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REPUBLIC GEOTHERMAL INC

DISCLAIMER

Chemical Stimulation Treatment of the Rossi 21-19 Well
Beowawe Geothermal Field

Geothermal Reservoir Well Stimulation Program

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. SUMMARY

Republic Geothermal, Inc. and its subcontractors performed Experiment No. 8 of the Geothermal Reservoir Well Stimulation Program at the Beowawe Geothermal Field in north-central Nevada in August 1983. The Rossi 21-19 well, selected for this stimulation experiment, was drilled by Chevron Resources Company in 1979. This well was noncommercial, even though it did intersect a high-temperature fluid zone. Test results suggested that it was limited by near-wellbore, restricted permeability.

A total of sixteen wells drilled in this area have identified a geologically complicated system that is charged from a deep carbonate reservoir. The reservoir temperature is in the range of 360-420°F. Most of the wells exhibit high productivities characteristic of a large, fracture-dominated reservoir with production rates measured in the range of 230,000 to 320,000 lb/hr. Hydraulic connectivity has been shown to exist between all the wells using pressure interference tests which further indicate that the reservoir has generally high areal permeability properties.

The stimulation experiment for Rossi 21-19 was a two-stage chemical treatment. A large volume of HCl acid solution was pumped in the first stage and the second stage contained a large volume of HCl-HF acid solution. Each of these acid stages was displaced deep into the formation with a water pad. Injection rates of about 15 BPM were used, and the injection pressure was maintained at a relatively low level to avoid hydraulically fracturing the formation. The acid solutions were intended to increase the permeability in existing reservoir flow channels by reacting with secondary mineralization, dispersing drilling mud residue, and etching the fracture faces. The experimental program provided for extensive testing to evaluate this technique as a means of enhancing near-wellbore, fracture permeability. It was a relatively inexpensive treatment applicable to most geothermal wells and does not require expensive zone isolation techniques. The total direct cost of the stimulation treatment (excluding RGI and Chevron labor) was $329,000, of which the Program share was $309,000. Chevron cost shared the experiment, paying a $20,000 share of the direct cost and providing engineering and supervisory labor and production test equipment valued at an additional $40,000.

The treatment was confined to the slotted liner interval below 4,369 feet. A pre-stimulation injection profile survey indicated that about 80 percent of the injected fluid was entering the formation below a restriction in the liner at 5,480 feet. This restriction prevented logging to find the exact injection interval. The HCl acid stage did not by itself produce any measurable stimulation effect, but was necessary to prevent formation of insoluble calcium fluoride precipitates in the formation during the HCl-HCF second stage. Injectivity tests performed during the experiment indicated a 2.2-fold increase in injectivity attributable to the stimulation effects of the second stage.

Unfortunately, mechanical complications with the well precluded an adequate production test. The shallow, low temperature zone in the well had previously been perforated for testing as an injection interval. Although this zone had exhibited very low injectivity characteristics and was not expected to cause any problems, it produced enough cold water into the wellbore to prevent initiation of flashing flow from the lower zone. Attempts to flow test the well were abandoned after producing it for approximately 14 hours by nitrogen lift.

In order to production test the well, the shallow perforated zone will have to be plugged off by cementing or by installation of a tieback casing string. If the well is production tested, it is reasonable to expect a significant increase in the productivity of the lower zone. However, the absolute level of productivity cannot be directly inferred from the injectivity data because the relationship of productivity to injectivity in a fractured reservoir is not always proportional.

Sandia National Laboratories and Los Alamos National Laboratory (LANL) both participated in the experiment, testing fracture mapping methods and providing data on the direction of fluid movement in the reservoir during the treatment. Sandia applied its surface electrical potential (SEP) method to map the movement of the treatment fluids in the reservoir. The acid solutions appear to move outward from the well along the suspected predominant NE-SW fracture direction. LANL was able to detect microseismic events during fluid injection using the triaxial geophone instrument in the neighboring well Ginn 1-13. This result was especially significant because the experiment was not a hydraulic fracturing treatment.

II. INTRODUCTION

Prior to the Beowawe Geothermal Field experiment, the Geothermal Reservoir Well Stimulation Program (GRWSP) had completed seven field experiments to stimulate geothermal wells. Two experiments were performed in a low-temperature reservoir at Raft River, Idaho; two experiments in a moderate-temperature reservoir at East Mesa, California; one experiment in a high-temperature, vapor-dominated reservoir at The Geysers, California; and two experiments in the high-temperature reservoir at Baca, New Mexico. It was the intent of the GRWSP to progressively increase the difficulty of the field stimulation experiments, primarily in terms of increasing reservoir temperature, to provide the stimulation technology needed by the geothermal industry. The originally proposed six field experiments accomplished this goal. The extension of the contract to provide for further field experiments provided the opportunity to test new techniques and materials under similar reservoir conditions. This type of comparison is necessary to determine the dependence of the treatment success or failure on reservoir factors, stimulation techniques, field procedures, and materials.

The Beowawe Geothermal Field was selected as a well stimulation site after a review of several geothermal wells offered by the industry. The field is in north-central Nevada, a few miles south of Interstate Highway 80 and approximately 30 miles southeast of Battle Mountain. It is in the Basin and Range province at the boundary between a plateau of volcanics to the south and the downfaulted Whirlwind Valley to the north. Geysers, fumaroles and boiling springs have deposited a large sinter terrace approximately 300 feet high at the northern base of the plateau. These numerous geothermal surface manifestations led Magma Power Company and Sierra Pacific Power Company to drill 11 shallow wells from 1959 through 1965. Chevron acquired the leases in 1973-1975 and began an extensive geologic study of the area. Chevron's first well, Ginn 1-13, was drilled in 1974 to a depth of 9,600 feet. Since then, Chevron has drilled four more wells (plus numerous shallow temperature holes). Only one of these wells, Rossi 21-19, is subcommercial and it is believed to have been damaged during drilling and/or completed in a limited area of restricted permeability. High-permeability, hydraulic communication has been shown to exist between all the wells in the reservoir.

Thus, the Rossi 21-19 well condition appears to be anomalous for the Beowawe area which has been identified as a commercially productive geothermal resource with temperatures near 370°F. The Beowawe system is probably a large and prolific resource which is a complicated combination of fractured and faulted horizons fed from a deep carbonate reservoir. The Rossi 21-19 conditions, located in this type of resource, make it a good candidate for a field experiment to evaluate a chemical stimulation treatment.

The discussion which follows provides an overview of the Beowawe Geothermal Field well characteristics, reservoir properties, a description of the experiment, and the evaluation of the results.

III. RESERVOIR DESCRIPTION

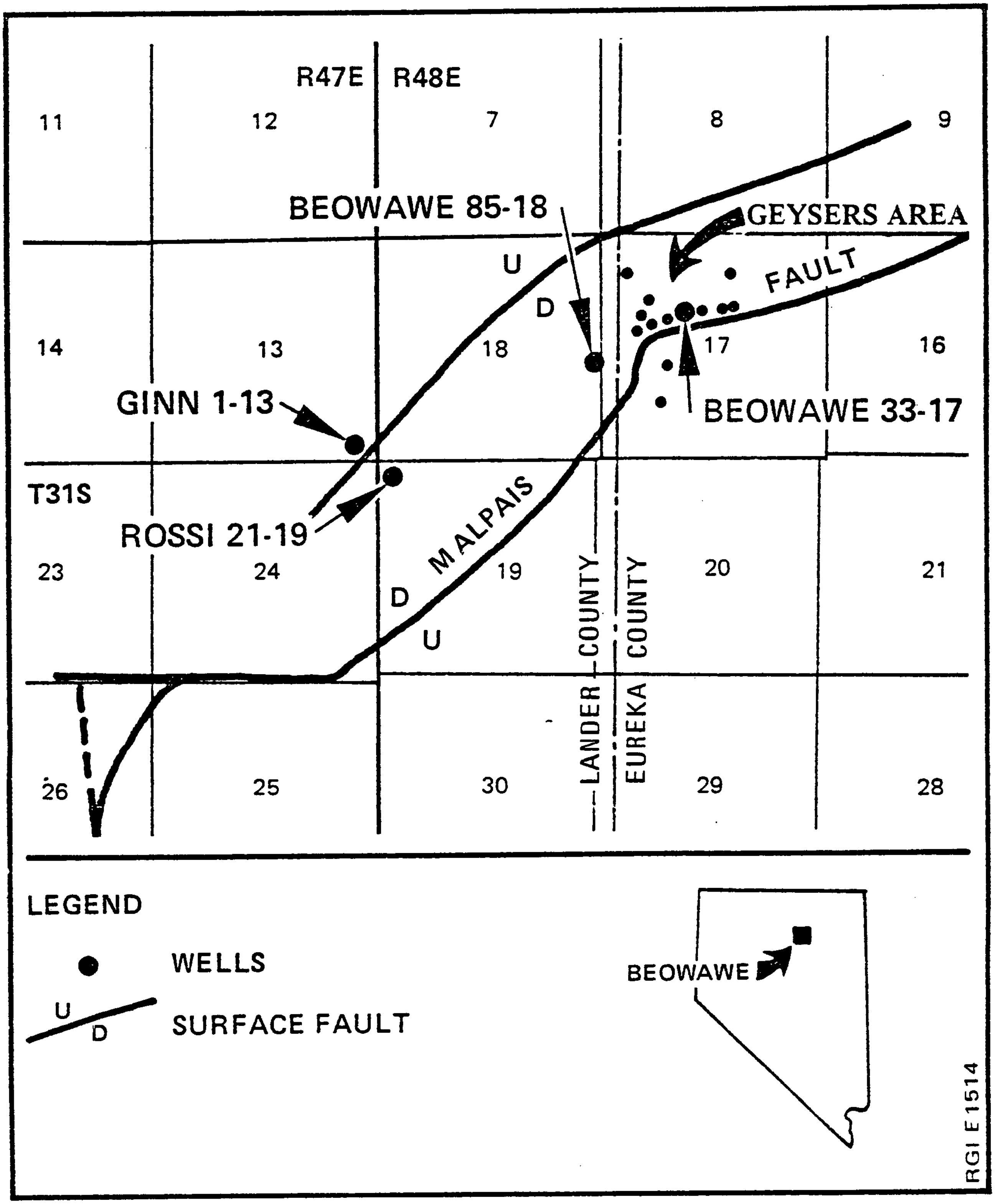
A. Geology

The Beowawe geothermal area is located along an east-northeast striking Basin and Range normal fault which marks the southeast boundary of Whirlwind Valley, a few miles southwest of the town of Beowawe (Figure 1). This area falls within the Battle Mountain heat flow high in north-central Nevada.

FIGURE 1

BEOWAWE GEOTHERMAL AREA

LANDER & EUREKA COUNTIES, NEVADA



The regional sedimentary basement is inferred to consist of a miogeosynclinal Paleozoic carbonate section, but this section has not been penetrated by any of the Beowawe wells drilled to date. The major Paleozoic unit in the Beowawe area is the Ordovician Valmy Formation which is composed of over 5,000 feet of siliceous shales and siltstones, quartzites, chert, greenstone, and minor limestone. The Valmy Formation is an allochthonous block thrust over the Paleozoic carbonates along the Roberts Thrust. These rocks are quite brittle and highly fractured with common siliceous veining.

Overlying the Valmy Formation is a graben filling sequence of Late Miocene to Pliocene volcanic rocks. Drill cuttings from several of Chevron's wells show this sequence to be about 4,500 feet thick. The series includes basaltic andesites, dacites, basalts, and minor tuffaceous sediments and tuffs. Basaltic andesites and diabase dikes are found intruding the Valmy Formation in several of the deep wells drilled at Beowawe. The stratigraphy is completed by a thin cover (up to about 300 feet) of Quaternary alluvium and a young siliceous sinter deposit along the Malpais fault (Figure 1).

The major faulting in the area is represented by two nearly orthogonal fault sets. The older fault system trends north-northwest and is probably of Mio-Pliocene age with possible younger reactivation. This system was at least partially responsible for the creation of a northwest-southeast trending trough, or graben in the Mio-Pliocene which was filled by the volcanic sequence described above. The primary surface expression of this system in the Beowawe area is the Dunphy Pass-White Canyon (Whirlwind-Crescent) fault zone, which appears to be the eastern boundary of the present hydrothermal system based on surface expressions and the locations of the high-temperature productive wells.

The lithology from the three deep Chevron wells (Rossi 21-19, Ginn 1-13, and Beowawe 85-18) shows that, in addition to the main surface trace, there is a fault between the 85-18 well and the Ginn and Rossi wells with about 1,900 feet of vertical displacement downdropped to the west (Figure 2). This shows up as an increase in the thickness of the volcanic section from about 2,600 feet in 85-18 to 4,500 feet in the Ginn and Rossi wells.

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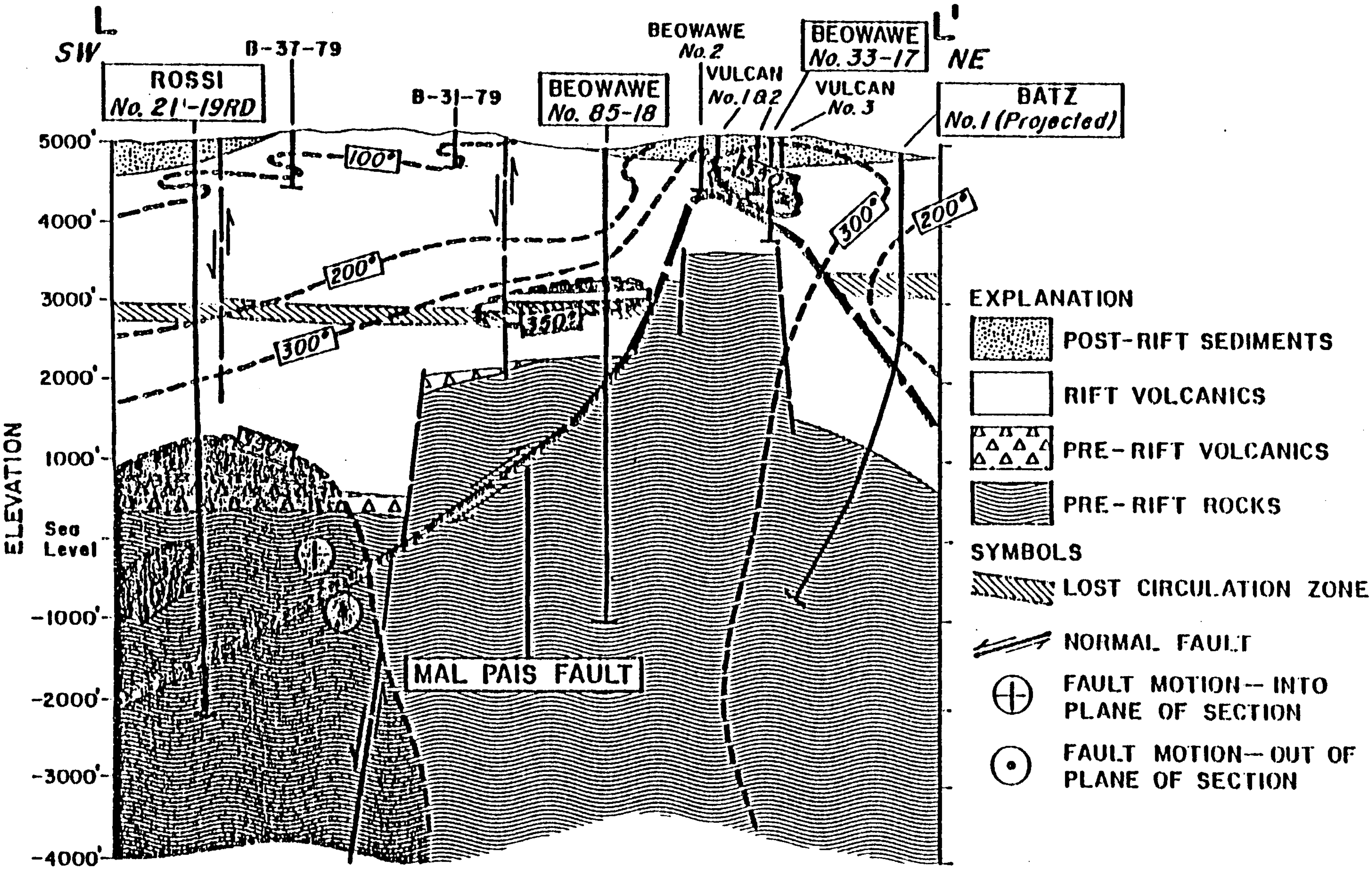
FIGURE 2



GEOLOGIC CROSS-SECTION – BEOWAWE AREA

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The other major fault system is the east-northeast trending Malpais fault zone which is a normal fault genetically related to Basin and Range tectonic extension. The Malpais fault forms the scarp which marks the southeast boundary of Whirlwind Valley. Most, if not all, of the geothermal surface manifestations (sinter deposit, hot springs, alteration) occur along the Malpais fault west of the Dunphy Pass-White Canyon fault.

