HYDRAULIC FRACTURE STIMULATION
AND ACID TREATMENT
OF WELL BACA 20

Geothermal Reservoir Well Stimulation Program

July 1983

Prepared by

Republic Geothermal, Inc.
11823 East Slauson Avenue
Santa Fe Springs, California 90670

for

U.S. Department of Energy

Under Contract No. DE-AC04-79AL10563

DISCLAIMER

TABLE OF CONTENTS

TABLE OF CONTENTS, continued

LIST OF TABLES

LIST OF FIGURES

I. SUMMARY

Well Stimulation Experiment No. 7 of the Department of Energy-sponsored Geothermal Reservoir Well Stimulation Program (GRWSP) was performed in Baca 20, located in Union's Redondo Creek Project Area in Sandoval County, New Mexico on October 5, 1981. This is believed to be the highest temperature (520°F) well in the world to be prop-fractured to date. The treatment selected was a large hydraulic fracture job designed specifically for, and utilizing frac materials specifically 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.; Terra Tek Inc.; and Vetter Research) have now completed seven 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 (500°F+), liquid-dominated resource; but a number of wells have not been of commercial capacity, primarily because of the absence of productive natural fractures at the wellbore. Baca 20 was selected for this stimulation treatment because it is located in one of the more productive areas of the field, but produced at subcommercial rates. As originally completed, this well would flow at 56,000 lb/hr with a wellhead pressure of 116 psig from a 3,300-foot openhole interval. A large hydraulic fracture treatment confined to an interval near the base of the Bandelier Tuff was selected as the best means of creating a highly conductive flow channel to connect with productive natural fractures in the reservoir. In preparation

for the treatment the well was recompleted to isolate a nonproductive 240-foot interval in the lower portion (4,850 feet to 5,120 feet) of the original 3,300-foot completion interval.

While frac fluid properties are known to degrade rapidly at high temperature, these effects were minimized by pre-cooling and by pumping at high rates (up to 84 BPM). The stimulation treatment consisted of a 3,000 bbl water pre-pad followed by 5,600 bbl of gelled water frac fluid for the pad and proppant transport. Sintered bauxite proppant was injected at increasing concentrations in the latter stages of the treatment. The 239,400 lb of proppant was split evenly between 16/20-mesh and 12/20-mesh, with the coarser material being injected last. Finely ground calcium carbonate was used as a fluid-loss additive. The hydraulic fracturing operations were completed without any significant problems or delays.

A prototype packer was utilized which was equipped with ethylene propylene diene methylene terpolymer (EPDM) elements and metal backup rings to ensure the mechanical integrity of the packer in the high temperature and pressure environment. The EPDM elements were a product of other DOE-sponsored research and development. In addition, a special instrument carrier was attached to the frac string to allow the measurement of bottomhole treating pressure data during the experiment.

The total direct field cost to the GRWSP for the fracture stimulation treatment and evaluation was $605,200. By prior agreement, Union Geothermal Co. of New Mexico, bore the cost of recompleting the well, rig mobilization, production testing, and a share of Schlumberger's logging services, all totaling an estimated $600,000.

During the fracture treatment, Los Alamos National Laboratory (LANL) performed a fracture mapping experiment using Baca 22 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 activity in a zone roughly 2,300 feet in length. Since the seismic events can occur well beyond the extent of any significantly widened fracture, the actual propped fracture is expected to be significantly shorter in length. Calculations of the dynamic fracture dimensions suggest fracture wings of approximately 340 feet in length and 600 feet in height may have been created.

Republic Geothermal, Inc. and Union Geothermal Co. of New Mexico performed two separate tests on Baca 20 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 1,000 md-ft. In a 14-day production test the well produced at an initial rate of 110,000 lb/hr, but declined to a stabilized rate of 50,000 lb/hr under two-phase flow conditions in the reservoir. The probable cause of the decline in flow rate is the reduction in relative permeability due to two-phase flow in the formation. Productivity was established in a previously non-productive interval, but the flow rate obtained is noncommercial.

Although the post-stimulation data did not show it, one possible explanation for the low productivity of the well was that the fluid-loss additive (calcium carbonate material) may have remained in the formation or in the newly created fracture and caused a substantial restriction to flow. To investigate this possibility, an HCl acid treatment was performed on the Baca 20 well in August 1982 to remove any calcium carbonate material in the fracture. Post-acid treatment production data, however, indicated no change in the productivity of Baca 20.

Thus, the analyses indicate that a highly conductive fracture was successfully created by the hydraulic fracture treatment, but it probably failed to intersect sufficiently productive natural fractures in the reservoir. Although the stimulation treatment did not result in a commercial well, the hydraulic fracturing technique shows promise for future stimulation operations (such as multiple zone treatments) and for being a valid alternative to redrilling.

II. INTRODUCTION

The U.S. Department of Energy-sponsored Geothermal Reservoir Well Stimulation Program 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.; Terra Tek, Inc.; and Vetter Research) have completed seven 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; one experiment in the high-temperature, vapor-dominated reservoir at The Geysers, California; and two experiments (the second of which is 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). In addition, the Valles Caldera area has been the subject of several detailed studies by the U.S. Geologic Survey (USGS) and other organizations. The high reservoir temperature and relatively shallow depth (3,000 feet to the top of the geothermal reservoir) made it a good, but challenging, candidate for field experiments in the evaluation of geothermal stimulation techniques, fracture fluids, proppants, and mechanical equipment. A number of 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 fractures required to make these wells commercial and that such stimulation may be an attractive alternative to redrilling.

The natural fracture system in the Redondo Creek area 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 orthogonal 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. The reservoir fluid total dissolved solids content of 6,000 ppm was not expected to chemically interfere with the stimulation fluids or tracers.

Of the wells drilled in the Redondo Creek area by Union, 10 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 two candidate wells (Baca 19 and 20) to the GRWSP group. Baca 20 was the better candidate based on both reservoir and logistical considerations.

The discussion which follows provides an overview of the Baca resource 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

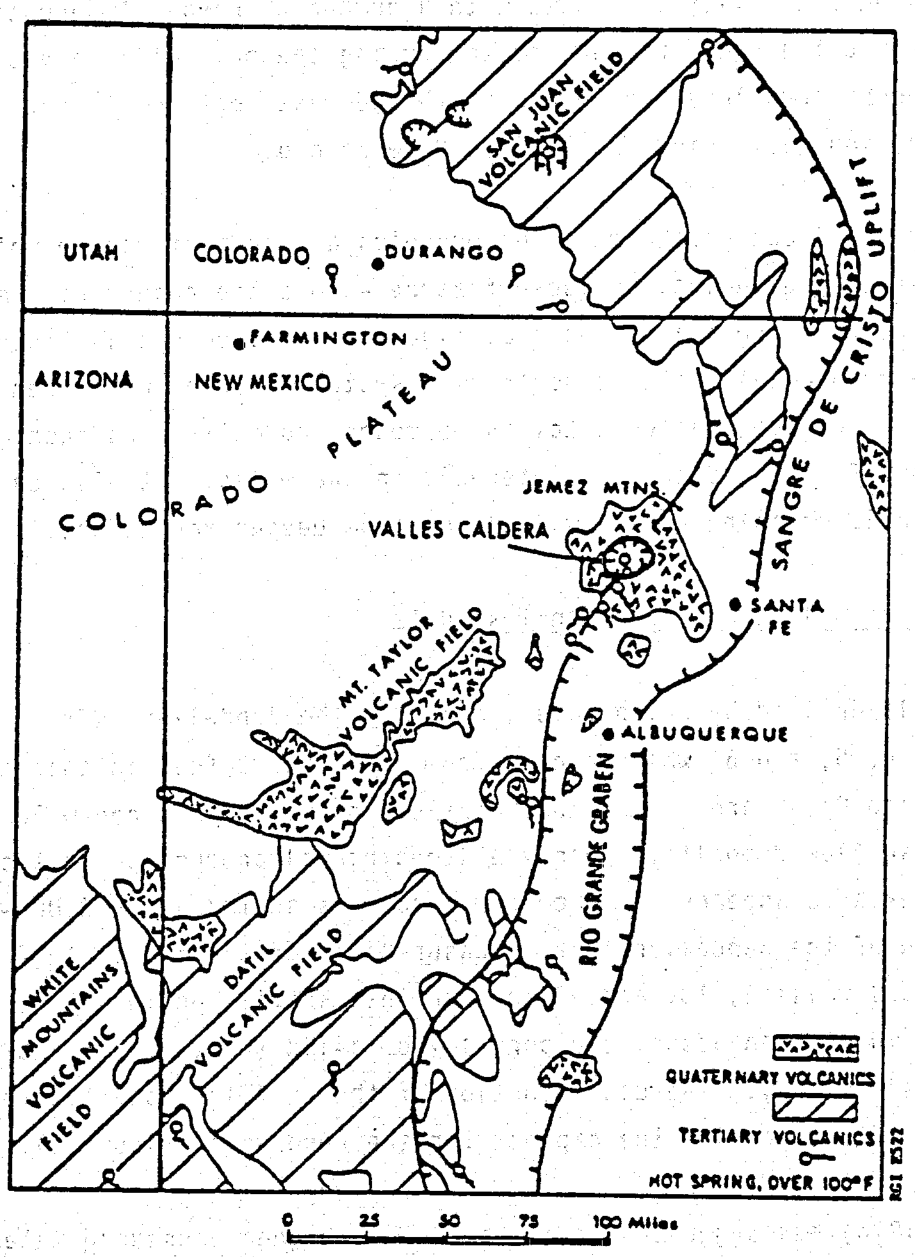
The Valles Caldera is a prominent geological structure located in north-central New Mexico in the Jemez Mountains about 55 miles north of Albuquerque and 40 miles northwest of Santa Fe (Figure 1). Dondanville (1978) describes the caldera as a complex volcanic highland of Pliocene and Pleistocene age. These highlands are composed of basalt, andesite and dacite, with more recent rhyolitic ash flows covering portions of older lava flows.

Dondanville (1978) described the Valles Caldera as a subcircular depression, 12 to 15 miles in diameter, with the caldera rim 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 rhyolitic domes.

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.

FIGURE 1

REGIONAL GEOLOGIC SETTING OF VALLES CALDERA



(After Dondanville, 1978, p. 157)

Following the collapse a resurgent central dome rose within the caldera, this dome is now known as Redondo Peak. This uplift 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 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 act as permeable conduits. As such, they not only form the producing intervals in the wells, but also can act as channels draining geothermal fluids from deeper formations.

B. Summary of Well and Production Test Data

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 non-welded rhyolitic ash flow deposits. Nearly all geothermal production in the Redondo Creek area appears to come from fractures in the lower 3,000-foot section 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

FIGURE 2
GEOTHERMAL FEATURES OF THE JEMEZ MOUNTAINS, NEW MEXICO

(After Hartz, 1976)

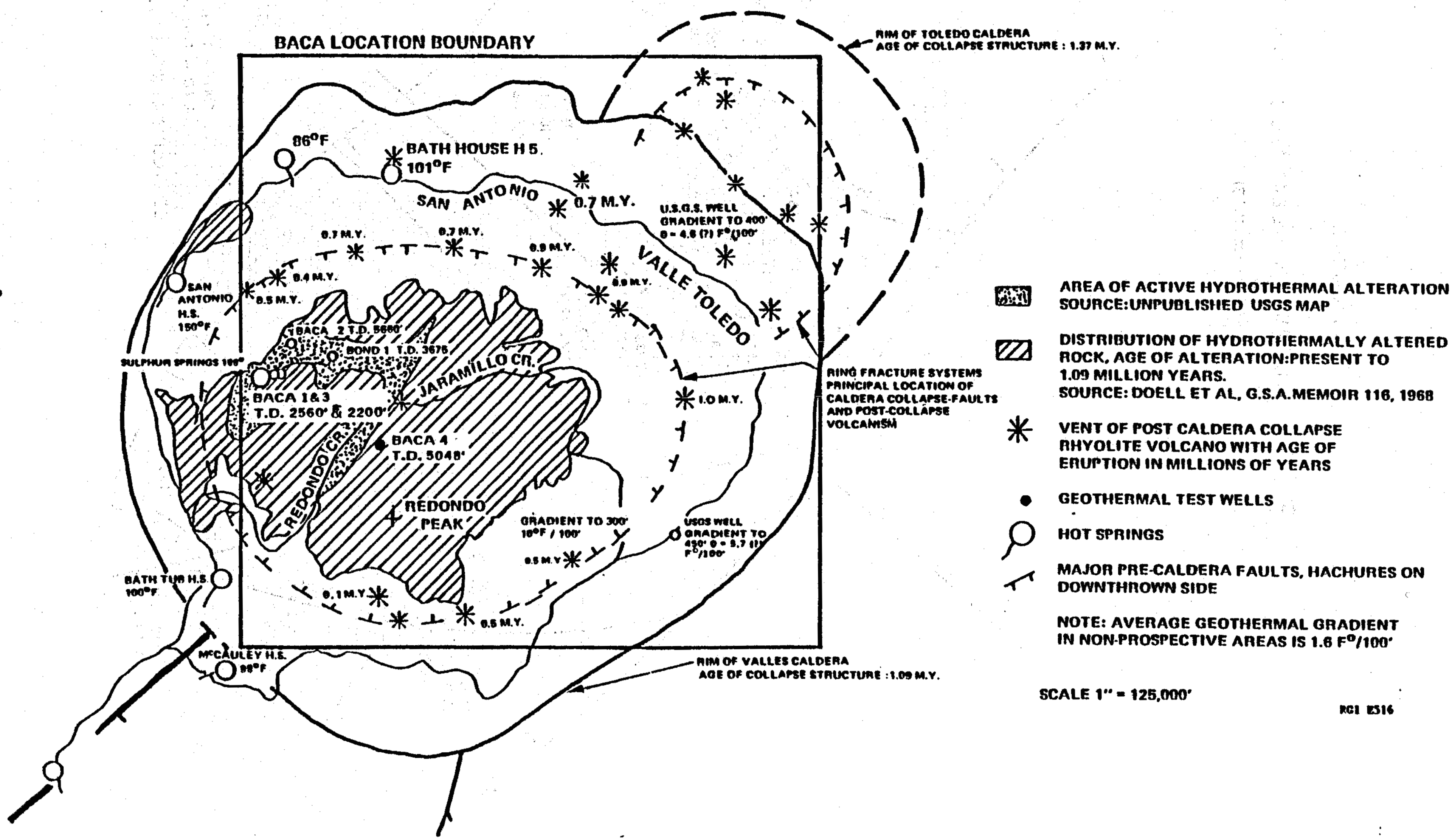


FIGURE 3

CONTOURS ON BASE OF THE BANDELIER TUFF

(After Hartz, 1976)

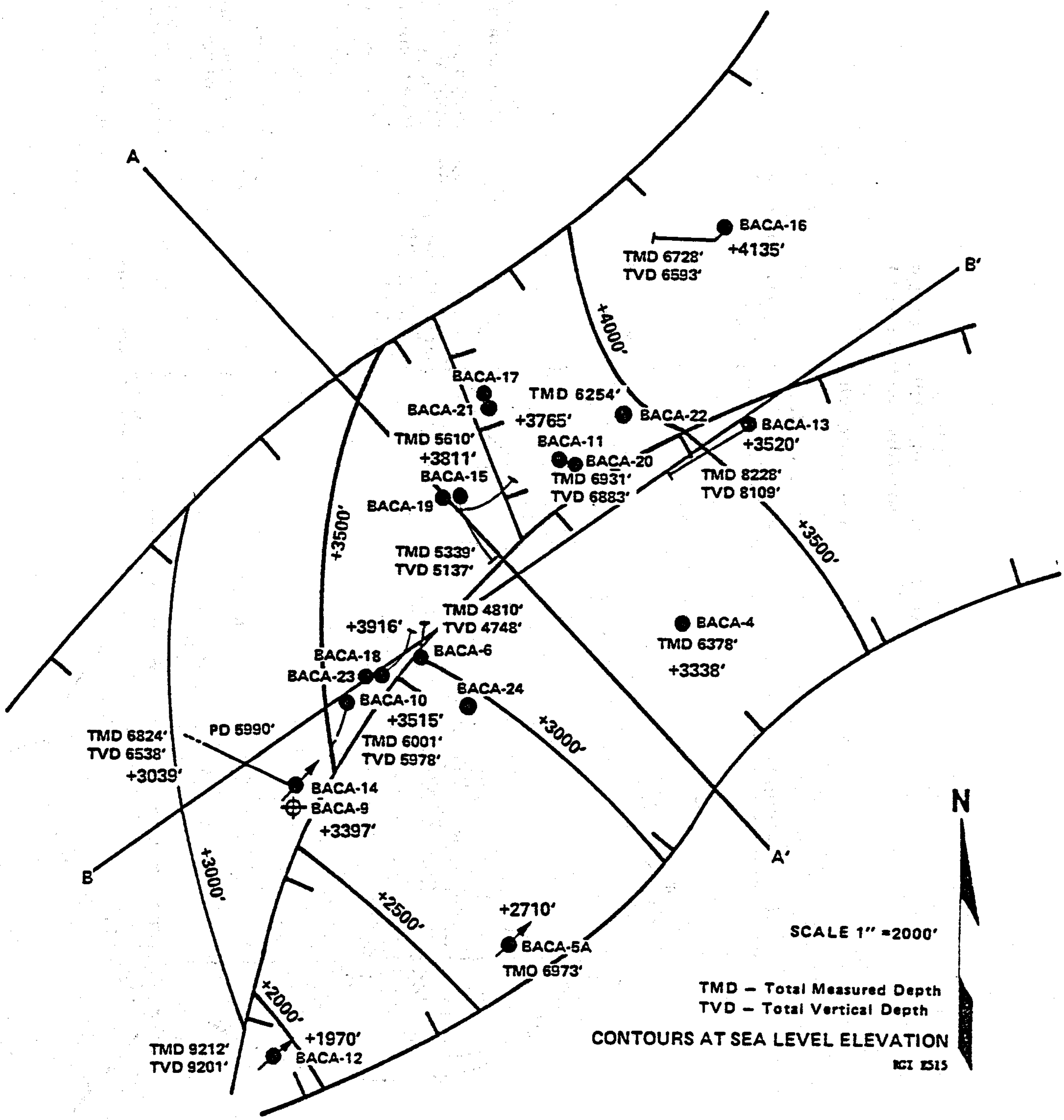


FIGURE 4

NW—SE CROSS SECTION THROUGH THE REDONDO CREEK AREA

(After Hartz, 1976)

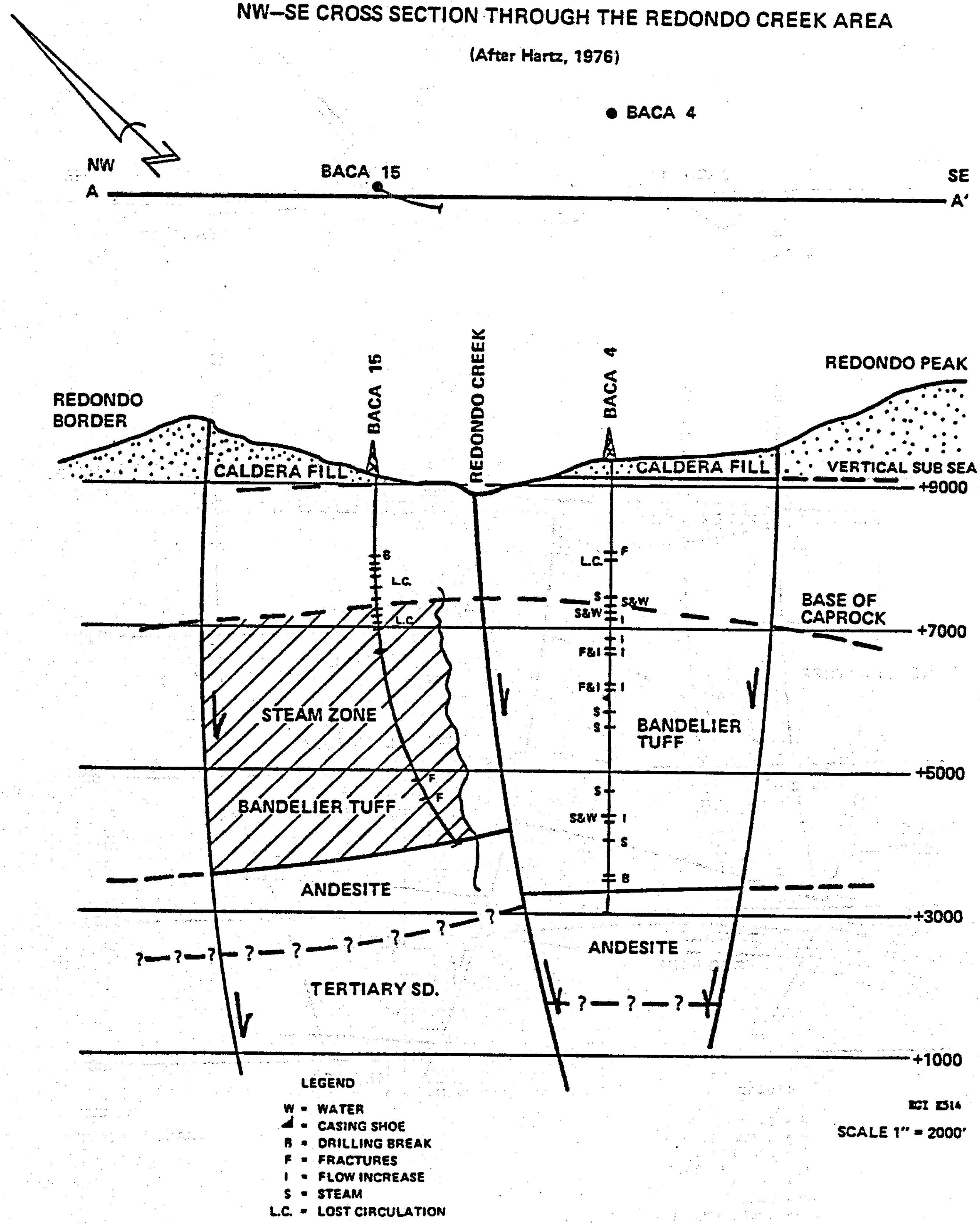


FIGURE 5

SW–NE CROSS SECTION THROUGH THE REDONDO CREEK AREA

(After Hartz, 1976)

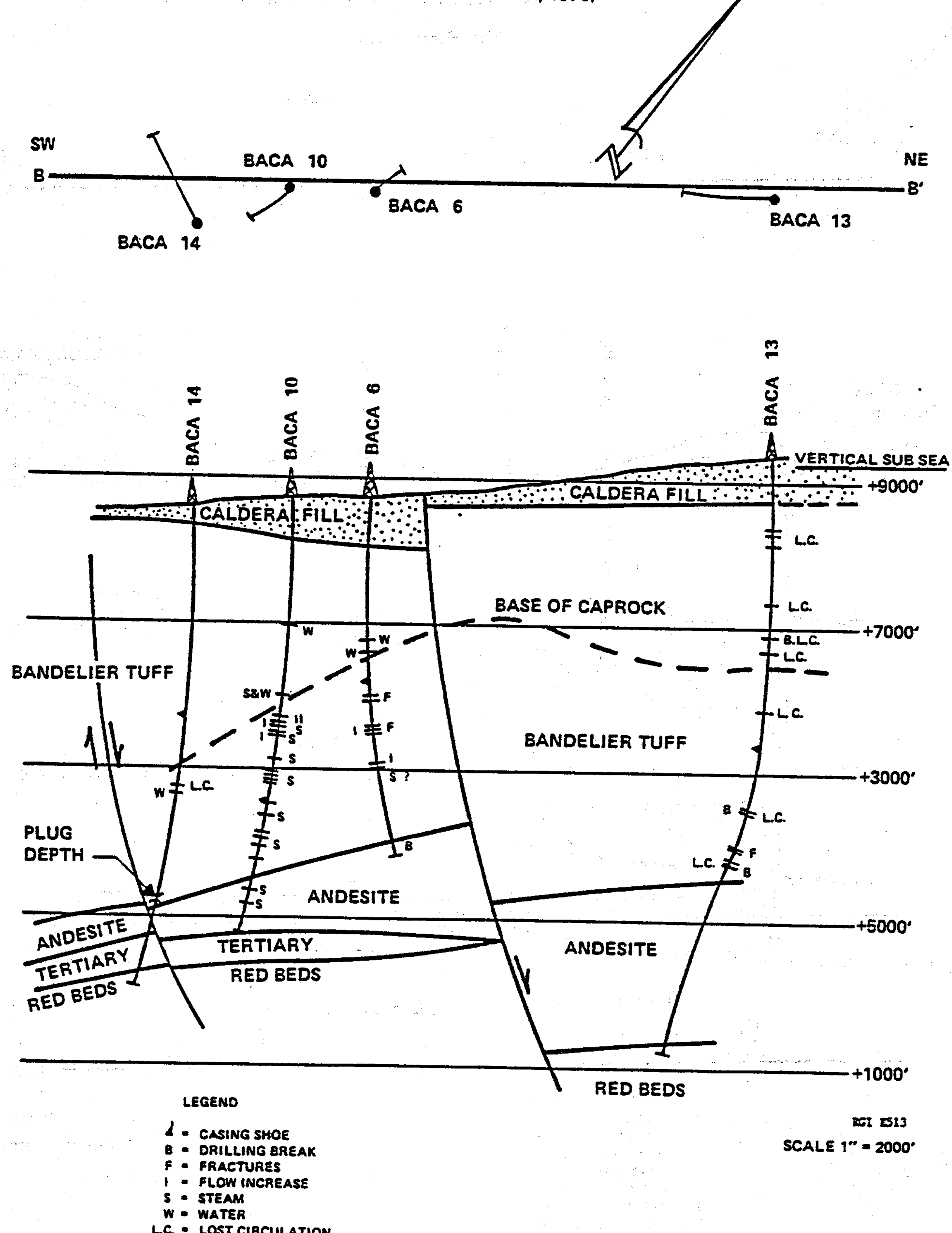
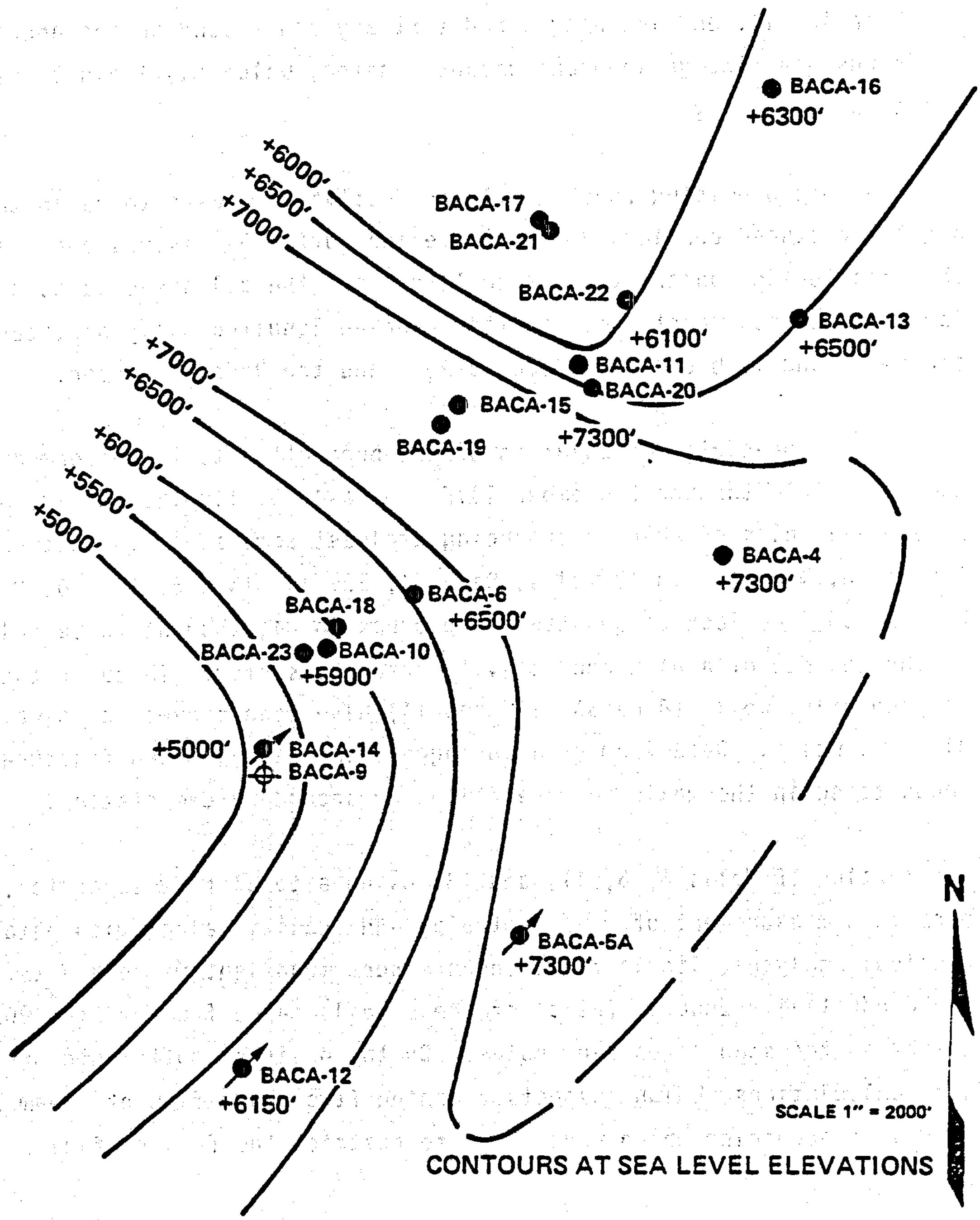


FIGURE 6

CONTOUR MAP ON THE BASE OF THE CAPROCK

(After Hartz , 1976)



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 percent, but very low permeabilities of 0.1 to 1.5 md (Hartz, 1976).

Baca 10, 11, and 16 encountered tertiary sands beneath the andesite. The sands are fine grained and unconsolidated, which may inhibit sustained productivity.

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.

Table 1 presents a tabulation of the production tests performed in the Baca field through September 1975. Baca 4, 6, 11, 13, 15, 19, and 20 are all wells capable of producing at least some steam and hot water (Atkinson, 1980a). In 10 wells, Baca 5A, 12, 14, 16, 18, 19, 20, 21, 22, and 23, the lack of substantial 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 of Wells 4, 6, 11, and 13, using a total flow separator, 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 (two-phase flow of steam and water) is occurring which would tend to restrict the flow of fluids

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 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)

Baca Well Pit Test Summary

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW LB/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR BASED ON ENTHALPY °F	
B-11-2*	1/11-25/74	311	121	105	49.6	205,000	746.6	676	@ 310 hrs range
							744-806	674-696	
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	638	@ 546 hrs range
							668-734	634-669	
B-11-5	6/26-9/25/74	2182	138	126.5	35.6	267,100	633.1	611	@ 745 hrs
			127	114	32.9	252,000	604	591	@ 1440 hrs
			129	124	26.9	164,300	526-671	532-635	@ 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	541	@ 1100 hrs range
							522-561	533-559	
B-13-3	5/14-6/6/75	471	110	92.5	31.6	257,200	581	575	@ 471 hrs range
							549-588	550-580	
B-13-4	6/13-20/75	163	110	87	27.0	273,200	537	540	@ 115 hrs range
							536-539	539-542	
	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)

Baca Well Pit Test Summary

WELL	DATE	FLOW TIME HRS	WELLHEAD PRESSURE PSIG	SEPARATOR PRESSURE PSIG	STEAM FRACTION	TOTAL MASS FLOW LB/HR	TOTAL FLUID ENTHALPY BTU/LB	RESERVOIR 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.

through the fracture system toward the wellbore, thus reducing the well productivity values measured in long-term flow tests (Hartz, 1976). 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, 19, and 23 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 isopermeability-thickness map which suggests a correlation of the fracture system 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 a positive skin factor suggests:

1. Formation damage which could be caused by scale build-up 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, and/or

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

TABLE 2

TRANSMISSIVITY VALUES FROM PRODUCTIVITY AND PRESSURE BUILDUP DATA

(After Hartz, 1976)

Well	Test Number	PI lbs/hr/psi	PI Transmissivity $\frac{kh}{\mu}$ $\frac{md\text{-}ft}{cp}$	Pressure Buildup Transmissivity $\frac{kh}{\mu}$ $\frac{md\text{-}ft}{cp}$
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

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 (2332 Avg.)	+ 4.3	2288	8100
Baca 15	1 (Two-phase Test)	7/14/75	8630*	- 2.9	911	5500
Baca 19	1	11/15/79	2510	+10.0	--	--
Baca 23	1 (DST)	3/26/81	2500	-4.0	700	2987
Baca 23	4	5/1/81	4340	--	--	3300
Baca 23	Injection Test 1 Buildup	5/28/81	3110	--	--	3400
Baca 23	Injection Test 1 Falloff	5/28/81	4270	0.012	--	3400

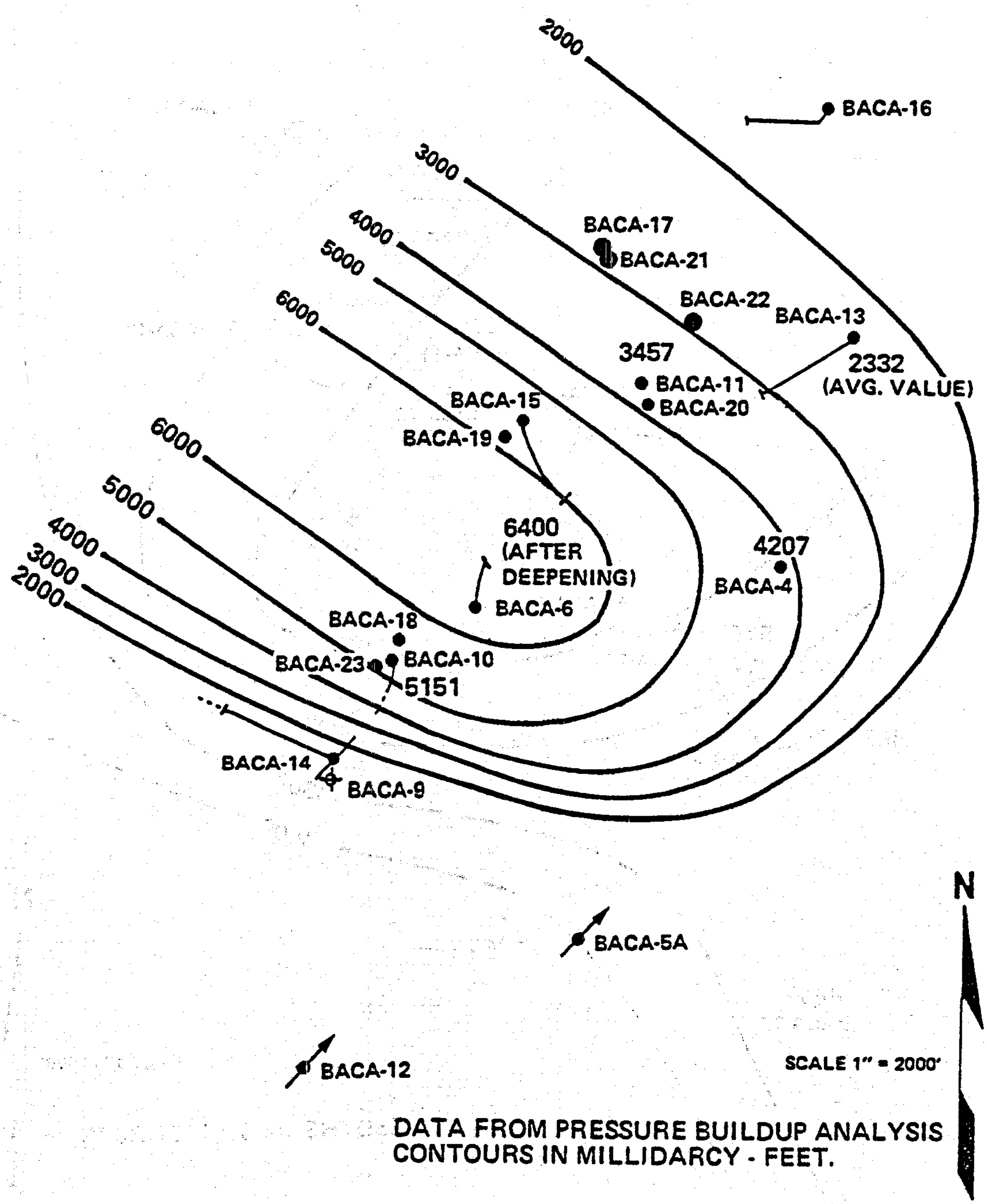
Average of all tests (except Baca 15, 19 and 23) — 4310 md-ft (using average for B-13 and value from B-6 test 6)

* Assumes drainage area contains steam only.

