRI rigged up and ran pre-frac temperature log. Logging frac interval at 1800 hours. Logging tool would not go below 3,408 feet. ODECO spotted last two frac tanks and CJC continued filling frac tanks with water. Halliburton spotted Mountain Mover and continued rigging up manifolding from pit. Sandia logging trailer was moved off location to make room for frac equipment.

Saturday
March 21, 1981

Rig ran sinker bar on wireline to 3,503 feet. No obstruction. Transports arrived with resin-coated sand and sintered bauxite proppants and Mountain Mover was loaded. Three hot oil trucks arrived to heat water in frac tanks. CJC finished hauling fresh water to frac tanks about noon. LANL began rigging up on Baca 6 with fracture mapping equipment. Halliburton W.O. blender; AOL approximately 2400 hours.

Sunday
March 22, 1981

Made up Otis packer on frac tubing and started in hole, hydrotesting tubing. First 11 joints tested OK, then Hydrotest truck broke down. R/D Hydrotest truck and continued running in hole without testing. Set packer at 2,964 feet at 1515 hours. Tested backside to 500 psi. Held OK. Halliburton gelled 11 tanks and rigged up frac units. Roads and location were muddy and a cat was required to pull Halliburton equipment up the road to the location. Began pumping frac job at 2103 hours. Shut down for 1-1/2 minutes at 2104 hours due to air in suction lines from pre-pad water tanks. Shut down at 2206 hours due to suspected leak in frac string or packer. Flow from annulus was found to be a result of the kill line from rig pump being left open by mistake - no tubing or packer leak. Restarted at 2216 hours. Completed frac job at 2348 hours.

Monday
March 23, 1981

Halliburton R/D frac lines and R/U blow-down line. Opened tubing valve at 0230 hours - no flow. Halliburton pumped residual fluid out of frac tanks to pit. Unseated packer and began POH 0300 hours. L/D packer at 0630 hours. Halliburton frac units rigged down and moved off. ODECO began moving frac tanks off location. Spotted Sandia logging trailer at 0730 hours. Ran post-frac temperature survey. Logging tool with 2 sinker bars would not go below 3,455 feet. Found fluid level with logging tool at approximately 1,250 feet. Logging tool out of hole at 1300 hours. While rigging down Halliburton, emptied Mountain Mover and found approximately 175 sacks of resin-coated sand left in Mountain Mover. Picked up 6-1/8" bit and RIH to 2,965 feet. Began circulating air and water. Continued circulation and RIH to 3,235 feet. Well flowing strongly. (Refer to Table A-1, Record of Post-Frac Flows.) Killed well and began POH at 2230 hours. Out of hole at 2400 hours.

Tuesday
March 24, 1981

Pressured up well with air to 900 psi. Cleaned out and connected flow line to pit. Preparing to flow well to pit. Opened well at 0900 hours. Blew down but would not flow. RIH with 6-1/8" bit to 3,235 feet. Circulated well with air and water; well began flowing on its own. Allowed well to flow until 1952 hours, then killed well and POH. (Refer to Record of Post-Frac Flows.) TIH with 4-1/2" DP and POH laying down.

Wednesday
March 25, 1981

TIH with 4-1/2" frac tubing and POH laying down. Changed to 3-1/2" pipe rams, made up 9 joints of 5-1/2", 17 ppf, F.J. liner, bottom 6 joints perfed with 1/2" drilled holes, top 3 joints blank. Hung with top of hanger at 3,173 feet, bottom of liner at 3,529 feet. Made up DST instrument carrier with RDC pressure and temperature instruments below Otis steam packer and RIH with 3-1/2" DP (Figure A-1). Set packer at 2,964 feet. Rigged up flow manifold and flow line on top of drillpipe. Began rigging up NOWSCO.