The lithology, geochemistry of the produced fluids, and the location of the productive zones in the deep Chevron wells indicate good geologic and reservoir continuity within the field. The isothermal portion of the temperature profile in the Ginn 1-13 below 8,000 feet indicates convective flow within the fractured Valmy Formation that may be the upper portion of the "main" reservoir inferred from production tests. This is a reasonable assumption since the maximum measured temperature of 417°F (214°C) in the well is in close agreement with the chemical geothermometer calculations for the produced fluids, which indicate a reservoir temperature of 437°F (225°C). The Beowawe brine has exceptionally low salinity with only 1,100-1,200 ppm total dissolved solids (Table 1).

The primary production zones in the wells drilled to date are found within the volcanic and sedimentary sequence at the intersection of the wellbore with the Malpais fault zone. The surface geothermal features are obviously controlled by the Malpais fault zone and its intersection with the north-northwest trending fault system. The reservoir may exist in the lower Valmy Formation and/or the deeper carbonate sequence inferred to underlie it. This "main" reservoir is apparently connected to the shallower volcanic production zone and is capable of recharging this shallow reservoir through the existing fault and fracture systems.

B. Reservoir Evaluation

The first Beowawe well testing was conducted by Magma Power Company on four of their wells located on the sinter terrace (Beowawe 2, Vulcan 1, Vulcan 2, Vulcan 3). They flowed each of the wells through separator

TABLE 1

WATER ANALYSES
BEOWAWE AREA

Component	Rossi 21-19 ppm	Ginn 1-13 ppm	Beowawe 33-17 ppm	Beowawe 85-18 ppm	Vulcan 2 ppm
Na	340	257	280	203	223
K	41	39	26	27	31
Ca	12	14	4	0.94	2.06
Mg	5.4	0.4	1.5	.04	.02
Al	15	-	78	.7	-
Li	2.3	1.8	1.8	1.5	1.4
Mn	1.05	-	0.05	.01	-
Fe	3.3	-	2.2	.1	-
U(ppb)	2	-	1.0	.1	-
As	0.05	-	0.07	-	-
B	2.0	2.3	-	2.7	1.4
F	15	11	14	12.6	-
Cl	110	76	65	57	49
CO_3	76	16	156	112	2
HCO_3	41	317	-	89	255
SO_4	440	60	122	73	110
Cu	0.01	-	0.04	-	-
Pb	0.005	-	0.023	-	-
Zn	0.7	-	0.1	-	-
Ag	0.01	-	-	-	-
Ba	0.10	-	0.25	-	-
Br	0.1	-	-	-	-
I	0.9	-	-	-	-
SiO_2	540	430	500	437	480
PH+	9.4	8.5	9.3	9.5	-
TDS	950	1,397	1,238	1,100	-
Data Source	(a)	(b)	(c)	(d)	(e)

(a) Chevron: Flow test 12-4-76. Average of five samples.
(b) Chevron: DST #5. Average of three samples.
(c) Chevron: Flow test 11-8-79. Average of four samples.
(d) Chevron: Flow test 1-8-81. Average of three samples.
(e) Chevron: Bottomhole sample 2-4-81. Average of three samples.

NOTE: Only Vulcan 2 analysis is of unflashed brine. All other samples were of the flashed brine. Reported numbers have not been corrected for flashed steam and therefore, represent maximum numbers.

facilities and measured surface pressures, temperatures, flowrates, etc. No bottomhole data were obtained, but the flowing bottomhole temperatures were estimated by Magma's consultant to be near 365°F. Although the data were of poor quality, the three Vulcan wells attained very high estimated rates of flow. Beowawe 2 produced about 500,000 lb/hr at about 20 psia wellhead pressure. After testing, the wells were allowed to flow for about a year, during which time visual checks of the discharge appeared to indicate a decrease in flowrate, although no flow measurements were made.

Temperature surveys made in 1965 indicated maximum temperatures of 340 - 345°F within the completion intervals of two of the tested wells. Based on these data, it was concluded that the Beowawe reservoir was depleting and being invaded by cold water.

Recent Chevron data indicates that the sinter terrace consists of a fractured stratigraphic interval to 650-900 feet, below which is a highly-permeable fault containing 320°F brine. Computer simulation of the Magma test data indicates the three high rate wells probably had flowing temperatures close to 380°F. These wells were only completed in the fractured interval. Beowawe 2 exposed the fault as well as the fractured interval. Its lower test flow rate is explained by the cooler fluid contribution from the fault. Additionally, as the other terrace wells continued to flow, this well acted as a flue and allowed the cooler brine to migrate into the fractured interval, thus causing the observed loss of temperature. Once the flowing wells were shut-in, pressure equalization was quickly reached, stopping the cooler brine influx and allowing the fractured interval temperatures to return to equilibrium.

Extensive well testing by Chevron commenced with the completion in late 1979 of Beowawe 33-17 on the terrace between two of the old Magma wells. Initially, the tests were conducted using a simple blooie line and a flowing temperature survey to estimate flow rate by the simplified "James Method." For later tests, the full James Method instrumentation was installed so that both flow rate and enthalpy could be monitored as a function of time. Bottom-hole pressures were measured and recorded in all tests using nitrogen-filled capillary tubing with a quartz transducer at the surface. A summary of the Chevron well tests is presented in Table 2.

In the first half of 1980, a number of static and flowing temperature-pressure surveys were made in Beowawe 33-17. In addition, four flow tests were also conducted, varying in length from one day to 16 days. The well was also flowed as a source of drilling water for three months during this period. Each successive flow period showed improvement in wellhead pressures and flow rates as the well cleaned up and the wellbore heated up.

By the first of 1981, Beowawe 85-18 had been drilled, and the old Magma terrace well, Vulcan 2, had been cleaned out. At this time, interference tests were conducted to determine the degree of continuity between the wells. Pressure responses in shut-in wells were observed within one hour, even at distances up to three-fourths mile.

As is common in well testing, the testing supplied many answers but also raised additional questions. Consequently, in late 1981, additional testing was conducted. The primary purpose was to test the injectivity of two intervals in each of two wells. The opportunity was also taken to instrument additional wells to check for interference. Once again, pressure responses were observed in less than one hour in shut-in wells up to 1-1/4 miles away.

The numerous interference tests conducted at Beowawe show hydrodynamic communication between all the wells. Response times are less than one hour, irrespective of the distance between wells. Analyses of the interference data verified the calculated permeability-thickness (kh) values obtained from several of the individual well flow and pressure build-up analyses. These results are illustrated in Figure 3.

TABLE 2

Beowawe Flow Test Summary

	Ginn 1-13	33-17	85-18	Vulcan 2	Rossi 21-19
Number of Flow Tests	1	6	4	1	3
Max. Static Temp., °F	420	365	360+	360+	386
Flow rate, Mlb/hr	285	305	320	240	280[1]
kh, md-ft	232,000	800,000	550,000	780,000	8953[2]
PI, lb/hr/psi	8,900	60,000	7,800	24,000	300

[1] Flow with nitrogen gas lift; well would not sustain flow naturally.

[2] kh calculated from injection test of 12-12-81.

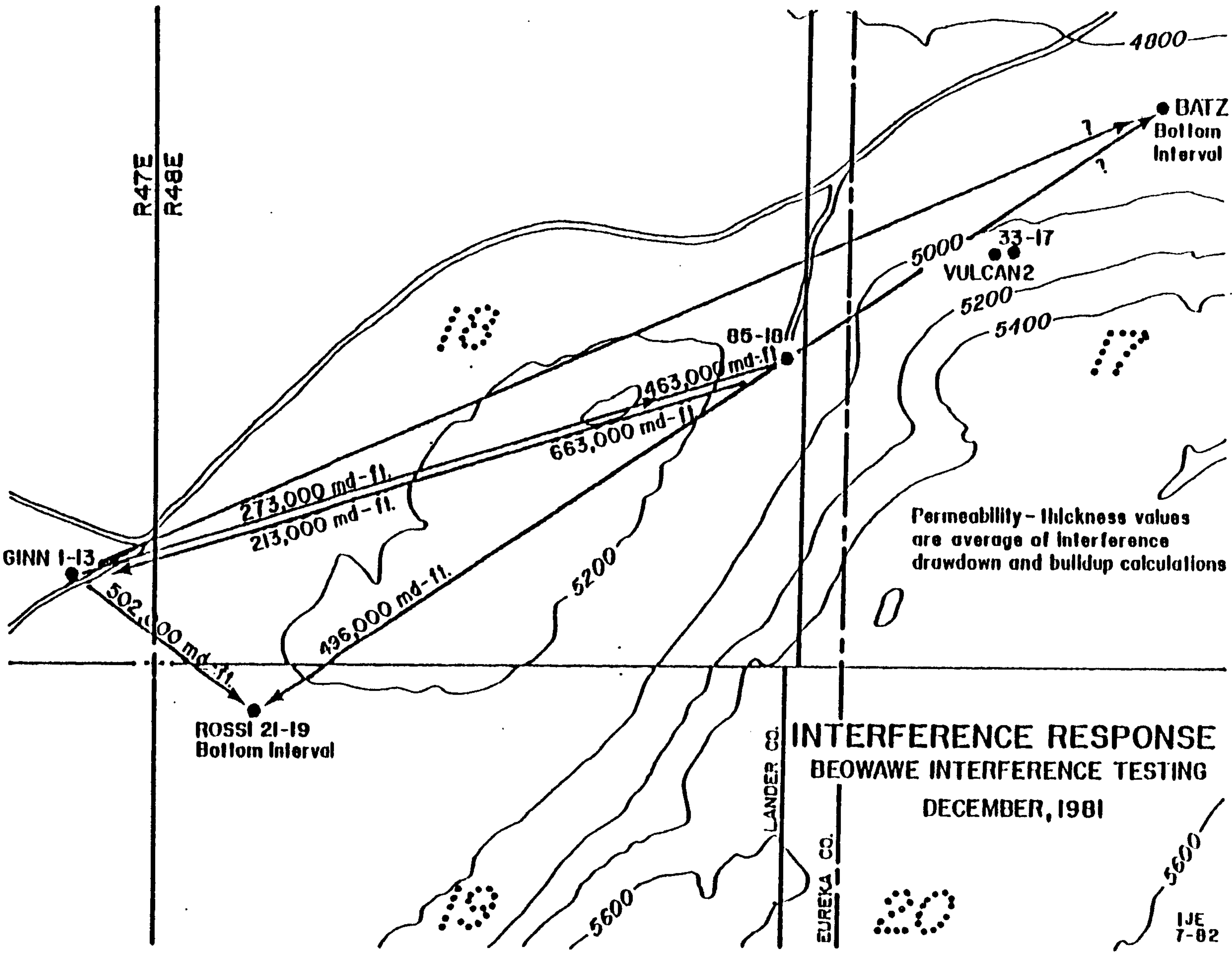

FIGURE 3

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The summary of the Chevron well tests (Table 2) shows that all the wells, except Rossi 21-19, flowed at rates of about 300,000 lb/hr total mass. These relatively low flow rates are due to mechanical completion restrictions. For example, the Ginn well was completed with about 9,500 feet of 7-inch casing to the surface and Beowawe 33-17 produces through a 6-5/8-inch blank and slotted liner. Chevron utilized a wellbore flow simulator and the Ginn flow test data to calculate that a "Ginn-type" well, with 13-3/8-inch casing to 1,500 feet and 9-5/8-inch casing to TD (9,500 feet), will produce about 1,000,000 lb/hr by natural flashing flow with 120 psig wellhead pressure. The permeability-thickness for most Beowawe wells is in the range of 200,000 to 800,000 md-ft, except for Rossi 21-19, thus confirming the extremely prolific nature of the reservoir.

Another important question to be answered is an estimate of the size of the reservoir. Due to the geologic complexity of Beowawe, this question can only be partially answered at this point in time. The steady state performance of Beowawe 33-17 after about 200 hours of flow is indicative of a steady state, infinite reservoir or perhaps a constant pressure "boundary". Flow data from other Beowawe wells indicate fluid volumes in excess of 10^{12} bbl. None of the tests have ever indicated a flow barrier or reservoir boundary, so that these fluid volume estimates represent minimum values.

IV. SELECTION OF WELL STIMULATION CANDIDATE

Rossi 21-19 has been tested three times since the well was deepened to 7,212 feet (Table 3). The lower interval (production zone 4,417-7,212 feet) is evidently completed in a localized area of restricted permeability as indicated by the short-term flow test data. The higher kh values calculated from the interference tests with the Ginn 1-13 and 85-18 wells are due to the larger area of good permeability between Rossi 21-19 and the other wells. The individual well tests and interference test results for the other wells support this conclusion.

TABLE 3

ROSSI 21-19 FLOW TEST SUMMARY

Test date	12-14-79	12-12-81	12-28-81	2-16-81	3-15-81
Test interval, ft	4,417-7,212'	4,417-7,212'	2,000-2,580'	4,417-7,212'	4,417-7,212'
Type	Production through csg w/N_2 @ 6,000' - well would not flow without N_2 lift.	injection falloff	injection falloff	interference with flow of Ginn-buildup & drawdown	interference with flow of 85-18-buildup & drawdown
Pressure datum, ft	6,000	5,000	2,300	5,000	5,000
Static BHP, psig	2,230	1,860	882	1,861	1,860
Flowing BHP, psig	1,825	2,450	1,587	-	-
Static temp	386°F @ 5,100'				
Flow rate, B/D	7,000-21,000	11,520	2,880		
lb/hr	150-280,000	168,000	42,000	285,000	323,000
Total flow time	90 minutes	480 minutes	440 minutes	56 hours	61 hours
kh, md-ft	1,543	8953	2,717	502,000	496,500
PI, B/D/psi	43	20	37		
Skin	0	-4.6	-2.0		

For example, the permeability-thickness indicated for Ginn 1-13 by the well test of 11/29/82 is 232,000 md-ft. This single well kh value is lower than the kh of 502,000 md-ft determined by the interference test between the Ginn and Rossi wells. Any transition to a zone of different permeability could not be determined because wellbore effects masked any later time developments in the pressure buildup. Two possible conclusions can be reached on the basis of these results. If the results are taken to be totally rigorous, then there exists a zone of permeability between the Rossi and the Ginn wells which is better than the permeability in the vicinity of either well. Alternatively, within the margin of error of pressure testing, the permeability-thickness of the formation between the two wells could be about equal to that around the Ginn well (232,000 md-ft).

To find the average permeability between two wells where beds of different permeability lie in series between the wells, the following equation is used -

$$k_{avg} = \frac{\Sigma L_i}{\Sigma L_i / k_i} \quad \text{or} \quad (kh)_{avg} = \frac{\Sigma L_i}{\Sigma L_i / (kh)_i} \qquad (1)$$

Attempts at an approximate description of the formation can be made based on a number of assumptions. As a first set of circumstances, it is assumed that only two distinct permeability zones exist and the kh of 8,953 md-ft for the Rossi well is accurate. Also, the $(kh)_{avg}$ has been determined by the interference test to be 500,000 md-ft. This approach does not make use of Ginn buildup data which is believed to be the most questionable information. Equation 1 can be rearranged to solve for the permeability-thickness of the high quality zone for different values of the lateral thickness, x, of the low permeability zone.

$$kh = \frac{1,850 - x}{\frac{1,850}{500,000} - \frac{x}{8,953}} \qquad (2)$$

The following table shows values of kh for different values of x.

x, ft	kh, md-ft
10	712,334
20	1,248,199
30	5,212,392
40	gives negative value of kh

If the results of the Ginn 1-13 well test are presumed to be accurate and the average kh between the Rossi and Ginn wells is in fact closer to 250,000 md-ft, then the results in the table below would be more realistic. Similar conclusions apply in regard to the size of the zone.

x, ft	kh, md-ft
10	292,851
20	354,232
40	617,278
60	2,563,237
70	gives negative value

This implies that the low permeability zone around the Rossi well must be small in extent. In fact, the results are relatively insensitive to large changes in the variables involved.