FIGURE 7

ISOPERMEABILITY—THICKNESS MAP, BACA, NEW MEXICO

(After Hartz, 1976)



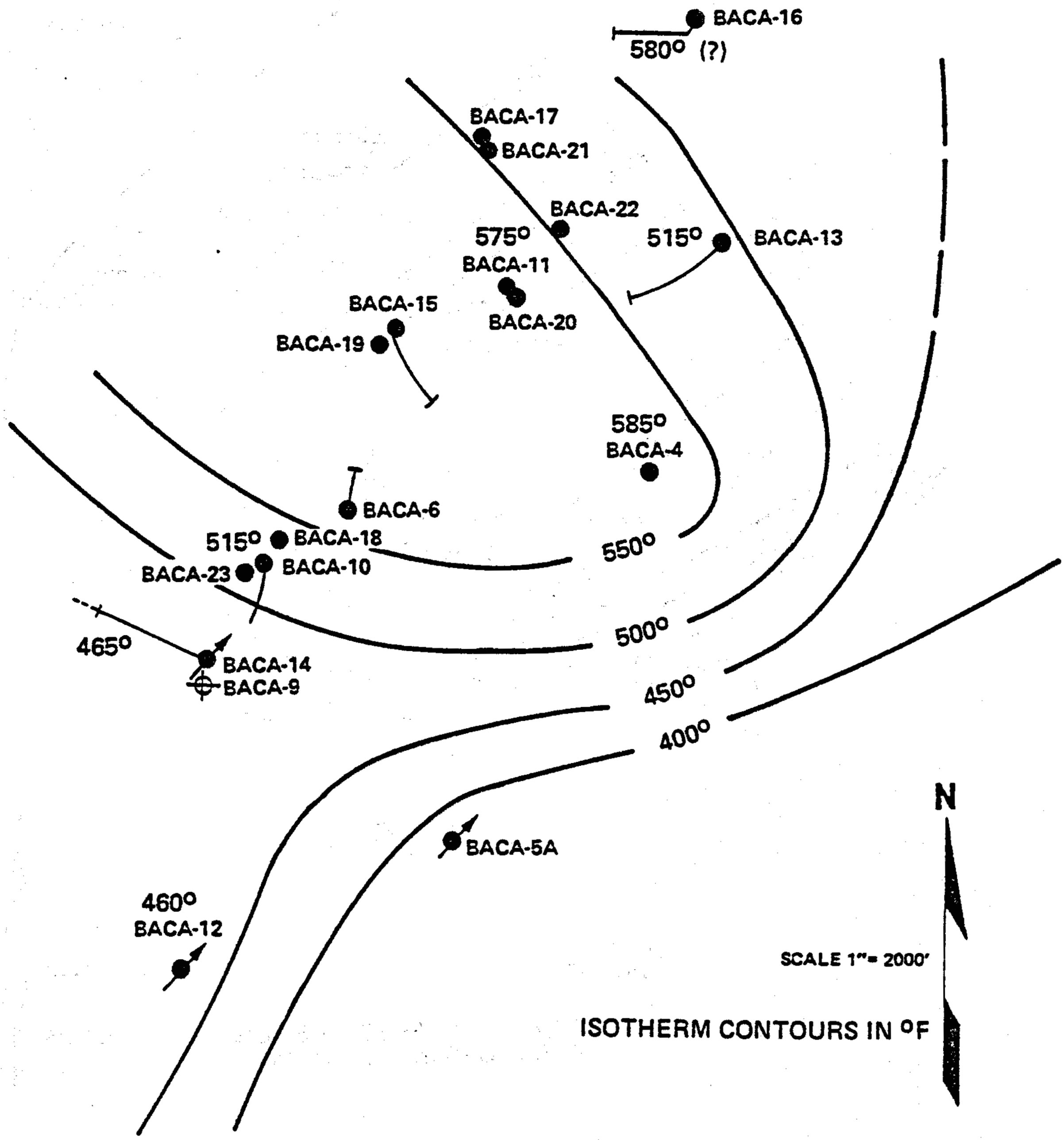
DATA FROM PRESSURE BUILDUP ANALYSIS
CONTOURS IN MILLIDARCY - FEET.

RGI E512

FIGURE 8

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

(After Hartz, 1976)



RGI E517

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. Total production from all wells during the test was 2.24×10^9 lb (total mass), and about 1.21×10^9 lb were reinjected into the reservoir.

During the six-month test, a noticeable decline was recorded for all three producers. 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 measurable 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 fluid volume or total mass in the reservoir is at least 4.6×10^{12} lb.

2. The reservoir has an average permeability-thickness (kh) of 6,000 md-ft and a porosity-thickness (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 (1978) 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 4 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.

TABLE 4

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) NONCONDENSABLE	H_2S CONCENTRATION (ppm) TOTAL STEAM	AVERAGE FLASH %	AVERAGE 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.

The fluids possessed about three percent (by weight) noncondensable gases. Approximately 99 percent of this gas is carbon dioxide (CO_2) with small amounts of hydrogen sulfide, nitrogen, hydrogen, ethane, and methane. These gases present corrosive problems and their evolution contributes to scaling.

IV. STIMULATION EXPERIMENT

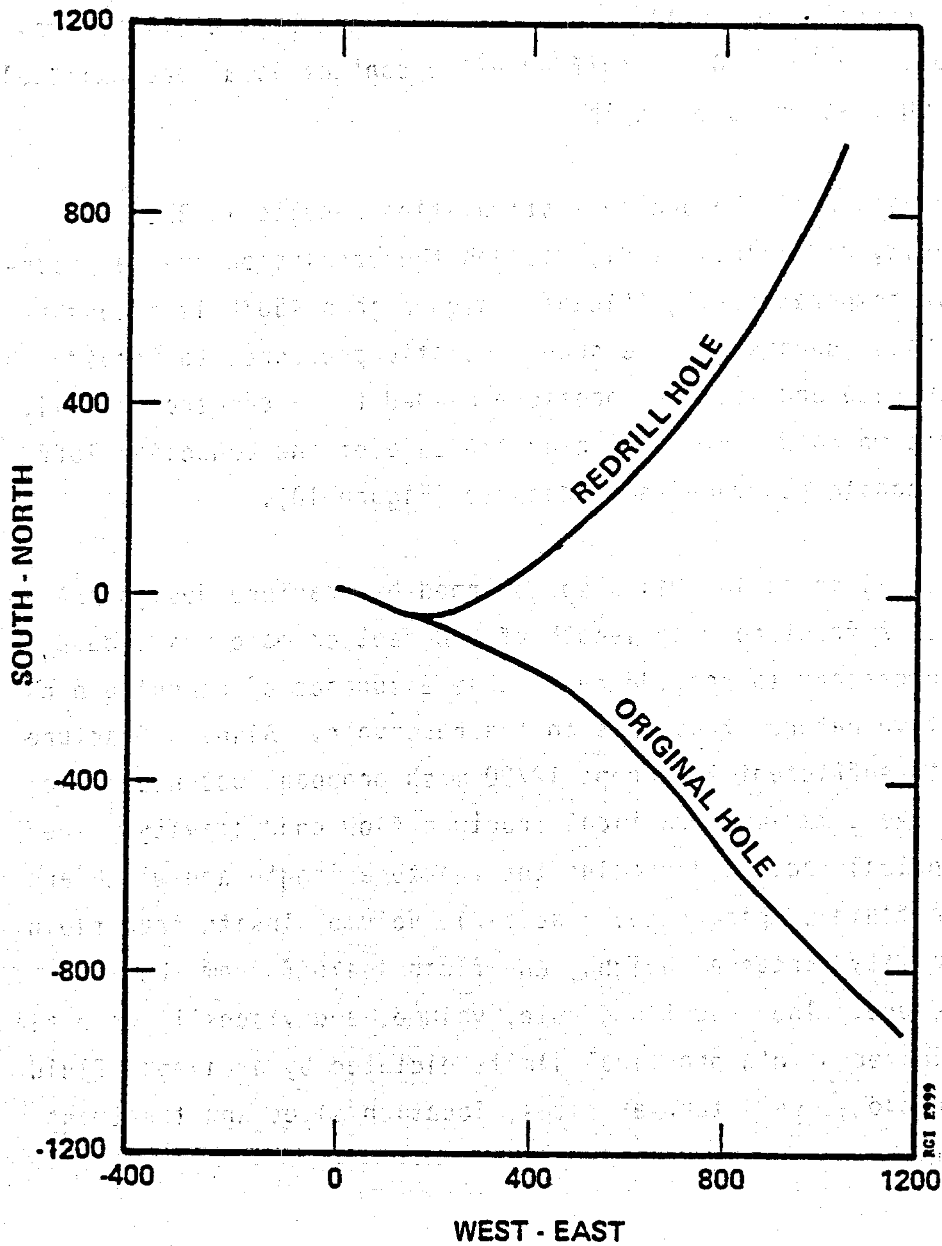
A. Selection of Well and Stimulation Interval

Two wells, Baca 19 and 20, were considered for Experiment No. 7. In general, both wells lie in a productive portion of the field but produce at noncommercial rates. Baca 19 has been tested at an average shortterm flow rate of 120,000 lb/hr with a 30 percent steam fraction. The well's production is characterized by surging on a 4 to 6 hour cycle with broad excersions of the flow rate and wellhead pressure. Because of this, the well is believed to produce from a two-phase zone of the reservoir. Baca 19 is adjacent to Baca 15 on the western end of a line of wells, namely Baca 13, 11, and 15 which are the best wells in the field.

Baca 20 is located between Baca 11 and 13 nearer the center of that group of wells. The original Baca 20 hole drilled toward the southeast was nonproductive (Figure 9). The well was then redrilled to the northeast and marginally noncommercial production was obtained. On a long-term test, the well produced at a stabilized rate of 56,100 lb/hr with a 56 percent steam fraction and a wellhead pressure of 116 psig.

Several factors favored Baca 20 as a stimulation candidate. The fact that it is more centrally located among the best wells in the field gave reasonable assurance that productive fractures exist near the wellbore. The fact that it produces from a single-phase zone of the reservoir was also considered to be a positive factor. Logistical considerations also favored Baca 20 because it is more accessible in bad

FIGURE 9
BACA 20 DIRECTIONAL DRILLING SURVEY
AVE. ANGLE METHOD
(UNPUBLISHED WELL DATA SUPPLIED BY UNION)



weather and the location could be enlarged to accommodate the surface equipment needed for a fracture treatment.

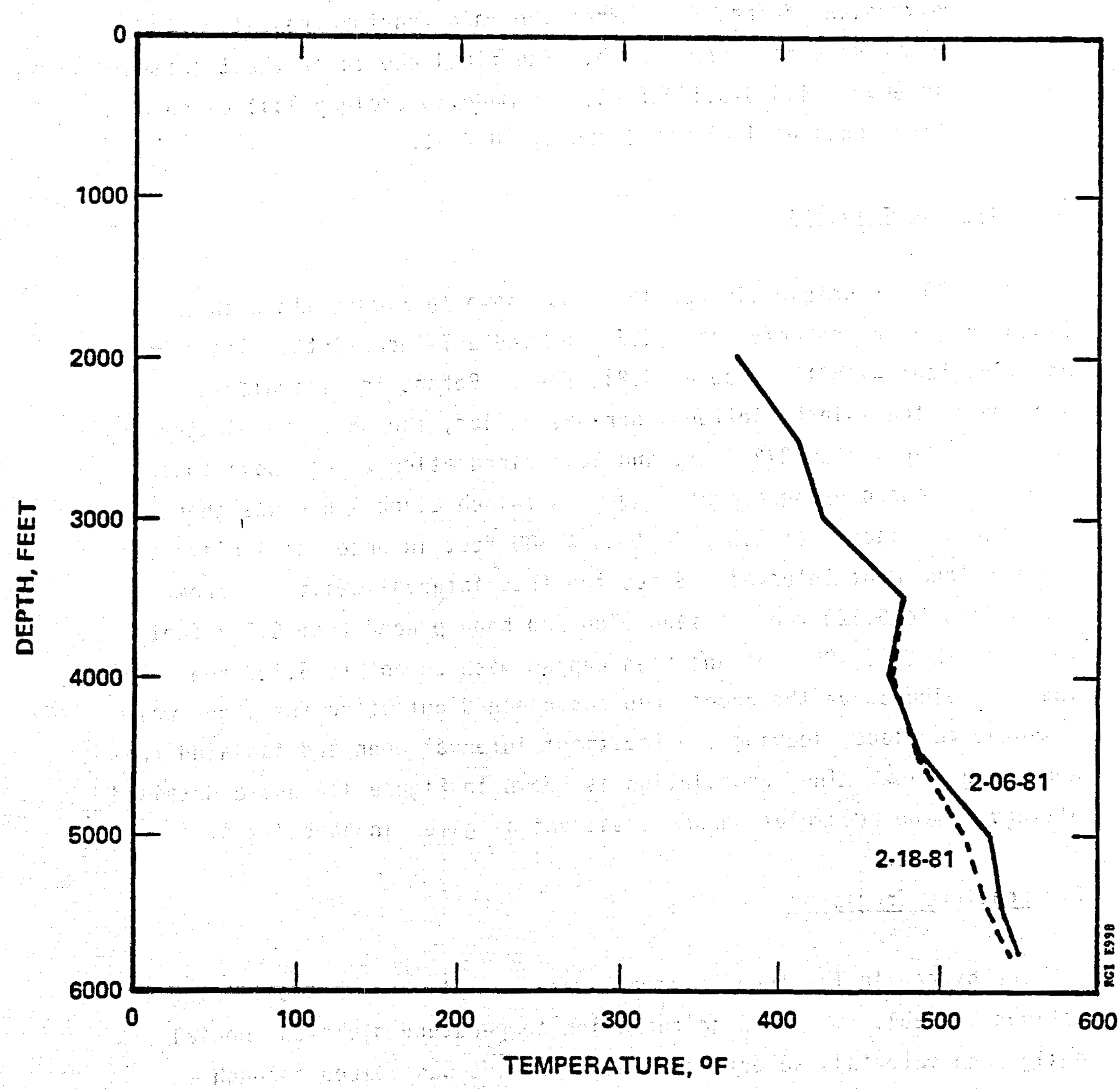
Selection of the treatment interval in Baca 20 was based on the following considerations:

1. In the Redondo Creek area natural fractures can be encountered at any depth in the Bandelier Tuff, but there is a higher incidence of productive fractures near the base of the formation. In Baca 20 the tuff/andesite contact is at approximately 5,200 feet measured depth.

2. Evaluation of the previous stimulation results in Baca 23 (Verity and Morris, 1981) yielded the conclusion that a reservoir temperature significantly higher than 450°F is necessary at Baca (because of the subhydrostatic pressure) to provide the flow rate and wellhead pressure needed for a commercial well. The temperature of 540°F near the base of the Bandelier Tuff was considered more than adequate (Figure 10).

3. Interval selection was also governed by fracture design criteria. A fracture wing length of 300 feet or more was judged to be necessary to provide reasonable assurance of reaching productive natural fractures in the reservoir. Also, a fracture width sufficient to accept 12/20-mesh proppant was needed to achieve a maximum practical fracture flow conductivity. The principal factors affecting the fracture length and width are frac fluid pumping rate, frac fluid volume, insitu frac fluid viscosity, interval height, and fluid leakoff from the main fracture. The frac fluid rate, volume, and viscosity were all maximized within practical limits dictated by available fluid technology, well tubular sizes, location size, and treatment cost.

FIGURE 10
TEMPERATURE SURVEYS FOR BACA 20
(UNPUBLISHED WELL DATA SUPPLIED BY UNION)



Fracture design calculations led to the conclusion that the treatment interval should be limited to a height of 300 feet or less. An overriding consideration in this regard is the fluid leakoff from the main fracture during the treatment. A greater interval height or the presence of significant natural fractures in the wellbore provides greater opportunity for diversion of frac fluid from the main fracture resulting in diminished fracture length. The final choice of the treatment interval, 4,880-5,120 feet, was made to exclude lost circulation zones at 4,850 feet and 5,120 feet.

B. <u>Well Recompletion</u>

Baca 20 was originally completed as shown in Figure 11A with a 9-5/8 inch liner cemented at 2,505 feet and a 7-inch slotted liner hung at 2,390 feet with the shoe at 5,812 feet. Before the stimulation treatment, the 7-inch slotted liner was pulled, the hole was plugged back to a depth of 4,873 feet, and lost circulation zones above that depth were cured using cement plugs. A 7-inch blank liner was then cemented in place from 2,383 feet to 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 had been placed from 5,827 feet total depth to 5,400 feet and then capped with cement to 5,120 feet. The sand plug above the cement cap was cleaned out after the liner was cemented in place, leaving the treatment interval open and isolated from above and below. The recompletion is shown in Figure 11B and a detailed history of the recompletion and treatment is given in Appendix A.

C. <u>Fracture Treatment</u>

The hydraulic fracture treatment was accomplished in the 11 stages defined in Table 5. The high formation temperature dictated special design and materials selection. The treatment was pumped through a 4-1/2 inch tubing string with a packer set at 2,412 feet, just below the

TABLE 5

BACA 20 TREATING SCHEDULE

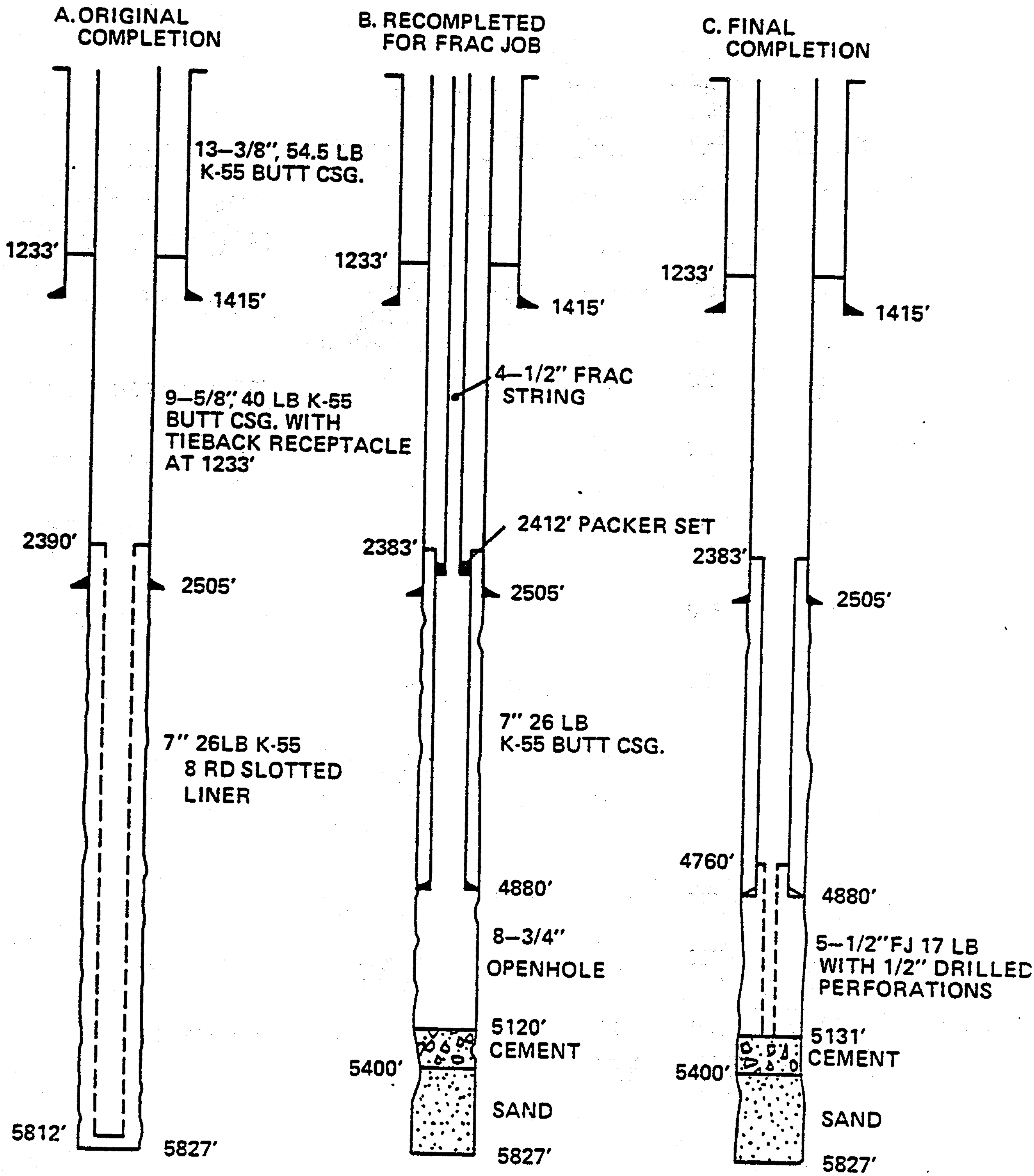
Stage No.	Planned Size (bbl)	Actual Size (bbl)	Proppant (lb/gal)	Proppant Size	Fluid
1.	2000	2000			FRESH WATER WITH FLUID LOSS ADDITIVE (FLA)
2.	500	639	0.39	100-MESH $CaCO_3$ (10,500 LB)	FRESH WATER WITH FLA
3.	500	350			FRESH WATER WITH FLA
4.	1500	1400			POLYMER GEL WITH FLA
5.	500	566	1.33	100-MESH $CaCO_3$ (31,500 LB)	POLYMER GEL WITH FLA
6.	500	500			POLYMER GEL WITH FLA
7.	1150	1168	0.46	16/20-MESH BAUXITE	POLYMER GEL
8. a	850	682	1.85	16/20-MESH BAUXITE	POLYMER GEL
b		378	2.77	16/20-MESH BAUXITE	POLYMER GEL
9.	300	450	2.11	12/20-MESH BAUXITE	POLYMER GEL
10.	750	451	4.21	12/20-MESH BAUXITE	POLYMER GEL
11.	150	151			FRESH WATER
	8700	8735			

RCI E1129

FIGURE 11

BACA 20 COMPLETION DETAILS

(All depths refer to KB, 24' AGL)



RGI E1103

7-inch liner hanger. A 3,000 bbl fresh water pre-pad (Stages 1-3) was used to cool the wellbore and fracture. In the following Stages 4-10, 5,600 bbl of crosslinked polymer gel frac fluid were injected, carrying 119,700 lb of 16/20-mesh sintered bauxite and 119,700 lb of 12/20-mesh sintered bauxite proppant in the last four stages. The frac fluid was a 60 lb/1,000 gal hydroxypropyl guar (HP guar) polymer gel mixed in fresh water and crosslinked as it was pumped. This fluid was a new high-pH system (Western HTFF-60) designed for improved stability at high temperature. Sintered bauxite proppant was used because of its laboratory demonstrated ability (GRWSP reports "Geothermal Fracture Stimulation Technology") to withstand high temperature and stress.

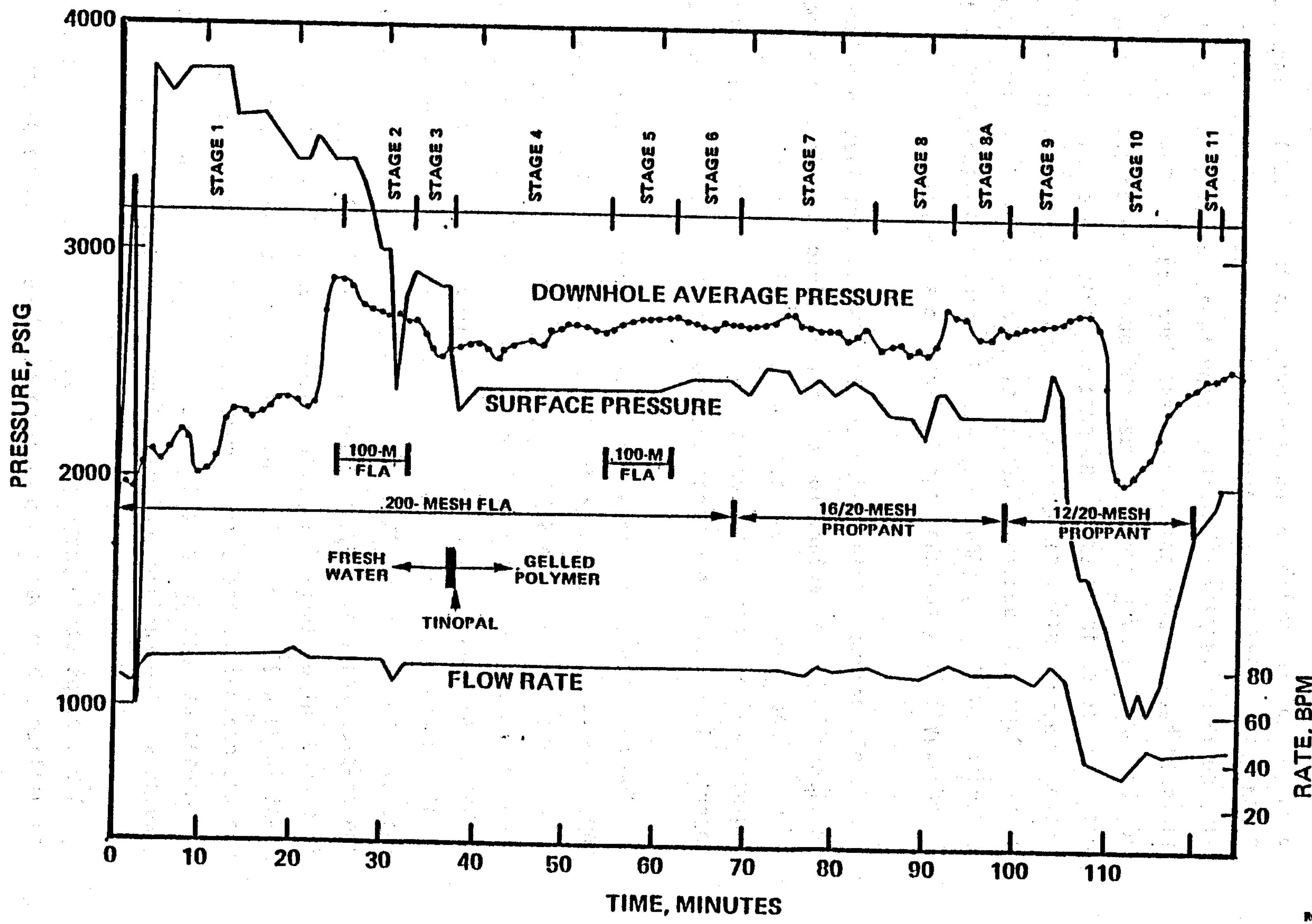
Finely ground calcium carbonate fluid-loss additives were included in Stages 1-6 in an effort to reduce frac fluid leakoff to the small natural fractures. Approximately 4,200 lb of 200-mesh and 42,000 lb of 100-mesh calcium carbonate were pumped. The 100-mesh material was injected in "slugs" to enhance the probability of bridging the fractures.

The majority of the treatment fluid was pumped at approximately 80 BPM. The rate was slowed to 40 BPM in Stage 10 and the proppant concentration was increased to 4.21 lb/gal in order to create a more widely propped fracture near the wellbore. The instantaneous surface shut-in pressure was measured soon after the treatment was initiated (1,000 psig) and again near the end of the job (1,300 psig), giving frac gradients of 0.63 psi/ft and 0.69 psi/ft, respectively. The treating record and pressure/rate history is shown in Figure 12. Because of an expected frac gradient of about 0.9 psi/ft (seen in an earlier stimulation experiment in Baca 23 - Verity and Morris, 1981) a total capacity of 11,000 hhp was brought to the site. However, the actual peak hydraulic horsepower used at Baca 20 was only 7,450 hhp because of the lower frac gradients. The surface equipment layout is shown in Figure 13.

A prototype steam packer, developed by Otis Engineering Corporation, was utilized which was equipped with ethylene propylene diene methylene

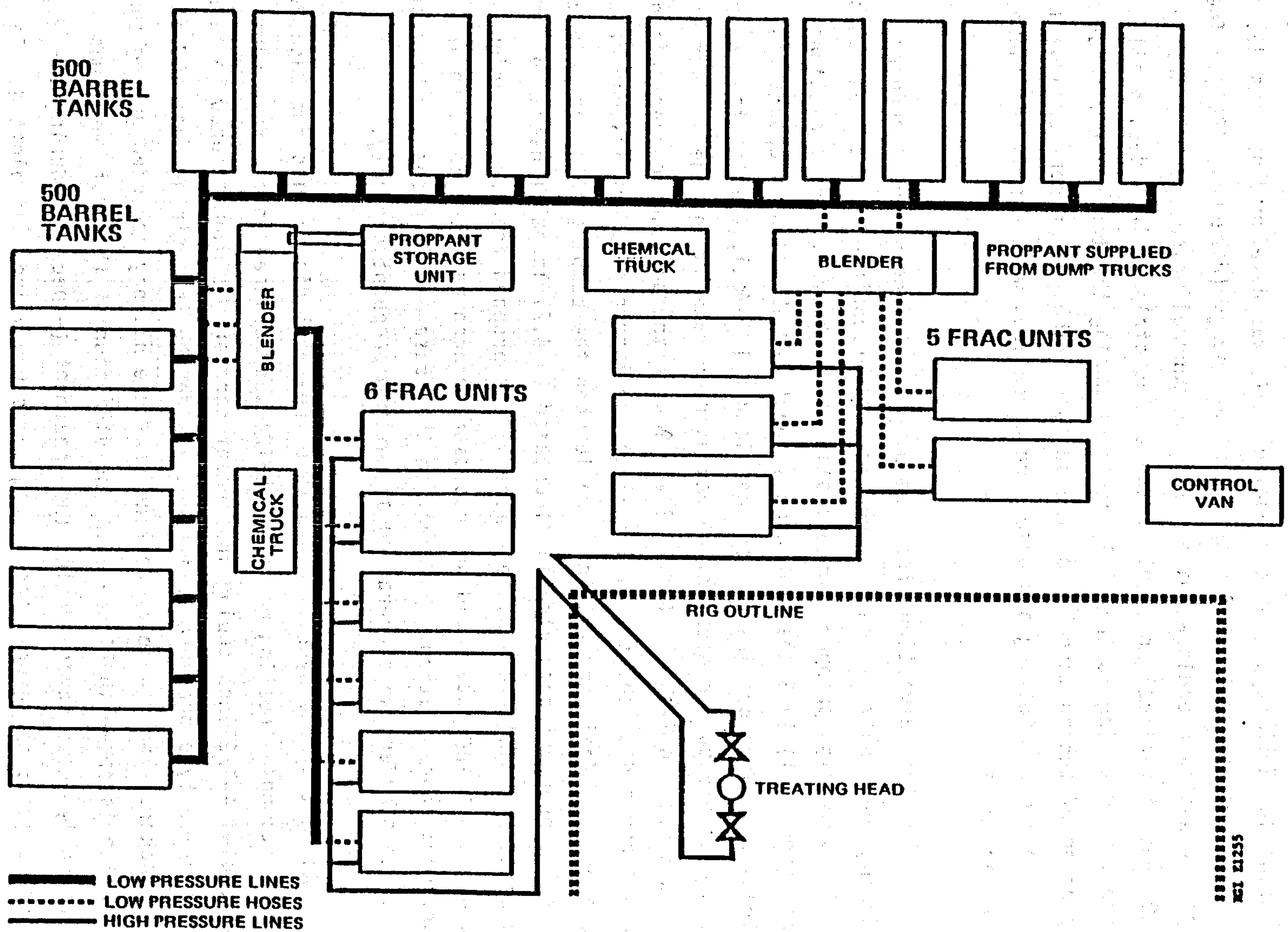
FIGURE 12

FRACTURE TREATING RECORD AND PRESSURE/RATE HISTORY
BACA 20



RGI 21130

FIGURE 13
SURFACE EQUIPMENT LAYOUT FOR BACA 20 FRAC TREATMENT



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.