Thursday
March 26

Finished rigging up NOWSCO. NOWSCO RIH with coiled tubing inside drillpipe and began lifting well with nitrogen. Well flowed up drillpipe with nitrogen lift at an average rate of approximately 1,400 B/D from about 0300 hours to 0801 hours. Shut in at surface manifold for pressure buildup. (Refer to Record of Post-Frac Flows.) Picked up Kelly and pumped water down drillpipe to kill well at 1500 hours. Unset packer and POH. Beginning at 2000 hours pressured up well with air and shut in preparing for flow test. Rig was released to Union at 2400 hours on March 26, 1981, for further flow testing and evaluation by Union.

TABLE A-1
RECORD OF POST-FRAC FLOWS
BACA 23

Date	Time	Activity	Net Prod Rate[1] (B/D)	Circ. Rate[2] (B/D)	Water Inj Rate[3] (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/23	0300	Released packer after frac. Water from annulus above packer was "dumped" into wellbore.					160	
	0300-1500	POH with frac string and packer and DRI ran post-frac temperature log.						
	1500-1900	RIH with bit to 2965' and condition water in mud tanks with caustic to pH 12.			1,944		484	
	1900	Begin circulating with air and water		10,500				
	1900-1930	RIH to 3235'		10,500				
	1930-2030	Circulating air and water to bring well on	0	10,500				130
	2030-2100	Circulating and flowing	12,523[4]	10,500		261		
	2100-2130	Circulating and flowing	12,523	10,500		522		180
	2130-2205	Circulating and flowing	12,523	10,500		826		190

Date	Time	Activity	Net Prod Rate[1] (B/D)	Circ, Rate[2] (B/D)	Water Inj Rate[3] (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
	2205-2210	Well flowing on its own	12,523			869		
	2210-2220	Killed well			5,830		40	
	2220-2400	POH			1,944		175	
3/24	0000-0900	Cleared blooie line and pressured up well with air to 900 psi. Holding pressure on well.						
	0900-0945	Blew well down - no flow						
	0945-1115	Removed orifice plates from blooie line			972		236	
	1115-1315	RIH with 6-1/8" bit			1,944		398	
	1315	Began pumping air and water down drillpipe to circulate and bring well on		11,060				
	1335	Broke circulation		11,060				
	1338-1409	Circulating and flowing	0	11,060		0		
	1409-1426	Circulating and flowing	8,250[5]	10,368		97		
	1426-1439	Circulating and flowing	17,600	10,368		256		

Date	Time	Activity	Net Prod Rate[1] (B/D)	Circ Rate[2] (B/D)	Water Inj Rate[3] (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/24	1439-1505	Circulating and flowing	15,615	9,039		538		
	1505-1544	Circulating and flowing	15,189	8,640		950		
	1544-1613	Flowing	15,189			1,255		
	1613-1615	Flowing	14,763			1,276		
	1615-1620	Flowing	17,716			1,337		
	1620-1625	Flowing	14,025			1,386		
	1625-1630	Flowing	11,101			1,425		
	1630-1635	Flowing	13,287			1,471		
	1635-1640	Flowing	14,025			1,520		
	1640-1706	Flowing	13,092			1,756		
	1706-1723	Flowing	12,159			1,900		
	1723-1729	Flowing	7,996			1,933		

Date	Time	Activity	Net Prod Rate(1) (B/D)	Circ, Rate(2) (B/D)	Water Inj Rate(3) (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/24	1729-1740	Flowing	7,043			1,987		
	1740-1800	Flowing	6,090			2,071		
	1800-1815	Flowing	8,458			2,159		
	1815-1830	Flowing	10,827			2,272		
	1830-1900	Flowing	11,864			2,519		
	1900-1930	Flowing	6,152			2,647		
	1930-1935	Flowing	10,150			2,683		
	1935-1947	Flowing	14,148			2,801		
	1947-1952	Flowing	10,500			2,837		
	1952-2015	Killed well			5,831	2,837	93	
	2015-2145	POH with drillpipe			1,944		215	
	2145-2245				972		255	