A similar analysis can be made using data for interference between the Rossi well and the Beowawe 85-18. The distance between the wells is 5,250 ft. and an average kh of 496,000 md-ft was calculated. Substituting these values into an equation (1) gives the following expression for the kh of the high permeability zone.

$$kh = \frac{5,250 - x}{\frac{5,250}{496,000} - \frac{x}{8,953}} \qquad (3)$$

The table below shows value of kh, for different values of x, the radius of the low permeability zone.

x, ft	kh, md-ft
10	553,459
20	626,288
50	1,040,008
100	gives negative value

The most recent results from the single well test of the 85-18 indicate a kh of 500,000 to 573,000 md-ft. Again the results seem to indicate a small damaged zone around the wellbore of Rossi 21-19.

The tests of the 85-18 well were carried on for a reasonably long period of time. This well shows a high individual well test kh value as well as a high interference test kh value with the other wells. No evidence of reservoir zones with greatly different permeability characteristics was apparent from any of these tests. This could mean that the zone of poor permeability near Rossi 21-19 is not extensive because its boundary does not significantly affect flow in the formation.

The other possible explanation for the lack of boundary effect would be the existence of a gradual transition from good to poor permeability. This is ruled out because such a condition would make it very unlikely for an average kh of 500,000 md-ft to exist between the wells. Also, transitions of the kh from 500,000 md-ft to half that value, which showed up as a distinct change of slope from one Horner plot straight line to another, occurred in the interference tests between the Ginn 1-13 and Beowawe 85-18 wells. No such evidence was noticeable in any of the tests involving the Rossi 21-19 well, indicating no such change in reservoir permeability occurs in the regions away from the wellbore.

The approximate radius of investigation of the Rossi falloff test of 12-12-81 can be calculated using the following equation:

$$r_{inv} = \sqrt{\frac{.00105kt}{\mu \Phi c}}$$

k = 8,953 md-ft/h ft

Φ = .2 (assumed)

μ = 1.52 cp

c_t = 8×10^{-6} psi^{-1}

t = 2.82 hrs. - last point which falls on Horner plot straight line of 12-12-81 test, lower interval

$$r_{inv} = \sqrt{\frac{.00105\ (8{,}953)\ (2.82)}{(.2)\ (1.52)\ (8 \times 10^{-6})h}}$$

$$r_{inv} = 3{,}301/\sqrt{h}$$

The results for different values of reservoir thickness, h, are shown in the table below:

h, ft	r_{inv}, ft
100	330.1
200	233
500	148
1,000	104

No definite value for the height of the production interval in the Rossi well was obtained. It is possible that the correct value for formation thickness may lie anywhere in a range between 100 and 1,000 feet. Interpretations of the electric log data suggest possible productive intervals at 4,400-4,600 feet, 5,000 feet, and near 6,100 feet. Porosity values from the openhole logs run 0-15 percent over most of the logged interval.

The time value used here is the point at which the data deviates from the Horner straight line. At this point pressure seems to be influenced by thermal effects, a constant pressure boundary, or a lateral increase in mobility and no longer exhibits infinite acting radial flow behavior. The results of this test, then, indicate that the Rossi well lies in a low permeability area of the reservoir. Any near-wellbore damage imposes a masking effect on the pressure data and delays the transition of pressure influence to the high permeability zone. It is possible that this near-wellbore damage would not show up as positive skin if the damaged zone extended to a radius about 100 times the wellbore radius or if the pressure results were influenced by multiple inflow zones as is expected. This could explain the absence of apparent skin damage effects on the pressure falloff data.

Thus, from the results of the interference and single well tests, it can be concluded that a highly productive reservoir exists throughout most of the developed area of Beowawe. If Rossi 21-19 has penetrated a zone of poor reservoir permeability, the zone is probably quite limited in extent, possibly extending as little as 50 to 100 feet from the well.

Speculation as to the cause of the low permeability zone near Rossi 21-19 includes several common geothermal resource problems besides a simple formation zone of low permeability in this area. During the drilling operations, approximately 2,000 bbl of drilling mud (a sepiolite system) and accompanying formation cuttings were lost into the permeable zones. In addition, the drilling mud solution was left in the wellbore for approximately two weeks before the first production test was performed. This could have caused damage to the fracture intervals encountered by the wellbore. The permeability restriction may also be the result of the precipitation of solids, such as calcium carbonate, silica, etc. from the geothermal fluid, on the fracture surfaces as the fluid rises and cools in the reservoir. It was reasonable, therefore, to expect that stimulating the lower interval with an appropriate acid treatment would remove the types of near-wellbore damage suspected and put the well in good communication with the high permeability reservoir system.

V. STIMULATION EXPERIMENT FOR ROSSI 21-19

A. Treatment

The stimulation treatment designed for Rossi 21-19 was basically a two-stage chemical treatment. Five injection tests were performed during the stimulation operations. Two injection tests were for the purpose of determining the vertical extent of permeable zones within the wellbore before and after stimulation. Three other injection tests were performed to acquire downhole pressure data for comparison of injectivities before stimulation, between the two acid treatment stages, and after stimulation. The acid solutions, nominal 15 percent HCl (first stage) and 12 percent HCl-3 percent HF (second stage), were intended to remove the near-wellbore restriction suspected to exist in the reservoir. These acids will react with secondary mineralization on the natural fracture surfaces (such as calcium carbonate and silica precipitated from the geothermal brine), with carbonate and siliceous materials in the formation matrix, and with drilling mud residue which may be present in the flow channels. The injection pressures and rates were maintained throughout the experiment at appropriate levels such that the injected fluid entered the existing permeable zones and the formation was not hydraulically fractured. The following is a brief description of the field operations which are described in detail in Appendix A.

As discussed in the previous sections, the Rossi 21-19 well was deepened to 7,212 feet in 1979 and was found to be subcommercial. During later operations Chevron isolated the producing interval with a bridge plug and perforated a zone from 2,000-2,580 feet in the 9-5/8-inch casing in order to convert this well to an injector. The injection zone was found to be unsatisfactory and, as indicated in Table 3, actually had a lower formation permeability-thickness than was found in the lower zone. The first operation performed on the well by the GRWSP was to reopen the deep production zone for the stimulation experiment. To do this, a rig was moved in and the bridge plug at 2,700-feet (Figure 4) was removed from the wellbore. Following this operation, a 3-1/2-inch tubing string was run into the wellbore and a packer set at approximately

CHEVRON ROSSI 21-19

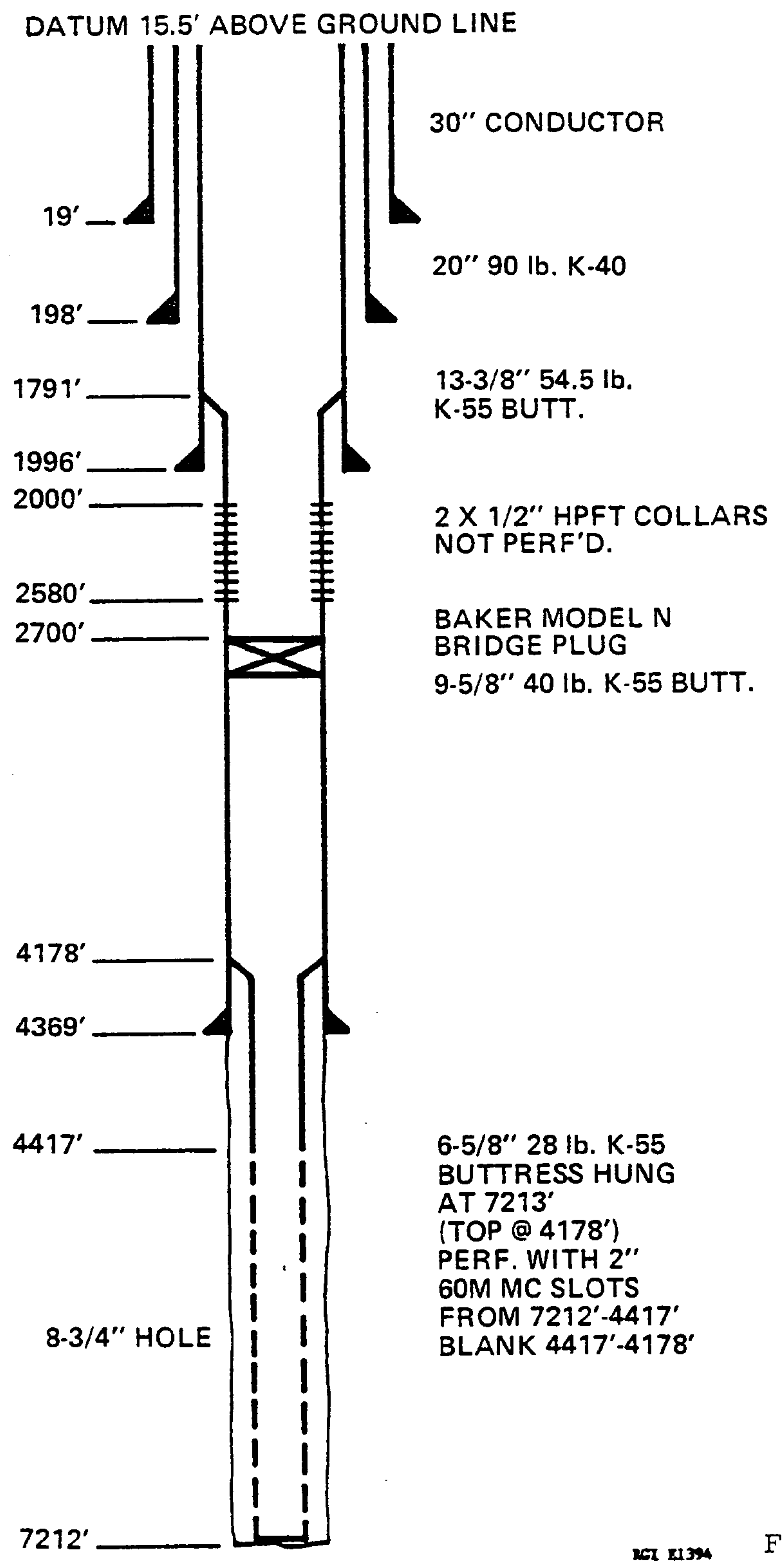

FIGURE 4

2,753 feet. Thus, the shallow perforated zone in the 9-5/8-inch casing was isolated from the deep production interval, and the subsequent treatment confined to the slotted liner interval below 4,369 feet.

At this time, two injection tests were performed on the isolated lower interval to establish the pre-stimulation well condition. (Surface pressure and rate data for the injection tests and acid treatments are tabulated in Appendix B.) Spinner and temperature logs were run during the first injection period to define the intervals accepting fluid and the distribution of the total flow. However, an obstruction in the liner at 5,480 feet prevented logging below this point even though approximately 80 percent of the injected fluid was going below this depth. Pressure and temperature data were obtained downhole during the second injection test and the subsequent pressure falloff period to evaluate the reservoir characteristics.

Following the completion of the pre-stimulation injection tests, the first stage acid treatment was pumped. Approximately 500 bbl of a 14.5 percent HCl solution was pumped at rates of 15-16 BPM. The HCl acid solution was intended to remove possible calcium carbonate deposits on the fracture faces and also to remove HCl-soluble material from the formation matrix. Laboratory tests on drill cuttings from Rossi had indicated an average formation solubility of 14 percent in HCl. These laboratory tests are documented in Appendix C. The first stage HCl injection and the presence of HCl in the second stage is required designed to prevent reactions between the HF (in the second stage) and the calcite and/or formation brine, saving the HF for reaction with siliceous minerals and preventing the precipitation of calcium fluoride and sodium fluosilicate. This is a conventional stimulation design approach for acidizing a formation of this type. The first stage acid solution was displaced into the formation with 2,446 bbl of water, during which the well's injectivity was monitored to evaluate the stimulation effect of the HCl acid solution. Downhole pressure and temperature data were acquired during the water injection and no significant change occurred in the injectivity of the well.

The second stage of the acid treatment consisted of 982 bbl of a 12 percent HCl and 3 percent HF acid solution pumped at about 15 BPM. This acid solution was intended to open up the natural fractures by: (1) dissolving siliceous secondary mineralization which may have accumulated on the natural fracture faces from the flow of geothermal fluids through the area, (2) removing mud and drill cuttings from the fracture channels, and/or (3) etching flow channels in the fracture faces; i.e., reacting with the quartz, chert, and shale material which makes up the producing formation. Laboratory tests of the acid/formation material interaction had shown an average solubility of 53 percent in the HCl-HF acid solution (Appendix C). The acid solution was displaced deep into the reservoir with 3,019 bbl of water. An injection test was performed during the water injection period to evaluate the stimulation effect of the acid treatment. Downhole pressure data (Table 4) were obtained as in the first stage and the injectivity showed a 2.2-fold increase over the pre-stimulation condition. In addition, a post-stimulation spinner log was obtained to 5,450 feet while injecting at a rate of about 15 BPM.

All injection tests were analyzed using both type curve and semilog analysis techniques. The results of injection falloff analyses are presented in Table 4. The downhole pressure measurements were significantly affected by temperature effects in the wellbore, implying that the principle zone of interest is located below the 5,000 foot depth where the pressure data were recorded. Therefore, these test results indicate a trend of improvement due to stimulation rather than providing absolute measurements of permeability-thickness.

B. Evaluation

1. Fluid Production

Upon completion of the final pumping period the packer and tubing were pulled from the well and the rig was moved out in preparation for a production test. A production wellhead and flowline with orifice meter and James tube were installed on the well. On August 26, the well was

TABLE 4

ROSSI 21-19 INJECTIVITY TESTS

Test	Date	Rate (BPM)	Initial Pressure (psig)	Pressure Change (psi)	Injectivity Index (B/D/psi)	Remarks
1	8-18-83	15.1	1938.9	629.7	34.5	Pre-Stimulation
2	8-20-83	15.2	1946.6	555.1	39.4	Pre-Stimulation
3	8-21-83	14.6	1909.8	479.1	36.3	After First Stage Acid Treatment
4	8-22-83	15.1	1905.6	247.3	87.9	Post-Stimulation

ANALYSIS OF INJECTION PRESSURE DATA

		Log-Log Curve Analysis		Semilog Analysis	
Test	Production Time (hrs)	Permeability-Thickness (md-ft)	Skin	Permeability-Thickness (md-ft)	Skin
1SI	1.58	5367	-3.6	4772	-3.71
2SI	2.03	1585	-6	3192	-4.4
3SI	2.43	4636	-4.2	4451	-4.2
4SI	2.5	18544	-2.14	18510	-2.5

kicked off with downhole injection of nitrogen gas through coil tubing and flowed for approximately eight hours with continuous nitrogen lift. The wellhead temperature peaked at 235°F with a wellhead pressure of 24-30 psig. The well flowed at an estimated rate of 200,000 lb/hr with 800 scfm of nitrogen injection at a depth of 1,780 feet, but when the nitrogen was shut off, the well died. The well's flow rate with nitrogen lift could only be estimated because the gas flow interferes with the normal function of the orifice meter and James tube. A second attempt was made to produce the well on August 27, but again the well failed to flow on its own when the nitrogen gas was shut off. Attempts to flow test the well were abandoned after producing it for approximately 14 hours by nitrogen lift. A temperature profile obtained in the well indicated the colder upper zone (2,000-2,580 feet), now open to the wellbore, was cross-flowing cold water (about 136°F) into the lower stimulation zone. This cold water influx was quenching the steam flash and preventing the well from flowing on its own.

Unfortunately, this mechanical complication with the well precluded an adequate production test. The shallow, low temperature zone in the well had previously been perforated for testing as an injection interval. Although this zone had exhibited very low injectivity characteristics and was not expected to cause any problems, it produced enough cold water into the wellbore to prevent initiation of flashing flow from the lower zone.