Only minor deviations from the planned pumping schedule occurred during the treatment and the desired goal of ending the treatment at a relatively high proppant concentration was achieved. The variations occurred: (1) in Stage 7 when only about 1/2 lb/gal of proppant was inadvertently added instead of the planned 1 lb/gal; (2) in Stage 8 when a higher proppant concentration was used to make up for the smaller amount used in Stage 7; (3) in Stage 9 when the proppant concentration was increased to about 2.11 lb/gal of the larger proppant instead of the planned 2 lb/gal; and (4) in Stage 10 when the pumping rate was reduced and the proppant concentration increased to 4.21 lb/gal (instead of the planned 3 lb/gal) to achieve a more widely propped fracture. A reduction in pumping rate would not necessarily accompany the increase in proppant concentration. However, in this case it was necessary because the two blenders were operating at maximum proppant capacity.

As part of the hydraulic fracture treatment diagnostics for Baca 20, the bottomhole treating pressure (BHTP) was measured in the frac tubing. A special 4-1/2 inch tubing instrument carrier was manufactured to carry an Amerada-type pressure instrument inside the frac string just above the packer. The downhole treating pressure history recorded during the frac job is shown in Figure 12. The vibration of the instrument was apparently quite severe during the treatment (especially during the first stage); therefore, the average pressure values are plotted. In general, the average BHTP correlates well with the maximum and minimum pressure value trends. For this reason, it is believed that the BHTP data can be used to interpret the fracture treatment. The frac gradient calculated from this data was 0.68 psi/ft which agrees quite well with the frac gradients calculated from surface shut-in pressures.

D. Experiment Costs

Direct field costs for recompletion, stimulation, and testing were originally estimated to be $1,147,300, of which $580,800 was the estimated GRWSP share. The actual total direct field cost to the GRWSP was $605,200. Of this total, $347,400 was for fracturing materials and services; $103,700 was for the rig and related equipment; $80,600 was for logging and other evaluation procedures; and $73,500 was for other materials and services. A more detailed cost breakdown is given in Table 6. By prior agreement, Union bore the cost of recompleting the well, rig mobilization, production testing, and a share of Schlumberger's logging services. Los Alamos National Laboratory contributed fracture mapping and temperature logging services. Sandia National Laboratories attempted to run an acoustic borehole televiewer on Schlumberger cable, but compatability problems with Schlumberger's equipment and tool problems prevented a successful run.

V. FRACTURE TREATMENT EVALUATION

A. Fracture Mapping

During the fracture treatment of Baca 20, Los Alamos National Laboratory performed a fracture mapping experiment using Baca 22, located approximately 1,500 feet from Baca 20, as an observation well. A triaxial geophone system was placed in the Baca 22 well at a depth of about 3,000 feet 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. A large number of

Table 6

Actual Direct Costs to GRWSP
For Stimulation and Evaluation
Baca 20 Fracture Treatment

Fracturing Materials and Services	
Fluids and proppants	$256,868
Pumping service, transportation, etc.	59,830
Water and water hauling	11,367
Frac tanks	12,386
Misc. service	6,972
	347,423
Rig daywork	74,875
Rig fuel	6,046
Equipment rentals	
Compressors	7,516
Drilling equipment	12,512
Other	3,756
	104,705
Expendable materials	7,999
Misc. services and equipment	
Packers	32,230
Nitrogen and coil tubing	10,664
Logging	44,112
Pressure and temperature survey instruments	3,740
DST instrument carrier	5,351
Crane and tractors	8,627
Rental equipment repair and inspection	18,125
Other	16,046
	138,895
Transportation of tubing and misc. equipment	6,183
Total	$605,205

discrete events (38) were recorded during the frac job; however, the geomagnetic orientation measurement of the tool was lost (Pearson, 1982). The microseismic activity, illustrated in Figures 14 and 15, occurred in a broad zone which was roughly 2,300 feet long, 700 feet wide, and 2,000 feet high. Given the conditions of this experiment, each mapped event location is probably known within 150 feet in relation to other rock failure locations, and may suggest that the stimulation treatment did not create a singular monolithic fracture. These data also indicate that the microseismic events were occurring above the injection zone in Baca 20.

Most of the microseismic events were recorded within the first hour after injection pumping commenced in Baca 20. This is in contrast to the previous fracture job in Baca 23 (Pearson, 1982) where many of the largest events occurred near the end of the pumping. That detectable rock failure was infrequent during the last stages of the stimulation treatment implies that comparatively little total energy was expended in the creation of new fractures. This energy could have been expended in the creation of additional frac width or more likely dissipated into the natural fracture system. 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 (i.e., more indicative of the fluid leakoff zone) and would not necessarily define a propped flow path to the wellbore at Baca 20.

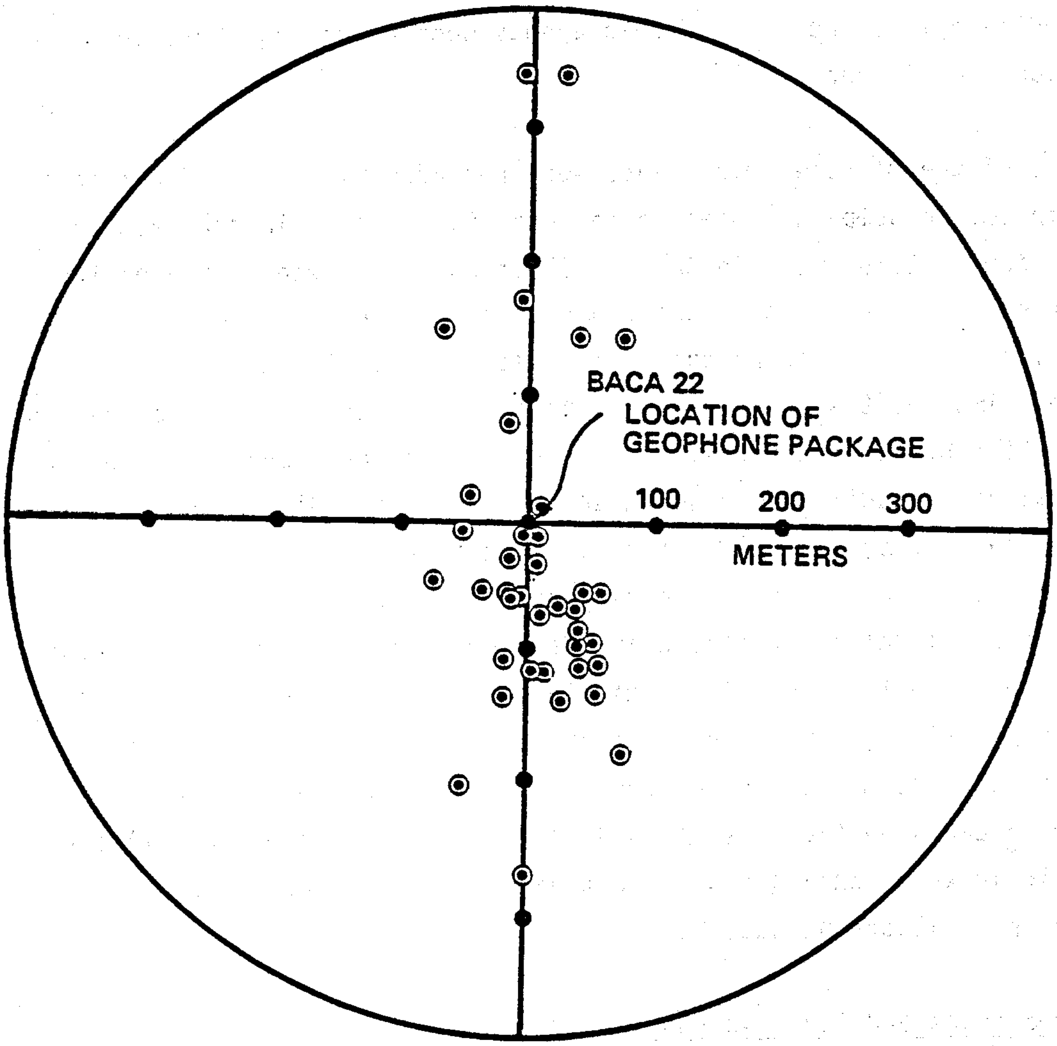
B. Temperature and Electric Log Surveys

The 240-foot isolated open 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 minor lost

FIGURE 14

BACA 20 MICROSEISMIC EVENT LOCATIONS

SHOWN IN PLAN VIEW
(NO GEOMAGNETIC ORIENTATION)

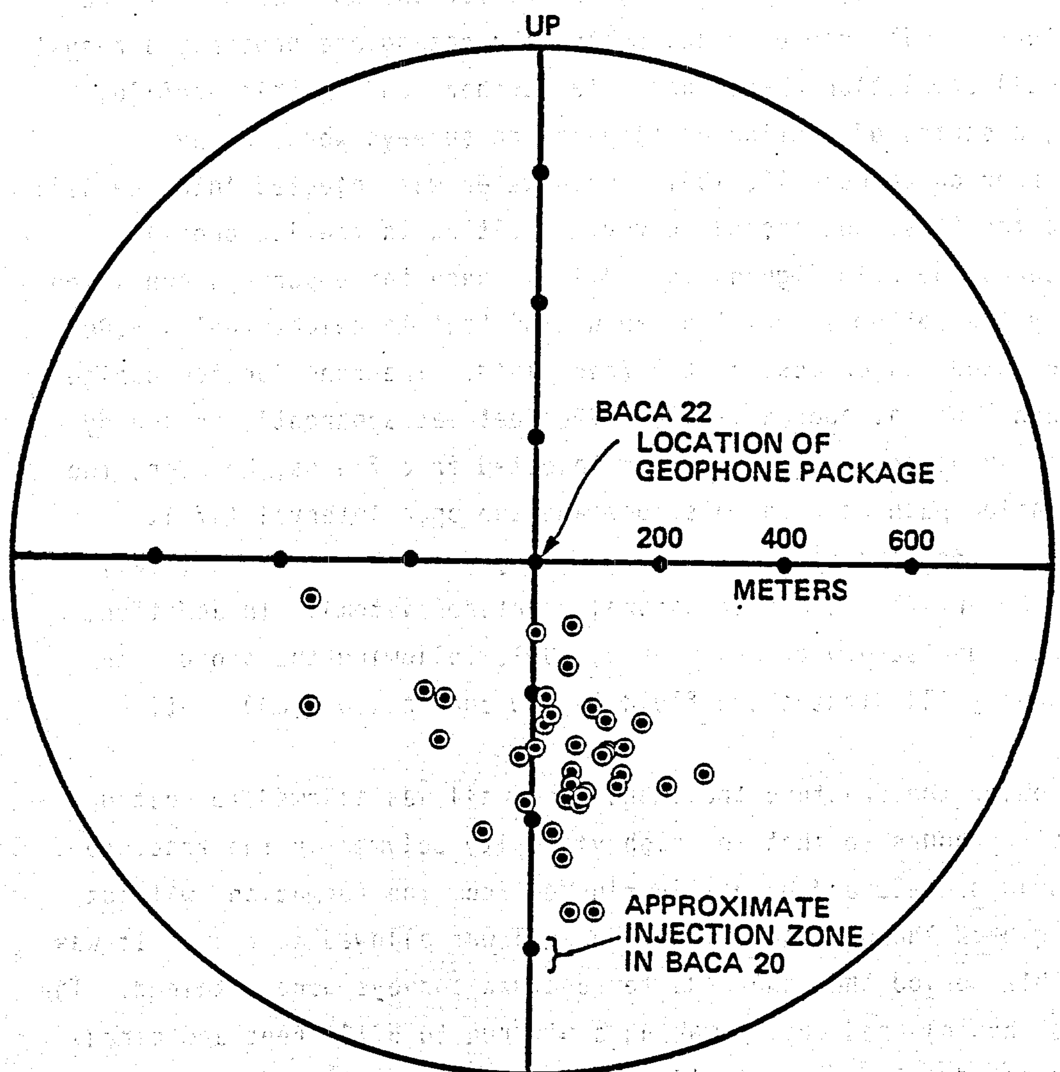


ESI E1178

FIGURE 15

BACA 20 MICROSEISMIC EVENT LOCATIONS

SHOWN IN VERTICAL PROJECTION (NO GEOMAGNETIC ORIENTATION)



ECI E1177

circulation zone existed in the open interval. Approximately 12 hours after the frac job was completed, the first of several temperature surveys, as shown in Figure 16, was obtained in the lower part of the well. Figure 17 shows the deeper portions of these surveys in more detail. LANL ran two continuous temperature surveys (LANL 10-6-81) separated by about four hours time. In general, these surveys showed the heat-up of the wellbore following the frac job and the same trends as the prefrac survey (RGI 10-4-81) except for the bottom zone of the open interval. The cooler zones behind the casing are probably a result of the well completion operations. To further confirm this profile, however, a series of continuous temperature surveys were run by Schlumberger on October 12, 1981. Cold water was injected into the well prior to the first and second survey, resulting in the low profile temperatures shown in Figures 16 and 17. These three surveys confirmed that only the bottom interval of about 100 feet in height (below 5,000 feet) accepted all or most of the frac fluid. The zone located behind the 7-inch liner at approximately 4,720 feet was apparently cooled by workover fluids and possibly by the injected frac fluids; however, the communication path between this zone and the open interval (if it exists) appears to be at some distance away from the wellbore (i.e., through the artificial and/or natural fracture system). In addition, the temperature survey of November 9, 1981, following the production test, clearly illustrates the fluid inflow zone below 5,000 feet.

Following the fracture treatment, the well was allowed to heat up for about 24 hours so that the high viscosity polymer in the fracture fluid would degrade and be easily flushed from the formation (without producing back the proppant) when the well was allowed to flow. It was during this period that the LANL temperature surveys were obtained. The well was then cleaned out by making a bit run to 5,134 feet and circulating aerated water. No significant amounts of solids were observed at the surface during the cleanout.

FIGURE 16

BACA 20 TEMPERATURE PROFILES
October 1981

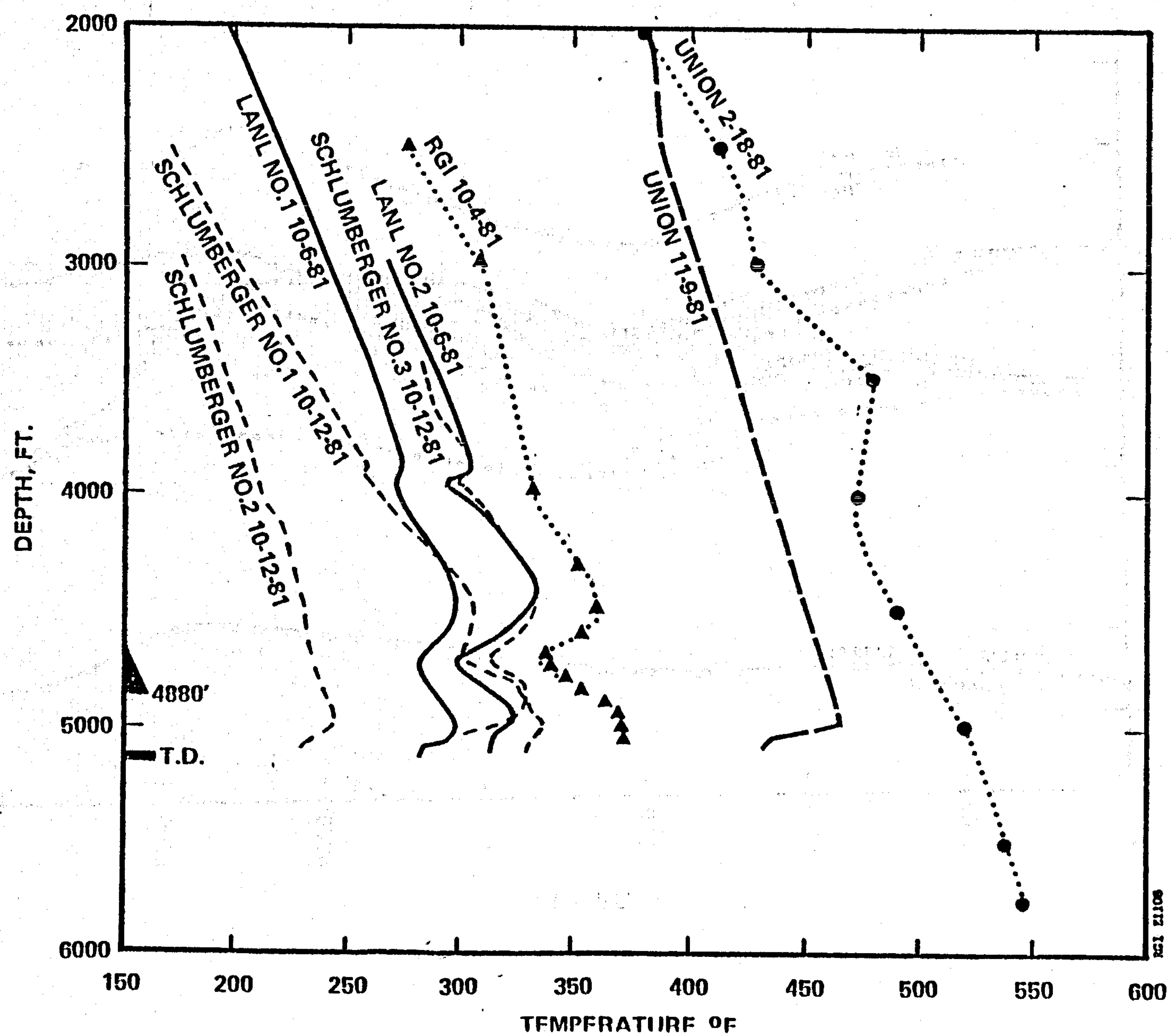
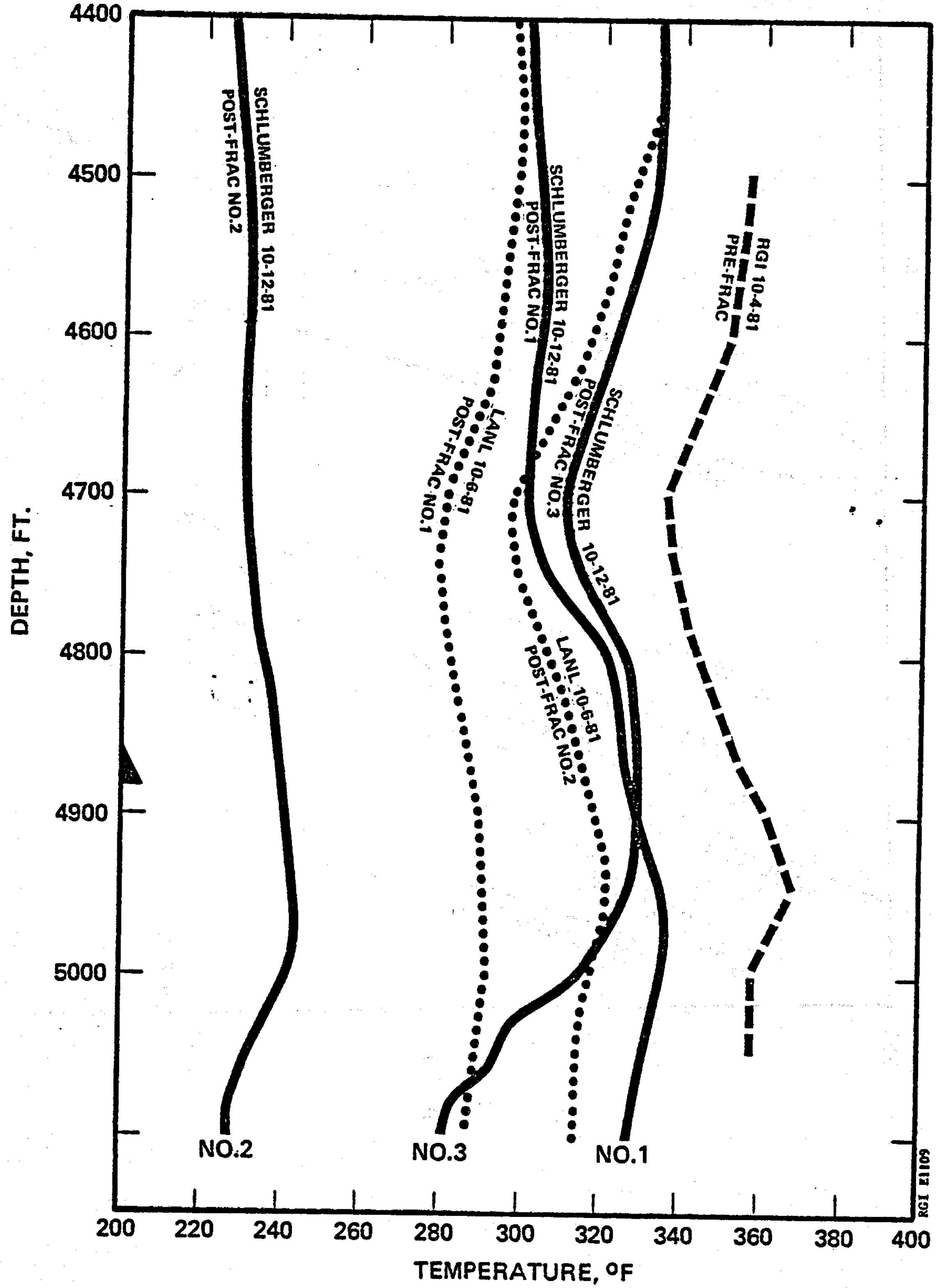


FIGURE 17

COMPARISON OF TEMPERATURE PROFILES ACROSS PRODUCTION INTERVAL October 1981



A suite of openhole electric logs (dual laterolog, compensated neutron-formation density, borehole compensated sonic, dipmeter, and fracture identification) were run in the open interval on October 8, 1981. A comparison of the pre-frac and post-frac logs did not indicate any significant changes which could be interpreted as new fractures (or high porosity zones), although in some intervals enhancement of existing porosity was noted. Furthermore, the inflow zones shown by the temperature data could not be clearly interpreted in this formation with the electric log data; therefore, these results were inconclusive. An attempt was made to obtain an acoustic borehole televiewer survey in the well utilizing equipment provided by Sandia National Laboratories, but it was not successful.

C. Production Tests

At this time it was determined that the well was worthy of final completion and testing. A cleanout run was made into the well to 5,131 feet, then a 5-1/2 inch pre-perforated liner was installed in the treatment interval as shown in Figure 11C. An attempt was made to perform a modified drillstem test (DST) in Baca 20 on October 9, 1981. However, shortly after the initiation of fluid flow at the surface, the nitrogen pump truck broke down and the test was terminated without obtaining interpretable data. On October 10-11, 1981 a 6-hour modified DST was successfully performed which was a combination of conventional DST methods and gas lift to maintain steady, single-phase flow to the wellbore. This DST method allowed the safe use of downhole tools and maintained a relatively low, steady flow rate of about 21,000 lb/hr throughout the test. The rates, given in Table 7, were obtained by gauging the flow into the 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 a depth of 3,000 feet was 320°F and indicated that the near wellbore area had not recovered from the injection of cold fluids. There was no

Table 7

Baca 20 Flow Rate
DST, October 10-11, 1981

Time	Water Rate (bbl/dy)	Volume (bbl)
2030-2045	1329	13.84
2045-2100	1170	12.19
2100-2115	1276	13.29
2115-2130	1223	12.74
2145-2200	1329	13.84
2200-2215	1329	13.84
2215-2230	1382	14.40
2245-2301	1396	15.51
2301-2330	1347	27.13
2345-0000	1382	14.40
0000-0023	1248	19.93
0100-0115	1276	13.29
0115-0130	1223	12.74
0130-0135	1276	4.43
0145-0200	1382	14.40
0200-0215	1276	13.29
0215-0230	1329	13.84

Total flow time, t_p = 6.32 hrs.
Average water flow rate = 1307 bbl/dy
Total mass flow rate average = (1.15)(1307) = 1500 bbl/dy

proppant material noted in the return fluids nor found in the wellbore following this test.

Conventional transient pressure analysis techniques were used to analyze the data, given in Table 8, which yielded a reservoir permeability-thickness of about 1,000 md-ft using the Horner technique shown in Figure 18. Application of the type curve matching technique to the drawdown data resulted in a similar value. This low reservoir permeability-thickness value, compared to other parts of the field, suggests this well may be in a less productive zone. The skin factor was calculated to be -4.8, which compares with the better wells in the field. Evaluation of the early-time pressure buildup data also indicated small wellbore storage effects and a period of fracture (linear) flow near the wellbore. Although the linear flow pressure effects were adynamic, the length of the propped fracture was calculated to be about 160 feet using conventional theory (Figure 19 and Table 8). The productivity index measured during this test was 260 lb/hr/psi. This PI value suggests that the well does not have the productivity potential of the better Baca wells (the range of PI's in other Baca wells is 220-430 lb/hr/psi).

Numerical simulation studies were performed to investigate the effects of fracture geometry, fracture conductivity, and reservoir permeability on the well's productivity using the DST data for the production history match. Although the resulting solutions are not unique, the general conclusions are that the fracture has high conductivity (i.e., permeability in the range of 600 darcies, which corresponds to laboratory data for this proppant material), the reservoir permeability-thickness is in the range of 1,000 md-ft (as calculated from the pressure data), and the propped fracture length is relatively short (about 300 feet) with a fracture volume close to the volume of proppant material injected. A comparison of the numerical simulation results with the DST pressure data is illustrated in Figure 20. Thus, the transient pressure data analysis and the numerical

Table 8

Baca 20 Pressure Buildup Data
DST, October 10-11, 1981

P_{ws} (psig)	Δt (hrs)
487.5	.0
496.5	.0167
507.6	.033
512.4	.05
514.0	.067
514.0	.083
515.0	.1
516.0	.117
517.0	.13
519.4	.15
520.0	.17
522.0	.25
524.7	.333
525.0	.417
526.5	.5
530.0	1.0
533.6	1.5
535.3	2.0
537.0	3.0
540.6	4.0
542.4	5.0
544.2	6.0
545.9	7.0

m = 40.4 psi/cycle (from Horner plot)
t_p = 6.32 hrs
Q_{avg} = 1,500 bbl/dy total mass flow

$$kh = \frac{162.5\ B\mu Q}{m} = \frac{(162.5)\ (1{,}500)\ (1.18)\ (.14)}{40.4}$$

$$= 1{,}000 \text{ md-ft}$$

Table 8, (cont.)

For skin -

$$s = 1.151 \left[\frac{P_{1\,hr} - P_{wf}}{m} - \log \frac{kh}{\varphi h \mu c_t r_w^2} + 3.23 \right]$$

$$= 1.151 \left[\frac{521.5 - 487.5}{m} - \log \left(\frac{1,000}{(.2)(100)(.14)(15 \times 10^{-6})(.133)} \right) + 3.23 \right]$$

$$= -4.8$$

For fracture length -

M_{vf} = 31.0 (from plot of P vs $\sqrt{\Delta t}$)

$$k\, x_f^2 = \left(\frac{-4.064 \quad qB}{M_{vf} h} \right)^2 \cdot \frac{\mu}{\varphi c_t}$$

$$x_f = \left[\left(\frac{(-4.064)(1,500)(1.18)}{(31)\ (100)} \right)^2 \cdot \frac{.14}{(.2)(15 \times 10^{-6})(10)} \right]^{1/2}$$

$$= 160 \text{ feet}$$

Note: Water properties correspond to average values between 500°F and 320°F.

FIGURE 18

BACA 20

PRESSURE BUILDUP HORNER PLOT

10-11-81

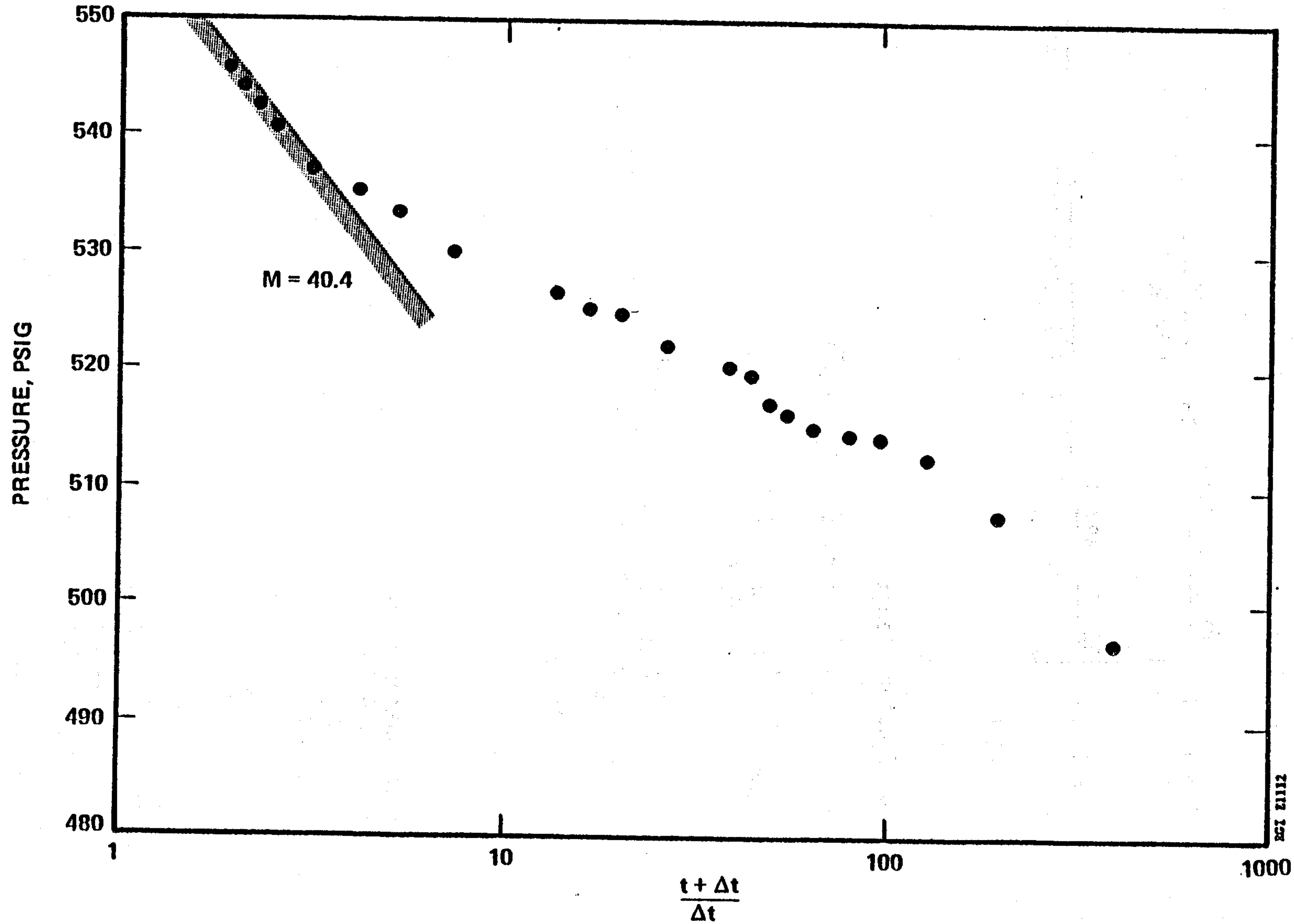


FIGURE 19

BACA 20
PRESSURE BUILDUP vs $\sqrt{\Delta t}$
10-11-81

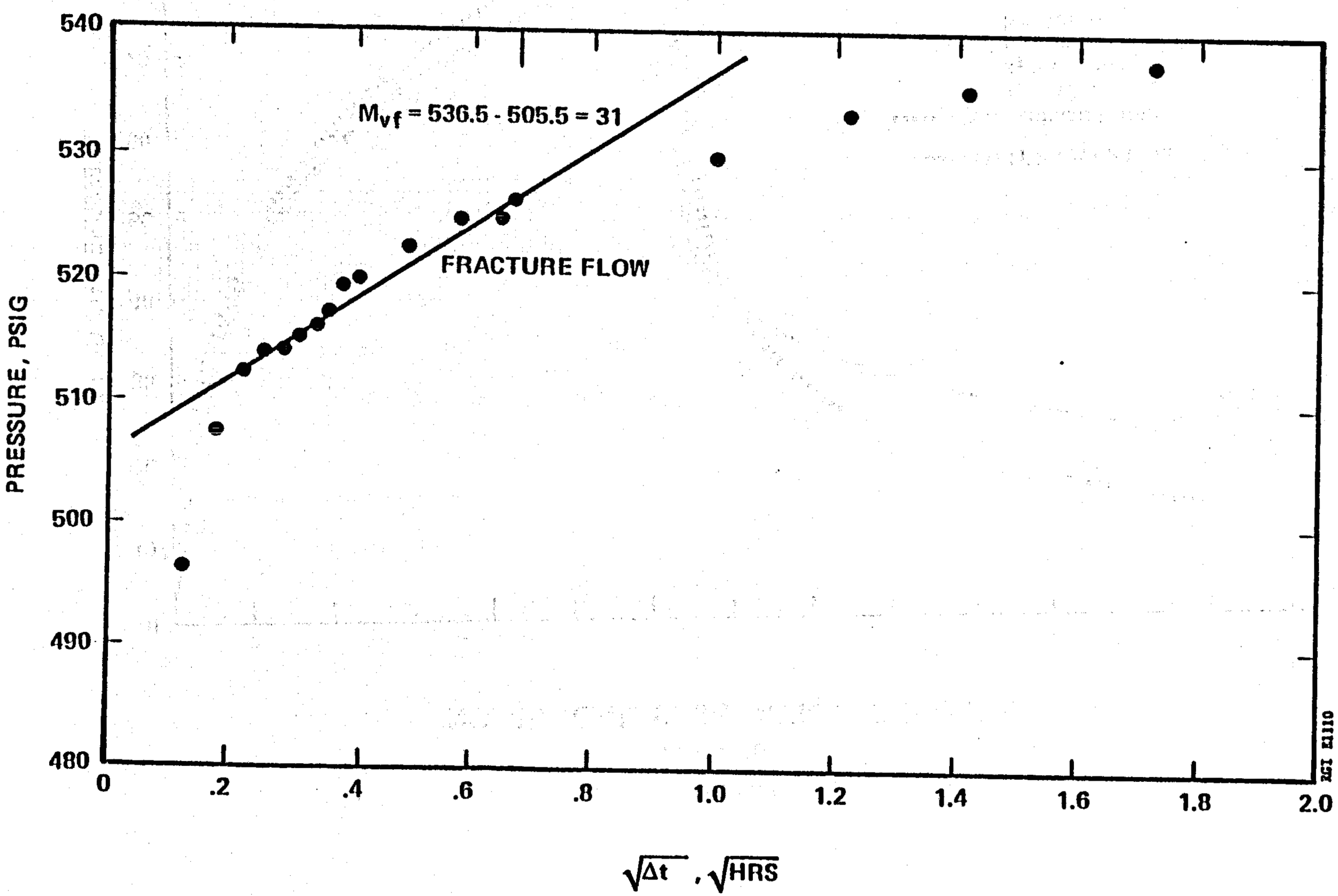
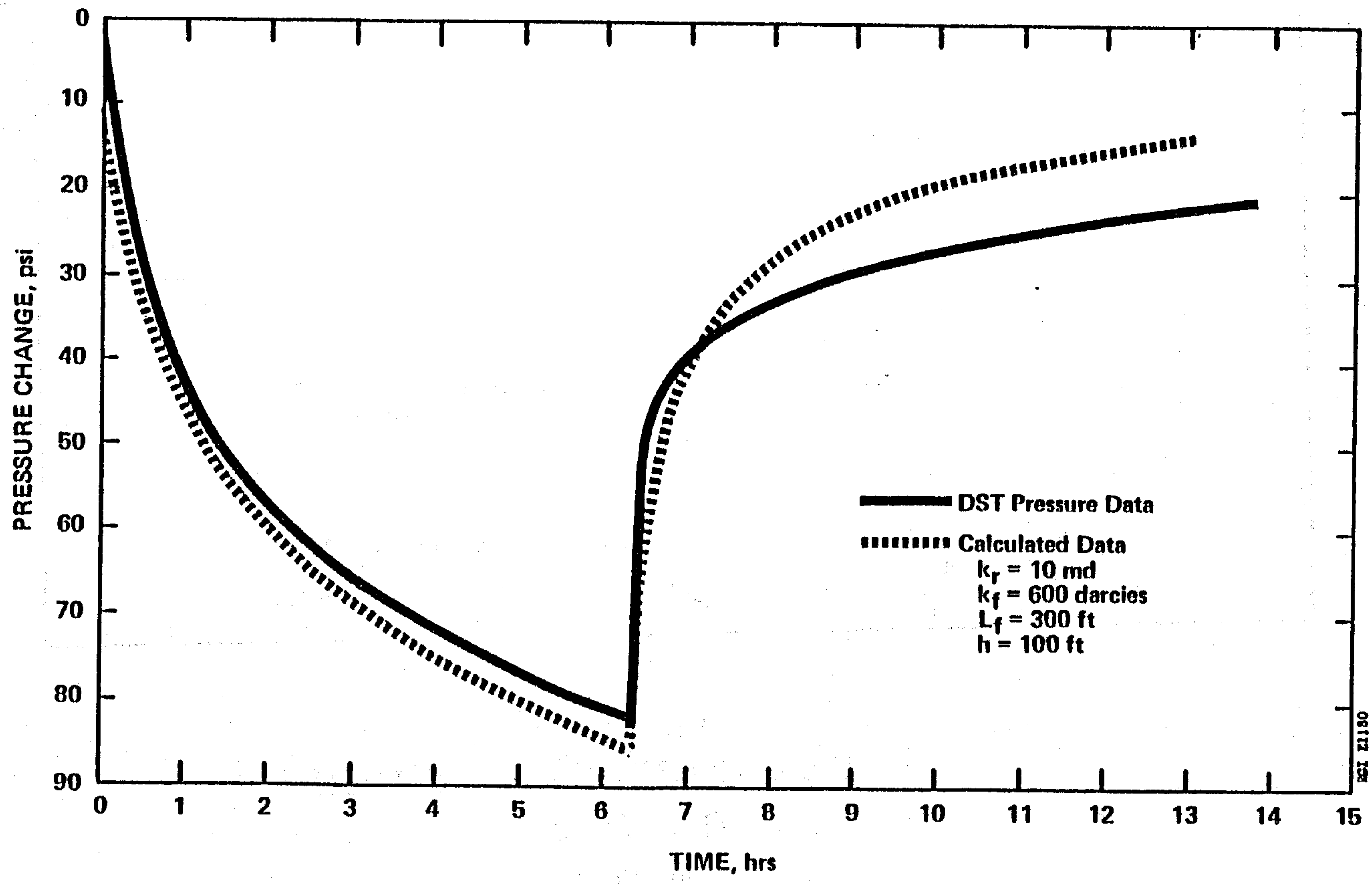