Date	Time	Activity	Net Prod Rate(1) (B/D)	Circ Rate(2) (B/D)	Water Inj Rate(3) (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/24	2245-2400	T.I.H. with tubing, preparing to L.D. tubing			1,944		357	
3/25	0000-0600	Finish T.I.H. and L.D. tubing			1,944		843	
	0600-0930	Change pipe rams in BOP			972		985	
	0930-1045	Rig up to run 5-1/2" liner			972		1,036	
	1045-1615	Run and hang 5-1/2" liner POH with drillpipe			1,944		1,481	
	1615-1930	Make up DST tools, flowline, etc.			972		1,491	
	1930-2200	RIH with DST tools and set packer			1,944		1,694	
	2200-2400	Rigging up NOWSCO			0		1,694	
3/26	0000-0221	Finished rigging up NOWSCO, RIH with coiled tubing & injecting nitrogen	0					
	0221-0301	Flowing up drillpipe with nitrogen lift	400(4)			11		
	0301-0331	Flowing up drillpipe with nitrogen lift	1,123			34		

Date	Time	Activity	Net Prod Rate(1) (B/D)	Circ. Rate(2) (B/D)	Water Inj Rate(3) (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/26	0331-0351	Flowing up drillpipe with nitrogen lift	1,296			52		
	0351-0358	Flowing up drillpipe with nitrogen lift	1,368			59		
	0358-0413	Flowing up drillpipe with nitrogen lift	1,440			74		
	0413-0428	Flowing up drillpipe with nitrogen lift	1,440			89		
	0428-0443	Flowing up drillpipe with nitrogen lift	1,498			105		
	0443-0458	Flowing up drillpipe with nitrogen lift	1,440			120		
	0458-0506	Flowing up drillpipe with nitrogen lift	1,440			128		
	0506-0536	Flowing up drillpipe with nitrogen lift	1,496			159		
	0536-0551	Flowing up drillpipe with nitrogen lift	1,498			174		
	0551-0606	Flowing up drillpipe with nitrogen lift	1,382			189		
	0606-0611	Flowing up drillpipe with nitrogen lift	1,468			194		
	0611-0626	Flowing up drillpipe with nitrogen lift	1,555			210		
	0626-0641	Flowing up drillpipe with nitrogen lift	1,498			226		

Date	Time	Activity	Net Prod Rate(1) (B/D)	Circ Rate(2) (B/D)	Water Inj Rate(3) (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/26	0641-0656	Flowing up drillpipe with nitrogen lift	1,440			241		150
	0656-0711	Flowing up drillpipe with nitrogen lift	1,325			255		
	0711-0717	Flowing up drillpipe with nitrogen lift	1,412			260		
	0717-0732	Flowing up drillpipe with nitrogen lift	1,498			276		
	0732-0747	Flowing up drillpipe with nitrogen lift	1,555			292		
	0747-0757	Flowing up drillpipe with nitrogen lift	1,469			302		
	0757-0801	Flowing up drillpipe with nitrogen lift	1,469			311		
	0801-	Shut in; end drillstem test				311		
	0801-1610	Shut in for pressure buildup						
	1610-1625	Pick up kelly and pump down drillpipe for 10 min.			9,330		65	
	1625-1658	Unseat packer and prepare to POH. Water in annulus "dumped" into wellbore					225	

Date	Time	Activity	Net Prod Rate(1) (B/D)	Circ. Rate(2) (B/D)	Water Inj Rate(3) (B/D)	Cum Net Prod for Period (BBL)	Cum Injec for Period (BBL)	Flowline Temp (°F)
3/26	1658-2000	POH, lay down packer and instruments, run sinker bar to 3525' to check for fill.			972		348	
	2000-2400	Pressured up well with air and shut in, preparing for flow test						

FOOTNOTES

1. Net producing rate measured by liquid level rise in mud tanks.

2. Liquid pumping rate of rig mud pumps while circulating with air and water. Water in mud tanks was treated with caustic to pH=12 before each period of circulation. A solution made with 25 gal of Unisteam plus 25 lbs of ammonium hydroxide in 10 bbls of water was injected into the air stream at 2 gpm while circulating.