In order to production test the well, the shallow perforated zone will have to be plugged off by cementing or by installation of a tieback casing string. If the well is production tested, it is reasonable to expect a significant increase in the productivity of the lower zone. However, the absolute level of productivity cannot be directly inferred from the injectivity data.

2. Fracture Mapping Experiments

Sandia National Laboratories and Los Alamos National Laboratory (LANL) both participated in the experiment by testing fracture mapping methods and providing data on the direction of fluid movement in the reservoir during the treatment. Sandia applied its surface electrical potential system (SEPS) to map the movement of the treatment fluids in the reservoir. LANL was able to detect and map microseismic events during fluid injection using the triaxial geophone instrument in the neighboring well Ginn 1-13. The LANL and Sandia fracture mapping experiments are documented in references 4 and 5 and are summarized briefly below.

The objective of the Los Alamos experiment was to seismically monitor the acid treatment process for evidence of reservoir strain release by locating any sources of induced microseismicity. During the two stages of acid treatment, the Los Alamos geophone package was deployed in well Ginn 1-13 about 2,000 feet NW of the injection site at Rossi 21-19. The seismic monitoring at Ginn 1-13 was conducted in several stages, starting at a depth of 6,500 feet about 1/2 hour before acid injection on August 21. Monitoring continued at 6,500 feet during acid injection (500 bbl at about 15 BPM rate) and subsequently during displacement of acid into the formation by flushing with 221 bbl of water. The tool was then moved to 5,500 feet just prior to injecting an additional 2,225 bbl of water at the same rate of about 15 BPM. Numerous microseismic events were observed during the latter half of the water injection stage and particularly subsequent to a sudden increase in the surface treating pressure. A marked decrease in microseismic activity was observed upon completion of water injection.

Monitoring was resumed on August 22 at a depth of 6,500 feet just prior to injecting 982 bbl of HCl-HF acid, followed by 297 bbl of water to displace the acid into the formation. The geophone package was then moved to 5,500 feet for the remainder of the water injection period. Pumping resumed and an additional 2,722 bbl of water was injected at a rate of about 15 BPM. Microseismic activity was not very obvious during this second acid treatment and subsequent water injection. Although apparently coherent "events" were recorded, they were very weak with high signal-to-noise ratios. The events recorded during the acid and first water injection on August 22 appear to have very different seismic signatures from those recorded the previous day during the first acid/water injection period.

The observed seismicity during the first acid stage is in itself enigmatic because the stresses normally required to break rock or to cause shear failure along preexisting fracture surfaces were not achieved hydraulically. It is postulated that the microseismic events resulted from shear failure caused by chemical weakening of cemented fractures. If this hypothesis is valid, microseismic events should have been more pronounced on the following day when the larger volume HCl-HF stage was injected, unless reservoir stresses had been sufficiently released the previous day.

The observed microseismics on the first day are grouped within the distance range of 1,580-2,110 feet from the Ginn well. These events appear to occur near the Rossi well, the furthest being no more than about 400 feet from the injection interval. The events also appear to occur along a generally linear trend which largely parallels the surface trace of the prominent Malpais Fault.

Sandia field tested the SEPS to determine the sensitivity of the technique to chemical treatments of geothermal wells and to map the directional nature of the treated zone. The surface electrical potential data were taken by measuring potentials at 65 ground probe locations placed circumferentially around Rossi 21-19 at distances of 750 feet, 2,000 feet, and 4,000 feet. The potential field was created by inducing electrical current flow through the earth.

Since the success of this diagnostic technique relies on changes in resistivity resulting from flow of a conductive fluid into the formation, quantitative estimates of expected resistivity contrasts were made before the field experiment. Resistivity of the in situ brine was measured at 80 ohm-meters. The HCl and HCl-HF acid solutions had resistivities an order of magnitude lower. Because of the resistivity contrast between the in situ brine and the surrounding earth, the Malpais fault -- trending at about 60° and 255° from Rossi 21-19 -- was seen in the pre-stimulation SEP data.

Post-stimulation data, when compared to the background data, indicate that the chemical treatments altered the in situ flow patterns. The predominant 60°/255° fracture is still present but the flow appears to be enhanced along the 60° azimuth. A second major flow path in the 15°/195° direction became apparent during the second acid stage. Some movement of the treatment fluids was also seen along an east-west path approximately 2,000 feet north of Rossi 21-19 with activity centered at the Ginn well.

3. Chemistry and Fluid Mixing

Ten samples of produced liquid were collected during the two attempts at initiating flow with nitrogen lift. The analytical results, given in Table 5, were examined for trends due to backflowing a mixture of spent acid injectate and native geothermal fluid. The results can also be compared with analyses of Rossi 21-19 liquid collected before the stimulation attempt and with liquid from Beowawe 33-17 which was used to supply treatment fluid to the stimulation experiment.

Compared to the pre-stimulation samples of Rossi 21-19 geothermal liquids, the produced fluid returns obtained are all significantly different in several categories. For example, they are higher in calcium (15- to 60-fold), higher in chloride (10- to 25-fold), and carry significant iron (up to 42 ppm). On the other hand, the concentrations are low compared to the injected acid. The calcium concentration that could have

TABLE 5

ANALYTICAL RESULTS FOR LIQUID SAMPLES

Rossi 21-19, August 26-27, 1983

Hour	1208	1304	1523	1607	1835	0925*	1030	1130	1145**	1250***	Vacuum Truck 8/20	Vacuum Truck 8/13	Rossi 21-19 4 Dec 76 5 Samples	Beowawe 33-17 8 Nov 79 4 samples
Na	334	409	165	478	502	249	408	521	550	641	265	272	340	280
Ca	199	294	26	393	550	83.6	324	536	534	710	1.92	3.11	12	4
K	66.3	85.5	13.4	109	135	40.2	99	136	142	172	28.6	28.6	41	26
Mg	73	82.6	13.4	97	99	29.7	72.2	98	103	108	<.04	-	5.4	1.5
Fe	25	18.1	1.16	42.3	41.3	7.61	15.5	38.8	35.4	24.0	.008	.314	3.3	2.2
Ba	4.66	3.40	.05	5.01	5.93	.84	3.42	6.27	5.5	7.38	<.03	-	.10	.25
Mn	2.87	3.64	.0738	4.63	5.11	.807	3.21	4.93	5.31	5.83	-	-	1.05	.05
Al	23.4	5.72	.26	11.9	8.04	3.31	3.68	8.74	7.8	4.55	.24	.24	15	78
Sr	1.6	1.9	-	2.3	3.4	.37	1.9	3.0	<2	4.4	-	-	-	-
Li	1.8	1.8	.8	2.1	2.3	1.4	2	2.6	3	2.9	1.5	1.5	2.3	1.8
Zn	.580	.214	.077	.352	.704	.142	.0816	.105	.23	-	-	-	.7	.1
Cu	.19	.019	-	.022	.20	.054	<.005	-	-	-	-	-	.01	.04
Cr	.165	.163	-	.24	.22	.066	.12	.18	-	.16	-	-	-	-
Ti	.064	<.002	-	-	-	-	-	-	-	-	-	-	-	-
V	.0713	.083	-	.148	.146	-	.076	.129	-	-	-	-	-	-
Pb	.06	-	-	-	-	-	-	-	-	-	-	-	.005	.023
Cl	1100	1440	246	1820	2200	490	1460	2220	2240	2670	58	50.5	110	65
HCO_3	85.4	26	109	18	21	249	41.5	22	22	112	75	160	41	-
SO_4	51	49	52.5	46	42.5	56.5	50.5	43.5	47.5	48	101	108	440	122
F^-	23.9	25.7	2.85	22	22.4	12.7	19.4	24.3	31.5	6.46	46.4	47.7	15	14
B	3.02	2.82	1.74	3.05	2.13	1.88	2.10	2.44	3.1	2.31	1.97	1.93	2	-
PO_4	2.4	.73	<.1	2.1	1.6	.1	.6	2.6	<3	<.3	-	<.1	-	-
CO_3	<1	<1	4.8	<1	<1	<1	<1	<1	<1	<1	193	157	76	156
SiO_2	60.4	59.4	26.2	82.3	76.7	44.3	75.1	96	82	69.2	85.5	27.9	540	500
pH	-	-	-	-	-	-	-	-	-	-	-	-	9.4	9.3
Ca/Mg	2.73	3.56	1.94	4.05	5.56	2.81	4.49	5.47	5.18	6.57	48	undef.	2.22	2.7
Fe/Mn	8.71	4.97	15.7	9.14	8.08	9.43	4.83	7.87	6.67	4.12	undef.	undef.	3.14	44
Cl/Na	3.29	3.52	1.49	3.81	4.38	1.97	3.58	4.26	4.07	4.17	.22	.19	.324	.232
Cl/SO_4	21.6	29.4	4.69	39.6	51.8	8.67	28.9	51	47.2	55.6	.57	.47	.25	.533
Cl/B	364	511	141	597	1033	261	695	910	723	1156	29.4	26.2	55	-
Ca X SO_4 X 10^{-4}	1.01	1.44	.136	1.81	2.34	.472	1.64	2.33	2.54	3.41	.0194	.0336	.528	.0056
Ca/Fe	7.96	16.2	22.4	9.29	13.3	11	20.9	13.8	15.1	29.6	240	9.9	36	1.82

*Steady flow, 200,000 lb/hr (est.) with 800 scf N_2
**N_2 stopped at 1245
***Well died at 1308
Vacuum truck fluid is Beowawe 33-17 flashed liquid.

been picked up by injectate reaction with limestone is more than 75 times greater than the measured concentrations. These features show that the dissolved components in the return fluid composition were dominated by the reacted acid injectate, but that the fluid volume was mainly native fluid from Rossi 21-19 and/or the Beowawe 33-17 fluid used during the experiment for injection testing and diluting and displacing acid.

When viewed as a set, the several liquid samples show a composition trend that is irregular with continued production, but shows a general increase in salinity. The last three samples, for example, show six of the seven highest analytical values for chloride and calcium. This is interpreted to mean that the main volume of acid injectate remained in the reservoir at the end of attempts to flow the well.

Acid attack on the casing appears to be minor. The ratio of Ca/Fe is not greatly different from what one might expect from leaching igneous rocks and is larger than what a serious casing attack would yield. Similarly, the ratio of Fe/Mn, generally 4 to 10, is much smaller than expected from attack on casing steels which contain about one weight percent Mn.

The amount of spent acid in the volume of fluid returns can only be estimated roughly, partly because the volume ratios of native/injectate fluid were large and variable, and partly because the cumulative production vs. sampling time was not well defined. However, of the nominal 10,000 bbl of fluid produced during nitrogen injection, only 140 to 700 bbl of volume represent the 1480 bbl of acid injectate. The apparently inferred small returns of injectate imply that considerable mixing of the injectate with native fluids occurred. Part of this dilution is due to the contribution of fluid from the shallow, cooler zone, estimated to be about one-fourth of the total flow. However, the balance of the 30- to 75-fold dilution is due to mixing of injectate with native geothermal fluid in the reservoir. The imbalance in the returns suggests that considerable mixing occurs in the reservoir, and is strong evidence that piston-like flow displacement did not occur.

C. Experiment Costs

The total direct cost for the field experiment, excluding RGI and Chevron labor, was $329,000. A detailed breakdown of the costs is given in Table 6. Of this total cost, Chevron's contribution was a $20,000 share of the direct cost for contract services. Chevron contributed an estimated additional $40,000 in the form of production test equipment and engineering and supervisory labor. The GRWSP share of $309,000 (excluding RGI labor) was composed of $118,100 for stimulation materials and services; $172,800 for the rig, transportation, rental equipment, and other services; and $18,100 for production testing.

VI. CONCLUSIONS AND RECOMMENDATIONS

Chevron's reservoir testing and the GRWSP field experiment have led to the following conclusions regarding Rossi 21-19.

1. Rossi 21-19 was chosen for the stimulation experiment because it was a noncommercial producing well, in contrast to other Beowawe wells which exhibit high productivities characteristic of a large, fracture dominated reservoir. Previous reservoir testing and analysis by Chevron indicated that the well's productivity was limited by near-wellbore restricted permeability.

2. The production interval (below 4,369 feet) in Rossi 21-19 was stimulated with a two-stage acid treatment of HCl and combination HCl-HF acids to improve the permeability of the natural fracture system. Injectivity tests before and after each acid stage indicate that injectivity was improved by a factor of 2.2 by the acid treatment.

TABLE 6

ACTUAL DIRECT COSTS FOR FIELD EXPERIMENT AND PRODUCTION TESTING CHEVRON ROSSI 21-19

Field Experiment	
Rig Services	$ 42,010
Stimulation Materials and Services	
Acids and additives	81,882
Pumping Service	13,992
Mobilization/demobilization of pumping equipment	1,728
Frac tank rental and transportation	12,160
Water hauling for stimulation and injection tests	8,358
	118,120
Other Services	
Service representatives for packer and fishing tools	15,052
Wireline services for fishing	1,714
Injection temperature, pressure, and profile logs	35,228
Water hauling to rig	1,343
Roustabout labor and subsistence	17,762
Rental equipment inspection and repairs	4,908
Welding	1,800
Surveying	1,826
Road grading	895
	80,528
Rentals	
BOP, drillpipe, fishing tools	14,241
Packer	15,992
Generator, forklift, jeep, crane, backhoe	11,714
Miscellaneous	1,084
	43,031
Transportation of rental equipment	20,303
Expendable materials and supplies	
Pipe, fittings, and miscellaneous materials	5,591
Diesel fuel	1,280
	6,871
Subtotal Field Experiment	310,863
Less Chevron's Cash Share	-20,000
Total Field Experiment Direct Cost to GRWSP	290,863

Production Testing

Nitrogen and coil tubing service	17,863
Transport test equipment to Beowawe	196
Total Production Testing	18,059
Total Field Experiment and Production Testing	$308,922

3. The planned post-treatment production test was aborted because cool water entering from a separate, shallow completion interval in the well prevented the well from flowing by natural flashing flow.

4. Fracture mapping experiments were carried out by both LANL and Sandia Laboratories. The Sandia surface electrical potential system was shown to be highly sensitive to the chemical treatment and was also responsive to fluid-filled fractures in the reservoir before any acid injection. Major acid flow paths were observed along the Malpais fault line (60°/255°) and along a 15°/195° path. LANL mapped seismic activity during the treatment along the direction of the Malpais fault and along an east-west trend. This was especially significant in that the treatment was carried out at pressures below fracturing pressure.

5. The acid treatment performed in Rossi 21-19 was a relatively simple and inexpensive procedure not requiring any recompletion work in the well. The principal complication to the job was the existence of the shallow, perforated zone which had to be isolated with a packer from the treatment and which later interfered with the production testing. A complete evaluation of the economic success of the treatment is dependent upon obtaining a suitable production test.

The following recommendations are made based on the experiment results.

1. The well should be production tested if sufficient funding can be made available. In order to carry out a production test, the upper, perforated zone will have to be temporarily excluded or permanently plugged off.

2. When the Beowawe field is developed commercially, it may be worthwhile to restimulate the well for an additional improvement in productivity. Another treatment would offer an opportunity to work toward optimized procedures and treatment fluids.

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APPENDIX A

Daily Reports

Daily Reports

ROSSI 21-19 ACID STIMULATION

Monday, August 1

Sandia wireline unit was delivered to location and off-loaded by G&S. G&S is mobilizing trailers and equipment.

Tuesday, August 2

Surveyor started field work and completed staking about half of the locations for Sandia's surface electrical potential (SEP) ground probes. G&S began installing ground probes and stringing wire for Sandia.

Wednesday, August 3

Surveyors finished staking ground probe locations and G&S continued to install probes and string wires to Sandia's trailer. G&S fabricated rig guy line anchors and buried them on location. Road uphill to Beowawe 33-17 (water supply well) is impassable. G&S worked on road with backhoe preparing to move 500 bbl tank and flowline materials to 33-17.

Thursday, August 4

G&S fabricated blooie line tiedowns for Rossi 21-19, prefabricated tank overflow piping for use at 33-17, and continued installing ground probes and stringing wire for Sandia.