FIGURE 20

BACA 20

NUMERICAL SIMULATION RESULTS



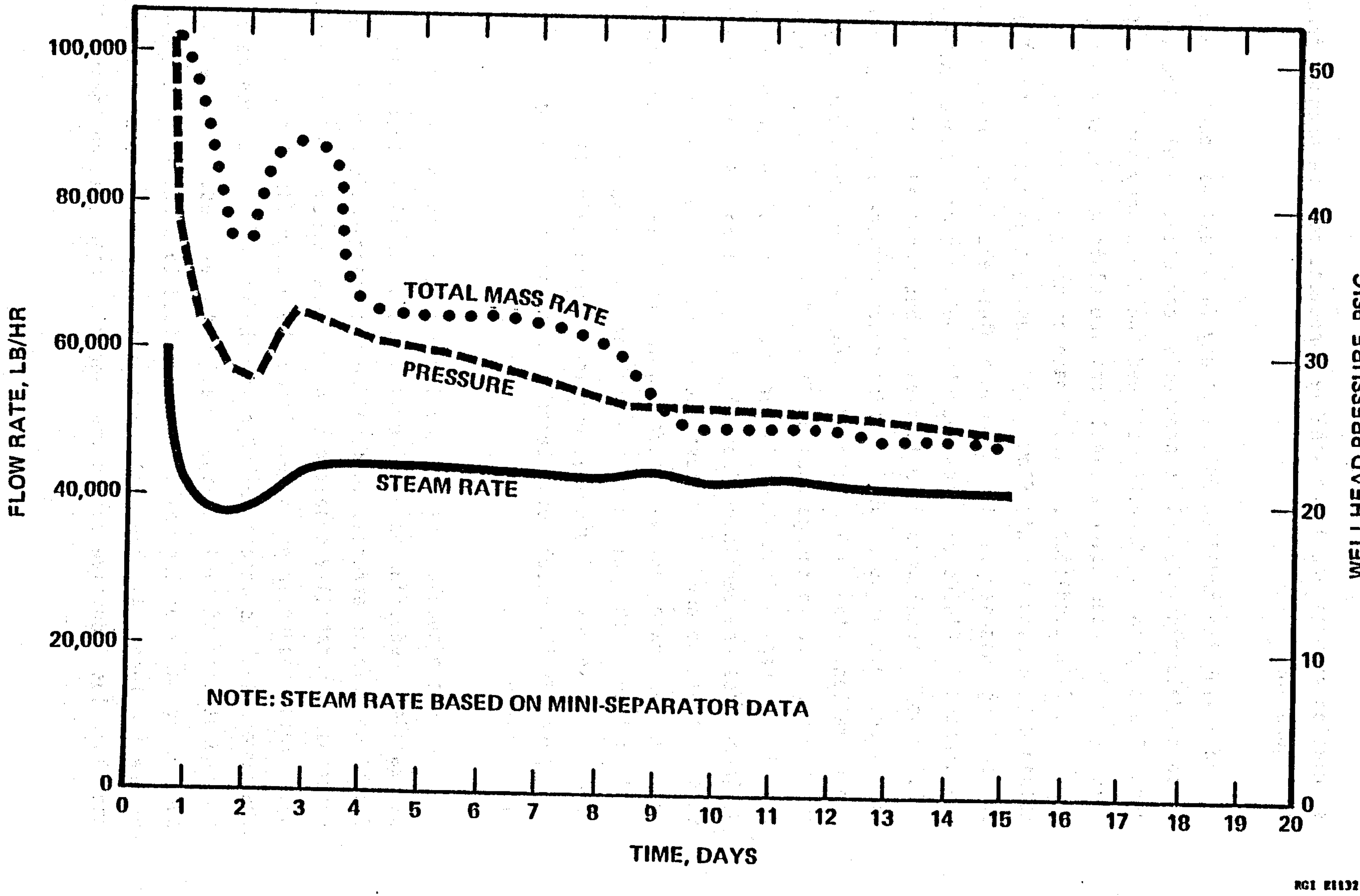
simulation results are in reasonable agreement for the propped fracture configuration.

Following the modified DST, a 14-day flow test was performed by Union to determine the well's productive capacity. A pipeline was installed between the Baca 20 wellhead and the nearby sump. The flow rate was calculated using a single orifice plate method to measure the two-phase flow conditions. An estimate of the steam fraction was obtained by taking a fluid flow sample (using a nozzle in the pipeline) and passing this sample flow through a mini-separator. The results, illustrated in Figure 21, show that the well produced approximately 110,000 lb/hr total mass flow initially, but declined rapidly to a final stabilized rate of about 50,000 lb/hr under two-phase flow conditions in the formation. The well exhibited a small kick on the second day, but quickly returned to the general declining trend. The measured steam fraction increased from about 50 percent to a final 86 percent with the wellhead pressure declining from 50 psig to a final 24 psig. These data suggest that the production test caused a large pressure decline in the well and two-phase flow was occurring in the formation. The formation cooling seen at the bottom of the wellbore in the November 9, 1981 temperature survey (Figure 16), obtained immediately after well shut-in, is apparently the result of a temperature drop in the fluid associated with flashing flow.

The most probable cause of the low productivity is the relative permeability reduction associated with two-phase flow effects in the formation. These effects, in turn, result principally from the low reservoir permeability conditions in this area combined with the sub-hydrostatic reservoir pressure. Since the design flowline pressure of the power plant is more than 100 psig, the well will not produce commercial quantities of fluid at those wellhead pressures. Because of the poor performance of the well, it was decided to perform an acid cleanout of the fracture. As previously discussed, calcium carbonate was used as the fluid-loss additive during the hydraulic fracture treatment. This

FIGURE 21

BACA 20 PRODUCTION TEST NO.2
10/26/81 - 11/9/81



material was used with the 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 did not indicate that the fracture conductivity had been damaged, it did not preclude the possibility that the calcium carbonate had plugged the natural fractures and flow paths in the formation which intersect the artificially propped fracture. The results of this acid cleanout treatment are discussed in Section VII.

D. Tracer Studies

In order to determine the fraction of injected frac fluid that was returned when production commenced, several chemical tracers were employed. The tracers were methanol, n-propanol, Tinopal CBS-X, and the polymer itself. All the chemicals (except the Tinopal CBS-X) are included in the normal composition of the frac fluid system which was injected during Stages 4-10 of the treatment.

The methanol used in the tracer study is contained in the Frac cide I™ bactericide. The bactericide was used in treating all 247,926 gallons of fracturing fluid. Based on a concentration of one gallon bactericide per 1,000 gallons fracturing fluid and a methanol concentration of 40 percent in the Frac cide I™, a total of 1,290 lb of methanol was injected. The n-propanol used in the tracer study is contained in the crosslinker material for the HP guar polymer system (Western HTFF-60). The concentration of the n-propanol in the crosslinker is 30 percent and a total of 620 lb was injected. The HP guar polymer acts as a tracer when the concentration of total organic carbon in the produced fluid is measured. The thermal degradation of the polymer is indicated by the ratio of carbohydrate to total organic carbon since the undegraded polymer ratio is about 2.4 (GRWSP report

"Raft River Well Stimulation Experiments"). Tinopal CBS-X, a fluorescent, water soluble tracer was added to the gelled fluid in Stage 4. A total of 55 pounds was used.

During the production testing done after the stimulation treatment, fluids were sampled and analyzed for their tracer content. Figures 22 through 24 show the analysis data on the tracer concentration in the returned fluids versus the cumulative flow volume. Table 9 lists the sample analysis data for all the tracers except the Tinopal CBS-X. Table 10 lists the sample analysis data for Tinopal CBS-X provided by Union.

Material balance calculations for the tracers, with the exception of the Tinopal CBS-X, indicated that approximately 20 percent of the fluid that was injected during the stimulation treatment was returned to the surface during the post-stimulation flow tests; i.e., 26 percent of the methanol, 19 percent of the n-propanol, and 21 percent of the polymer (total organic carbon). The data for Tinopal CBS-X, show that this tracer generally behaves like the others but gives only a one percent material return. This tracer may be excessively adsorbed or is not as readily soluble in water as originally thought. However, the low recovery of the Tinopal CBS-X is more likely related to the fact that, unlike the other tracers, it was injected as a slug early in the treatment. The frac fluids injected in the early stages may have been pushed far enough into the formation to intersect the natural fracture system and be diluted by the reservoir fluids and/or trapped in the formation. The total frac fluid volume, therefore, does not appear to have been contained within a fracture system which was swept back to the wellbore as a slug by the reservoir fluids.

The chemical data also indicates that the polymer was thermally degraded by the time the first samples were obtained; i.e., low carbohydrate return. This degradation was more rapid than observed during the Baca 23 experiment and probably results from the higher formation

Table 9

Tracer Concentration and Fluid Production Data

Cumulative Production (10^6 lb)	Methanol (ppm)	N-Propanol (ppm)	Total Organic Carbon (ppm)	*Carbohydrate/ Total Organic Carbon
0.36	28	15	108	.06
2.59	28	14	104	.06
4.71	25	11	87	.08
6.87	20	8	69	.10
8.78	16	6	59	.10
10.0	13	<5	52	.13
11.5	10	<5	45	.17
12.9	8	<5	43	.18
14.7	7	<5	43	.17
16.1	6	<5	48	.14
18.6	6	<5	43	.16
26.8	5	<5	32	.21
28.1	5	<5	32	.23
29.2	4	<5	30	.24

* Note: Ratio of polymer carbohydrate to total organic carbon (Undegraded polymer ratio is 2.4).

Table 10

Concentration of Tinopal CBS-X

Cumulative Production After Fracturing, Million Pounds	Tinopal CBS-X Tracer Concentration Parts Per Billion
0.36	48.
0.48	32.
0.64	19.
0.72	37.
0.94	45.
0.98	57.
1.14	62.
1.51	40.
1.64	38.
1.79	43.
1.93	48.
2.07	47.
2.20	57.
2.27	41.
2.35	42.
2.42	53.
2.51	43.
2.57	49.
2.66	43.
2.72	49.
2.81	48.
2.96	49.
3.02	45.
3.15	45.
3.29	39.
3.42	37.
3.68	31.
4.04	39.
4.41	55.
4.71	62.
5.23	64.
5.51	60.
5.98	38.
6.30	33.
6.57	24.
6.74	27.
7.13	25.
7.65	18.
8.43	21.
8.91	21.
9.27	22.
10.13	14.
11.58	10.
12.44	7.
12.99	6.

Table 10, (cont.)

Cumulative Production After Fracturing, Million Pounds	Tinopal CBS-X Tracer Concentration Parts Per Billion
14.60	5.
15.89	7.
18.27	3.
19.17	1.
20.36	1.
21.38	1.

FIGURE 22

CONCENTRATION OF METHANOL AND N-PROPANOL TRACER VERSUS CUMULATIVE PRODUCTION BACA 20

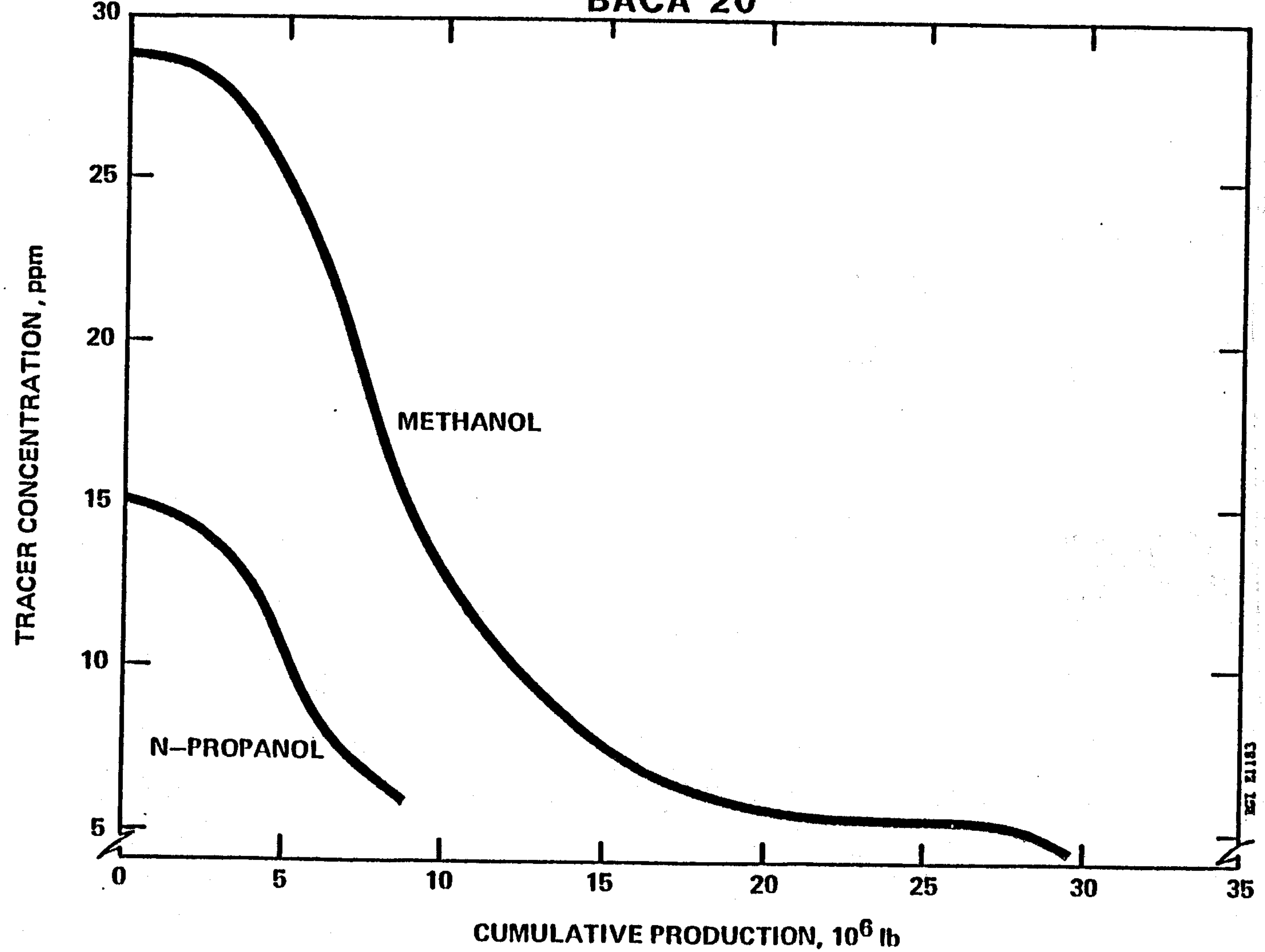


FIGURE 23

CONCENTRATION OF TOTAL ORGANIC CARBON VERSUS CUMULATIVE PRODUCTION

BACA 20

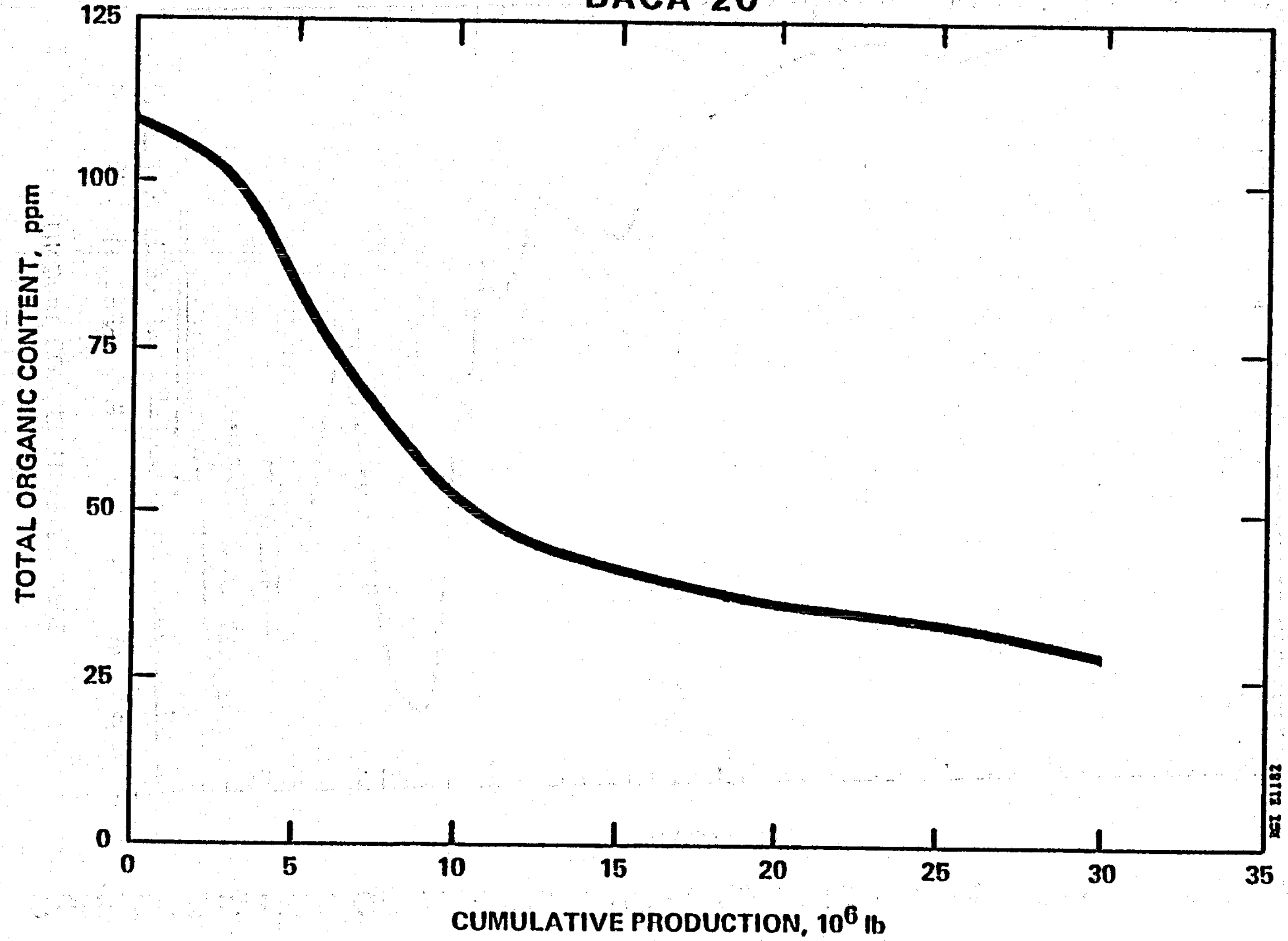
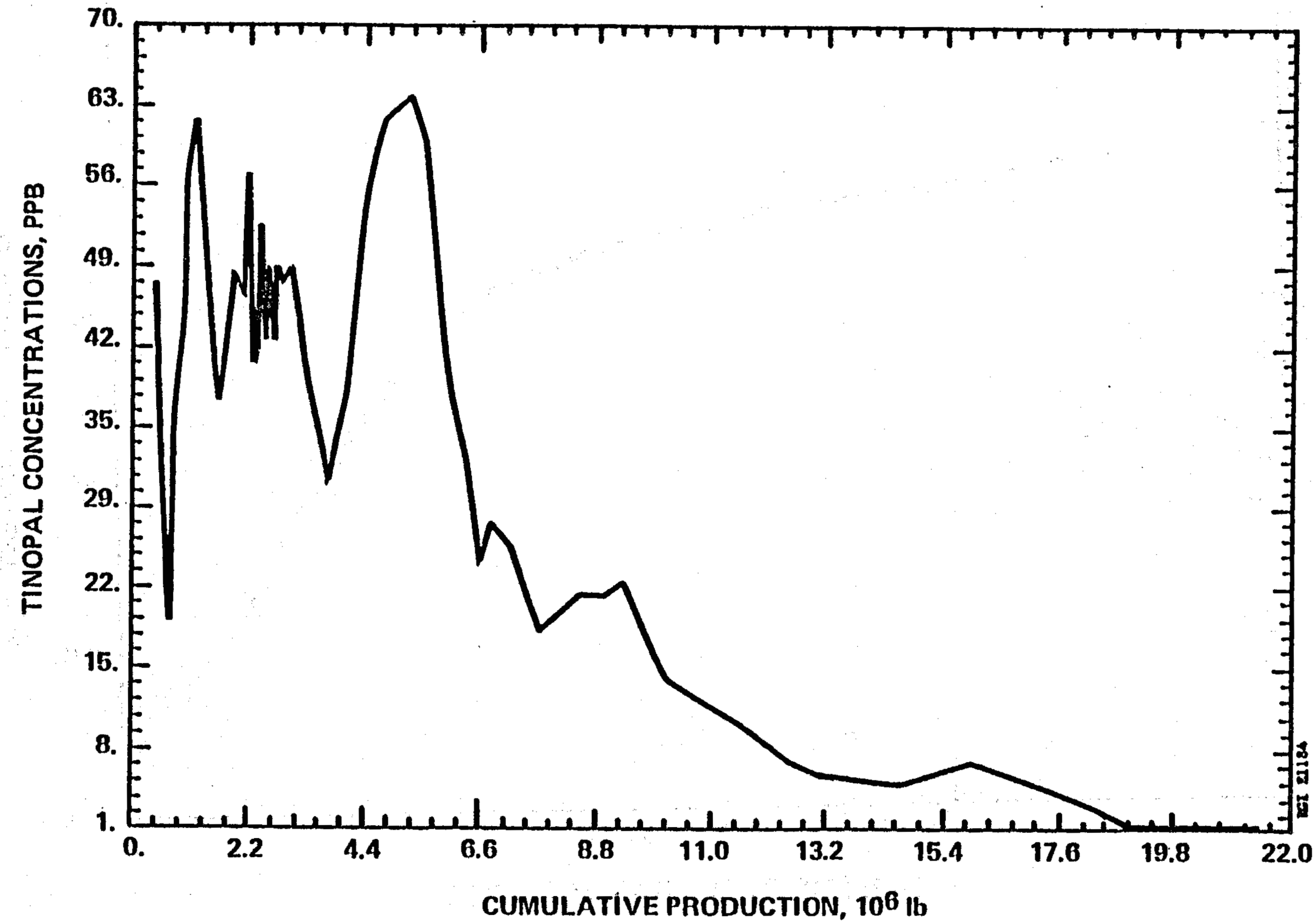


FIGURE 24

CONCENTRATION OF TINOPAL CBS-X VERSUS CUMULATIVE PRODUCTION

BACA 20



temperature. The Baca 20 tracer results are in general agreement with the tracer results obtained during the Baca 23 stimulation experiment in that there was relatively low tracer material return, an early appearance of reservoir fluid, thermal degradation of the polymer, and general mixing of the Tinopal CBS-X tracer throughout the return fluids. The data from this experiment are not sufficient to further quantify the reasons for the variations in tracer returns.

VI. FRACTURE DESIGN TECHNIQUES

A. Fracture Geometry Models

Because of the lack of information on the response of a fracture-dominated type resource to a hydraulic fracture treatment, a parameter study was performed using several methods published in literature which calculate dynamic fracture geometry. Theoretical calculations were made using the Geertsma (1969) linear and radial fracture growth models, the Perkins-Kern (1961) fracture geometry model, and the Nolte (1979, 1982) fracture geometry model. Considering the Geertsma linear flow model first, it was estimated that after the initial 3,000 bbl cooling water pre-pad was injected, the fracture width would be small and the total fracture volume would also be small (essentially negligible). Thus, at the 80 BPM rate and with an effective frac fluid viscosity of 300 cp, the fracture starts to significantly increase in width and volume only at the beginning of Stage 4 (Sinclair, 1971). Assuming a large fracture height configuration (i.e., a 600-foot vertical fracture height), the initial injection of 1,200 bbl of high viscosity frac fluid would create a 130-foot fracture length with a 0.266 inch fracture width. Table 11 shows the continued growth of the fracture calculated for the job as the injected fluid volume increased. The large fracture width calculated herein (0.432 inches) may explain the ease in which the large diameter proppant was placed in the fracture. The calculated dynamic fracture length was 340 feet at shutdown.

TABLE 11

BACA 20 FRACTURE GEOMETRY FROM GEERTSMA LINEAR FLOW MODEL

INJECTION RATE (BPM)	80.
PRE–PAD VISCOSITY (CP)–INITIAL 3,000 bbl	0.1
VISCOSITY (CP) FOR FRAC FLUID	300.
FRACTURE HEIGHT (FT)	600.
ROCK SHEAR MODULUS (PSI)	2600000.
FRACTURING FLUID COEFFICIENT $(FT/\sqrt{MIN})$	0.002
SPURT LOSS (FT^3/FT^2)	0.002

WIDTH (IN)	LENGTH (FT)	FRAC VOL. (FT^3)	EFF %	FLUID VOL. (bbl)	INJECTION TIME (min.)
.010	84.	84.	0.5	3000	38
.266	130	3,424	14.5	4200	53
.344	216	7,425	22.8	5800	73
.394	283	11,131	26.8	7400	93
.432	340	14,652	29.	9000	125

RGI E1243

The Geertsma radial flow model was also considered, however, the basic model assumption that the fluid enters into the formation at a single point was considered to be inappropriate. The temperature data, discussed earlier, show that the frac fluid entry zone covered a vertical height of about 100 feet at the wellbore (and possibly greater vertical height in the reservoir). By slight modification of the frac fluid efficiency value, the radial flow model does produce results in reasonable agreement with the linear flow model (as given in Table 12), but the assumed fracture shape, geometry, and boundary conditions cannot be correlated with experimental data.

The Perkins-Kern geometry model was considered next. The Geertsma model differs from the Perkins-Kern model only in the assumption of a no-slip boundary at the top and bottom of the fracture. Because of the boundary condition assumption, the Perkins-Kern model tends to predict a somewhat longer, thinner fracture. Howver, for the case considered here, the effect of the boundary condition is negligible because (1) the fraction height is large, and (2) the high viscosity fracture fluid forces a wide fracture and tends to mask any difference between the models. The availability of BHTP data, which is utilized by the Nolte analysis (and which assumes the same boundary conditions as the Perkins-Kern model) lead to the comparison of the Geertsma model results with the fracture geometry from the Nolte model. A Nolte-type pressure decline plot was constructed (as shown in Figure 25) using the pressure falloff data presented in Table 13. A comparison of the results of the Nolte pressure decline analysis to the Geertsma fracture geometry models shows good agreement as given in Table 12. It should also be noted that the estimate of time to fracture closure (49.2 min) is in reasonable agreement with that observed from the linear flow plot analysis (37 min) shown in Figure 26.