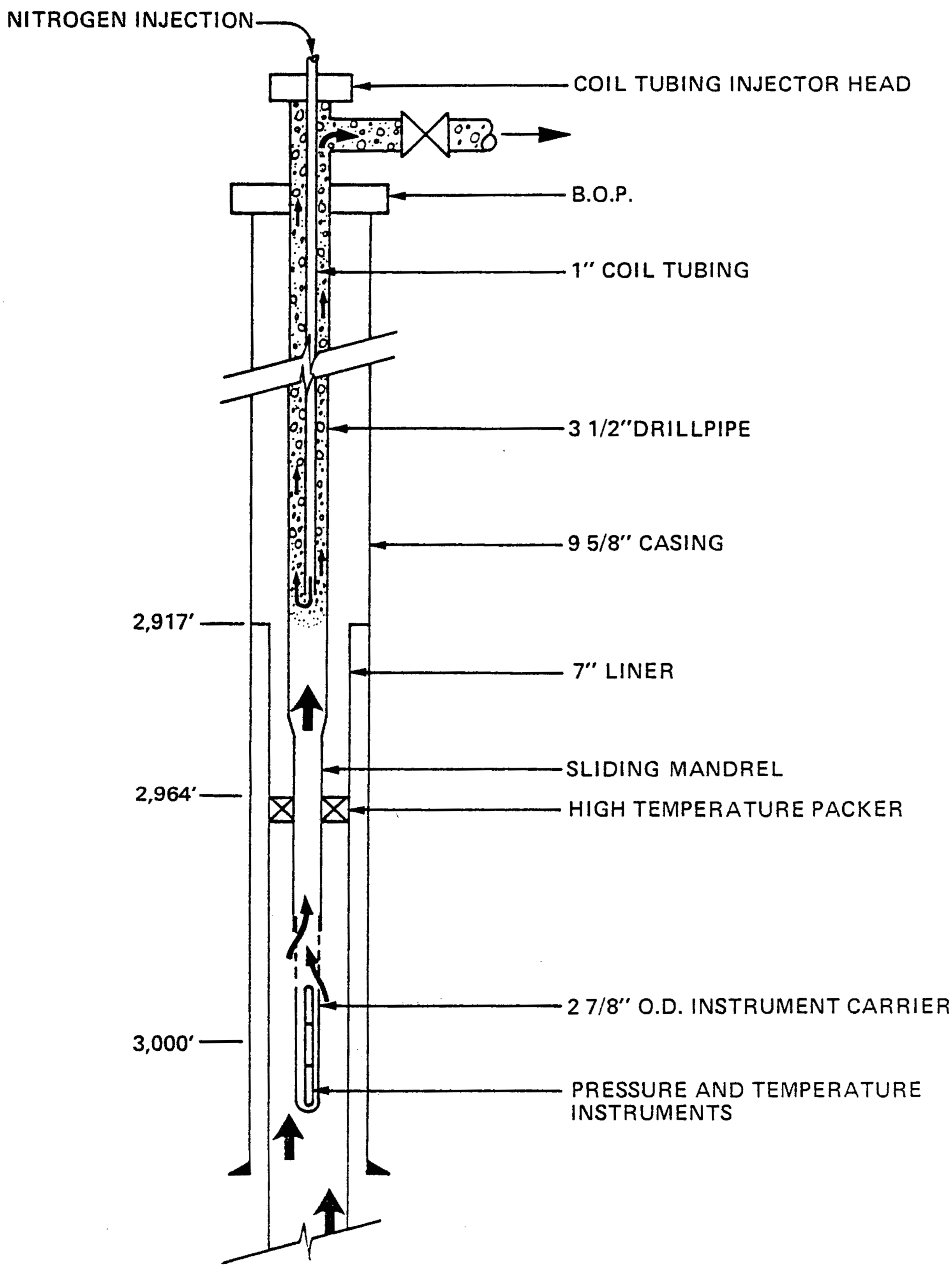
3. Water from reserve pit pumped down well to keep it dead.