Friday, August 5

G&S moved 500 bbl tank and piping materials to Beowawe 33-17. Welder fabricated flow line to tank. G&S continued to string wire for Sandia's SEP probes.

Saturday, August 6

G&S hauled 1,000 feet of 4" rental irrigation pipe to Beowawe to be installed from water tank at Beowawe 33-17 to water truck loading point at bottom of hill. G&S worked on piping at Beowawe 33-17.

Sunday, August 7

G&S worked on installing 4" water line downhill from Beowawe 33-17.

Monday, August 8

G&S finished installing 1,000 feet of 4" water line from 33-17 and used backhoe to repair water haul road. G&S finished stringing wires for Sandia's SEP network and worked on Rossi 21-19 master valve. Western Oil Well Service Company (WOWSCO) delivered rig mud pit, pump, etc. to Rossi location.

Tuesday, August 9

Western Oil Well Service Company Rig No. 29 moved in, rigged up, and installed BOP. G&S finished piping work at Well 33-17, opened well, and filled 500 bbl tank. Well flows approximately 400 bbl per hour. G&S hauled two loads of water from 33-17 and filled rig mud pit.

Wednesday, August 10

Made up six, 4-3/4" D.C.'s in doubles and stood back. Made up Baker plug plucker, junk sub, and bumper sub and hung in derrick. W.O. 3-1/2" tubing. Two frac tanks were delivered.

Thursday, August 11

W.O. 3-1/2" tubing, truck with tubing broke down in Austin, NV. Called for G&S tractor to pick up trailer load of tubing in Austin and haul to location. Three more frac tanks were delivered. G&S set anchors for blooie line and leveled area of location for remaining frac tanks.

Friday, August 12

Measured in hole with Baker plug plucker, junk sub, bumper sub, and six, 4-3/4" D.C.'s. Tagged B.P. at 2,721' K.B. Circulated water at 5-6 BPM and milled on B.P. for 2± hours. Milled 1± foot then lost circulation and milling tool stuck. Attempted to circulate and worked pipe for three hours. Mill did not move. Called for a backoff shot and fishing tools.

Saturday, August 13

Circulated and worked pipe while W.O. backoff truck. Plug plucker came free and was free of B.P. Circulated with full returns and attempted to sting back into B.P., but could not. Milled on B.P. 20 minutes and B.P. began to move downhole. Chased B.P. to 4181' (on liner top). POH without B.P. Replaced shear pins in Baker plug plucker, RIH, circulated and attempted to sting into B.P. with retrieving head. POH, no recovery.

Sunday, August 14

Made poor boy junk basket from 8-1/8" O.D. washover shoe. RIH with junk basket and bumper sub and set down on B.P. at 4,181'. Bumped down several times and made 1' to 4,182'. Pulled off bottom with 12,000 lb overpull then lost drag and POH with no recovery. Nothing had been inside of junk basket. Made up BHA consisting of same junk basket/milling shoe, bumper sub, jars, and D.C.'s. RIH, tagged B.P. at 4,181', milled 50 minutes and made 1.5' to 4,182.5'. Bumped down on B.P. and POH. No recovery. Scratch marks extended 5-1/4" up inside junk basket.

Monday, August 15

Made up BHA consisting of 8-5/8" flat bottom mill, junk sub, bumper sub, jars, and D.C.'s. RIH, tagged B.P. at 4,182.5' KB. Milled and circulated (conventional and reverse) for a total of four hours. (Actual milling time = 1 hour). Recovered broken pieces of B.P., rubber, and mill cuttings. Made 2' to 4,184.5' then suddenly lost circulation to lower zone and stopped milling. Tagged L.T. or remaining portion of B.P. at 4,185.0' and POH. Ran three stands of tubing on sandline and could not get below L.T.

Tuesday, August 16

Made up BHA consisting of 5-5/8" F.B. mill, bumper sub, jars, and six 3-1/2" D.C.'s. RIH on 3,231' of 2-7/8" DP and 3-1/2" tubing. Tagged BP at 4,184'. Spudded and milled lightly, attempting to get into liner with no success. Milled 6" in 20± minutes, then spudded and worked pipe and broke through into liner. RIH and hit obstruction at 5,445'. Spudded and made hole to 5,480'. Began POH LDDP and excess tubing.

Wednesday, August 17

LD 3-1/2" D.C.'s, jars, bumper sub, and 5-5/8" mill. Picked up Otis 9-5/8" Therma-Trieve packer with 20' expansion joint and seating nipple above expansion joint. RIH on 3-1/2" tubing, dropped plug, and pressure tested tubing, no test. Retrieved and redressed plug. Dropped plug and tested to 2,500 psi, ok. Set packer at 2,640'. Attempted to test packer by pressuring annulus. Filled annulus and pressured to 200+ psi, then pressure broke back to zero, possibly due to perforations breaking down. Baker production services attempted to run static temperature log, but had a failure in electronic panels. BJ-Hughes rigged up.

Thursday, August 18

Baker Production Services attempted to fix logging panels, no success. Baker called for parts and service man from Fort Worth. Cannot run spinner survey until later on 8/19. Decided to run injectivity test with Baker's Panex downhole P&T system. Baker rigged up Panex system and RIH with P-T tool with well shut in. Shut-in P&T at 5,000' = 1,916 psig and 211.5°F. Began injectivity test at 1523 hours, pumping at two BPM and increasing to 15 BPM in 15 minutes. Annulus began to blow due to apparent packer leak. S.I. annulus and continued to pump. Pumped at 15 BPM for 80 minutes with surface pressure increasing from 1,470 to 1,830 psig. Average annulus pressure = 350 psig. S.I. for pressure falloff test. Injectivity test will be repeated because of leakage to upper zone.

Friday, August 19

POH with Baker Panex P-T tool. Baker repaired panels and rigged up production logging tool string with spinner, temperature, CCL, GR, and multi-shot R/A tracers injector. Made three or four aborted runs with tool problems. After correcting problems, RIH and made four R/A tracer velocity shots above and below packer. Approximately two BPM were flowing down casing below packer with well shut in. Zero velocity in tubing. Packer leak is indicated. Ordered new packer and proceeded with injection profile survey. BJ began injecting water down tubing at 1455 hours. Stabilized rate at 12 BPM at 1502 hours and continued for 80 minutes while running injection profile surveys in slotted liner interval. Made three passes with spinner and six R/A tracer velocity shots. 80%-90% of injection is in the interval 5,100'-5,400'. During one pass, inadvertently ran past B.P. junk at 5,480' to 5,607' with no obstruction. Did not tag fill. Pulled hard through B.P. junk at 5,480'. POH with logging tools. RD lubricator and injection lines. Unset packer, POH and L.D. packer. New packer due to arrive Saturday a.m.

Saturday, August 20

W.O. Otis packer. Packer arrived at 1100 hours. Made up 9-5/8" Otis hydraulic set packer with seating nipple and wireline guide below packer and 5' expansion joint above. RIH on 3-1/2" tubing. Set packer at 2,753', tested tubing to 2,500 psi and retrieved standing valve. Light blow on annulus after setting packer. RU BJ-Hughes lines on tubing and RU Sandia to run pressure and temperature tools and current injection probe on Sandia's seven-conductor line. Sandia started in hole at 1640 hours. Pressure tool failed at 600'. RIH to L.T. at 4,185' logging temperature and pulsing current injection probe. Injectivity test delayed until Baker

Production Services can get in hole with back-up pressure tool. POH. Sandia out of hole at 1825 hours. RU Baker Production Services Panex P-T logging tool and RIH to 5,000' for injectivity test. Initial shut in T&P at 5,000' = 267°F, 1,947 psig. BJ started pumping at 1958 hours at six BPM. Increased rate to 15 BPM at 2005 hours and maintained 15 BPM average until S.D. at 2200 hours. Choke line from annulus left open - no blow. Total 1,831 bbl injected. Surface tubing pressure increased from 1030 psig to final pressure of 1460 psig at 15 BPM. Final BHP at 15 BPM injection = 2,502 psig at 5,000'. Final shut-in BHP at 0400 hours on 8/21 = 1,957 psig. POH with P-T tool.

Sunday, August 21

BJ-Hughes began pumping first acid stage at 0904 hours, consisting of 500 bbl of 14.5% HCl with 20 gal EDTA, 4 gal C-15 inhibitor, and 25 gal Z-5 (formic acid) per 1,000 gallons. Pumped at 15.1-16.3 BPM rate with 1,160-1,320 psig surface treating pressure. Displaced acid into formation with 221 bbl water (75 bbl overflush). Rate and pressure = 15.6 BPM, 1,430 psig at end of displacement. S.D. at 0949 hours. ISIP = 340 psig. S.I. tubing pressure after five minutes = 80 psig. Baker Production Services RIH with Panex P-T tool to 5,000'. S.I. T&P at 5,000' at 1132 hours = 250°F,, 1908 psig. BJ began pumping water at 1134 hours. Pumped 2,225 bbl and S.D. at 1400 hours. Rate 15.0 - 14.6 BPM. Surface treating pressure 1,100-1,490 psig. ISIP = 340 psig. Final injection pressure and temperature at 5,000' at 1359 hours = 2,489 psig, 146.3°F. Panex tool hung at 5,000' for pressure falloff. Final P&T at 0720 hours on 8/22 = 2,009 psig, 301°F. BJ mixed 40,000 gal of 12% HCl - 3% HF acid. Acid contains 20 gal EDTA, 8 gal C-15 inhibitor, and 25 gal Z-5 (formic acid) per 1,000 gallon.

Monday, August 22

Baker Production Services POH with Panex P-T tool. BJ-Hughes began pumping 12% HCl - 3% HF acid at 0842 hours. Pumped 982 bbl of acid at 15.0-15.5 BPM except rate was reduced to 12.8 BPM from 0915-0930 hours because hose leak on blender discharge was causing frac pump to lose prime. S.D. once from 0930-0955 hours to repair leak at treating head. Also repaired hose leak. Displaced acid with 297 bbl of water (150 bbl overflush) and S.D. at 1031 hours. Final rate and surface treating pressure at end of displacement = 15.0 BPM, 1,590 psig.

Tubing on strong vacuum after six minutes. Baker Production Services RIH to 5,000' with Panex P-T tool for injectivity test. BJ started pumping water at 1234 hours. S.D. at 1259 hours with 231 bbl injected because pressure tool failed. Pressure tool started working again. BJ restarted injection at 1333 hours. S.D. at 1347 hours with an additional 179 bbl injected because of pressure tool failure. Cause of intermittent tool failures not known. Baker POH with Panex and RIH to 5,000' with Hewlett-Packard pressure tool. BJ started pumping at 1650 hours. Injected 2,312 bbl at average rate of 15 BPM and S.D. at 1920 hours. Final injection rate and surface treating pressure = 15.1 BPM, 1,270 psig. BHP indicates a 2.3-fold increase in Injectivity Index compared to previous injectivity test. H-P pressure tool hung at 5,000' for pressure falloff. Baker POH at 0130 hours on 8/23 and make up production logging tool string.

Tuesday, August 23

Baker Production Services RIH with production logging tool string consisting of temperature, spinner, CCL, GR, and R/A tracer injector. Attempted to run S.I. temperature log, but temperature tool failed. Attempted to get temperature tool working by injecting water to cool it. With temperature tool hanging at 2,869', BJ started pumping water (six BPM) down tubing at 11:44 hours. Injected 82 bbl and S.D. at 11:56 hours. Temperature tool still not working. Unable to repair temperature tool. Decided to eliminate temperature log and proceed with injection spinner survey. BJ started pumping at 13:37 hours. Injected 1109 bbl at average 15.4 BPM and S.D. at 14:49 hours to pull production logging tools through tubing. Final pumping rate and surface injection pressure = 14.8 BPM, 1,250 psig. ISIP = 330 psig; 1 minute, 30 psig; 1+ minute, 0 psig. Logging tools out of hole, released Baker. BJ started pumping again at 15:25 hours to inject remainder of water in frac tanks. Pumped at 6.7 BPM, 30 psig with blender only, then started frac unit at 15:34 hours and increased rate to 18.8 BPM, 1,600 psi. Injected 892 bbl and S.D. at 16:19 hours. Final rate and surface injection pressure = 18.6 BPM, 1,780 psig. ISIP = 190 psig; 1 minute, 30 psig; 1 minute 45 seconds, 0 psig. BJ RDMO. Unseated packer and began POH, L.D. tubing. Pulled to 1,500'± and rig S.D. for the day. G&S crane helped load out Sandia and BJ equipment.

Wednesday, August 24

Finished POH with packer, L.D. tubing. Western Oil Well Service R.D. and removed BOP. Released rig at 11:00 hours. G&S installed tree from 85-18 on Rossi 21-19. G&S worked with Sandia to dismantle SEP ground probe network.

Thursday, August 25

G&S finished installing blooie line/James tube and meters for production test. Cudd Pressure Control rigged up coil tubing unit and nitrogen pumper, ready to kick well off in a.m.

Friday, August 26

Cudd Pressure Control started in hole with coil tubing at 0807 hours to kick well off with nitrogen. Staged in hole to 1,780' injecting N_2 at rates increasing from 400 to 800 scfm. Lifted from 1,750'-1,780' at 800 scfm from 1023 hours to 1248 hours. Well unloaded intermittently from 0949 hours to 1147 hours, then flowed steadily at estimated rate of 200,000 lb/hr with 800 scfm N_2 injection. Attempted to run deeper with coil tubing, but could not get past L.T. at 1,791'. WHT peaked at 213°F. At 1248 hours, reduced N_2 rate to 400 scfm, then to 200 scfm at 1316 hours. Well stopped flowing at 1331 hours. Shut off N_2 and POH with C.T. to put on centralizer to get past L.T. Well flowed intermittently while POH. Out of hole at 1400 hours. Started in hole with centralizer on C.T. at 1420 hours. RIH to 700' injecting N_2 at 200 scfm, then increased N_2 to 800 scfm and continued RIH to 1,780'. Could not get past L.T.

Continued to inject N_2 at 1,780' at 800 scfm from 1447 hours-1533 hours; 1,200 scfm, 1533 hours-1538 hours; 1,500 scfm, 1538 hours-1602 hours; 1,200 scfm, 1602 hours-1634 hours; 800 scfm, 1634 hours-1817 hours. WHT peaked at 235°F at 1800 hours with WHP = 24-30 psig. Well flowed at estimated rate of 200,000-250,000 lb/hr with 800 scfm N_2 injection. Shut off N_2 at 1817 hours. With C.T. at 1,780', static N_2 pressure at surface = 425 psig at 1841 hours. Cudd POH with C.T. and S.D. for night.

Saturday, August 27

Cudd Pressure Control started in hole with coil tubing at 0700 hours to kick well off with nitrogen. Ran into hole to 2,000' injecting N_2 at rates increasing from 400 to 800 scfm from 0723 hours-0825 hours. Well unloaded intermittently from 0755 hours-0906 hours, then flowed steadily at estimated rate of 200,000 lb/hr with 800 scfm N_2 injection. Ran in deeper with coil tubing starting at 0906 hours-1042 hours and stopped at 4,100'. WHT peaked at 250°F. Continued to inject N_2 at 800 scfm at 4,100' until N_2 ran out at 1245 hours. Well flow declined and died at 1308 hours. Cudd POH with C.T., rigged down and moved out at 1500 hours. Rigged up LANL/DRI for pressure, temperature, and spinner surveys. DRI tools malfunctioned. RIH with LANL temperature tool with 5-1/2" diameter to 4,458'; hit obstruction. POH and removed centralizer band around tool, reducing diameter to 4-1/2", and RIH to 5,450'. Obtained temperature profile data. POH and RD the LANL equipment at 0115 hours on August 28.

Sunday, August 28

G&S completed removal of tank and flow line at Well 33-17. Disassembled Chevron's flow test equipment at Rossi 21-19 and cleaned up well sites.

Monday, August 29

G&S completed clean up and removal of equipment from Rossi 21-19 site. Last field report.