The only assumed value for both the Geertsma linear and Nolte fracture geometry theories is the 600-foot fracture height. The differing boundary conditions of the two theories cause slight differences in

TABLE 12

FRACTURE GEOMETRY COMPARISON

PARAMETER		GEERTSMA LINEAR FRACTURE ANALYSIS	GEERTSMA RADIAL FRACTURE ANALYSIS	NOLTE FRACTURE ANALYSIS
FLUID LEAKOFF COEFFICIENT		0.002 FT/$\sqrt{MIN}$ PLUS 0.002 FT^3/FT^2 SPURT LOSS	0.002 FT/$\sqrt{MIN}$ PLUS 0.002 FT^3/FT^2 SPURT LOSS	0.002216 FT/$\sqrt{MIN}$
FLUID EFFICIENCY		0.29	0.28	0.291
FRAC HEIGHT		600 FT	----	600 FT
FRAC LENGTH	TOTAL	680 FT	776 FT	846 FT
	ONE SIDE	340 FT	388 FT	423 FT
FRAC WIDTH (AVG.)		0.432 IN	0.356 IN	0.379 IN
CLOSURE TIME		----	----	49.2 MIN

RCI E1247

TABLE 13

NOLTE PRESSURE DECLINE DATA

Δt (min)	δ $(\Delta t/t_{INJ})$	P_{bh} @2,361′ (psig)	$\Delta P(.25,\delta)$ (psi)	$\Delta P(.5,\delta)$ (psi)	$\Delta P(.75,\delta)$ (psi)
1	.0081	2114			
5	.0406	1912			
10	.0813	1753			
15	.122	1655			
20	.163	1543			
25	.203	1462			
30	.244	1396			
35	.285	1335	52		
40	.325	1284	103		
45	.366	1242	145		
50	.407	1198	189		
55	.447	1160	227		
60	.488	1122	265		
65	.528	1093	294	20	
70	.569	1067	320	46	
75	.610	1041	346	72	
80	.650	1017	370	96	
85	.691	996	391	117	
90	.732	975	412	138	
95	.772	953	434	160	12
100	.813	936	451	177	29
105	.854	915	472	198	50

RGI E1246

FIGURE 25

NOLTE PRESSURE DECLINE ANALYSIS PLOT FOR BACA 20

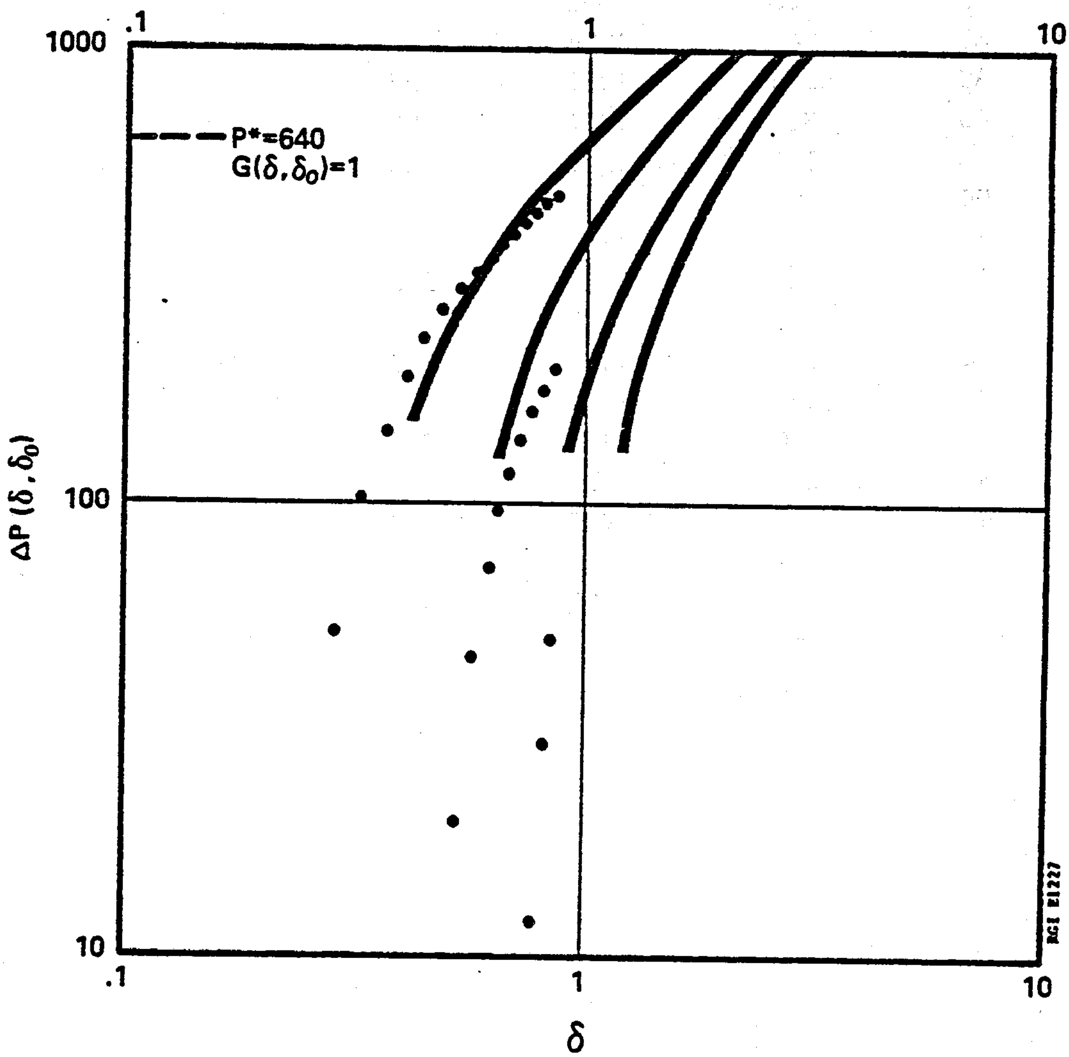
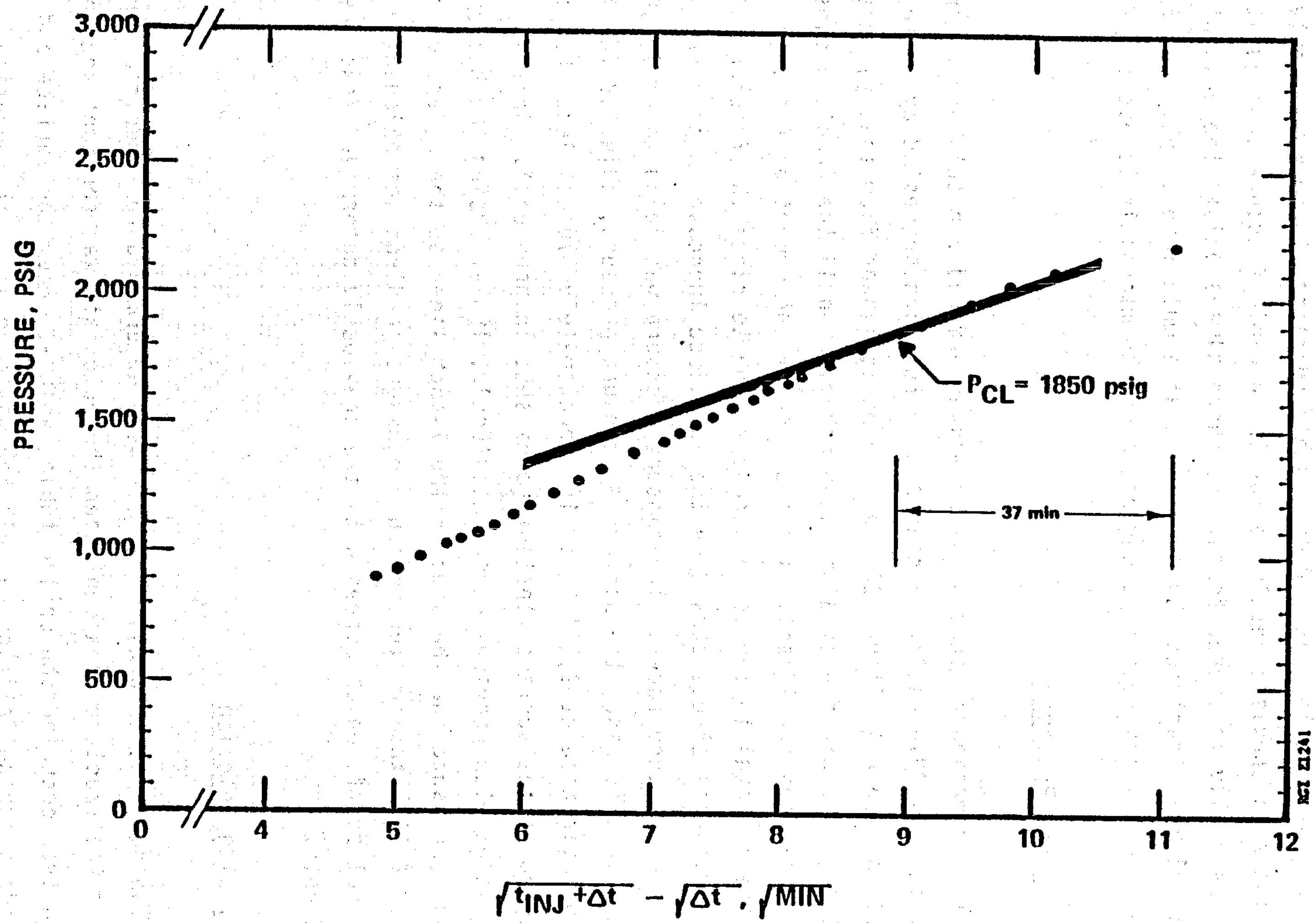


FIGURE 26

BOTTOMHOLE TREATING PRESSURE DECLINE PLOT

BACA 20



configuration, but good general agreement. These results compare favorably with the measured data discussed previously; however, if the fracture is not symmetrical or simple in shape, then the assumptions for either model are invalid. Under such conditions, these models only provide an approximate estimate for the dynamic fracture configuration. In a naturally fractured formation, there always exists the possibility that multiple fractures may open and that a much more complicated fracture geometry may result as suggested by the microseismic event data.

B. Closure Pressure

The formation closure pressure was determined for this experiment by plotting the BHTP falloff versus a time function suggested by Nolte (1979) as shown in Figure 26. According to linear flow theory, this plot should exhibit a straight line behavior until the fracture closes (i.e., becomes nonlinear). The pressure at the moment of fracture closure is equal to the total stress acting to close the fracture plus any additional stress caused by the localized increase in pore pressure near the fracture faces. The closure pressure was found to be 1,850 psig. In this case, the bottomhole closure pressure, adjusted for the hydrostatic head at 2,361 feet, is approximately 470 psi less than that measured at the surface (instantaneous shut-in pressure). This is consistent with previous experience (Erdle, 1981). Using the bottomhole closure pressure and the shoe of the 7-inch liner as the reference depth (4,880 feet), the fracture closure pressure gradient was calculated to be 0.601 psi/ft which agrees with the previously determined fracture gradients.

C. Tubing Friction

Tubing friction pressure losses were determined for specific periods during the fracture treatment when the pump rate was constant and one fluid type occupied the entire tubing volume. From the surface and BHTP records a tubing friction calculation was made using the equation

$$P_{tf} = P_s - P_{bh} + P_h$$

where

P_{tf} = Tubing friction pressure loss (psi)
P_s = Surface pressure (psig)
P_{bh} = Bottomhole pressure (psig)
P_h = Hydrostatic pressure (psig)

For Stages 4, 5, and 6 of the stimulation treatment, the treating record shown in Figure 12 gives

P_s = 2,400 psig
P_{bh} = 2,700 psig @ 2,361 feet
P_h = (0.433) 2,361 feet = 1,022 psig

Substituting in the above equation, the measured value for the tubing friction pressure loss is

P_{tf} = 722 psi (measured)

Using Western's tubing friction curves (1979) for a 4-1/2 inch frac string and a flow rate of 80 BPM, the friction pressure loss was found to be 340 and 700 psi per 1,000 feet of tubing for uncrosslinked and crosslinked HP guar fluids respectively. The calculated results show that the uncrosslinked frac fluid tubing friction pressure loss agrees reasonably well with the measured value from the treating records.

P_{tf} = 803 psi (calculated - uncrosslinked fluid)

P_{tf} = 1,653 psi (calculated - crosslinked fluid)

Even though the frac fluid was heated to about 100°F to speed crosslinking reaction time (estimated to be approximately 60 sec), an incomplete crosslink was probably formed in the tubing; hence, the tubing friction pressure loss is closer to the uncrosslinked value.

VII. ACID TREATMENT

A. Treatment Design

As discussed in Section V, Baca 20 produced at subcommercial rates following the hydraulic fracture stimulation experiment. As a possible remedy, an acid treatment was proposed to dissolve the finely ground calcium carbonate material used as a temporary plugging agent (fluid-loss additive) in the fracture treatment and which may have remained in the formation or in the propped fracture. The acid treatment was designed to remove 47,800 lb of calcium carbonate fluidloss additive using a hydrochloric (HCl) acid solution.

Successful removal of the calcium carbonate fluid-loss additive from the formation in Baca 20 was considered to have two potential benefits: (1) commercial productivity might be realized; and (2) more importantly, information might be obtained on the behavior of the fluid-loss additive which is critical to the design of future hydraulic fracture treatments.

Fine particulate matter is used almost universally in hydraulic fracture stimulation treatments for the purpose of temporarily plugging the formation along the path of the newly created fracture. By stemming the "leak-off" of fracture fluid to the surrounding formation, the growth of the fracture is enhanced. There are, however, potential complications involved with the use, or non-use, of fluid-loss additives. The potential penalties for not using a fluid-loss additive, especially in high permeability geothermal reservoirs, are a severe limitation in the length of fracture achieved and a possible early termination of the treatment due to proppant screen-out. The potential penalty for using a fluid-loss additive occurs when the well is returned to production. Ideally, the fine fluid-loss additive flows out of the formation, through the proppant pack, and out of the well. However, there has always been a serious concern that a substantial portion of the material may not flow out of the well and may, indeed, partially plug the formation and/or the fracture proppant pack.

Silica sand is the most common fluid-loss additive and has been used in most of the previous GRWSP experiments (Campbell, et al., 1981). However, in response to the concern about permanent plugging, finely ground calcium carbonate was used in Baca 20 as a substitute for sand, so that in the event it did not flow back out of the well it could be dissolved insitu with hydrochloric acid. In order to check for possible detrimental effects of the proposed treatment, Halliburton Services conducted a laboratory test simulating a propped fracture in Baca formation material at elevated temperature and closure stress (Appendix B). These tests indicated that acid had no adverse effect on fracture conductivity due to proppant failure or embedment.

During the post-fracture treatment testing described previously, no production of calcium carbonate fluid-loss additive was observed and it was believed that most of it still resided in the formation. Analysis of pressure data from the drillstem test suggested that a highly permeable fracture exists, but that it did not communicate with high conductivity natural fractures in the formation. One explanation for this result was that the fluid-loss additive plugged the flow channels in the formation. There is no diagnostic technique, however, that can establish this with any degree of certainty other than an acid treatment that would remove the material from the formation and possibly change the productivity of the well. Therefore, it was deemed important, both for the purpose of reaching a conclusive result in Baca 20 and for the purpose of guiding the design of future stimulation work, to do the acid treatment in Baca 20.

B. Treatment Execution

An acid treatment was performed in Baca 20 on August 11, 1982. The treatment consisted of injecting 43,900 gal of an 11.9 percent hydrochloric acid solution into the formation interval 4,880 to 5,120 feet and then displacing it with 37,300 gal of fresh water. The treatment was designed to dissolve 47,800 lb of finely ground calcium carbonate fluid-loss additive which was injected into the same interval during the fracture treatment. The quantity of acid used was 32 percent greater than the theoretical requirement. Details of the treatment and the associated rig operations are given in Appendix C. The total direct field cost for the treatment was \$60,400, compared to the original estimate of \$63,100. A detailed cost breakdown is given in Table 14.

The high static temperature in the treatment interval (520°F) required that several precautions be taken to prevent acid corrosion damage to the well tubulars. In preparation for the treatment an oil well-type servicing rig was moved in and well control equipment was installed on the well. A bailer was used to check for fill in the producing interval and then 2-7/8" tubing was run to a depth of 4,836 feet for use as a temporary acid injection string. The acid was mixed on-site in tanks with a corrosion inhibitor chemical added to provide protection for the well tubulars up to 250°F for a minimum of four hours. In order to cool the wellbore to within the effective range of the corrosion inhibitor, 200 bbl of fresh water were pumped down the tubing-casing annulus immediately prior to injecting the acid. Following the injection of cooling water, acid injection commenced at an average rate of 10.8 BPM down the tubing while fresh water was injected simultaneously down the annulus at an average rate of 5.1 BPM. A volume of 29,680 gal of acid solution with an average concentration of 17.0 percent was pumped down the tubing. The annular water injection served to cool the tubulars and to dilute the acid solution above the treatment interval to yield 43,900 gal of acid at an average concentration of 11.9 percent. Upon completion of the acid injection, the acid

Table 14

Actual Direct Costs to GRWSP
For Acid Treatment
Baca 20

Stimulation Materials and Services	
Acid and additives	$19,995
Pumping service	3,474
Mobilization and transportation	906
Water hauling	4,852
Tanks, rental and transportation	4,241
Misc. materials and service	1,433
	34,901
Rig and related equipment	
Mobilization	8,932
Daywork and fuel	6,231
	15,163
Equipment Rentals	
Tubing	1,139
Other	1,103
	2,242
Expendable materials	1,016
Transportation of rental equipment	991
Misc. services and equipment	
Manifold valves and fittings	4,283
Welding and backshoe	375
Rental equipment inspection	1,204
Other	256
	6,118
Total	$60,431

was displaced with fresh water and then the tubing was lowered to a depth near the bottom and an additional 632 bbl of water was pumped (half down the tubing and half down the annulus) to displace any acid from the bottom of the hole and to overdisplace the acid into the formation. The tubing was then pulled and the well was prepared for production testing.

C. Post-treatment Testing

After the acid treatment, Union elected to run a caliber survey in Baca 20 to check the condition of the casing before testing the well. The casing was found to be in satisfactory condition. A scale buildup, varying in thickness from 3/8" to 3/4", was found between the depths of 890 feet and 250 feet, but was not sufficient to interfere with the proposed production testing operations.

A 5-day, post-acid treatment production test was performed during August 1982. The average mass flow rate, assuming an 80 percent flash, was calculated to be about 50,000 lb/hr with a wellhead pressure of 22 psig. Compared to the 3-day, pre-acid treatment production test, which gave an average rate of 60,000 lb/hr with a wellhead pressure of 27 psig, the data show no change in the productivity of Baca 20. The well continues to experience a large pressure drawdown which causes the reservoir fluid to flash in the formation. Insitu flashing of the fluid severely reduces the flow capacity because of relative permeability effects associated with two-phase flow. Transient pressure data obtained during both these tests were not quantitatively interpretable with regard to single-phase permeability-thickness calculations, but the data did confirm that no improvement in the well's flow capacity was achieved.

A temperature profile (Figure 27) measured in Baca 20 following the acid treatment showed that the injected fluid distributed itself primarily between 4,950 and 5,100 feet. This generally agrees with the previous wellbore data which indicates the primary inflow zone is below 5,000 feet in the open interval.

D. Review of Chemical Data

After the injection of acid (711 bbl) and pre- and post-acid pads of fresh water (2,978 bbl), the well was produced as described above. Thirty-six samples of liquid were recovered between the 10,000 and 500,000 pounds of liquid produc- tion. These were analyzed for Ca, B, Fe, Mg, Mn, Na, and K. The changes in concentrations of those elements are interpreted in this section. The acid was essentially spent and/or diluted. The predominance of the returned fluid samples had a pH range of 3.5 - 4.5.

This discussion is intended to quantify several items:

- Fraction of injection water which was returned.
- Fraction of $CaCO_3$ fluid-loss additive which was dissolved.
- Efficiency of acid use on the $CaCO_3$.
- Amount of casing lost to the acid.
- Reliability of the calculated results.

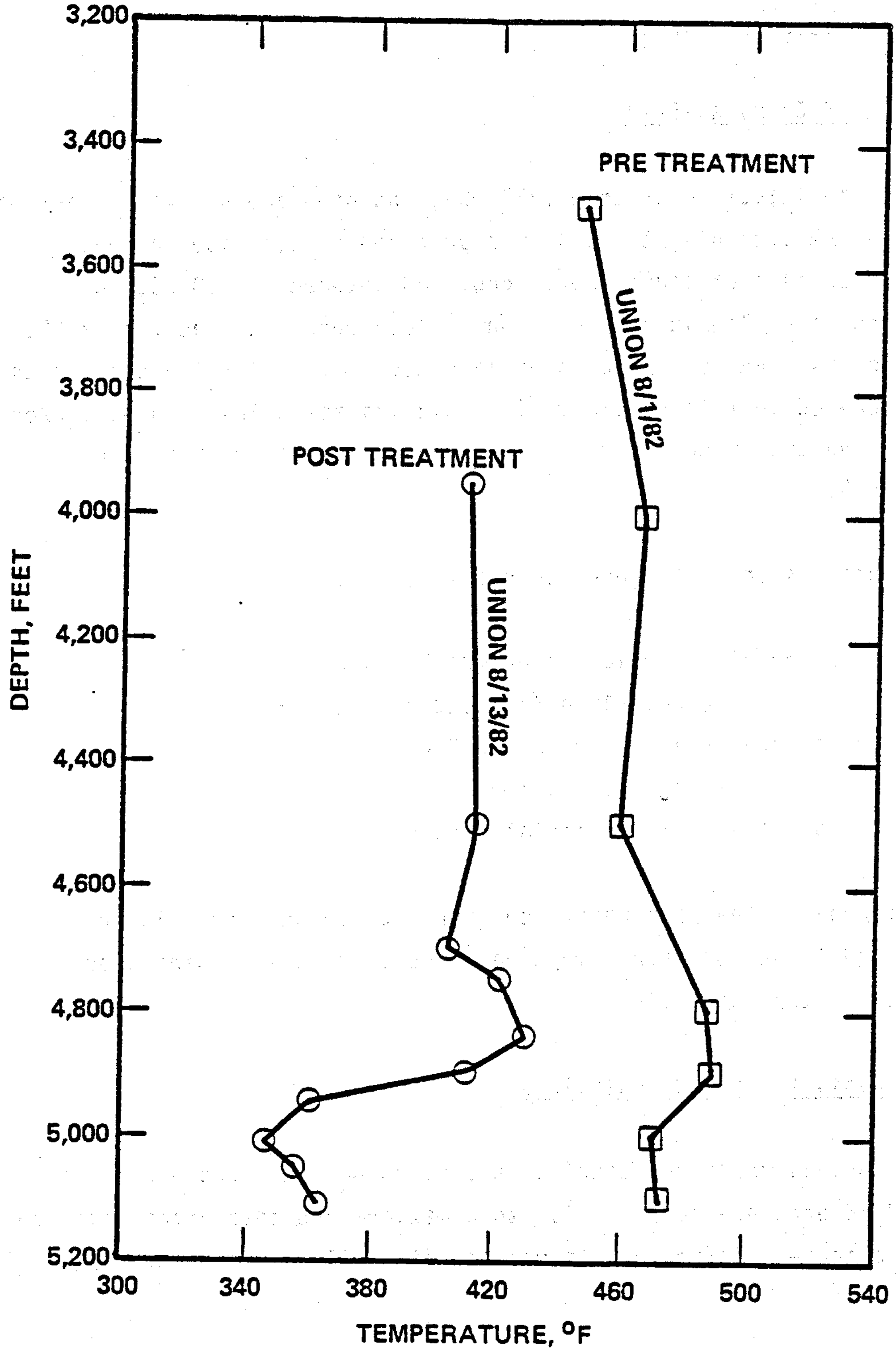
Additionally, the pattern of concentration changes for single elements and the comparisons among patterns suggest something about how fluids mix in the reservoir.

1. Basis for the Calculations

For all analyzed materials except boron, the concentrations in fluid returns are seen to rise to a maximum and thereafter diminish. This outcome is expected because the first fluids returned represent

FIGURE 27

BACA 20 TEMPERATURE PROFILES
August 1982



ECI E1291

nonacidic displacement fluids. Higher concentrations thereafter are a consequence of the acid reactions. Data for concentrations and cumulative production are shown in Appendix D (constituent analyses were provided by Union).

Concentrations, observed after the maximum level is reached, empirically show a linear relationship between the logarithm of the concentration and the cumulative mass of production. Figure 28, for calcium, is an example. Specifically, d(ln C)/dM is a constant. This mathematical form has analogy with radioactive decay in that the discharge coefficient (slope of the ln C vs M plot) characterizes the discharge of the analyte from the reservoir in the same way that a decay constant of a radioelement characterizes its activity. Analogous to the half-life of a radioelement, which is the time required for half the initial amount to decay, the half-volume for a fluid component is the amount of production (in mass units) required for its concentration to diminish to one-half of some earlier value. The half-volumes are given by ln 0.5/slope, analogous to half-lives which are given by ln 0.5/decay constant. These are listed with other data in Table 15. The discharge coefficient (the slope of the fitted line) is obtained by making a linear least squares fit to the post-maxima data of Table D-5. Least squares correlation coefficients have high values; most are in the range of 0.96 to 0.99.

Boron data are exceptional in having no maximum, but rather a continuously increasing concentration. The reasons for this fact and special treatment of boron data will be described later.

Table 15 shows the results of making linear least squares fits to the several sets of data. In addition, the total amounts of components returned by the produced fluid are listed. The row labeled "Returns on Inc. Concn." refers to the initial part of the production wherein the concentration was increasing. The entered

TABLE 15
Selected Values and Calculated Results
Based on Analytical Data

	Mg	Fe	Mn	Ca-22**	56-B*	K-160**	Na-800**
C(max)(ppm)	50	225	160	5100	32	93	4280
M@Cmax	81000	17000	15200	63000	-0-	110000	960000
-Slope $x10^5$	.6010	.5897	.5017	.2949	.2035	.1174	.0896
Correlation Coeff.	.989	.979	.9934	.971	.,59	.965	.921
Half-volume (pounds)	115300	117500	138000	235000	340600	590000	774000
Returns on Inc. Conc.(1)	2.02	1.91	1.22	160	-0-	5.12	205
Returns on Dec. Conc.(2)	5.11	34.5	29.5	1436	24.2	69.2	4383
Apparent Returns (pounds)	7.13	36.4	30.7	1596	24.2	74.3	4588
Return @ 100% efficiency	32.8	167	141	7344	NA	342	21110
Pounds of HCl equivalent	98.2	218	188	13360	NA	319	33460

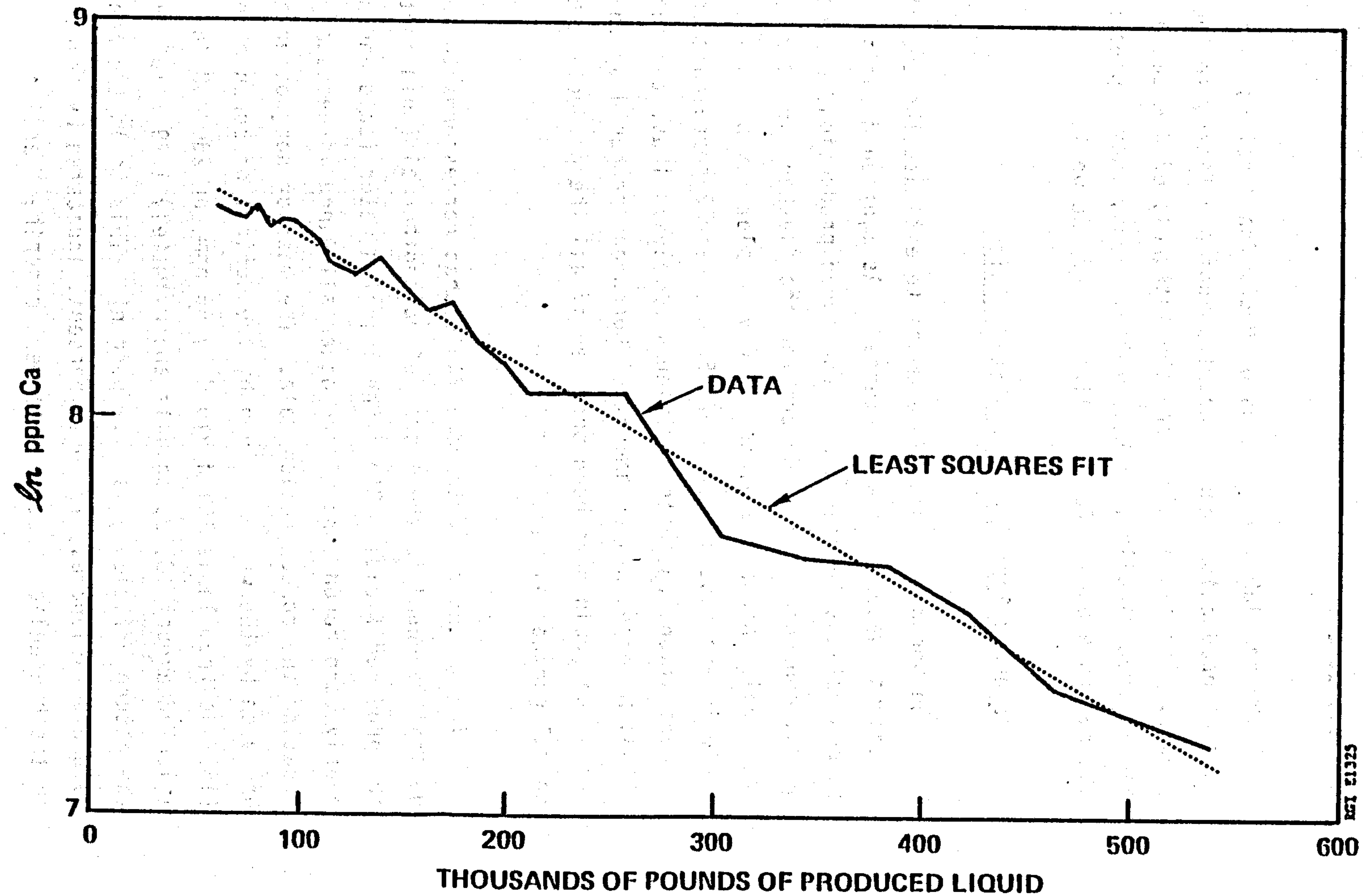
* Boron value represents a deficit of production. See text

**Adjustments to Ca, Na, and K represent their concentrations in normal geothermal residual flashed liquid.

(1) Computed as 0.5 (Cmax $x10^{-6}$)(M@Cmax)=pounds of analyte
(2) Computed as (Cmax $x10^{-6}$/-k)exp(-kM@Cmax)=pounds of analyte

FIGURE 28

LOGARITHM OF CALCIUM CONCENTRATION vs. CUMULATIVE LIQUID PRODUCTION



values were calculated using 1/2 (Cmax)(M@Cmax) where M@Cmax is the pounds of production corresponding to the maximum interpolated concentration.

The row labeled "Returns on Decr. Con." refers to the latter part of production where concentrations are fitted to the ln C vs M data. The table values are the integrals of CdM between M@Cmax and ∞, specifically $(C_0/-k)\exp(-km)$. Thus, they represent all the return expected for the lifetime of the well.

2. Returned Fraction of Injected Fluids

The boron data provide a means to estimate the amount of non-geothermal water that was returned. As mentioned earlier, boron concentrations increased with continued production, approaching the normal concentration of 56 ppm for the flashed liquid produced by this well. Accordingly, the ln C vs M plot for boron and data in Table 15 are made in terms of "56-B" where B represents the boron concentrations found in individual samples. Thus, the integral of (56-B)dM represents an amount of boron not produced by the reservoir but which would have been produced if all the production had been normal geothermal water.

The amount of geothermal fluid that corresponds to the boron deficit is equal to the amount of nongeothermal fluid contained in the produced fluids. Since the injected water (acid and pads) had nearly zero boron content, no other allowance is necessary in treating the concentration data. The mass of nongeothermal water produced by the well is given by the deficit of boron production (15.7 lb from Table 15) divided by 56 ppm; or 280,400 lb. The injected amount (3,690 bbl) is approximately 1.29×10^6 lb, hence the return efficiency is 21.7 percent. This is in the range of return efficiencies, 19 to 26 percent, indicated by tracers utilized in the hydraulic fracture treatment described earlier.

To the degree that 56 ppm represents the true boron concentration in residual (flashed) liquid, it would appear that 68.8 percent of fluids injected into Baca 20 are permanently retained.

3. Fraction of $CaCO_3$ Fluid-Loss Additive Removed

The returns of Ca are 1,596 lb (Table 15) after allowance for the 22 ppm expected in normal flashed liquid. Since the return fraction, based on boron, is only 0.217, the actual amount of Ca dispersed in all the liquids of this acid job is apparently 7,344 lb. This corresponds to 18,300 lb of $CaCO_3$. The amount of $CaCO_3$ fluid-loss additive placed in the well was 47,800 lb, thus, the acid appears to have dissolved 38.3 percent.

This outcome suggests that once the acid found a pathway through the fluid-loss additive, subsequent increments of acid could pass through the $CaCO_3$ zone and react with the country rock. The high returns of Na corroborate this interpretation. Table 15 shows that, in units of chemical equivalents, more than 5 times as much Na as Ca was delivered back in produced fluids.

The high Na returns also suggest that some Ca might have been mobilized from the same silicate rocks that yielded the Na, thereby inflating the apparent amount of $CaCO_3$ dissolved. However, the correlation coefficient for the Ca data is much closer to the ideal value of unity than is the coefficient for Na. This suggests that the source of Ca was less dispersed than the source for Na. Thus, the error in the $CaCO_3$ estimate due to Ca mobilized from silicate rocks is judged negligible.

4. Efficiency of Acid Attack on $CaCO_3$

The 18,300 pounds of $CaCO_3$ apparently dissolved by the acid was the result of injecting 45,570 pounds of HCl. At 100 percent efficiency, that amount of HCl could dissolve 62,500 pounds of $CaCO_3$. The efficiency of acid utilization on the target $CaCO_3$ is 29 percent. The pH's of return fluids show that all the acid was consumed. It is useful to estimate how much casing and country rock were dissolved by the acid which did not attack the $CaCO_3$. By considering the acid reaction with rock, it is possible to account for all of the injected acid by the amounts of Na, Ca, et al returned.

5. Casing Dissolution

The direct Fe returns (Table 15) are apparently 36.4 pounds which indicates that 167 lb of iron were mobilized by the acid. This is a reasonably small and acceptable amount, indicating successful functioning of the inhibitor used to reduce the acid attack on the casing.

However, the Mn returns suggest a less favorable outcome. Manganese is scarce in rocks and in casing steels compared to iron. For example, API casing steels carry about one percent Mn; in igneous rocks the Fe:Mn ratio is about 60:1. Thus, the nearly equal amounts of Fe and Mn indicated in Table 15 require interpretation if the analytical results are accepted at face value.

If the 30.7 lb of Mn represent only one percent of the acid-dissolved casing, then 3,000 lb of Fe must have been mobilized and all but 36 lb of that must have deposited in the rocks. For comparison, the 5-1/2 inch perforated liner contains a total of about 6,200 lb of Fe. These postulated iron deposits could be hydrolysis products formed when residual acidity of the transporting solution was consumed by reactions with $CaCO_3$ and/or country rock. In some zones, $FeCO_3$ would be a plausible solid form. The iron and its solid counterparts are carried only by the moving liquid, thus the deposition, if true, must be in the flow channels. This might partially explain the failure of the stimulation to yield improved production rates.

The Mn could have come from the country rock. Mn returns would represent the dissolution of about 25,000 pounds of country rock, presuming a Mn content of 0.4 percent. The mobilized Fe must be assumed to have deposited in the formation. By comparison, the Na returns could indicate leaching of up to 570,000 pounds of country rock. Thus, an ambiguity remains about whether acid attack on the casing is represented by the returns of Fe or of Mn, but the physical data suggest the casing dissolution is small.

6. Reliability of the Results Calculated Above

There are several reasons to suspect that individual calculated values in Table 15 might contain substantial errors. There are serious questions about the accuracy of the fluid production data and these affect the discharge coefficients. Also, there are aspects of the chemical data which make some sets of those data appear suspect.

On the other hand, most of the data appear well behaved in the sense that qualitative features of plots appear reasonable. Also, relative values for slopes and M@Cmax are in correct sequence as regards expected chemical behaviors of components. Some elaboration about those factors is presented in this section.

Measurements of fluid production are based on pressure differentials across an orifice plate in the two-phase production line. In order to succeed with that approach, an estimate of the vapor fraction is required. Such an estimate can be obtained by sampling the flow line with a "mini-separator" in a way done commonly by Union's personnel. In the case at hand, no mini-separator was used, instead, the estimates of vapor fraction were based on measurements made on Baca 20 during an earlier production test. The true correspondence between these tests is unknown. It is known from previous experience that the flash fraction increases during the flow test until a steady-state condition is reached. Therefore, the use of a constant 80 percent flash is probably high.