4. Zero flash assumed because of low flowline temperature.

5. Rate shown for flow period on 3-24-81 is 1.5 times the liquid rate measured in the mud tanks. This allows for an estimated 15-20% flash to atmosphere and for an estimated 15-20% of the flow which was diverted directly to the reserve pit and could not be measured.

FIGURE A–1

BACA 23 DST EQUIPMENT SCHEMATIC



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Appendix B

DYNAMIC FRACTURE GEOMETRY PREDICTIONS*

Two distinct fluids were used in this stimulation treatment, i.e., the pre-pad water and the gelled fluid. Because these fluids have very different properties, two cases were run to calculate the fracture geometry. The assumptions made for these cases relate to the effect of the water pre-pad on the generation of a fracture. One case assumes the effect of the water pre-pad can be superimposed on the calculated fracture geometry by adding the appropriate length (150 feet) and volume (10 percent) to the fracture geometry created by the thick fluid (see Case 1). The second case assumes the water pre-pad generates no fracture and the gelled fluid provides essentially all the fracture length and volume (see Case 2). The two cases are as follows:

* Case 1, Stage 1 - water pre-pad cools and starts 150-ft fracture in 90 minutes. Frac growth continued with injection of Stages 2-8.

INJECTION RATE (BPM) 40

VISCOSITY (CP) .1

FRAC HEIGHT (FT) 200

ROCK MODULUS (PSI) 6000000

FLUID LOSS ADD (LB/KLBBL) 25

FLUID LOSS COEFS 0.01

WIDTH (in)	LENGTH (ft)	VOLUME (cu.ft)	EFF. (%)	TIME (min)	
0.03	55.25	54.51	2.43	10.00	
0.03	78.76	84.93	1.89	20.00	
0.03	96.61	109.62	1.63	30.00	
0.04	111.67	131.40	1.46	40.00	
0.04	124.96	151.21	1.35	50.00	Stage 1
0.04	136.97	169.60	1.26	60.00	
0.04	148.02	186.87	1.19	70.00	
0.04	158.31	203.24	1.13	80.00	
0.04	167.97	218.87	1.08	90.00	

Change effective fracture height 300 ft
effective frac rate 70 BPM
effective fluid loss coefficient 0.003
effective flid viscosity 50 cp

WIDTH (in)	LENGTH (ft)	VOLUME (cu.ft)	EFF. (%)	TIME (min)	
0.21	296	1656	38.33	100	
0.23	375	2829	32.73	110	
0.24	436	3819	29.45	120	Stage 2-8
0.25	488	4716	27.27	130	
0.26	536	5557	25.71	140	
0.27	579	6335	24.42	150	

* "Interactive Fracture Design Model," report prepared by Petroleum Training and Technical Services for DOE/DGE-sponsored Geothermal Reservoir Well Stimulation Program, May 1980.

Case 2, Stage 1 - Generates negligible fracture volume or length. Frac growth begins as Stage 2 is injected.

INJECTION RATE (BPM) 70

VISCOSITY (CP) 50

FRAC HEIGHT (FT) 300

ROCK MODULUS (PSI) 6000000

FLUID LOSS ADD (LB/KLBBL) 10

FLUID LOSS COEFS 0.003

WIDTH (in)	LENGTH (ft)	VOLUME (cu.ft)	EFF. (%)	TIME (min)	Elapsed Job Time (min)	
0.18	93.63	860.00	43.76	5.00	-	
0.21	146.62	1506.57	38.33	10.00	100	
0.22	188.75	2065.85	35.04	15.00	-	
0.23	224.96	2572.49	32.72	20.00	110	
0.24	256.78	3035.25	30.89	25.00	-	
0.24	285.97	3472.46	29.45	30.00	120	Stage 2-8
0.25	313.07	3888.57	28.27	35.00	-	
0.25	338.49	4287.14	27.27	40.00	130	
0.26	363.26	4682.85	26.48	45.00	-	
0.26	386.00	5051.96	25.71	50.00	140	
0.27	407.77	5410.68	25.03	55.00	-	
0.27	428.66	5759.31	24.42	60.00	150	