APPENDIX B

Surface Injection Pressure and Rate Data

SURFACE INJECTION PRESSURE AND RATE DATA

ROSSI 21-19

August 18, 1983

Injectivity Test

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
12:35				RIH with pressure & temperature instruments
12:50				POH - instruments failed
14:04				Baker Production Services RIH with T&P tools
15:25	2.0	0	0	Start water injection. Will increment rate to 15 BPM over a period of 15 minutes.
15:40	15.0	1470		
15:43			150	S.I. annulus because of packer leak
15:45	14.9	1600		210 psig annulus pressure
16:00	14.9	1760	418	350 psig annulus pressure
16:22	15.1	1830	760	400 psig annulus pressure
17:00	15.1	1820	1290	360 psig annulus pressure S.D.
ISIP	0	620		260 psig casing pressure
1 min.	0	140		130 psig casing pressure
4 min.	0	10		10 psig casing pressure
1715	0			Annulus on vacuum

ROSSI 21-19

August 19, 1983

Injection Profile Survey

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
0700-14:35				Waiting on Baker Production Services; problems with production logging tools
14:55	2	0		Began water injection for injection profile log
14:56	5	30		Increased rate to 5 BPM. Zero annulus pressure
14:58	10	600	15	Increased rate to 10 BPM
15:02	12	800	70	Maintain 12 BPM rate
				Spinner and R/A tracer surveys being run in 6-5/8" liner
15:13				Checked annulus-found pressure. Possible transducer problem
15:14	12	1030	225	Pressure on annulus being recorded
15:30	12	1080	407	Pumping at 12 BPM
15:45	12	1120	590	
16:05	12.1	1160	840	
				Rig pump pressure gauge showing 300 psi on annulus. Transducer indicates 820 psig. BJ will check transducer after pumping stops.*
16:22	12.0	1200	1045	Stop pumping - surveys complete
ISIP		380		
1 min		120		
2 min		80		
3 min		50		
4 min		30		
5 min		20		

*Note: Annulus pressure recording probably off 500± psi

ROSSI 21-19

August 20, 1983

Injectivity Test

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
1400-1500				Set and tested packer at 2,758' and retrieved test plug.
19:58	6.0	50	0	Start water injection. Baker P&T tools at 5,000'.
20:05	15.0	1030	70	Increased rate
20:15	15.0	1270	211	
20:30	15.0	1390	444	
20:45	15.0	1410	672	
21:00	15.0	1430	904	
21:30	15.1	1460	1364	
22:00	15.2	1460	1831	S.D.
ISIP		300		
1 min		190		
2 min		160		
3 min		130		
4 min		100		
5 min		80		

ROSSI 21-19

August 21, 1983

First Stage Acid Treatment
and Injectivity Test

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
9:04				Start HCl acid injection
9:05	15.2	1160		
9:10	15.1	1160	90	
9:13	15.4	1200	146	Acid to top of slots
9:16	15.2	1220	181	
9:20	15.9	1250	250	
9:25	16.2	1260	330	
9:30	16.3	1300	414	
9:35	16.2	1320	500	End acid stage, begin displacement with water.
9:40	15.7	1360	78	
9:44:15	15.6	1400	146	Water to top of slots
9:45	15.6	1400	157	
9:49	15.6	1430	221	End displacement. Baker ready to RIH with P-T tool for injectivity test.
ISIP		340		
9:50 (1 min)		170		
9:54 (5 min)		20		
9:56 (7 min)		Vac.		
11:34				Baker Panex P-T tool at 5,000'. Start water injection
11:35	15.0	1100	10	
11:40	15.1	1420	96	
11:50	15.0	1350*	250	
12:00	15.0	1390	403	
12:25	14.8	1530	785	
13:20	14.8	1530	1625	
13:30	14.8	1520	1774	
13:41	14.7	1510	1939	
13:46	14.6	1500	2016	

August 21, 1983 (continued)

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
13:52	14.5	1490	2104	
14:00	14.6	1490	2225	Shut down
ISIP		340		
14:01 (1 min)		200		
14:05 (5 min)		30		

ROSSI 21-19

August 22, 1983

Second Stage Acid Treatment
and Injectivity Test

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
8:42				Started HCl-HF acid injection
8:47	15.5	980	86	
9:15				Reduced rate. Leaking suction hose, losing prime.
9:20	12.7	660	593	
9:25	12.8	640	658	
9:30	12.9	580	723	
9:30:30			733	S.D. leak at treating head
9:55				Restart
10:05	15.1	1410*	876	
10:10	15.2		955	
10:11:30			982	End acid stage, begin displacement with water
10:14:30	15.0		45	
10:19:30	15.0		121	
10:31		1590*	297	End displacement. Baker ready to RIH with Panex P-T tool.
ISIP		330		
12:34				P-T tool at 5000'. Start pumping
12:59				S.D., Panex problems
13:34				Restart
13:46				S.D., Panex problems. Baker POH with Panex and RIH to 5,000' with Hewlett Packard pressure tool.
16:50				Restart
17:38	15.1	1270	726	
17:45	15.2	1280	835	
18:21	14.9	1280	1393	
18:31	15.0	1280	1547	
18:55	15.2	1280	1920	

August 22, 1983 (continued)

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
19:20	15.1	1270	2312	S.D.
ISIP 30 sec		100		

*Pressure reading is from mechanical gauge on pump truck. Transducer on treating head failed.

ROSSI 21-19

August 23, 1983

Injection Profile Survey

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
				Baker RIH with production logging tools
11:44				Started pumping to cool logging tool at 2,869'. Tool not functioning properly.
11:46	6.3	10		
11:47	6.2	20	25	
11:55	5.7	30	74	
11:56			82	S.D. - Spinner tool failed. POH, repaired and reran.
13:37				Started pumping
13:43	15.1	1200	100	
13:50	15.2	1220	200	
13:56	14.8	1200	300	
14:03	14.8	1180	400	
14:17	14.9	1240	600	
14:23	14.9	1240	700	
14:29	14.9	1240	800	
14:35	14.9	1260	900	
14:42	14.9	1250	1000	
14:49	14.8	1250	1109	S.D. to pull logging tool, survey complete
ISIP		330		
1 min		30		
1+ min		0		
15:25				Started pumping with blender only. (Crew on rig floor) Injecting to dispose of excess water from frac tanks.
15:33	6.7	30	1143	
15:34			1151	Started pumping with frac unit
15:35	18.8	1600	1167	
15:38	15.4	1080	1224	Reduced rate; frac unit red lined

August 23, 1983 (continued)

Time	Injection Rate (BPM)	Surface Treating Pressure (psig)	Cum. Vol. Injected Per Stage (bbls)	
15:40	15.4	1090	1254	
15:42				Added standby pumper
15:43	18.8	1680	1304	
15:48	19.0	1760	1405	
15:50	19.0	1770	1444	
16:07	18.6	1770	1770	
16:12	18.6	1770	1865	
16:16	18.5	1760	1942	
16:19	18.6	1780	2001	
ISIP		190		
1 min		30		
1 min 45 sec		0		

APPENDIX C

BJ-Hughes Laboratory Report

BJ-HUGHES Inc.

1133 AVENUE "G" EAST • ARLINGTON, TEXAS 76011 • PHONE (817) 640-0600

Acid Solubility and Petrographic Analyses of Drill Cutting Samples From Chevron's Rossi 21-19 Well Located in the Beowawe Geothermal Field, Nevada.

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

BJ-HUGHES SERVICES

REPORT NO. 4382 C

LABORATORY REPORT

BJ-HUGHES SERVICES
A DIVISION OF HUGHES TOOL COMPANY

PETROLEUM ENGINEERING LABORATORY
1133 Avenue G East
Arlington, Texas 76011

LABORATORY REPORT NO. 4382 C

DATE August 2, 1983

SUBJECT: Acid Solubility and Petrographic Analyses of drill cutting from Chevron's Rossi 21-19 Well
Republic Geothermal, Inc.

The analyses were performed on composite samples prepared from cutting taken from 4241' - 7200'. The petrographic analyses included Scanning Electron Microscopy/Energy Disspersive Spectroscopy (SEM/EDAX) and X-ray diffraction analysis.

SUMMARY: Acid solubility tests show the interval is predominantly a siliceous rock having varying amounts of calcareous and iron material content. Solubility in hydrochloric acid (15%) ranged from 6.89% to 22.39%, with an average HCl acid solubility of 14.05%. Solubility in hydrochloric-hydrofluoric (12% HCl - 3% HF) acid mixtures was higher and ranged from 32.27% to 77.77%. Average solubility in HCl-HF acid was 52.64%. The high solubility is probably due to the fine-grained texture of the formation and heavy coating of the matrix with silt and clay mineral particles.

Scanning Electron Microscopic and EDAX analysis performed on eight (8) samples revealed the fine-grained texture of the siliceous rock. The visual porosity is primarily from pore systems and hairline fractures. The pores are dominantly secondary, having been enlarged into solution cavities and cavernous voids. The rock matrix and pore openings are shown to be coated with fine silt and clay minerals.
Illite, chlorite and montmorillonite are the dominant clay minerals with calcite and iron minerals also present.

X-ray diffraction analysis were conducted on eight (8) selected samples for mineral composition. Quartz was by far the dominant mineral found in all samples. Other mineral groups present include carbonates (calcite and dolomite), clay minerals (Illite, Chlorite and Montmorillonite), feldspars (Albite and Anorthite), mica (Vermiculite) and iron sulfide (pyrite). Illite is the dominant clay mineral, followed by chlorite and montmorillonite. The palygorskite clay mineral detected may be from the drilling mud.

ANALYZED BY KV, JC, JLB, GM

DISTRIBUTED TO CLS, JP, MS, Mr. C.W. Morris SIGNED BY Gene Marcillas

SAMPLES SUBMITTED:

One hundred and twenty (120) samples from an interval covering 2,959 feet (4241' - 7200') were received. Based on visual lithology, the samples were divided into 18 composite lab samples for analyses. In addition, a composite of all cutting samples was prepared and analyzed.

LAB SAMPLE	COMPOSITE OF SAMPLES
A	4241, 4271
B	4301, 4335, 4357
C	4403
D	4418, 4433, 4448
E	4463, 4478, 4500, 4591
F	4622, 4637, 4655, 4670, 4685
G	4719, 4734, 4751, 4765, 4788
H	5300, 5330, 5346
I	5361, 5376, 5391, 5404, 5420, 5438, 5453, 5469
J	5484, 5500, 5515, 5530, 5545, 5560, 5575, 5590, 5605, 5620, 5635, 5650, 5700
K	5710-20, 5730-40, 5750-60, 5770-80, 5790-5800, 5810-20, 5830-40, 5850-60, 5870-80, 5890-5900, 5910-20, 5930-40, 5950-60, 5970-80, 5990-6000, 6010-20, 6030-40, 6050-60, 6070-80
L	6090-6100, 6110-20, 6130-40, 6150-60
M	6170-80, 6190-6200, 6210-20, 6230-40, 6250-60, 6270-80, 6290-6300, 6310-20, 6330-40
N	6390-6400, 6410-20, 6430-40, 6450-60, 6470-80, 6490-6500, 6510-20
O	6530-40, 6550-60, 6570-80, 6590-6600, 6610-20, 6630-40, 6650-60
P	6670-80, 6690-6700, 6710-20
Q	6730-40, 6750-60, 6770-80, 6790-6800, 6810-20, 6830-40, 6850-60, 6870-80, 6890-6900, 6910-20, 6930-40, 6950-60, 6970-80
R	6990-7000, 7010-20, 7030-40, 7050-60, 7070-80, 7090-7100, 7110-20, 7130-40, 7150-60, 7170-80, 7190-7200.

NOTE: Cuttings below 5650 feet were smaller in size than the cuttings above this depth.

LABORATORY ANALYSES AND RESULTS:

I. Acid Solubility

The acid solubility of the samples in 15% HCl and 12% HCl - 3% HF acid solutions was determined gravimetrically. Results of these tests are shown below:

Lab Sample	Acid Solubility - % 15% HCl	12% HCl - 3% HF
A	21.32	70.88
B	6.89	42.75
C	14.37	43.53
D	15.52	51.57
E	15.56	53.03
F	17.38	66.00
G	8.79	49.13
H	7.65	43.83
I	22.81	54.37
J	12.52	39.61
K	8.89	43.42
L	7.42	32.27
M	12.39	47.68
N	16.85	77.77
O	18.09	74.80
P	12.70	49.45
Q	19.05	60.22
R	14.65	47.15
*S	14.58	52.85

* Composite of all cutting samples.

1) Average Solubility in 15% HCl = 14.05%
2) Average Solubility in 12% HCl - 3% HF = 52.64

II. Partial Chemical Analysis

Iron (Fe) and calcium (Ca) determination was made on samples A, I, K, and composite (A-R). Results are shown below:

Sample	Constituent - % by Weight Fe as Fe_2O_3	Ca as $CaCO_3$
A	7.4	11.2
I	2.8	11.7
K	5.9	5.0
Composite (A-R)	6.8	7.3

III. X-Ray Diffraction Mineral Percentages

	SAMPLE IDENTIFICATION LETTER								
MINERAL	A	D	F	I	J	N	P	Q	COMPOSITE
Quartz	52	84	60	72	90	27	94	74	78
Cristobilite						9			
Calcite	19		13	8		16		14	6
Dolomite				8	2				
Illite		14	18	7	4	3	6		7
Clinoclore						17			
Palygorskite	9								
Montmorillonite								5	
Albite	13							7	4
Anorthite						28			
Vermiculite	7		4						5
Pyrite		2	4	5	4				

BJ HUGHES

MINERAL INFORMATION

SiO_2 Group

Quartz: A tectosilicate with the lowest symmetry and most compact structure. Nearly three-quarters of the rocky crust of the earth is made up of minerals in this group.
Composition: SiO_2

Cristobilite: A naturally occuring SiO_2 polymorph. Similar to quartz except it has a higher symmetry and has a more expanded structure.
Composition: SiO_2

Clay Mineral Group

Illite: A mica-like clay mineral and is the chief constituent in many shales.
Composition: $Al_2Si_2O_5\ (OH)_4$

Clinoclore: A member of the chlorite clay group and is high in iron content.
Composition: $(Mg, Fe)_3\ (Si, Al)_4\ O_{10}\ (OH)_2 \cdot (Mg, Fe)_3\ (OH)_6$

Palygorskite: An alumino-Mg-silicate, classified as a phyllosilicate. Not a common clay mineral, has characteristics similar to attapulgite and sepiolite.
Composition: $(OH_2)_4\ (OH)_2\ Mg_5\ Si_8O_{20}\ 4\ H_2O$

Montmorillonite: Dominant clay mineral in bentonite and has the property of expanding several times its original volume when placed in fresh water.
Composition: $Al_2Si_2O_5\ (OH)_4$

LABORATORY ANALYSES AND RESULTS: continued

Feldspar Group

Albite: A plagioclase feldspar and a major rock forming mineral.
Composition: $NaAlSi_3O_8$

Anorthite: Like albite, a plagioclase feldspar.
Composition: $CaAl_2Si_2O_8$

Mica Group

Vermiculite: A platy mineral formed chiefly as an alteration of biotite.
Composition: $K(Mg, Fe)_3(AlSi_3O_{10}) \cdot (OH)_2$

Carbonates

Calcite: An anhydrous carbonate and one of the most common widespread minerals.
Composition: $CaCO_3$