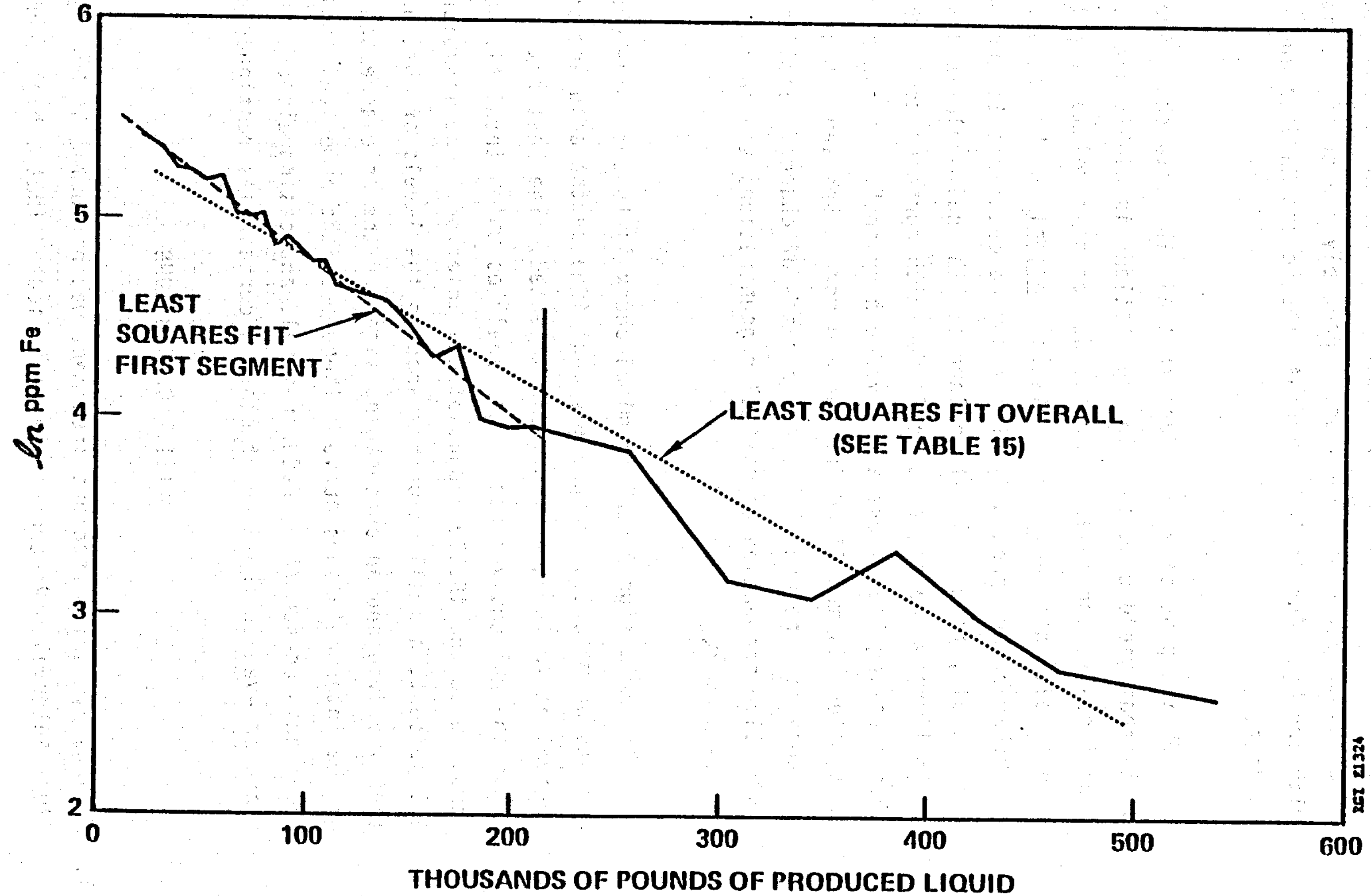
Some of the chemical data can be interpreted as showing two nearly-linear segments in the plot of ln C vs M plot rather than one (Fe, Mg, Na, and B). Figure 29 for iron is an example. The later segment has a shallower slope in all cases. This would be expected if flash percent were to increase as production continued. The entries in Table 15 all refer to the best-fit lines for the entire set of data, however. This causes the integrations to yield larger values because those slopes are of greater magnitude.

The iron and magnesium analyses appear to be confounded. For the early data, half-volume values for Fe and Mg are 87,500 and 86,600 pounds, respectively, and for the whole data sets, 117,500 vs 115,300 pounds. Even their correlation coefficients with production volume are nearly identical; .9908 vs .9938 for Fe and Mg in the early data and .979 vs .989 for whole data sets. When Fe values are regressed against Mg values the correlation coefficient exceeds .999. The root-mean-square mismatch between reported Mg values and the correlation with Fe is only 1.1 ppm which is smaller than expected errors in manipulation.

The calculated returns of Mg were less than one-fourth those of Mn, but Mg/Mn ratios in igneous rocks are near 30:1. Thus, the Mg appears scarce in the returns compared to Fe, Mn, and Na.

FIGURE 29

LOGARITHM OF Fe CONCENTRATION vs. CUMULATIVE LIQUID PRODUCTION



However, the value for M@Cmax for Mg is substantially larger than the counterpart for Fe, indicating that the Mg was mobilized more remotely from the wellbore. Probably the error, if any, is with the Mg. One is led to retain the Fe and Mn data and reject the Mg data.

On the plus side, the fact that all the data show clear linear plots that yield plausible interpretations is highly significant. Additionally, the relative magnitudes of half-volumes for the several elements can be established _a priori_ on the basis of chemical behavior and proximity of the source materials to the wellbore. For example, from smallest to largest, the half-volumes listed in Table 15 show the sequence Fe-Ca-Na which corresponds to the sequence casing/fluid-loss additive/country rock. It can be expected that materials mobilized further and more dispersedly from the wellbore will return with smaller rates of change. Similarly, the cumulative production at maximal concentrations are in the sequence Mn~Fe<Ca<Na<K.

The most significant chemical check is to determine whether the amounts of materials apparently mobilized by the acid are chemically equivalent to the amount of acid injected. The last row in Table 15 shows the HCl equivalents of the analytes which total 47,640 pounds compared to the 45,570 pounds of HCl injected. The mismatch is only 4.5 percent, a small value compared to the levels of most uncertainties involved and an encouraging sign for the relevance and accuracy of the interpretations above. Therefore, the numerical implications about acid consumption, $CaCO_3$ removal, and casing attack, can be accepted even in the face of other uncertainties mentioned above.

VIII. CONCLUSIONS

1. A large hydraulic fracture treatment was performed at Baca 20 in a 520°F interval. Production tests indicated that a high conductivity

fracture was propped near the wellbore and communication with the reservoir system was established. It is believed that this is the highest temperature well in the world to be prop-fractured to date.

2. The productivity of the treated zone in Baca 20 declined to a non-commercial level following the fracture treatment. The probable cause is 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 fracture.

3. Both the Geertsma and Nolte fracture geometry models provide results which appear to agree with the measured data. However, the naturally fractured formation may be a far more complex system than can be accurately described by the simple assumptions inherent in these models.

4. Results of the two fracturing experiments combined with Union's other drilling and testing experience point to at least one characteristic of the Baca reservoir which makes it less viable as a candidate for hydraulic fracture stimulation than it was originally thought to be. The high temperature combined with a relatively low reservoir pressure and a relatively low reservoir kh increases the likelihood of two-phase flow in the formation. A proppant-filled fracture which is highly conductive under normal single-phase flow conditions becomes more restrictive in two-phase flow because of relative permeability effects and turbulence.

5. Although the stimulation treatment did not result in a commercial well, the hydraulic fracturing technique shows promise for future stimulation operations (such as multiple zone treatments) and for being a valid alternative to redrilling and/or new well drilling in high temperature geothermal reservoirs.

REFERENCES

Albright, J. N., and Pearson, C. F., "Location of Hydraulic Fractures Using Microseismic Techniques," SPE paper 9509, September 1980.

Dondanville, R. F., "Geologic Characteristics of the Valles Caldera Geothermal System, New Mexico," Geothermal Resources Council, Transactions, v. 2, p. 157-159, July 1978.

Erdle, J. C.: "Results of Hydraulic Fracturing Treatment BHP Analysis in Peru," SPE paper 10310 presented at the 56th Annual Fall Technical Conference and Exhibition, San Antonio, Texas, October 1981.

Geertsma J.: and deKlerk, F.: "A Rapid Method of Predicting Width and Extent of Hydraulically Induced Fractures," J. Pet. Tech. (December 1969) p. 1571-81.

Geothermal Fracture Stimulation Technology, V I, Fracturing Proppants and Their Properties, July 1980, V II, High Temperature Proppant Testing, July 1980, V IV, Proppant Analysis at Geothermal Conditions, January 1981, Geothermal Reservoir Well Stimulation Program, DOE Contract No. DE-AC-32-79AL10563.

Hartz, John D., "Geothermal Reservoir Evaluation of the Redondo Creek Area, Sandoval County, New Mexico," Union Oil Company Report, pp. 87, September 1976.

Morris, C. W., Verity, R. V., and Sinclair, A. R., "Raft River Well Stimulation Experiments," Geothermal Resources Council, Transactions v. 4, September 1980.

Nolte, K. G.: "Determination of Fracture Parameters from Fracturing Pressure Decline," SPE paper 8341 presented at the 54th Annual Technical Conference and Exhibition, Las Vegas, Nevada, September 1979.

Nolte, K. G.: "Fracture Design Considerations Based on Pressure Analysis," SPE paper 10911 presented at the 1982 SPE Cotton Valley Symposium, Tyler, TX, May 20, 1982.

Pearson, C. F., personal communication, January 11, 1982.

Perkins, T. K. and Kern, L. R.: "Widths of Hydraulic Fractures," J. Pet. Tech. (September 1961) p. 937.

Raft River Well Stimulation Experiments, Geothermal Reservoir Well Stimulation Program, DOE Contract No. DE-AC-32-79AL10563, August 1980.

Sinclair, A. R.: "Heat Transfer Effects in Deep Well Fracturing," J. Pet. Tech. (December 1971) p. 1484-92.

Smith, R. L. and Bailey, R. A., "Resurgent Cauldrons," Geologic Soc. of America, Memoir 116, p. 613-662, 1968.

Van Buskirk, R. G., Enriss, D. D., and Prater, F. M., "Tests on Baca 17 Tuff Geothermal Well Cores," Terra Tek, TR79-79A, p. 21, October 1979.

Verity, R. V. and Morris, C. W.: "Fracture Stimulation of Union's Baca Well 23," Geothermal Resources Council, Transactions V 5, October 1981.

Western Company, Stimulation Fluid Friction Pressure Handbook, 1979.

APPENDIX A

APPENDIX A

HISTORY OF BACA 20 FRACTURE STIMULATION
(All depths refer to KB, 24' AGL)

9/11-15/81	Moved in Brinkerhoff-Signal Rig No. 78.
9/16/81	Made trip with 7" casing scraper. Pulled and recovered 7" liner. RIH to top of fish at 5,827', no fill. Rigged up loggers.
9/17/81	Ran logs.
9/18/81	Finished running logs. Sanded back from 5,827' to 5,500'.
9/19/81	Sanded back from 5,500' to 5,400'. Plugged back with cement from 5,400' to 5,079'.
9/20/81	Sanded back from 5,079' to 4,873'. Spotted (3) 300 linear foot cement plugs. Tagged top of cement at 4,618'.
9/21/81	Plugged back hole from 4,618' to 3,825' with cement. Circulated hole with 25% returns. Spotted cement plug No. 6 (300 linear feet) at 3,825'.
9/22/81	Tagged cement plug No. 6 at 3,271'. Drilled out cement, losing 30 BPH. At 3,934' began losing 150 BPH. Drilled to 3,950' and spotted cement plug No. 7 (300 linear feet).
9/23/81	Tagged cement at 3,767'. Circulated with 40 BPH fluid loss. Drilled out cement 3,767' to 3,997' with 180 BPH loss. Continued drilling out cement to 4,106' and then spotted cement plug No. 8. Tagged cement at 3,850'. Circulated with 120 BPH fluid loss. Spotted plug No. 9 at 3,825'.
9/24/81	Drilled out cement to 4,650'. Lost all circulation at 4,650' and ratholed ahead to 4,653'.
9/25/81	Spotted cement plug No. 10 (300 liner feet). Tagged cement at 4,460'. Filled hole and circulated with 200 BPH fluid loss. Spotted plug at No. 11 at 4,415'. Circulated with 200 BPH loss. Spotted plug No. 12 at 3,900'.
	Built up and contoured location with gravel to provide for good tank drainage.
9/26/81	Spotted cement plug No. 13 at 3,850'. Gelled up circulating water. Began drilling out cement.

Spotted ten 500 bbl horizontal frac tanks on location with the use of a hydro-crane.

9/27/81 Drilled out cement.

Began filling frac tanks with water.

9/28/81 Finished drilling out cement and cleaned out sand to 4,897'. Fluid loss increased to 300 BPH. Switched to aerated water and cleaned out to 5,120'. Sanded back to 4,908'. Spotted a 100 linear foot cement plug at 4,872'.

Continued filling frac tanks with water.

9/29/81 Tagged top of cement at 4,775'. Circulated hole taking 294 BPH. Spotted cement plug No. 15. Tagged cement at 4,500'. Drilled out cement to 4,692'.

Completed filling 10 frac tanks with water. LANL ran gauge ring and temperature tool to 3,875' in Baca Well No. 22.

9/30/81 Drilled out cement from 4,692' to 4,890' with 20 BPH fluid loss. Ran 7", 26 lb K-55 LT&C blank liner to 4,880'. Top of liner at 2,383'.

10/1/81 Cemented liner with 1,065 cubic feet spherelite cement (180% excess). Cement job consisted of following: HOWCO pumped 112 cubic feet preflush, 56 cubic feet water, 133 cubic feet Flowcheck, 112 cubic feet water, 835 cubic feet class "H" cement with 50 lb/sack spherelite, 40% SSA-1, 4% gel, 5% lime, 1% CFR-2, 0.4% HR-7. Tailed in with 230 cubic feet class "H" cement with 40% SSA-1, 0.5% CFR-2, 0.3% HR-7. Displaced with 709 cubic feet water. C.I.P. at 0230 hours. No cement on top of 7" liner. POH. Started picking up tubing at 1200 hours and finished at 2000 hours. Stood tubing in derrick. Tested 7" liner lap. Lap took 4 BPM at 4,000 psi.

Built up and contoured last side of location for setting of remaining 9 frac tanks. Picked up 4-1/2" EUE tubing string and stood same in derrick.

10/2/81 Changed WKM master valve on B-20. Squeeze cemented 7" liner lap.

10/2/81 Moved in and spotted remaining 9 frac tanks and Western's Sandmaster. Began filling tanks with water. Installed LANL lubricator on Baca No. 22.

10/3/81	RIH with 8-3/4" bit. Tagged top of cement at 2,230'. Drilled out cement to top of 7" liner hanger (2,383'). RIH with 6-1/8" bit. Found no cement in liner top. Continued filling frac tanks with water. Off-loaded bauxite from transports into Sandmaster and dump trucks. RGI took over rig cost as of 1700 hours 10/3/81. Hot oilers began heating water to be used for gelling frac fluid.
10/4/81	Cleaned out cement and sand to 5,120'. LANL and Sandia attempted borehole televiewer log twice without success. Ran Kuster temperature survey. Finished heating water in frac tanks from 60°F to 100°F. Began gelling fluid.
10/5/81	Finished gelling frac fluid. LANL ran pre-frac temperature log. Tagged well bottom at 5,060' with temperature tools. Made up Otis 7" packer, crossovers, and 8 foot pup joint carrying pressure instrument on 4-1/2" EUE tubing. Started in hole at 0500 hours. Hit 9-5/8" x 7" liner hanger 18 feet high. Worked pipe for 30 minutes but unable to go any deeper. POOH. Discovered aluminum wireline guide on bottom of packer slick joint was badly beaten. Mule-shoed guide, reset clocks in Kuster instruments, and proceeded in hole. Set packer at 1200 hours. Packer set with top at 2,412', bottom at 2,417', and bottom of slick joint at 2,434'. Pressure-tested annulus to 1,000 psi. Held pressure for 6 minutes. Rigged up frac head and made final preparations. Began frac stimulation at 1620 hours and completed same at 1823 hours. Tubing remained pressured at 1930 hours but was on vacuum at 2000 hours. Unset packer and POOH. Rigged up LANL to run temperature log. Western rigged down and moved out frac equipment.
10/6/81	LANL ran two temperature logs four hours apart. Minimum point recordings were 280°F and 297°F. Waited on well to heat up. Ran 3 point Kuster temperature survey. Minimum recording was 308°F. Waited on well to heat up.
10/7/81	Continued waiting on well to heat up - a total of 24 hours. Started in hole with 6-1/8" bit at 0300 hours. Began pumping 6.0 BPM of Baca No. 13 produced water and 600 CFM air at 0530 hours. First returns seen at 0730 hours. Increased water pump rate to 7.2 BPM at 0745 hours. Used fresh water in place of produced water at 0900 hours. Decreased water rate to 6.6 BPM and increased air rate to 850 CFM at 1200 hours. Stopped circulation at

1420 hours and POH. No significant amount of solids over shaker at any time during cleanout. Schlumberger rigged up and ran logs.

10/8/81 Schlumberger continued running logs until 1100 hours. Made clean out run with 6-1/8" bit to 5,131'. Ran 5-1/2" F.J. perforated liner. Hung liner at 4,760' with shoe at 5,131'. RIH with 6-1/8" bit to 3,746'. Started pumping 6 BPM produced water and 750 CFM air. Broke circulation after 35 minutes. Well made between 100-150 BPH. (Injected produced water at average 410 BPH during logging and at average 290 BPH after logging). Hole was full at one point during logging operation.

10/9/81 Continued circulating well. Increased air rate to 1,800 CFM and 700 psi. Well producing 150-200 BPM. Stopped pumps at 1700 hours. Well continued to flow for 30 minutes. Made up Otis 7" packer on 3-1/2" and 4-1/2" combination DP string. Set Kuster instruments clock and installed instruments in tubing stinger below packer. RIH and set packer at 2,966' for DST. Rigged up NOWSCO coil tubing unit. Started pumping nitrogen at 0445 hours while running in hole with coil tubing to 2,800'. First flow at 0630 hours. Nitrogen truck broke down at 0730 hours.

10/10/81 Shut-in well while waiting on another nitrogen truck. Pulled tubing out of hole at 1130 hours. Set tubing head in rig floor, unset packer at 1255 hours and POH. Redressed packer and reset Kuster clocks. RIH with packer and instruments. Set packer at 2,966' and tested annulus to 500 psi. Rigged up coil tubing head and RIH with tubing at 1954 hours. Started pumping nitrogen at 400 SCFM with coil tubing at 1,090'. Continued in hole with tubing to 2,800', at 2305 hours reduced nitrogen to 350 SCFM to maintain uniform fluid production rate. At 0136 hours increased rate to 400 SCFM to off-set fluid production rate decline. Shut off nitrogen and shut-in well at 0234 hours to begin pressure buildup phase of DST. POH with coil tubing. Had nitrogen blow down for approximately 5 minutes while trying to get Kelly clock to seal.

10/11/81 Kept well shut-in for pressure buildup until 1034 hours. Had 60 psi on drillpipe string. Pumped water down drillpipe and bled off nitrogen pressure. Released packer at 1111 hours and POH. Laid down 4-1/2 frac tubing string. RIH with sinker bars to 5,131'-no fill. Laid down extra 3-1/2" drillpipe and 4-3/4" drill collars. Wait on Schlumberger.

10/12/81	Rigged up Schlumberger. RIH with temperature tool and casing collar locator (CCL) tool to 1,900'. Temperature (360°F) too hot for logging tools. POH. Pumped in one hole volume of water. RIH with logging tools and logged temperature from 3,000' to 5,069'. (Log No. 1). Recorded minimum temperature of 302°F at 4,720'. POH. Injected 1,066 bbl of water. RIH with temperature and CCL tools and logged temperature from 3,000' to 5,140' (Log No. 2). POH. Waited for two hours allowing well to heat up. RIH with temperature from 3,500' to 5,147'. (Log No. 3). POH. Rigged down Schlumberger. Laid down drillpipe.
10/13/81	Laid down drillpipe. Nippled down BOPE. Released rig at 1400 hours.

APPENDIX B

FORM 1012 R-6 LITTLE'S 112485 6M 9/80

CHEMICAL RESEARCH AND DEVELOPMENT DEPARTMENT

HALLIBURTON SERVICES
DUNCAN, OKLAHOMA

RE IVED
0 1981

LABORATORY REPORT

No. S30-B062-81

To Dr. David S. Pye
Union Geothermal Division
Box 6854
Santa Rosa, CA 95406

Date July 7, 1981

We give below results of our examination of the submitted core.

Submitted by Dr. David S. Pye for Union Geothermal - Republic Geothermal

Marked Union Oil - Republic Geothermal Project
Boco NM
Core #B-17 5150' Welded Bandelier Tuff
Core #B-22 6000' Paliza Canyon Andesite

PURPOSE

A fracturing treatment using 12/20 bauxite as the proppant and calcium carbonate as the fluid loss additive was considered as a treatment. These cores were submitted for acid flow studies through the 12/20 bauxite packed fracture bed in an effort to determine if acid subsequently flowed to remove the calcium carbonate would reduce the fracture conductivity. The calcium carbonate was not used since it would reduce the original fracture conductivities. The entire test procedure was discussed with Dr. Pye prior to the actual test.

RESULTS

The test procedure and results along with a partial core analysis is included in the Data Section of this report.

There appeared to be no core face or proppant damage in the test as performed.

DATA

FRACTURE FLOW CAPACITY TESTS

Procedure

Step 1 - The two submitted cores had 2.50" O.D. core plugs drilled and mounted in lead. A steel screen was placed around the circumference of the core to contain the proppant. A 0.25" fluid entry hole was drilled in the middle of the core and a perforated tubing placed in it to keep the proppant out of the entry hole.

Step 2 - 12/20 bauxite at 2#/ft^2 of fracture was placed on the bottom core and leveled. The entire system was flooded with kerosene to remove any air from the system and from the proppant bed. The top core was then placed on the proppants, rotated slightly to level off the proppant bed then closure pressure applied.

Step 3 - The fracture conductivities were measured at closure pressures of 0.2, 0.4, 0.6 and 0.8 psi/ft. and reported.

Step 4 - The device was left at the 0.8 psi/ft. closure pressure and the temperature raised to 325°F with the system closed in.

Step 5 - The entire system was pressured to 1000 psi and acid flowed radially through the proppant bed at 325°F for 60 minutes at 20 ml/minute with the 0.8 psi/ft. closure pressure still applied.

Step 6 - The acid was removed and replaced with kerosene, then the device was closed in and allowed to cool overnight to room temperature.

Step 7 - The fracture conductivity was remeasured at 0.8 psi/ft. using the same system as in the original flow tests (step #3).

Step #8 - The cores were removed and the core face observed. No effect of proppant embedment on the core face was noted.

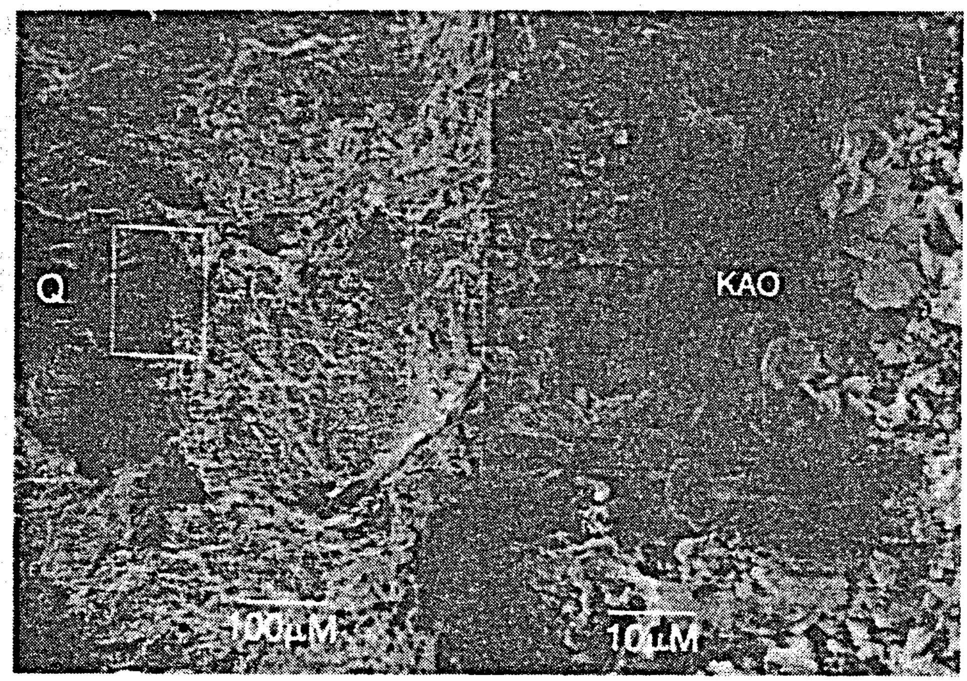
RESULTS

Test	Core No.	Closure Force Gradient (psi/ft)	Closure Force psi	Closure Force Total (lbs)	FF Capacity (md ft.)
Before Acid	B17-5150'	0.2	1,030	5,005	8,066
		0.4	2,060	10,011	7,057
		0.6	3,090	15,017	6,738
		0.8	4,120	20,023	6,415
After Acid		0.8	4,120	20,023	7,057
Before Acid	B22-6000'	0.2	1,200	5,832	6,977
		0.4	2,400	11,664	6,977
		0.6	3,600	17,496	6,742
		0.8	4,800	23,328	6,506
After Acid		0.8	4,800	23,328	7,331

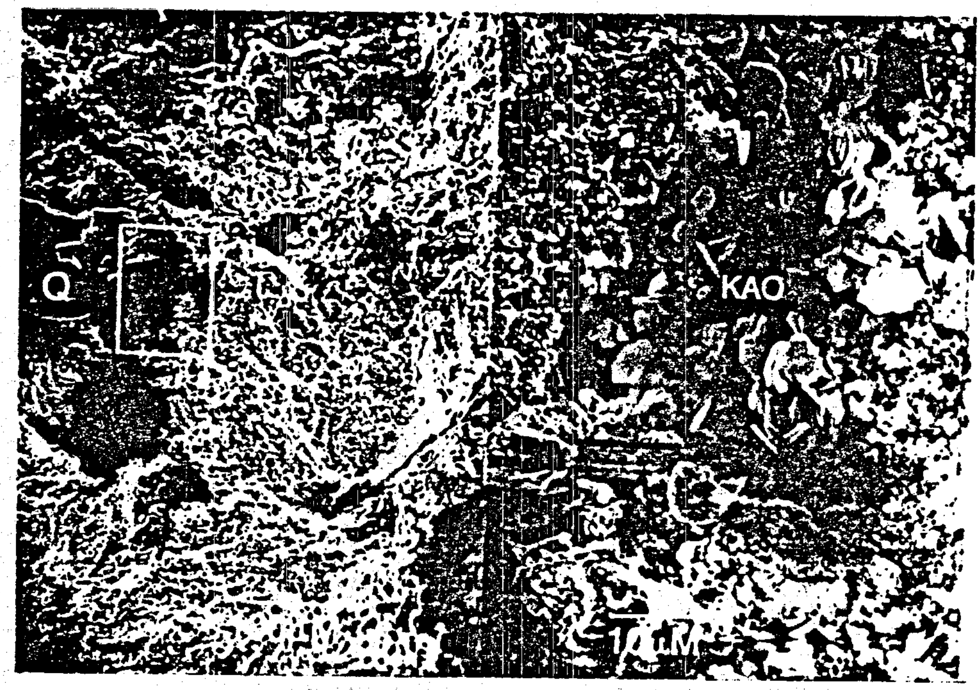
X-RAY DIFFRACTION ANALYSIS

	5150' 1	6000' 2
Quartz	Large	Moderate
Feldspar	Major	Major
Kaolinite	Small	-
Illite	Trace	-
Chlorite	-	Small
Solubility*	1.8	2.9

*Solubility in dilute HCl as $CaCO_3$.

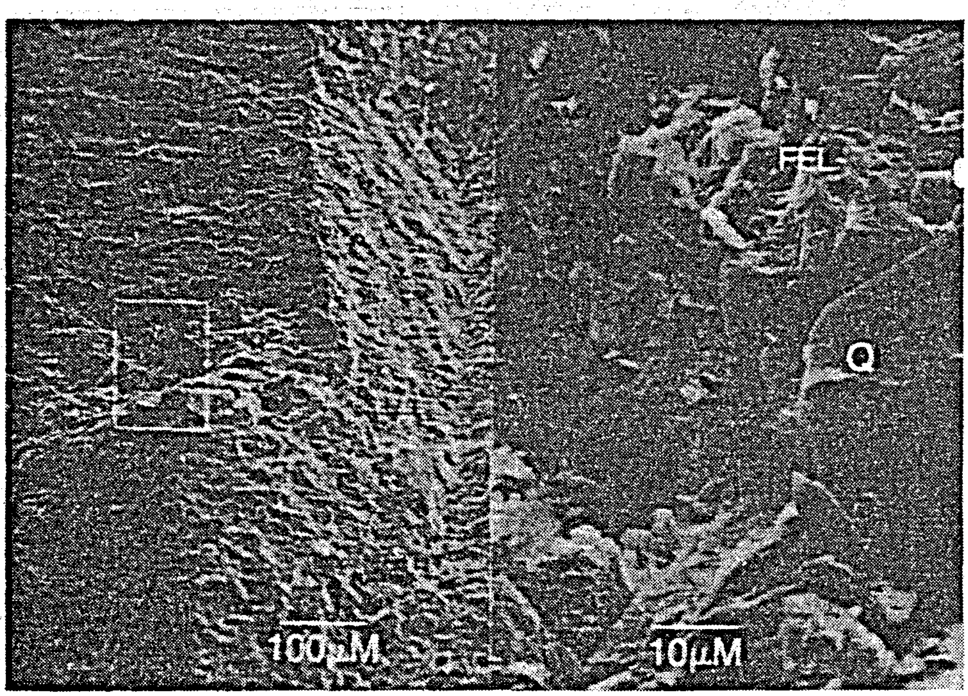

Q
KAO
100µM
10µM

SCANNING ELECTRON MICROSCOPE ANALYSIS

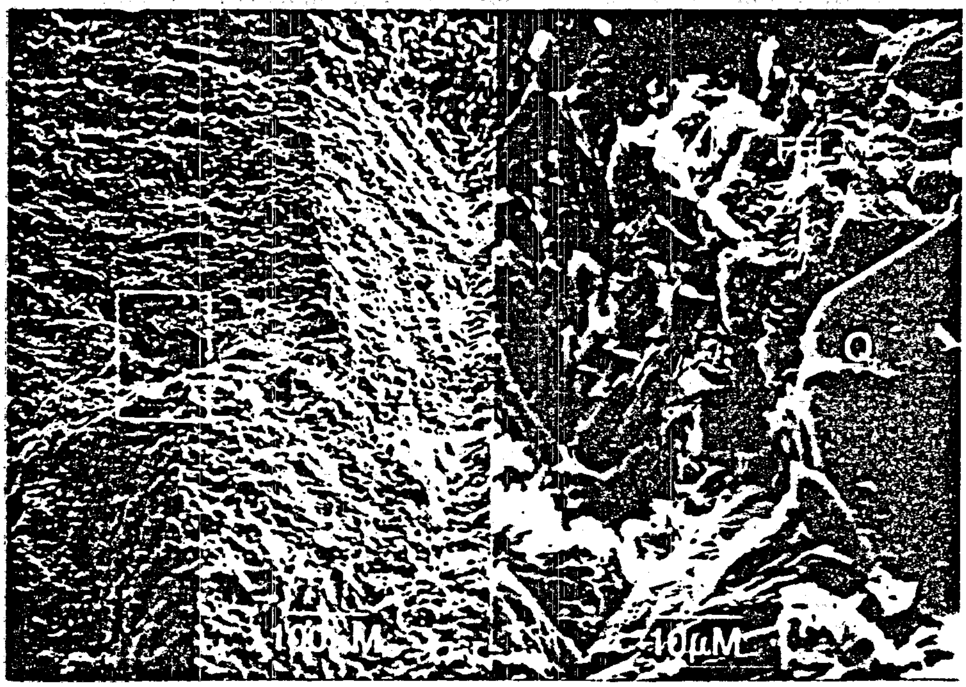


Core #1, Depth 5150', Magnification 100X, 1000X, Neg. No. 21975-1426

This sample has a framework of feldspar grains ranging in size from debris to very coarse sand (1.4 mm). Fine to coarse silt size (.008 - .031 mm) quartz grains are also present, some of these secondary quartz. Kaolinite, along with the quartz pieces and feldspar debris, covers the surface. Porosity appears to be fair. Some large quartz grains were also observed (.40 mm). The photo shows a potential pore space infilled with kaolinite. The very fine stuff is debris, kaolinite, quartz, and feldspar.


FEL
Q
100µM
10µM

SCANNING ELECTRON MICROSCOPE ANALYSIS



Core #2, Depth 6000', Magnification 100X, 1000X, Neg. No. 21975-1425

This sample has a framework of feldspar. Grain size could not be determined. No porosity was observed. The feldspar surface shows signs of partial weathering. A very small amount of chlorite is present in places as coating. Some quartz was also observed. The photo shows a potential intergranular area.

DATA BOOK REFERENCE

The data presented in this report are recorded in Chemical Services Book No. 4251, pages 59, 72 and 73; Analytical Book No. 4355, page 61; Analytical Book No. 4393, page 24; and Analytical Book No. 4389, page 25.

cc: Mr. G. M. Pruett
Mr. T. Garvin
Mr. J. McLean
Mr. R. M. Lasater
Mr. E. J. Stahl, Jr.
Mr. G. C. Broaddus

Respectfully submitted,

Laboratory Analyst

Stewart-Kistler-Blanton-Ketchum

HALLIBURTON SERVICES

By S E Fredrickson

rdf

S. E. Fredrickson fk

APPENDIX C

HISTORY OF BACA 20 ACID TREATMENT
(All depths refer to original K.B., 24' AGL)

8/1/82 Union ran static pressure and temperature surveys from surface to 5,100'.

8/3/82 Met with workover rig contractor (Action Well Service) at location to review program and establish schedule for rig move-in; discussed equipment requirements, logistics, etc.

Union began pre-stimulation flow test of Baca 20. Opened well at ±1030 hours. Flowing 107,150 lb/hr (total mass flow) with 74 psig WHP at 1145 hours; declined to 82,140 lb/hr with 51 psig WHP at 1415 hours. Two-phase flow rates measured through 6" orifice using assumed 80% steam quality.

8/4/82 Met with Smith Energy Services to review acidizing program, discussed frac tank and rig placement, set tentative schedule of operations, etc. Well flowing 60,800 lb/hr, 33 psig WHP at 0900 hours.

8/5/82 Odeco moved in and set frac tanks on location (400 bbl tanks). Well flowed at average 54,000 lb/hr, 28 psig WHP. Shut in at 1707 hours, ending flow test. Union RIH with pressure tools to 5,000' for buildup survey.

8/6/82 Moved in Action Well Service Rig No. 6 on location, spotted mud pump and pit and pipe rack. Began filling frac tanks with fresh water. Installed deadmen for Baca Nos. 20 and 11.

Union POH with pressure buildup tools, ran pressure and temperature gradient survey from 2,000' to 5,000', and reran pressure tools to 5,000' for continuation of buildup survey.

8/7/82 Completed filling frac tanks - 2,280 bbl total. (5-tanks with 400 bbl/ea, 2-tanks with 140 bbl/ea).

Union POH with pressure buildup tools and ran pressure and temperature gradient survey from surface to 5,000'.

8/8/82 Met with Union Geothermal representative (Fred Wilson), discussed program, scheduling, wellhead manifolding, method of killing well, etc.

Union ran pressure and temperature gradient survey from surface to 5,000'. Fluid level at ±2,700'.

8/9/82 Wellhead pressure 274 psi at 0830 hours.

1030 hours: Wellhead equipment above 10" master valve and flowline spool was removed by Union personnel.

1030-1200 hours: Installed wellhead blowdown and kill manifold. Tied in blowdown lines to 10" flowline.

1200-1330 hours: Spotted rig, raised mast, secured guy lines.

1330-1650 hours: Unloaded 180 joints 2-7/8" 6.5# N-80 tubing (HOMCO). Installed BOP equipment consisting of 6" double hydraulic ram-type BOP and tubing stripper.

1650-1720 hours: Bled off wellhead gas pressure 250 psi to 0 psi.

1720-1800 hours: Pumped 120 bbl water down casing, well on vacuum. Refer to Table C-1, Summary of Fluid Volumes Injected. Chemical analysis of water is given in Appendix D.

1800-1845 hours: Rigged up bailer and oil saver. Closed in well for night.

Note: Total water pumped into well this date-120 bbl.

8/10/82 0700-0845 hours: Wellhead pressure 30 psi, bled off and pumped in 80 bbl water, well on vacuum. Continued pumping water at ±1 BPM to keep well dead.

0845-1030 hours: Made two bailer runs, dropped through bridge at 5,100', found bottom at 5,112' K.B., attempted to bail - no recovery.

1030-1600 hours: Picked up and measured in hole 2-7/8" tubing. Rabbitted all tubing prior to running. Found bottom at 5,112', POH. Closed in well for night.

Note: Total water pumped into well this date - 1,170 bbl.

8/11/82 0800-0915 hours: Wellhead pressure 45 psi, bled off, pumped in 80 bbl water, well on vacuum. Continued pumping water at ±1 BPM from frac tank.

0915-1015 hours: RIH with 155 joints 2-7/8" tubing (open ended) to 4,836' - Note: string floats located, 1 joint and 3 joints above bottom and TIW safety valve at surface.

1015-1300 hours: Smith Energy Services finished rigging up and mixing acid. Acid (HCl) was diluted to a nominal 15% concentration in frac tanks on location. Acid contained 10 gal of CIA-2 corrosion inhibitor/1,000 gal and 1 gal of SAA-1 surfactant/1,000 gal.

1300-1328 hours: Smith Energy Services pressure tested surface lines and pumped 200 bbls of fresh water down tubing/casing annulus at 10 BPM rate to cool tubing and casing before pumping acid. Annulus pressure = 0.

1328-1446 hours: Smith Energy Services pumped 711 bbls (29,862 gal) of nominal 15% HCl/down tubing (open-ended at 4,836') at average 10.8 BPM rate while continuing to pump fresh water down annulus at 5.1 BPM rate. Acid was sampled periodically as it was being pumped. (Sample documentation and analytical results are given in Tables C-2 and Appendix D.) S.D. twice for a total of 12 minutes to repair small leaks in acid lines. Tubing rate/pressure range = 9.8-12.8 BPM/1,100 - 2,730 psig. Annulus pressure = 0. The acid solution was sampled as it was being pumped.

1446-1451 hours: Smith Energy Services pumped 51 bbl of fresh water to displace tubing while continuing to pump water down annulus at 5.1 BPM.

1451-1500 hours: RIH to 5,083' to displace any acid from bottom of hole.

1500-1532 hours: Rigged up Smith Energy Services to pump displacement water.

1532-1604 hours: Pumped displacement water down tubing and casing at average 10 BPM down each side - 632 bbl total displacement water pumped. Annulus pressure built up to maximum 200 psi near end of displacement.

1600-1615 hours: RIH with tubing and tagged bottom at 5,112'.

1615-1900 hours: POH laying down 2-7/8" tubing. Pumped fresh water into well at ±1 BPM while POH - total 170 bbl. Closed in well for night. No evidence of acid corrosion on any part of tubing.

8/12/82 — 0800-1000 hours: Laid down rig and tore out BOP equipment. Rig released to Union Geothermal at 1000 hours.

8/13/82	Union ran pressure and temperature gradient survey from surface to 5,100'.
8/14/82	Union ran Dia-Log minimum I.D. caliper from 2,350' to surface. Attempted repeat log, but tool failed. Ran casing profile caliper from 565' to surface - casing ok. Pumped 180 bbl of fresh water into well to keep it dead while logging.
8/26/82	Union began post-stimulation flow test at 0925 hours. Flowing 109,100 lb/hr (total mass flow) with 82 psig WHP at 0945 hours. Two-phase flow rates measured through 6" orifice using assumed 80% steam quality.
8/27/82	Continued post-stimulation flow test.
8/28/82	Well flowed at average rate of 47,850 lb/hr at 24.5 psig WHP.
8/29/82	Well flowed at average rate of 47,350 lb/hr with 23.5 psig WHP.
8/30/82	Well flowing 46,740 lb/hr with 22 psig WHP at 0910 hours. Shut in well at 0955 hours. End of test.

Table C-1
SUMMARY OF FLUID VOLUMES INJECTED
AUGUST 9 - 14, 1982

	BBLS
Fresh water* injected for cooling and well control before acid	1,755
Nominal 15% HCl acid solution pumped down tubing	711
Fresh water* injected down annulus while injecting acid down tubing	335
Fresh water* injected for displacement and well control after acid	708
Fresh water* injected while running caliper logs on 8/14/82.	180

*Fresh water was hauled from spring near Baca Well No. 24.

TABLE C-2

DOCUMENTATION OF "AS PUMPED" HCl ACID SAMPLES
BACA 20 ACID TREATMENT

AUGUST 11, 1982

Sample No.	Time Taken	Vol. of Acid Pumped (bbls)	Sp. Gr. Measured in Field	HCl Con. Inferred from Sp. Gr. (%)	HCl Con. Measured in lab (%)	Acid Vol. Represented by Sample (bbls)
1	1337	40	1.075	15.0	15.3	61
2	1342	83	1.074	14.8	15.5	188
3	1416	416	1.077	15.5	18.0	221
4	1427	524	1.077	15.5	17.4	123
5	1441	662	-	-	18.1	118

APPENDIX D

TABLE D-1

FLOW DATA ACQUIRED AFTER FRACTURE ACIDIZATION OF BACA 20

Date	Time	Sample Number	Rate (lb/hr)	Average Rate (lb/hr)	Time (hr)	Δ Cum. Prod. (lb)	Cumulative Produced (lb)
8/26/82	925						0
8/26/82	945		109,102		.33	36004	3600
8/26/82	955	1		104,366	.167	17429	53433
8/26/82	1000		99,631		.083	8269	61702
8/26/82	1025	2		90,053	.417	37552	99254
8/26/82	1055	3		90,053	.50	45026	144,281
8/26/82	1100		80,475		.083	6679	150,960
8/26/82	1125	4		73,767	.417	30761	181,721
8/26/82	1155	5		73,767	.50	36884	218,605
8/26/82	1225	6		73,767	.50	36884	255,488
8/26/82	1255	7		73,767	.50	36884	292,372
8/26/82	1325	8		73,767	.50	36884	329,255
8/26/82	1330		67,059		.083	5566	334,821
8/26/82	1355	9		59,385	.417	24764	359,585
8/26/82	1425	10		59,385	.5	29692	389,277
8/26/82	1455	11		59,385	.5	29692	418,969
8/26/82	1525	12		59,385	.5	29692	448,662
8/26/82	1555	13		59,385	.5	29692	478,355
8/26/82	1625	14		59,385	.5	29692	508,047
8/26/82	1655	15		59,385	.5	29692	537,740
8/26/82	1725	16		59,385	.5	29692	567,432
8/26/82	1825	17		59,385	1.0	59385	626,817
8/26/82	1925	18		59,385	1.0	59385	686,202
8/26/82	2025	19		59,385	1.0	59385	745,587
8/26/82	2125	20		59,385	1.0	59385	804,972
8/26/82	2225	21		59,385	1.0	59385	864,357
8/26/82	2325	22		59,385	1.0	59385	923,742
8/27/82	0025	23		59,385	1.0	59385	983,127
8/27/82	0125	24		59,385	1.0	59385	1,042,512
8/27/82	0525	25		59,385	4.0	237540	1,280,052
8/27/82	0925	26		59,385	4.0	237540	1,517,592
8/27/82	0945		51,710		.33	17064	1,534,656
8/27/82	1325	27		49,781	3.67	182696	1,717,353
8/27/82	1730	28		49,781	4.083	203256	1,920,609
8/27/82	2130	29		49,781	4.0	199124	2,119,732
8/28/82	0130	30		49,781	4.0	199124	2,318,856
8/28/82	0905	31		49,781	7.583	377489	2,696,346
8/28/82	0907		47,852		.033	1579	2,697,925
8/28/82	2043	32		47,602	11.60	552182	3,250,108
8/29/82	915	33		47,602	12.53	596453	3,846,561
8/29/82	915		47,353		0	-	3,846,561
8/29/82	1938	34		47,045	10.383	480,468	4,335,030
8/30/82	0823	35		47,045	12.75	599,823	4,934,853
8/30/82	0910	36		47,045	.783	36,836	4.971,689
8/30/82	0935		46,737		.417	19,489	4,991,179
					96.167		

Note: Rates assume 80% steam fraction

TABLE D-2

TREATING FLUIDS USED IN ACIDIZATION OF BACA 20

(a)

Acid As Received From Supplier

Sample Number	Al mg/l	B mg/l	Ca mg/l	Fe mg/l	Li mg/l	Mg mg/l	Mn mg/l	K mg/l	Na mg/l	Si mg/l
1	<.4	.3	59	1.0	<.2	12	<.02	1.9	33	5.3
2	<.4	.3	53	1.2	<.2	11	<.02	2.0	32	4.2
3	<.4	<.2	53	1.1	<.2	11	<.02	2.9	31	4.7

(b)

Acid As Pumped at the Surface During Acidization

											Wt. % HCl
1	.9	1.0	63	884	<.2	7.1	5.8	46	22	15	15.3
2	.4	.9	58	873	<.2	5.8	5.1	31	24	16	15.5
3	.6	.7	52	843	<.2	7.1	6.7	22	38	13	18.0
4	.6	1.0	51	891	<.2	7.1	7.1	22	30	13	17.4
5	.6	.6	51	888	<.2	7.2	6.8	20	34	12	18.1

Water Used to Dilute Acid Prior to and During Acidization

1	<.4	<.2	80	.1	<.2	1.5	.07	6.4	12	13

(c)

TABLE D-3

ANALYSIS OF PRODUCED FLUIDS FROM BACA 20
WITHOUT ANY SPECIAL SAMPLE HANDLING

(a)
Filtrate Analysis

Sample Number	Al mg/l	B mg/l	Ca g/l	Fe mg/l	Li mg/l	Mg mg/l	Mn mg/l	K g/l	Na g/l	Si mg/l
5	< 4	30	5.81	174	82	49	168	1.37	5.83	89
15	< 4	33	5.23	106	84	29	124	1.36	5.53	132
25	< 4	39	2.94	34	76	8.8	47	1.11	4.65	539
30	< 4	46	1.70	6.5	73	< 5	20	.995	4.46	91
35	< 4	52	.802	6.6	63	< 5	6.3	.821	4.03	607

(b)
Flash Corrected Filtrate Analysis

SAMPLE NUMBER	Al mg/l	B mg/l	Ca g/l	Fe mg/l	Li mg/l	Mg mg/l	Mn mg/l	K mg/l	Na g/l	Si mg/l
5	< 1	6.0	1.16	34.8	16.4	9.8	33.6	274	1.17	17.8
15	< 1	6.6	1.05	21.2	16.8	5.8	24.8	272	1.11	26.4
25	< 1	7.8	0.59	6.8	15.2	1.8	9.4	222	.930	108
30	< 1	9.2	0.34	1.3	14.6	< 1	4.0	199	.892	18.2
35	< 1	10.4	0.16	1.3	12.6	< 1	1.3	164	.806	121

TABLE D-4

ANALYSIS OF SOLIDS FOUND IN FLUID SAMPLES
(See Table 3)

(a)
Precipitate Analysis

Sample Number	Major > 10%	Moderate 1-10%	Slight 0.1-1%	Trace < 0.1%
5	Si, Fe	Na, Al	Ti, Ca, Mg	Cu, Sr, Mn
15	Si	Fe	Na, Ca	Mg, Sr, Cu, Mn, Ti, Al
25	Si	Fe, Na	Ca	Mg, Cu, Mn, Sr, Al
30	Si	Fe, Na	Ca	Mg, Sr, Al
35	Si	Na	Fe	Mg, Sr, Ca

(b)
Quantitative Analysis of Precipitate

Sample Number	Solid Content (g/l)	Elemental Content of Precipitate in Percent Si	Fe	Na
5	1.88	27.9	1.59	1.17
25	1.96	27.2	0.26	0.96
30	1.51	35.8	0.38	1.17

TABLE D-5

ANALYSIS OF LIQUID PHASE FROM BACA 20 WITH SPECIAL SAMPLES HANDLING*

Prod. lb.	Al, mg/l	B, mg/l	Fe, mg/l	Li, mg/l	Mg, mg/l	Mn, mg/l	K, mg/l	Si, mg/l	Ca, mg/l	Na, mg/l
0.1069E+05	0.175E+01	0.239E+02	0.218E+03	0.620E+02	0.480E+02	0.158E+03	0.110E+04	0.672E+03	0.466E+04	0.495E+04
0.1985E+05	0.195E+01	0.239E+02	0.224E+03	0.640E+02	0.500E+02	0.160E+03	0.112E+04	0.648E+03	0.474E+04	0.507E+04
0.2886E+05	0.115E+01	0.239E+02	0.212E+03	0.620E+02	0.460E+02	0.150E+03	0.111E+04	0.630E+03	0.470E+04	0.487E+04
0.3634E+05	0.395E+01	0.239E+02	0.197E+03	0.620E+02	0.440E+02	0.144E+03	0.112E+04	0.534E+03	0.476E+04	0.479E+04
0.4372E+05	0.215E+01	0.239E+02	0.188E+03	0.620E+02	0.420E+02	0.142E+03	0.112E+04	0.612E+03	0.476E+04	0.491E+04
0.5110E+05	0.215E+01	0.239E+02	0.100E+03	0.620E+02	0.380E+02	0.136E+03	0.109E+04	0.602E+03	0.460E+04	0.461E+04
0.5848E+05	0.315E+01	0.259E+02	0.184E+03	0.680E+02	0.400E+02	0.144E+03	0.118E+04	0.648E+03	0.510E+04	0.497E+04
0.6586E+05	0.235E+01	0.259E+02	0.152E+03	0.580E+02	0.360E+02	0.136E+03	0.121E+04	0.680E+03	0.500E+04	0.499E+04
0.7192E+05	0.195E+01	0.259E+02	0.150E+03	0.580E+02	0.360E+02	0.134E+03	0.118E+04	0.662E+03	0.496E+04	0.489E+04
0.7786E+05	0.215E+01	0.279E+02	0.152E+03	0.700E+02	0.360E+02	0.134E+03	0.122E+04	0.684E+03	0.510E+04	0.503E+04
0.8380E+05	0.135E+01	0.279E+02	0.128E+03	0.700E+02	0.300E+02	0.124E+03	0.123E+04	0.696E+03	0.486E+04	0.499E+04
0.8974E+05	0.295E+01	0.299E+02	0.136E+03	0.700E+02	0.320E+02	0.126E+03	0.124E+04	0.696E+03	0.494E+04	0.503E+04
0.9568E+05	0.195E+01	0.299E+02	0.128E+03	0.720E+02	0.300E+02	0.124E+03	0.125E+04	0.700E+03	0.492E+04	0.509E+04
0.1016E+06	0.155E+01	0.299E+02	0.120E+03	0.700E+02	0.280E+02	0.118E+03	0.122E+04	0.708E+03	0.480E+04	0.495E+04
0.1075E+06	0.295E+01	0.299E+02	0.120E+03	0.700E+02	0.260E+02	0.114E+03	0.122E+04	0.700E+03	0.468E+04	0.495E+04
0.1135E+06	0.215E+01	0.299E+02	0.106E+03	0.700E+02	0.240E+02	0.106E+03	0.119E+04	0.680E+03	0.442E+04	0.479E+04
0.1254E+06	0.155E+01	0.299E+02	0.102E+03	0.680E+02	0.220E+02	0.102E+03	0.116E+04	0.652E+03	0.430E+04	0.469E+04
0.1372E+06	0.275E+01	0.339E+02	0.900E+02	0.760E+02	0.220E+02	0.102E+03	0.129E+04	0.724E+03	0.448E+04	0.517E+04
0.1491E+06	0.235E+01	0.319E+02	0.860E+02	0.740E+02	0.190E+02	0.920E+02	0.123E+04	0.688E+03	0.416E+04	0.493E+04
0.1610E+06	0.175E+01	0.339E+02	0.740E+02	0.720E+02	0.166E+02	0.840E+02	0.120E+04	0.702E+03	0.392E+04	0.481E+04
0.1729E+06	0.215E+01	0.339E+02	0.780E+02	0.740E+02	0.168E+02	0.860E+02	0.122E+04	0.704E+03	0.400E+04	0.491E+04
0.1847E+06	0.115E+01	0.339E+02	0.540E+02	0.740E+02	0.132E+02	0.700E+02	0.120E+04	0.732E+03	0.364E+04	0.483E+04
0.1966E+06	0.115E+01	0.339E+02	0.520E+02	0.700E+02	0.124E+02	0.660E+02	0.114E+04	0.690E+03	0.346E+04	0.455E+04
0.2086E+06	0.175E+01	0.339E+02	0.520E+02	0.680E+02	0.114E+02	0.620E+02	0.107E+04	0.650E+03	0.320E+04	0.429E+04
0.2560E+06	0.115E+01	0.359E+02	0.460E+02	0.700E+02	0.104E+02	0.580E+02	0.111E+04	0.696E+03	0.318E+04	0.449E+04
0.3036E+06	0.155E+01	0.359E+02	0.240E+02	0.640E+02	0.756E+01	0.320E+02	0.972E+03	0.670E+03	0.222E+04	0.399E+04
0.3434E+06	0.950E+00	0.379E+02	0.220E+02	0.660E+02	0.516E+01	0.280E+02	0.978E+03	0.714E+03	0.210E+04	0.413E+04
0.3042E+06	0.115E+01	0.399E+02	0.200E+02	0.660E+02	0.516E+01	0.280E+02	0.986E+03	0.682E+03	0.206E+04	0.415E+04
0.4240E+06	0.115E+01	0.379E+02	0.200E+02	0.620E+02	0.456E+01	0.240E+02	0.918E+03	0.674E+03	0.182E+04	0.389E+04
0.4638E+06	0.115E+01	0.419E+02	0.154E+02	0.620E+02	0.336E+01	0.174E+02	0.882E+03	0.672E+03	0.151E+04	0.383E+04
0.5392E+06	0.115E+01	0.459E+02	0.134E+02	0.600E+02	0.256E+01	0.138E+02	0.860E+03	0.696E+03	0.131E+04	0.383E+04
0.5396E+06	0.950E+00	0.439E+02	0.910E+01	0.540E+02	0.176E+01	0.939E+01	0.758E+03	0.634E+03	0.995E+03	0.347E+04
0.7694E+06	0.115E+01	0.459E+02	0.798E+01	0.540E+02	0.156E+01	0.739E+01	0.748E+03	0.616E+03	0.875E+03	0.351E+04
0.8670E+06	0.950E+00	0.499E+02	0.778E+01	0.580E+02	0.136E+01	0.659E+01	0.784E+03	0.644E+03	0.811E+03	0.375E+04
0.9170E+06	0.950E+00	0.499E+02	0.716E+01	0.540E+02	0.116E+01	0.559E+01	0.744E+03	0.590E+03	0.737E+03	0.359E+04
0.9944E+06	0.950E+00	0.539E+02	0.778E+01	0.600E+02	0.116E+01	0.599E+01	0.798E+03	0.634E+03	0.795E+03	0.385E+04

*Analysis of samples which were acidified and diluted on site.

TABLE D-6

ANALYSIS OF PRODUCED FLUIDS FROM BACA 20
CORRECTED FOR 80% FLASH WITH SPECIAL SAMPLE HANDLING*

Prod. lb.	Al, mg/l	B, mg/l	Fe, mg/l	Li, mg/l	Mg, mg/l	Mn, mg/l	K, mg/l	Si, mg/l	Ca, mg/l	Na, mg/l
0.5343E+05	0.350E+00	0.470E+01	0.436E+02	0.124E+02	0.959E+01	0.316E+02	0.219E+03	0.124E+03	0.932E+03	0.989E+03
0.9925E+05	0.390E+00	0.470E+01	0.446E+02	0.128E+02	0.999E+01	0.320E+02	0.224E+03	0.130E+03	0.948E+03	0.101E+04
0.1443E+06	0.230E+00	0.470E+01	0.424E+02	0.124E+02	0.919E+01	0.300E+02	0.222E+03	0.126E+03	0.940E+03	0.973E+03
0.1817E+06	0.790E+00	0.470E+01	0.384E+02	0.124E+02	0.879E+01	0.288E+02	0.223E+03	0.107E+03	0.952E+03	0.957E+03
0.2186E+06	0.430E+00	0.470E+01	0.376E+02	0.124E+02	0.839E+01	0.284E+02	0.223E+03	0.122E+03	0.952E+03	0.981E+03
0.2555E+06	0.430E+00	0.470E+01	0.360E+02	0.124E+02	0.759E+01	0.272E+02	0.218E+03	0.120E+03	0.936E+03	0.921E+03
0.2924E+06	0.630E+00	0.518E+01	0.368E+02	0.136E+02	0.799E+01	0.286E+02	0.237E+03	0.130E+03	0.102E+04	0.993E+03
0.3293E+06	0.470E+00	0.518E+01	0.304E+02	0.136E+02	0.719E+01	0.272E+02	0.242E+03	0.136E+03	0.100E+04	0.997E+03
0.3596E+06	0.390E+00	0.518E+01	0.300E+02	0.136E+02	0.719E+01	0.268E+02	0.236E+03	0.132E+03	0.992E+03	0.977E+03
0.3893E+06	0.430E+00	0.558E+01	0.304E+02	0.140E+02	0.719E+01	0.268E+02	0.245E+03	0.137E+03	0.102E+04	0.101E+04
0.4190E+06	0.270E+00	0.558E+01	0.256E+02	0.140E+02	0.599E+01	0.248E+02	0.245E+03	0.139E+03	0.972E+03	0.997E+03
0.4487E+06	0.590E+00	0.598E+01	0.272E+02	0.140E+02	0.639E+01	0.252E+02	0.248E+03	0.139E+03	0.908E+03	0.101E+04
0.4784E+06	0.390E+00	0.598E+01	0.256E+02	0.144E+02	0.599E+01	0.248E+02	0.250E+03	0.140E+03	0.984E+03	0.102E+04
0.5080E+06	0.310E+00	0.598E+01	0.240E+02	0.140E+02	0.559E+01	0.236E+02	0.244E+03	0.142E+03	0.960E+03	0.989E+03
0.5377E+06	0.590E+00	0.598E+01	0.240E+02	0.140E+02	0.519E+01	0.228E+02	0.245E+03	0.140E+03	0.936E+03	0.989E+03
0.5674E+06	0.430E+00	0.598E+01	0.212E+02	0.140E+02	0.479E+01	0.212E+02	0.238E+03	0.136E+03	0.884E+03	0.957E+03
0.6268E+06	0.310E+00	0.598E+01	0.204E+02	0.136E+02	0.439E+01	0.204E+02	0.232E+03	0.130E+03	0.860E+03	0.937E+03
0.6862E+06	0.550E+00	0.678E+01	0.196E+02	0.152E+02	0.439E+01	0.204E+02	0.257E+03	0.145E+03	0.896E+03	0.103E+04
0.7456E+06	0.470E+00	0.638E+01	0.172E+02	0.148E+02	0.379E+01	0.184E+02	0.246E+03	0.138E+03	0.832E+03	0.985E+03
0.8050E+06	0.350E+00	0.678E+01	0.148E+02	0.144E+02	0.331E+01	0.168E+02	0.240E+03	0.140E+03	0.784E+03	0.961E+03
0.8644E+06	0.430E+00	0.678E+01	0.156E+02	0.148E+02	0.335E+01	0.172E+02	0.245E+03	0.141E+03	0.800E+03	0.981E+03
0.9237E+06	0.230E+00	0.678E+01	0.108E+02	0.148E+02	0.263E+01	0.140E+02	0.240E+03	0.146E+03	0.728E+03	0.965E+03
0.9831E+06	0.230E+00	0.678E+01	0.104E+02	0.140E+02	0.247E+01	0.132E+02	0.228E+03	0.138E+03	0.692E+03	0.909E+03
0.1043E+07	0.350E+00	0.678E+01	0.104E+02	0.136E+02	0.227E+01	0.124E+02	0.215E+03	0.130E+03	0.640E+03	0.857E+03
0.1280E+07	0.230E+00	0.718E+01	0.920E+01	0.140E+02	0.207E+01	0.116E+02	0.222E+03	0.139E+03	0.636E+03	0.897E+03
0.1518E+07	0.310E+00	0.718E+01	0.480E+01	0.128E+02	0.151E+01	0.640E+01	0.194E+03	0.134E+03	0.444E+03	0.797E+03
0.1717E+07	0.190E+00	0.758E+01	0.440E+01	0.132E+02	0.103E+01	0.560E+01	0.196E+03	0.143E+03	0.420E+03	0.825E+03
0.1921E+07	0.230E+00	0.798E+01	0.560E+01	0.132E+02	0.103E+01	0.560E+01	0.197E+03	0.136E+03	0.412E+03	0.829E+03
0.2120E+07	0.230E+00	0.758E+01	0.400E+01	0.124E+02	0.912E+00	0.480E+01	0.184E+03	0.135E+03	0.363E+03	0.777E+03
0.2319E+07	0.230E+00	0.838E+01	0.308E+01	0.124E+02	0.672E+00	0.348E+01	0.176E+03	0.134E+03	0.302E+03	0.765E+03
0.2696E+07	0.230E+00	0.918E+01	0.268E+01	0.120E+02	0.512E+00	0.276E+01	0.172E+03	0.139E+03	0.263E+03	0.765E+03
0.2698E+07	0.190E+00	0.878E+01	0.164E+01	0.108E+02	0.352E+00	0.168E+01	0.152E+03	0.127E+03	0.199E+03	0.693E+03
0.3847E+07	0.230E+00	0.918E+01	0.160E+01	0.103E+02	0.312E+00	0.148E+01	0.150E+03	0.123E+03	0.175E+03	0.701E+03
0.4335E+07	0.190E+00	0.998E+01	0.156E+01	0.116E+02	0.272E+00	0.132E+01	0.157E+03	0.129E+03	0.162E+03	0.749E+03
0.4935E+07	0.190E+00	0.998E+01	0.144E+01	0.100E+02	0.232E+00	0.112E+01	0.149E+03	0.120E+03	0.147E+03	0.717E+03
0.4972E+07	0.190E+00	0.108E+02	0.156E+01	0.120E+02	0.232E+00	0.120E+01	0.160E+03	0.127E+03	0.159E+03	0.769E+03

*Analysis of samples which were acidified and diluted on site.