Dolomite: Carbonate of calcium and magnesium
Composition: $CaMg(CO_3)_2$

Sulfides

Pyrite: The most common and widespread sulfide mineral.
Composition: FeS_2

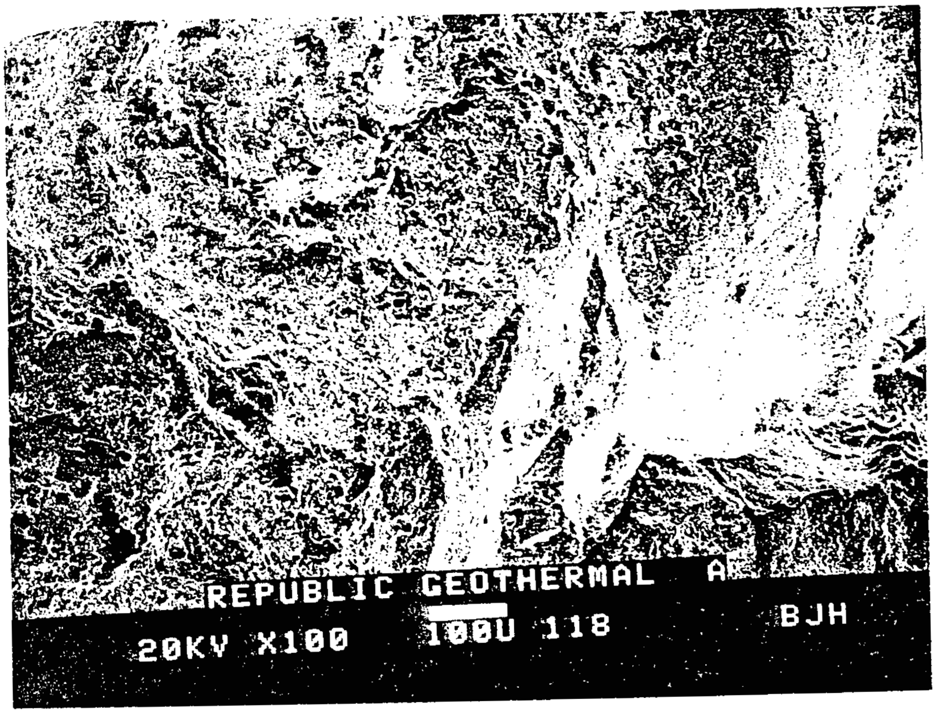
IV. SEM/EDAX ANALYSIS

SEM MICROGRAPHS

SAMPLE	MICROGRAPH	DESCRIPTION
A	118 100X	View of drill cutting showing a very fine grained siltstone lithology. The visual porosity is low and shows to be primarily from "voids" which have been enlarged in places into solution cavities and cavernous voids.
A	121 2000X	Individual void showing platy assessory minerals or rock fragments coating the walls of the pore. In the upper left corner, a small amount of chlorite clay (plate-like) can be seen.
D	128 100X	Micrograph showing the complex nature of the porosity and mineral composition of these cutting sandstone samples. The porosity appears to be caused by fractures which have been filled with fine clay mineral particles.
D	131 1000X	Pore cavity with a hairline fracture in view. The wall of the pore is coated with clay mineral particles. The left side appears to contain montmorillonite clay particles.
F	137 100X	Micrograph of very fine grained silicous rock. Visual porosity is low and is primarily from hairline fractures and voids.
F	134 1000X	View of a void opening coated with calcite and platy accessory minerals.
I	151 100X	View of a fine grained, platy siltstone. Visual porosity is mainly from small pores which may or may not be interconnected. Silt and clay mineral particles are coating the surface.
I	146 1000X	Micrograph of the platy siliceous surface. Clay mineral particles and fine silt fragments coat the surface restricting porosity.

SEM MICROGRAPHS

SAMPLE	MICROGRAPH	DESCRIPTION
J	518 100X	View of a drill cutting showing a fine-grained, platy siltstone. Porosity is largely from pores on the surface which have been enlarged into solution cavities and cavernous voids.
J	521 1000X	View looking into a cavernous void with montmorillonite clay mineral particles attached to the surface.
N	533 200X	A siltstone having a very fine-grained texture. Low porosity is evident and surface is irregular shaped. Rock surface is heavily coated with silt and clay mineral particles.
N	530 2000X	Micrograph showing the creamy texture of montmorillonite clay mineral particles coating the matrix.
P	536 200X	A fine-grained, platy siltstone. Visual porosity is primarily through fractures or layers of the platy texture. Clay mineral particles or silt fragments heavily coat rock surface.
P	541 1000X	Micrograph showing platy surface and fine particles attached to surface. Visual microporosity is present because of natural fractures.
Q	547 100X	A very fine-grained siltstone. Visual porosity is from pores which have been enlarged into solution cavities and cavernous voids. Fine clay mineral particles coat the surface.
Q	552 2000X	Looking into a void with clay mineral (montmorillonite) coating the walls. Some individual calcite particles are seen also.



REPUBLIC A
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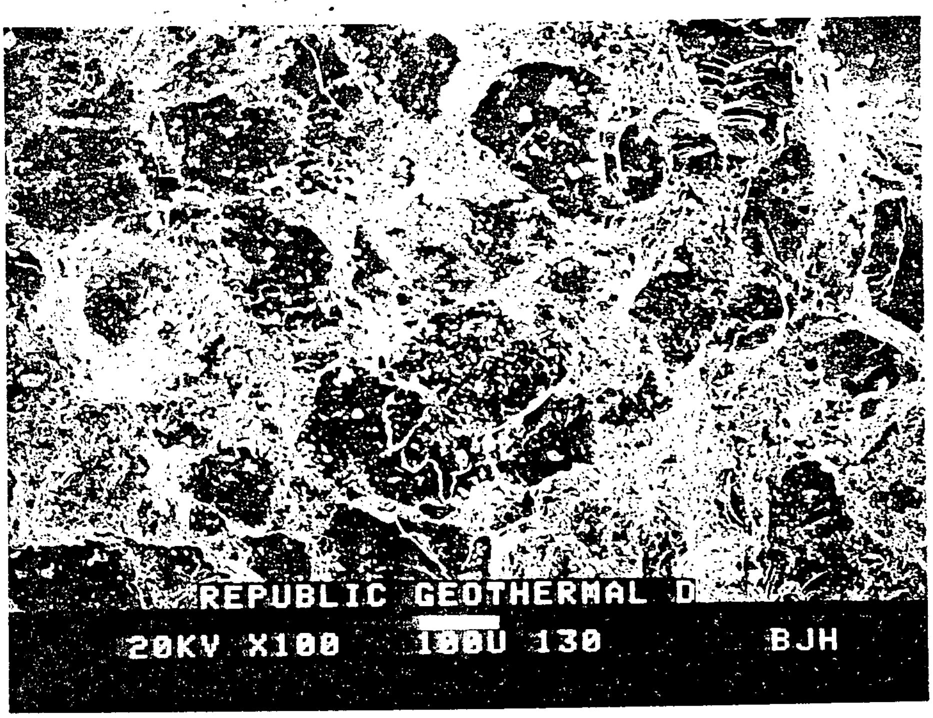
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
NOST
21-JUL-83

	CONCENTRATION		
	WT.%	AT.%	% S.E.
NAK	0.12	0.16	82.18
MGK	1.02	1.34	6.85
ALK	6.22	7.32	1.43
SIK	52.81	59.63	0.38
S K	13.80	13.65	0.95
K K	7.31	5.93	1.45
CAK	6.02	4.77	1.72
FEK	12.70	7.21	1.52
	100.00		

SAMPLE A, MICROGRAPH 118; 100X. View of drill cutting showing a very fine grained siltstone lithology. The visual porosity is low and shows to the primarily from "voids" which have been enlarged in places into solution cavities and cavernous voids.

SAMPLE A, MICROGRAPH 121; 2000X. Individual void showing platy assessory minerals or rock fragments coating the walls of the pore. In the upper left corner, a small amount of chlorite clay (plate-like) can be seen.



REPUBLIC D
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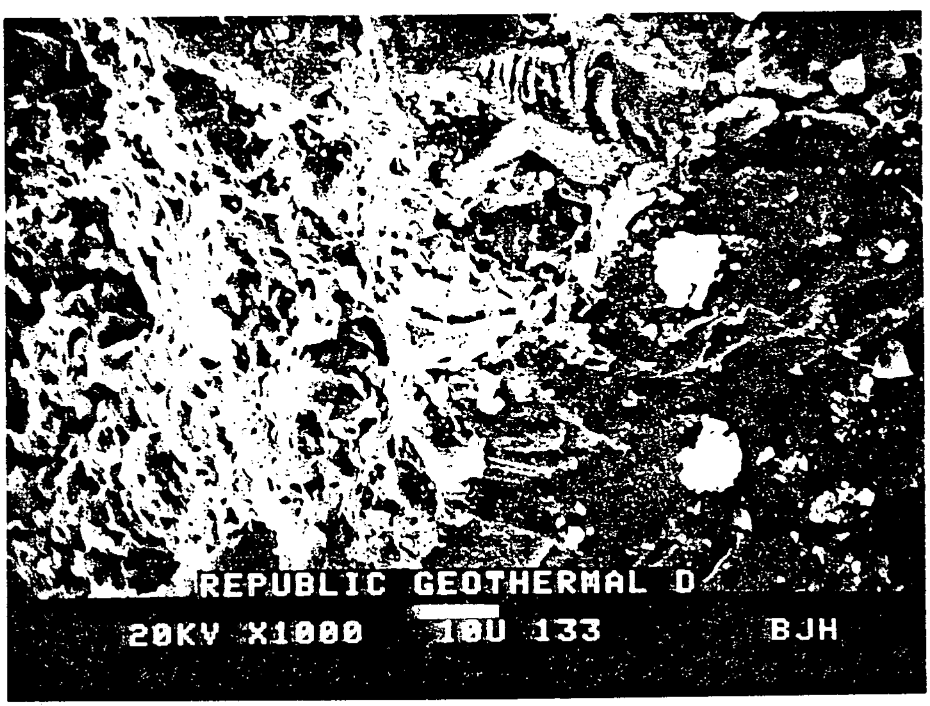
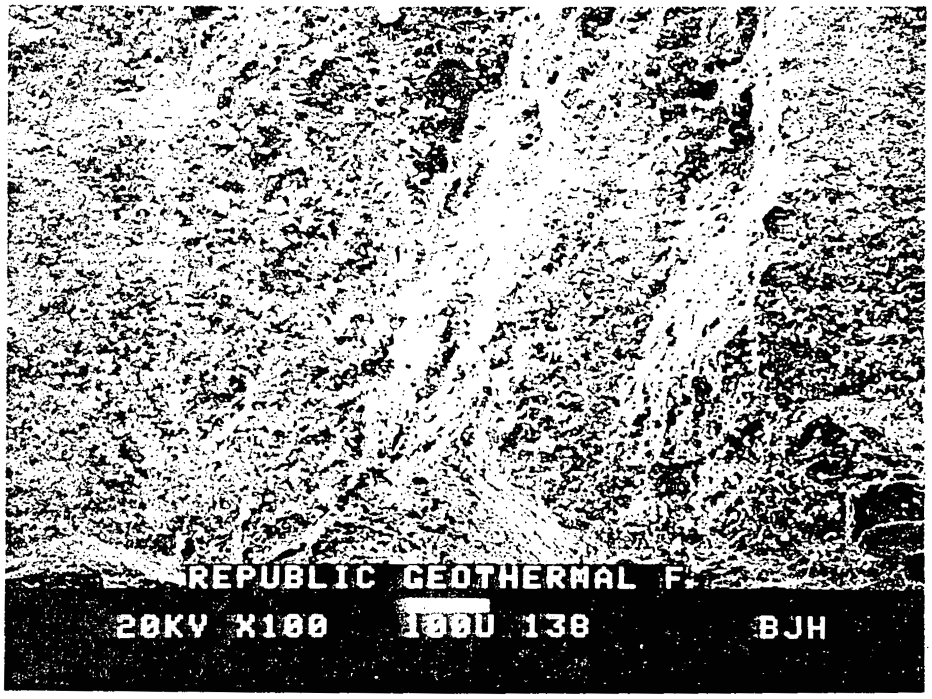
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
NOST
21-JUL-83

	CONCENTRATION		
	WT.%	AT.%	% S.E.
NAK	0.19	0.24	48.58
MGK	1.57	1.91	4.91
ALK	3.50	3.83	2.37
SIK	73.89	77.71	0.35
S K	9.75	8.98	1.53
K K	3.81	2.88	3.06
CAK	2.87	2.11	3.94
FEK	4.43	2.34	4.75
	100.00		

SAMPLE D, MICROGRAPH 128; 100X. Micrograph showing the complex nature of the porosity and mineral composition of these cutting sandstone samples. The porosity appears to be caused by fractures which have been filled with fine clay mineral particles.



SAMPLE D, MICROGRAPH 131; 1000X. Pore cavity with a hairline fracture in view. The wall of the pore is coated with clay mineral particles. The left side appears to contain montmorillonite clay particles.



REPUBLIC F
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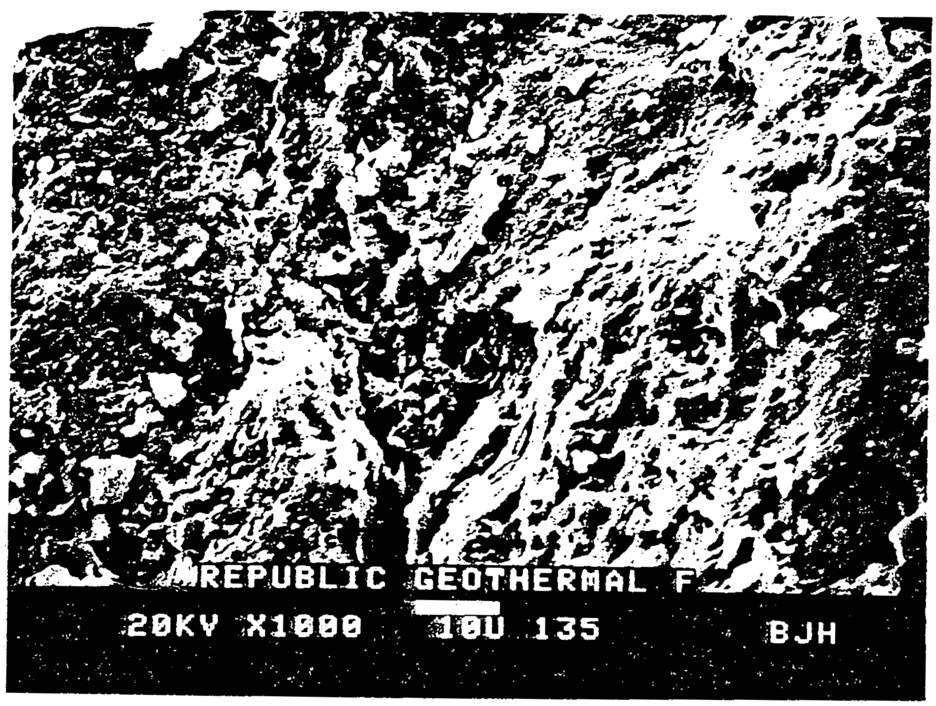
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
MOST
21-JUL-83

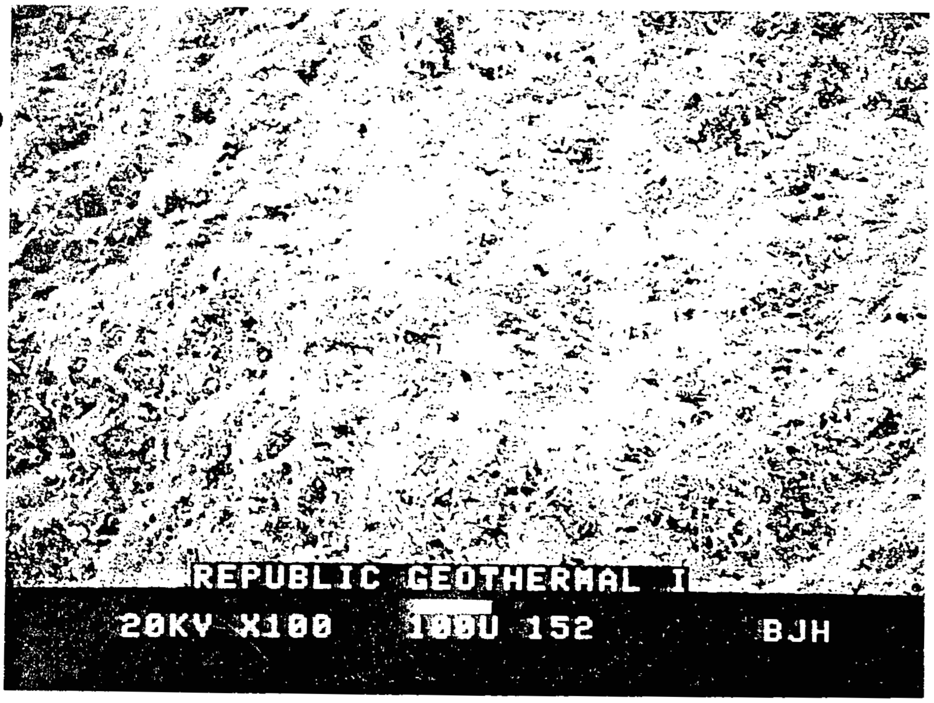
CONCENTRATION

	WT.%	AT.%	% S.E.
NAK	0.15	0.19	52.64
MGK	1.19	1.46	5.23
ALK	4.80	5.31	1.59
SIK	68.41	72.77	0.32
S K	10.69	9.96	1.19
K K	6.76	5.16	1.60
CAK	4.09	3.05	2.40
FEK	3.91	2.09	4.09
	100.00		

SAMPLE F, MICROGRAPH 137; 100X. Micrograph of very fine grained silicous rock. Visual porosity is low and is primarily from hairline fractures and voids.