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

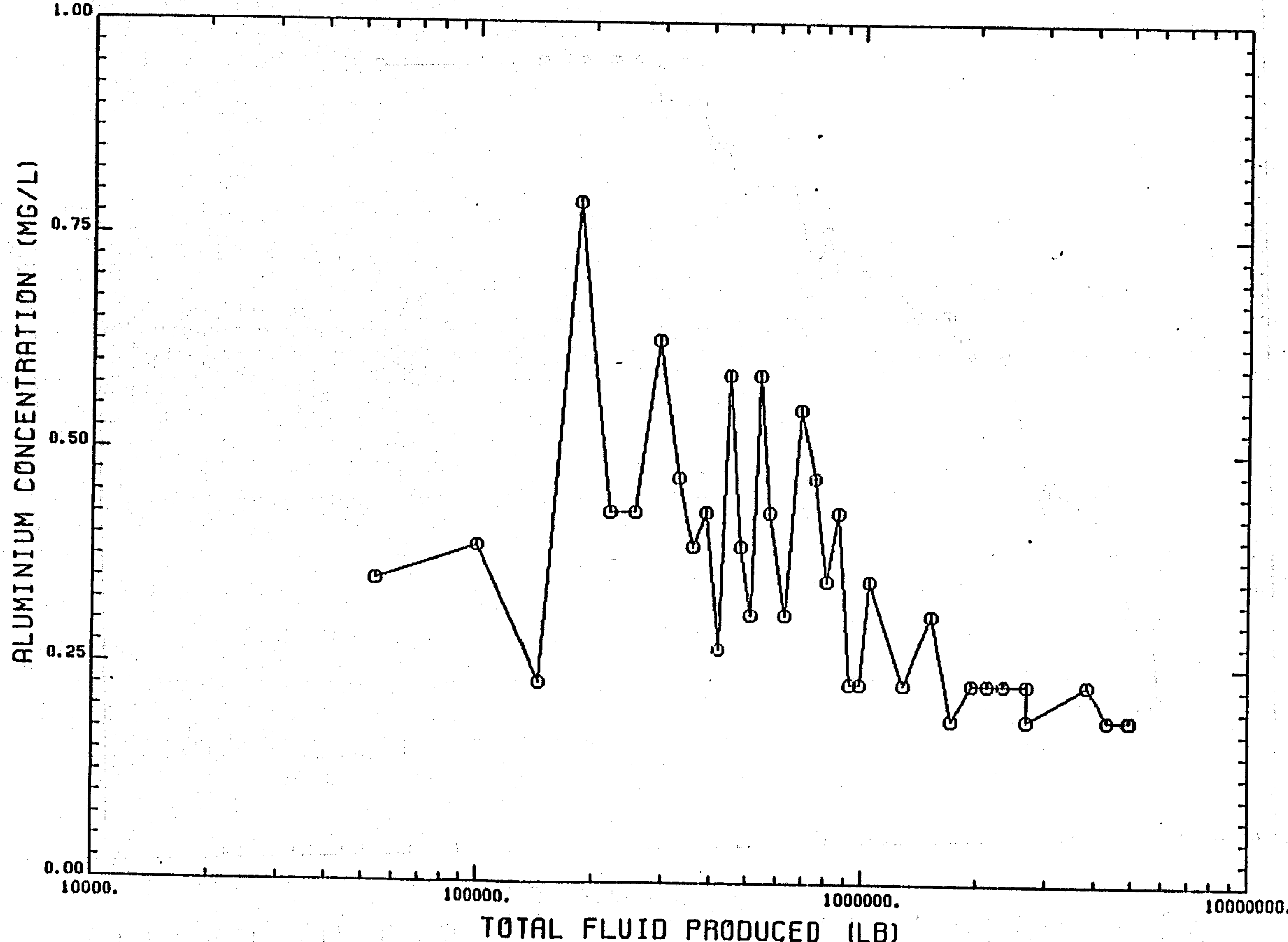


FIGURE D-1

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

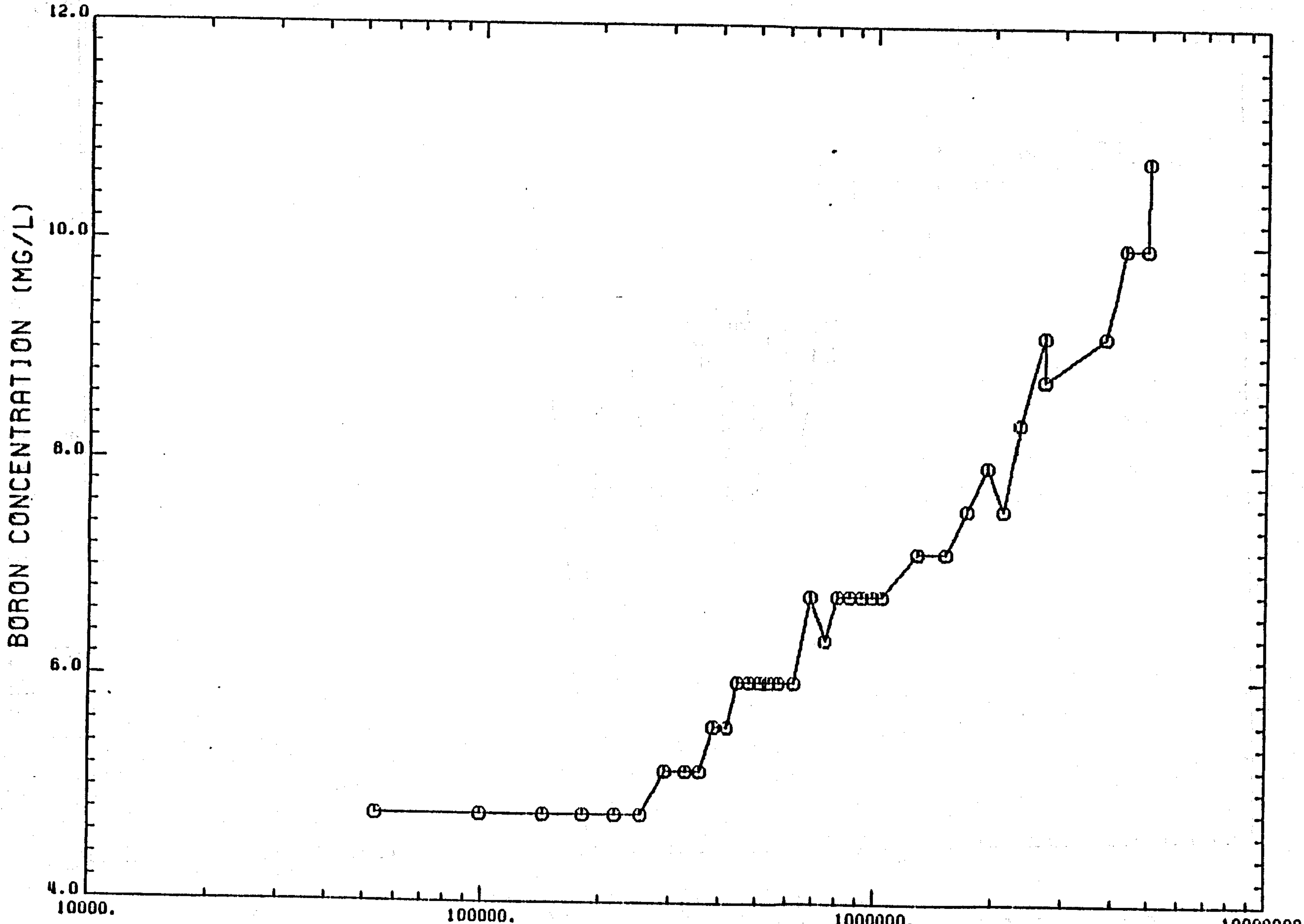


FIGURE D-2

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

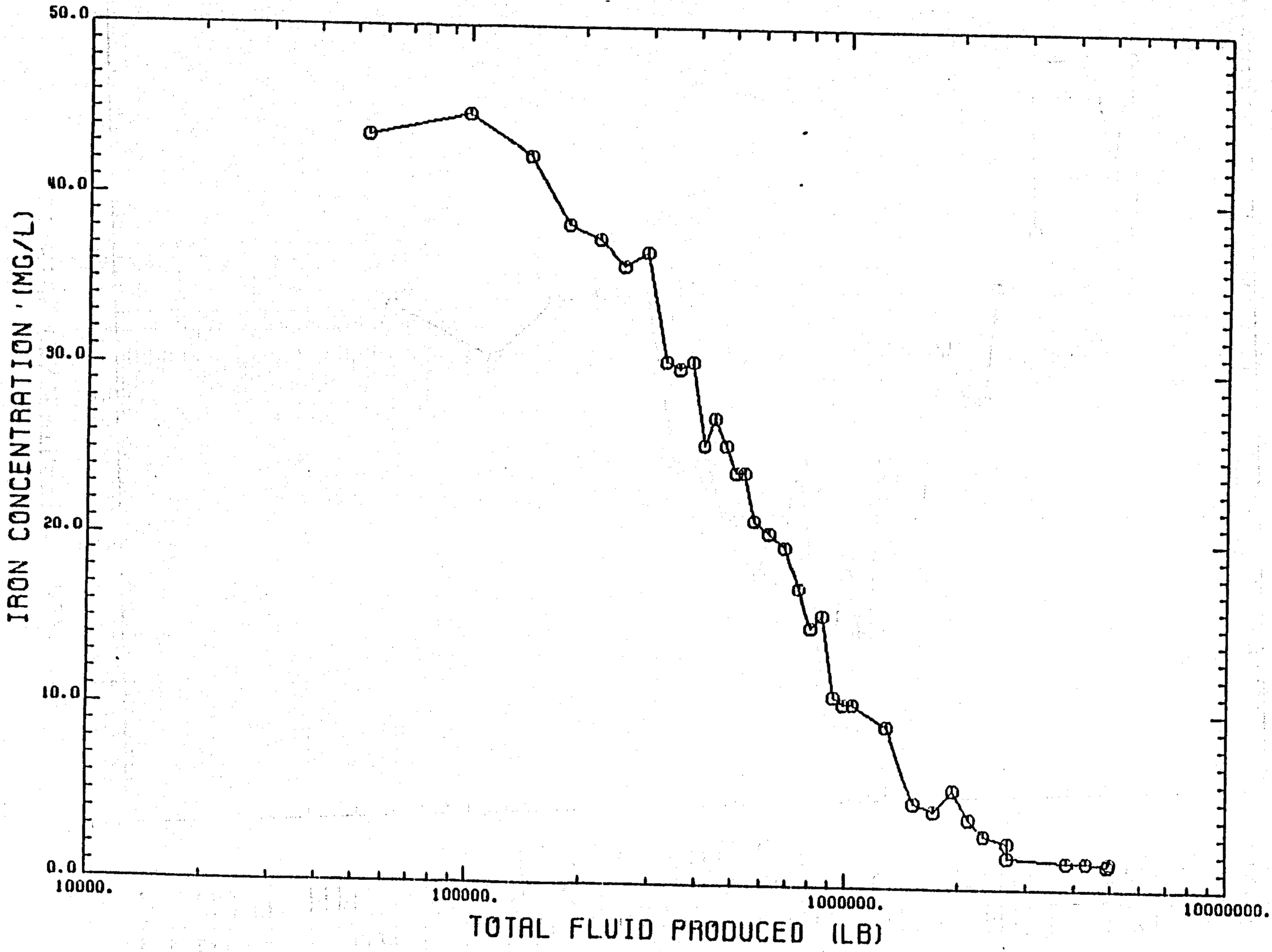


FIGURE D-3

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

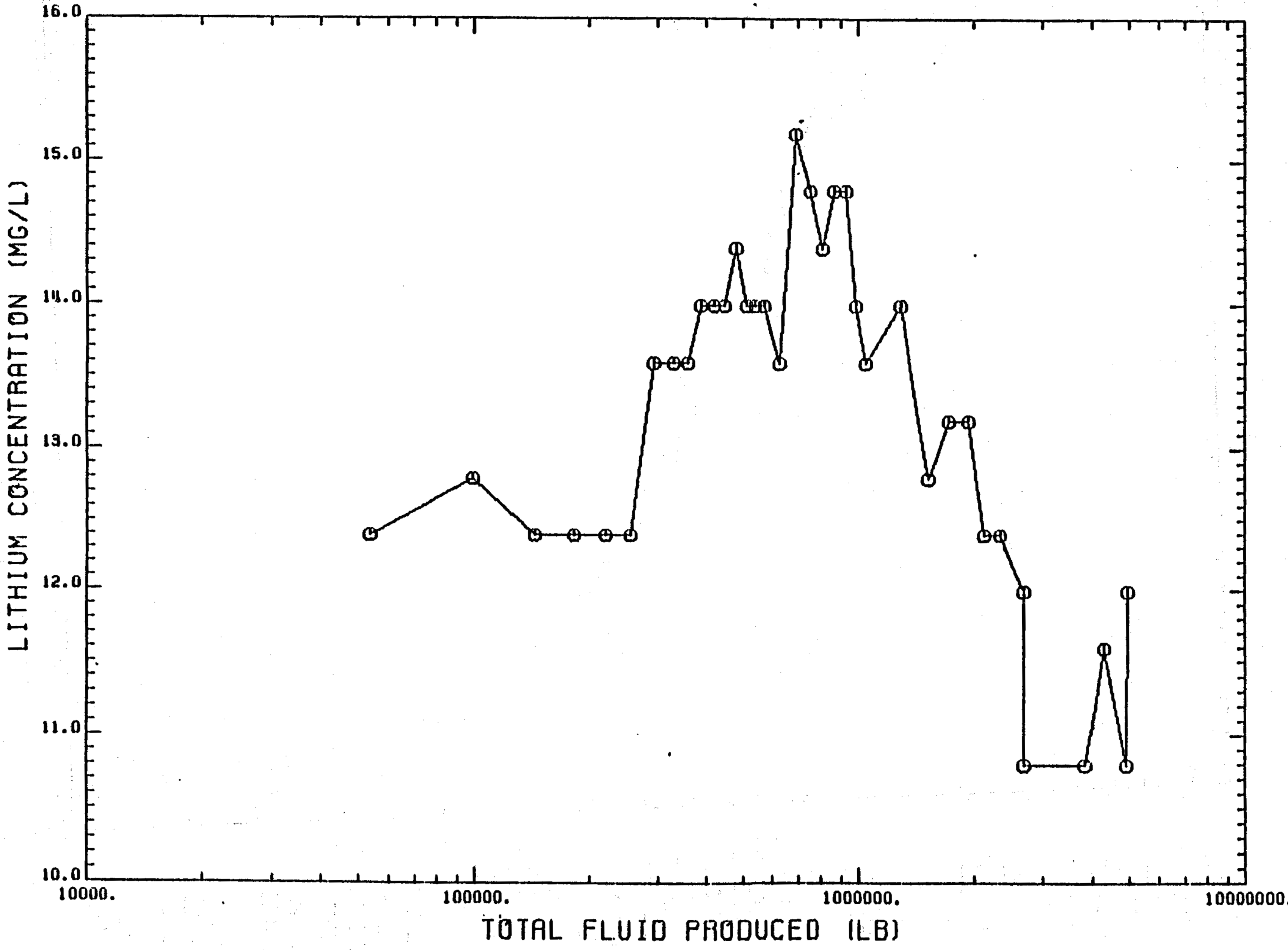


FIGURE D-4

FLASH CORRECTED POST FRACTURE ACIDIZATION
FLUID ANALYSIS OF PRODUCTION FROM BACA 20
(8/26-30/82)

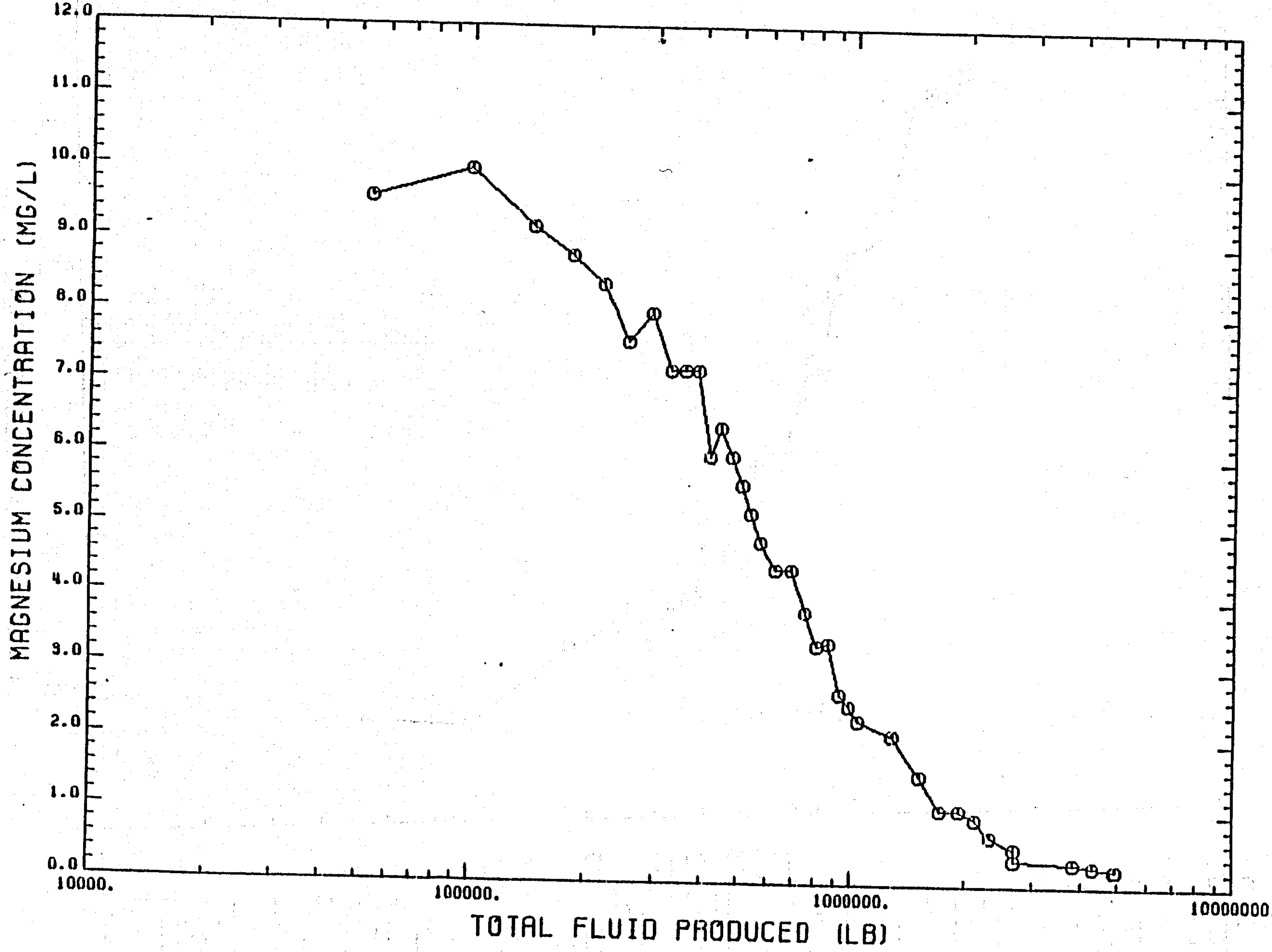
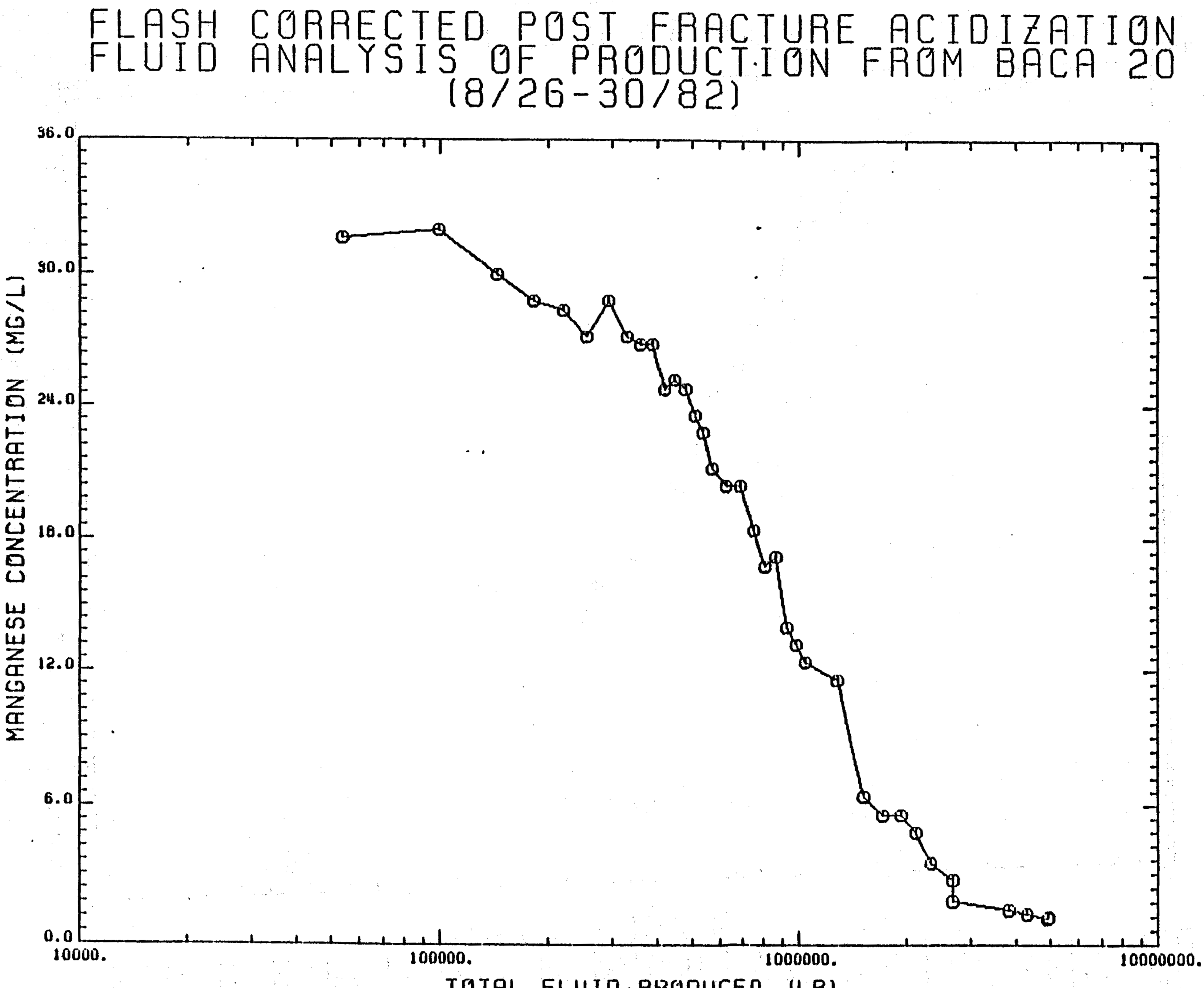


FIGURE D-5



FLASH CORRECTED POST FRACTURE ACIDIZATION
FLUID ANALYSIS OF PRODUCTION FROM BACA 20
(8/26-30/82)
36.0
30.0
24.0
18.0
12.0
6.0
0.0
10000.
100000.
1000000.
10000000.
MANGANESE CONCENTRATION (MG/L)
TOTAL FLUID PRODUCED (LB)

FIGURE D-6

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

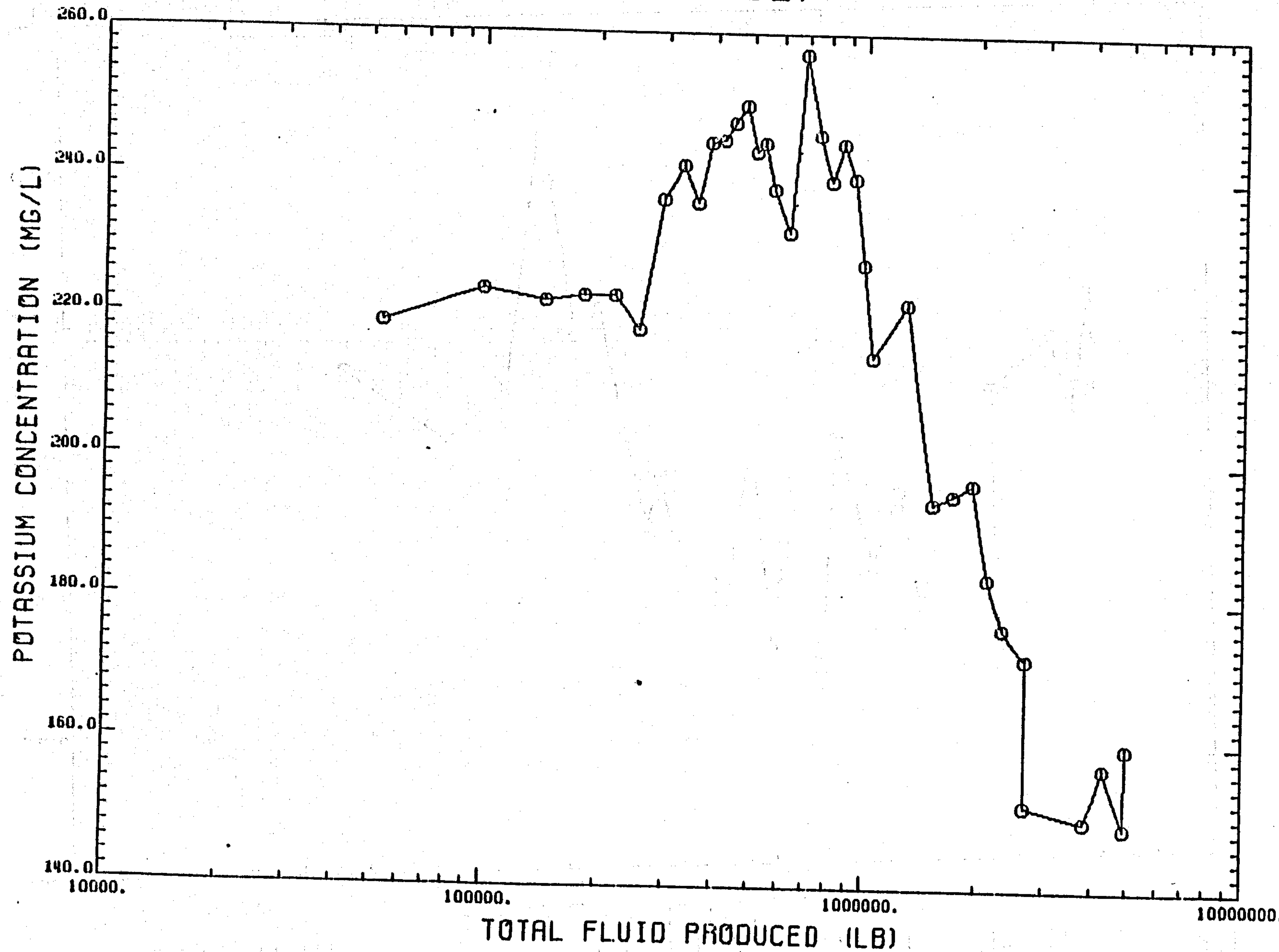


FIGURE D-7

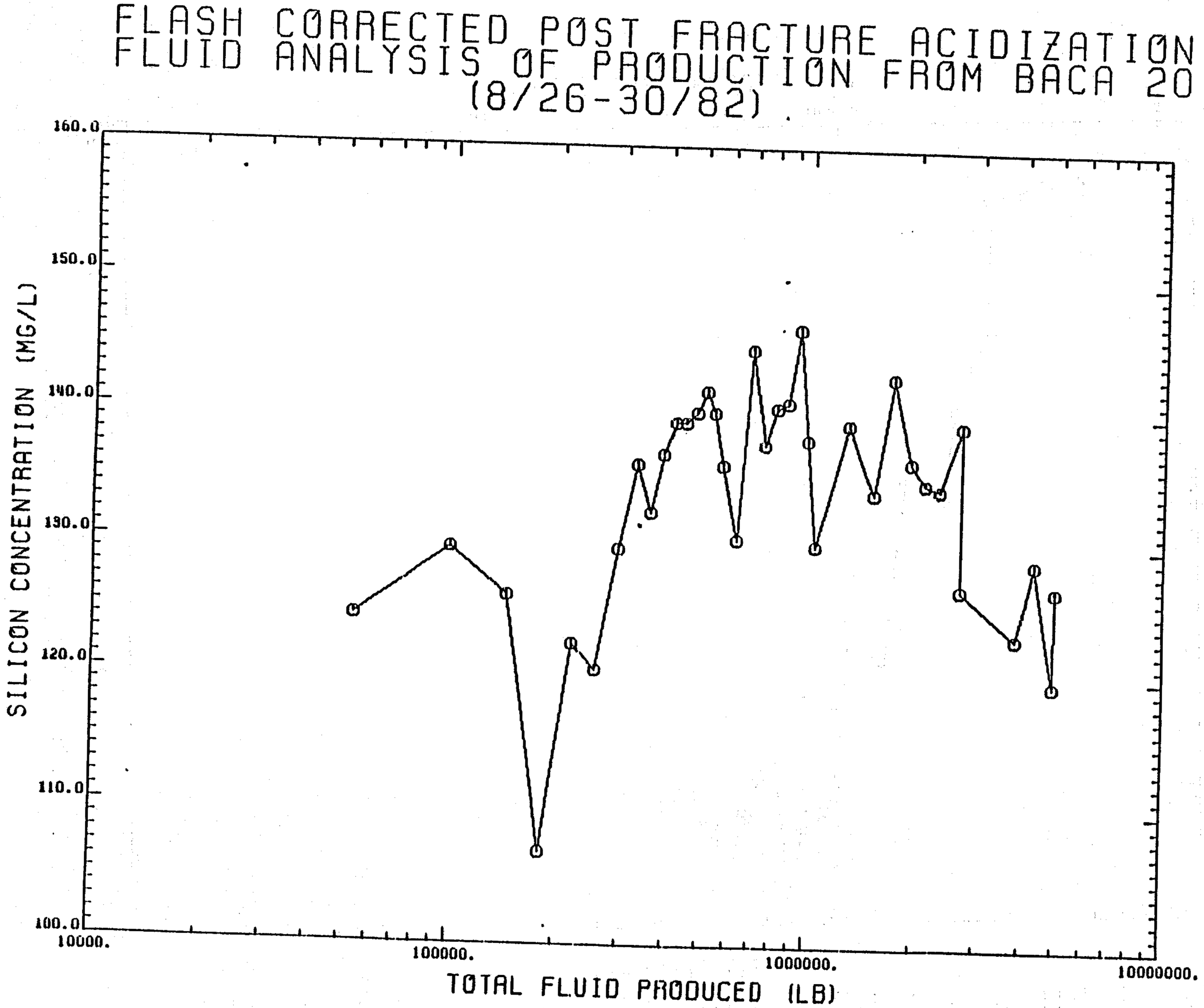

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)
160.0
150.0
140.0
130.0
120.0
110.0
100.0
SILICON CONCENTRATION (MG/L)
10000.
100000.
1000000.
10000000.
TOTAL FLUID PRODUCED (LB)

FIGURE D-8

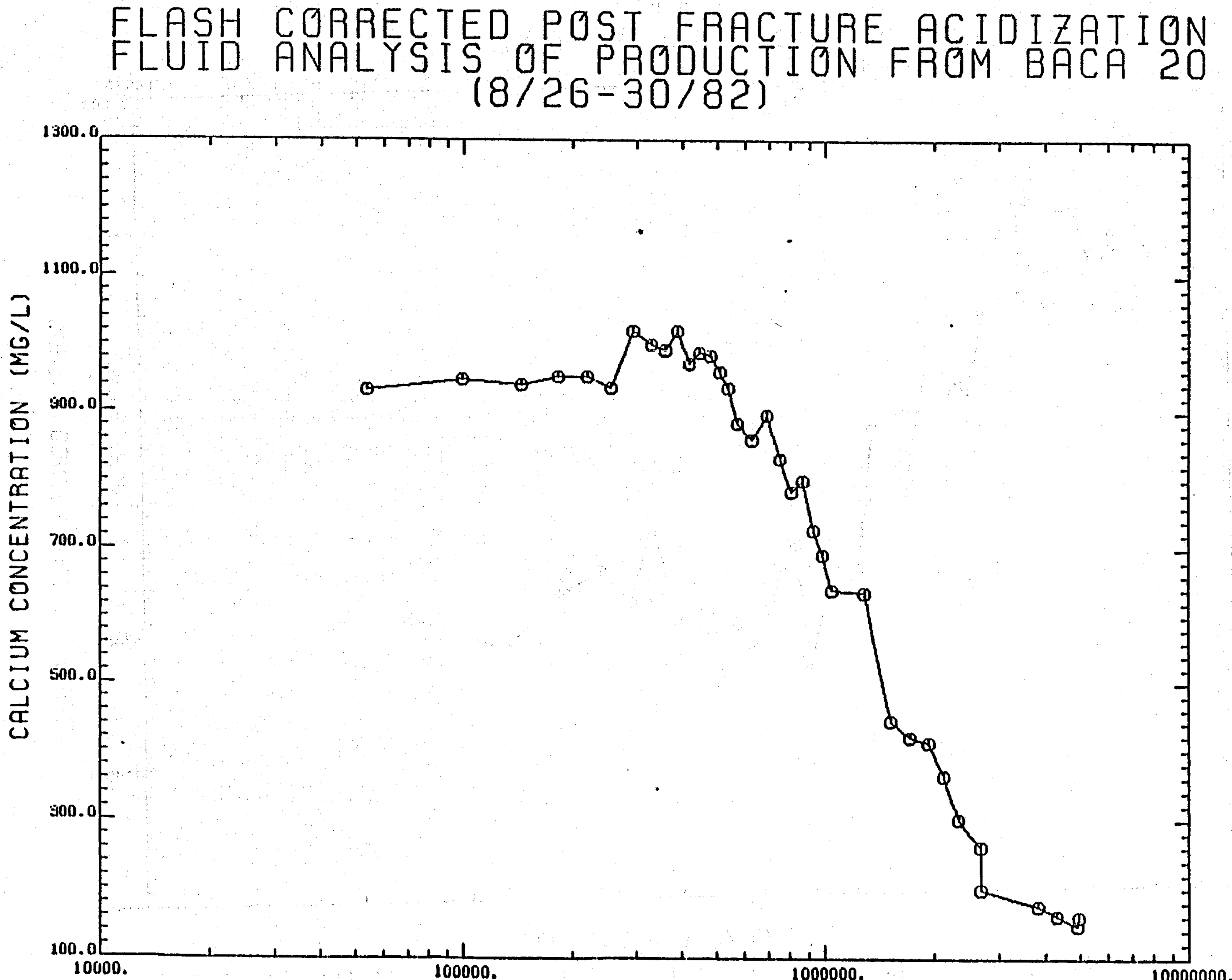

FLASH CORRECTED POST FRACTURE ACIDIZATION
FLUID ANALYSIS OF PRODUCTION FROM BACA 20
(8/26-30/82)
1300.0
1100.0
900.0
700.0
500.0
300.0
100.0
CALCIUM CONCENTRATION (MG/L)
10000.
100000.
1000000.
10000000.
TOTAL FLUID PRODUCED (LB)

FIGURE D-9

FLASH CORRECTED POST FRACTURE ACIDIZATION FLUID ANALYSIS OF PRODUCTION FROM BACA 20 (8/26-30/82)

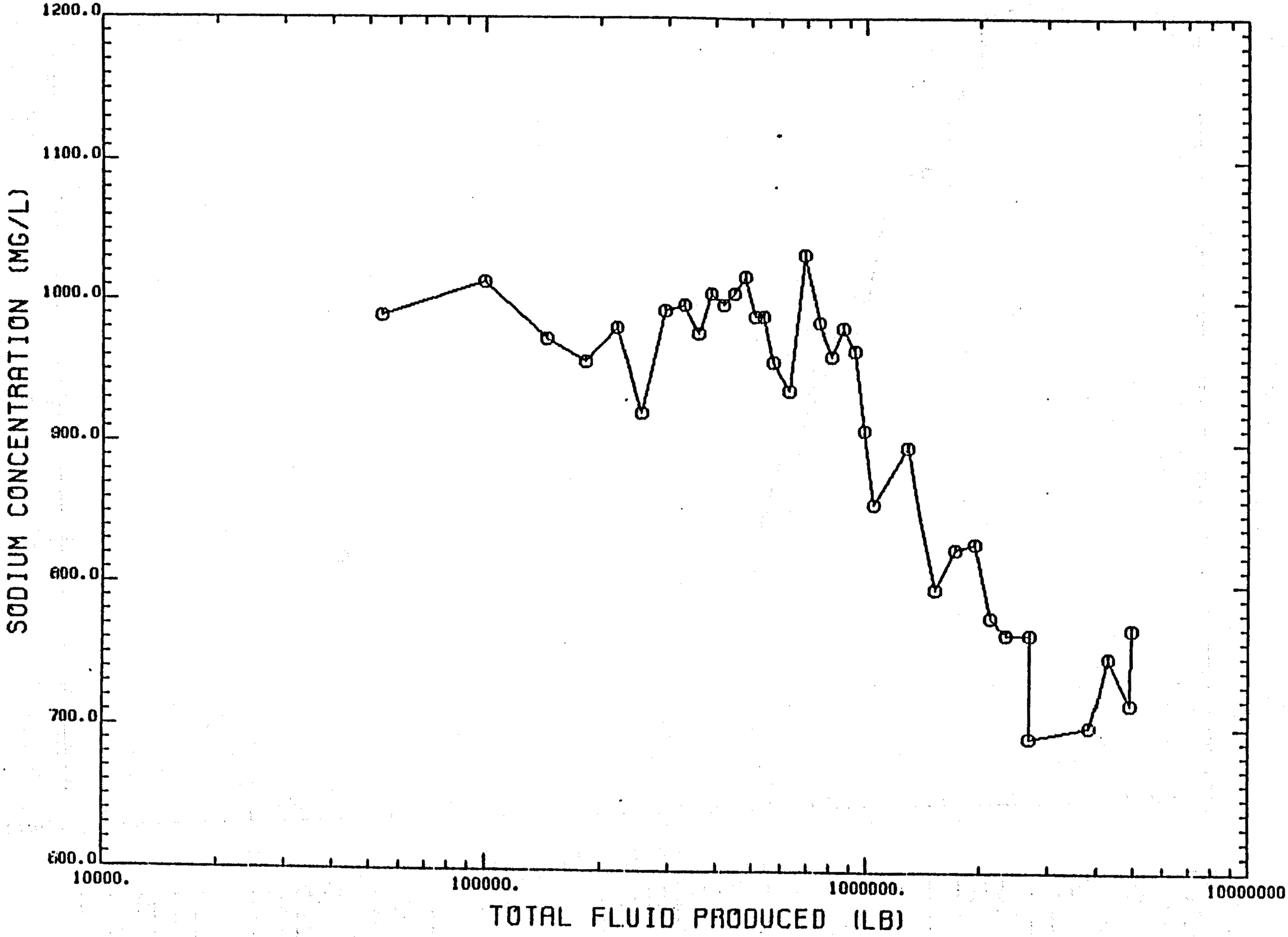


FIGURE D-10