SAMPLE F, MICROGRAPH 134; 1000X. View of a void opening coated with calcite and platy accessory minerals.



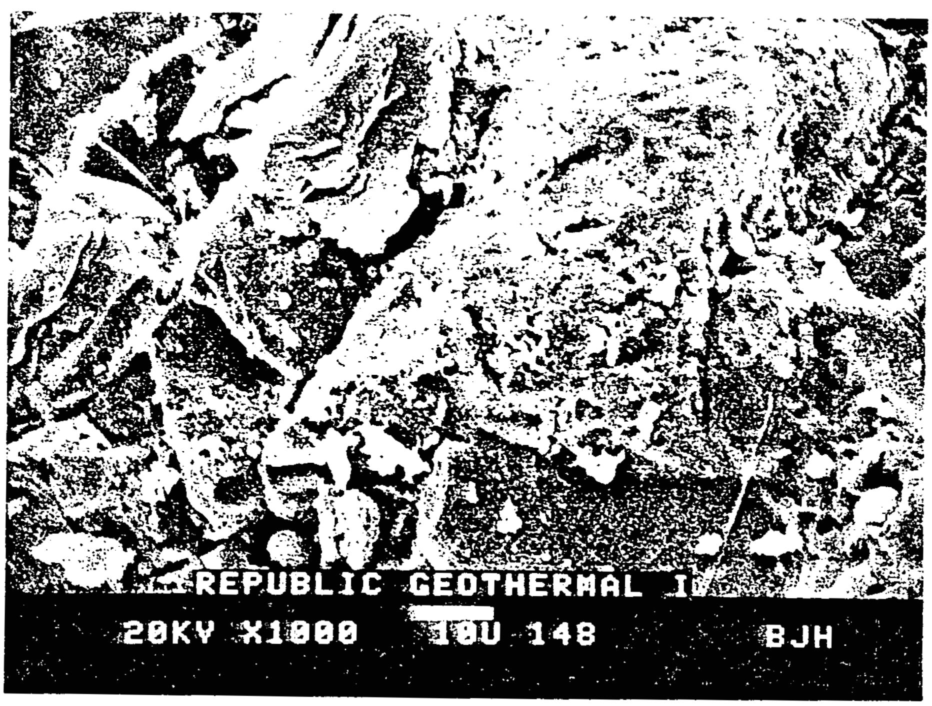
REPUBLIC I
KV=20.0 TILT=30.0 TKOFF=29
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
MOST
21-JUL-83

CONCENTRATION

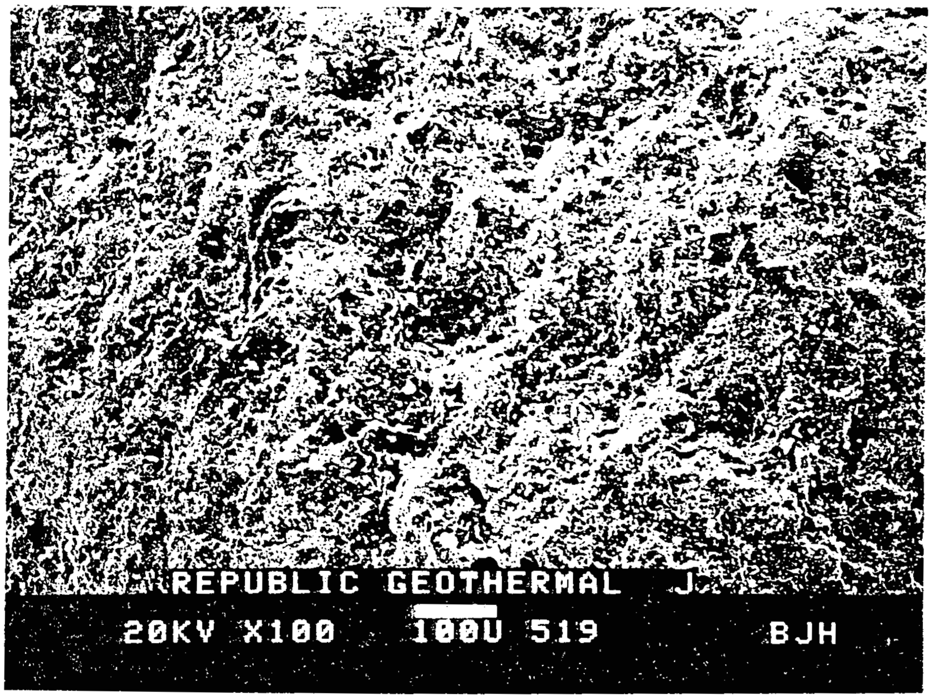
	WT.%	AT.%	% S.E.
NAK	0.03	0.04	292.29
MGK	1.62	2.21	4.32
ALK	4.35	5.34	1.69
SIK	40.64	47.96	0.38
S K	8.31	8.59	1.11
K K	5.92	5.02	1.45
CAK	31.60	26.13	0.51
TIK	2.41	1.67	4.07
FEK	5.12	3.04	2.90

	100.00		

SAMPLE I, MICROGRAPH 151; 100X. View of a fine grained, platy siltstone. Visual porosity is mainly from small pores which may or may not be interconnected. Silt and clay mineral particles are coating the surface.



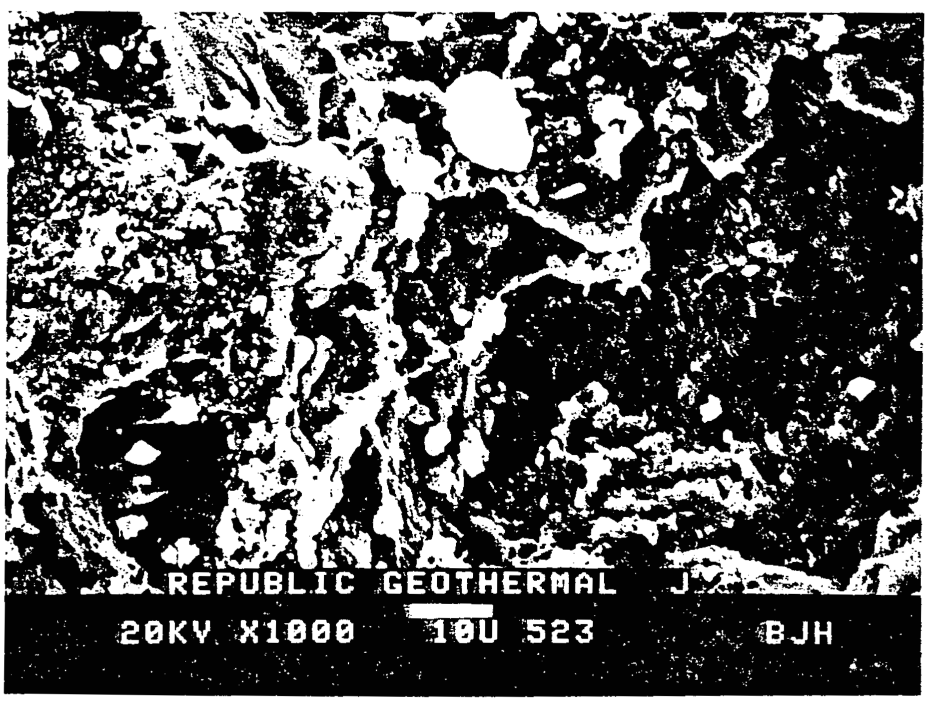
SAMPLE I, MICROGRAPH 146; 1000X. Micrograph of the platy siliceous surface. Clay mineral particles and fine silt fragments coat the surface restricting porosity.



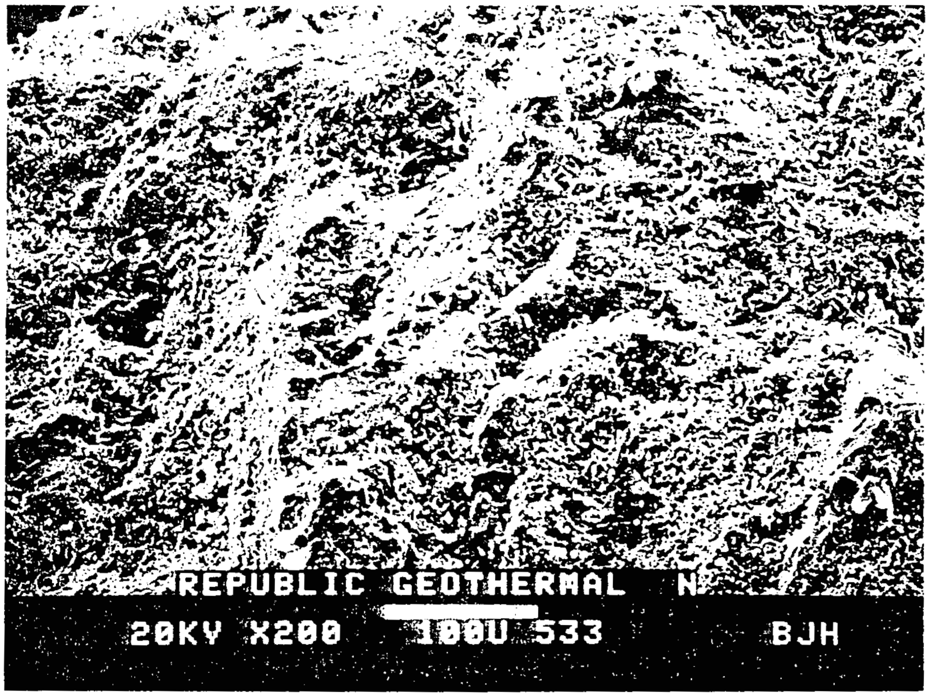
REPUBLIC J
KV=20.0 TILT=30.0 TKOFF=2
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
NOST
22-JUL-83

	CONCENTRATION		
	WT.%	AT.%	% S.E.
NAK	0.10	0.14	81.77
MGK	2.06	2.67	3.29
ALK	5.19	6.07	1.41
SIK	54.18	60.82	0.32
S K	13.18	12.96	0.86
K K	6.53	5.27	1.40
CAK	4.98	3.91	1.76
TIK	4.07	2.68	2.48
FEK	9.71	5.48	1.69
	100.00		

SAMPLE J, MICROGRAPH 518; 100X. View of a drill cutting showing a fine-grained, platy siltstone. Porosity is largely from pores on the surface which have been enlarged into solution cavities and cavernous voids.



SAMPLE J, MICROGRAPH 521; 1000X. View looking into a cavernous void with montmorillonite clay mineral particles attached to the surface.



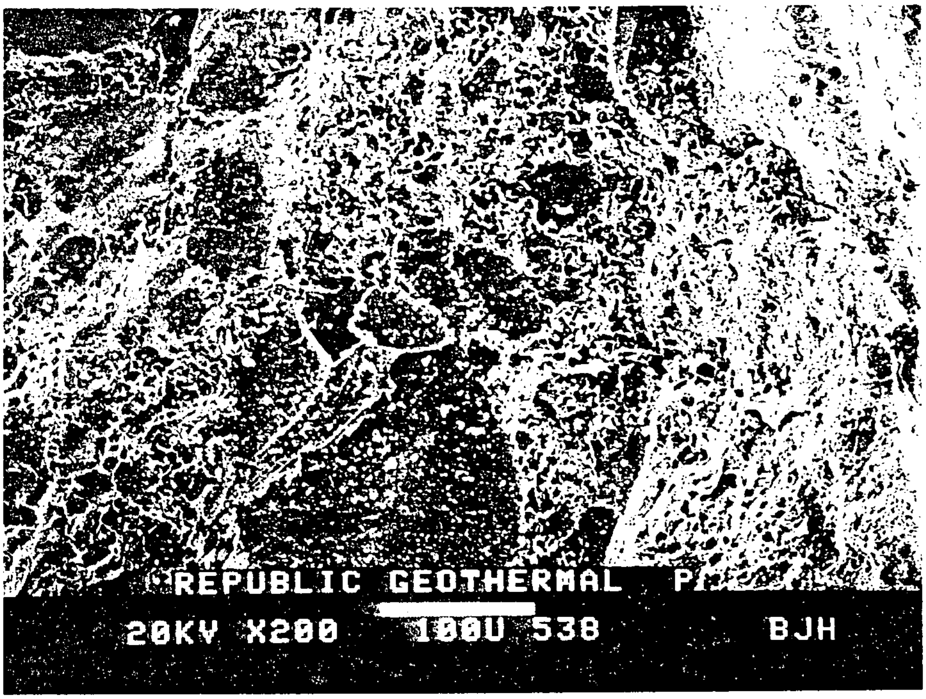
REPUBLIC N
KV=20.0 TILT=30.0 TKOFF=2
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
NOST
22-JUL-83

CONCENTRATION

	WT.%	AT.%	% S.E.
NAK	0.16	0.24	67.90
MGK	3.08	4.48	2.69
ALK	11.44	15.01	0.87
SIK	32.46	40.92	0.43
S K	4.36	4.81	1.52
K K	9.18	8.31	0.91
CAK	3.69	3.26	1.83
TIK	3.61	2.67	2.13
FEK	32.03	20.30	0.61
	100.00		

SAMPLE N, MICROGRAPH 533; 200X. A siltstone having a very fine-grained texture. Low porosity is evident and surface is irregular shaped. Rock surface is heavily coated with silt and clay mineral particles.

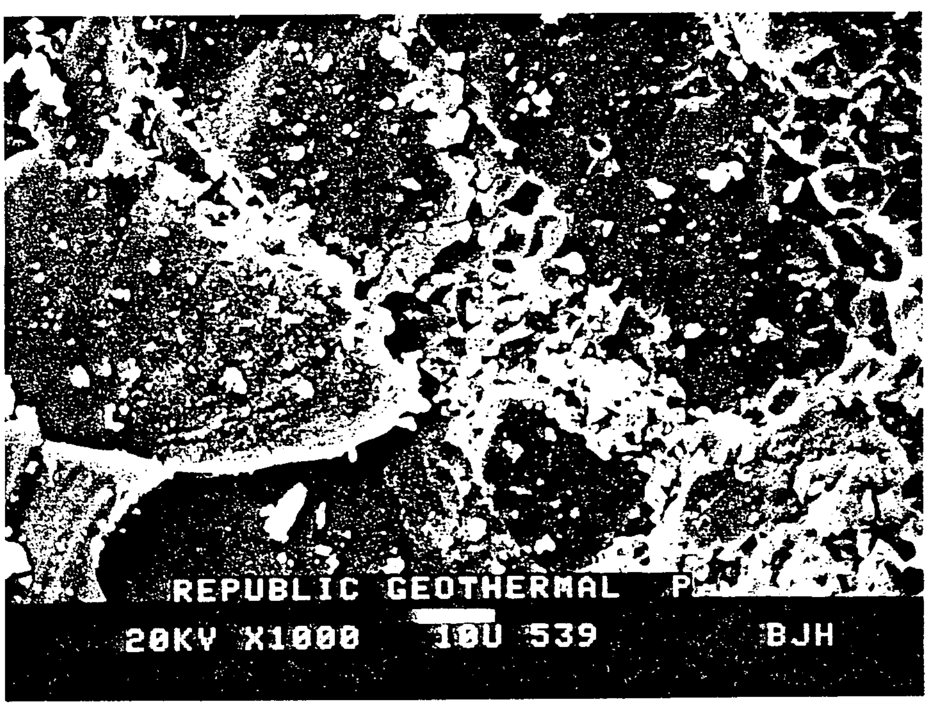
SAMPLE N, MICROGRAPH 530; 2000X. Micrograph showing the creamy texture of montmorillonite clay mineral particles coating the matrix.



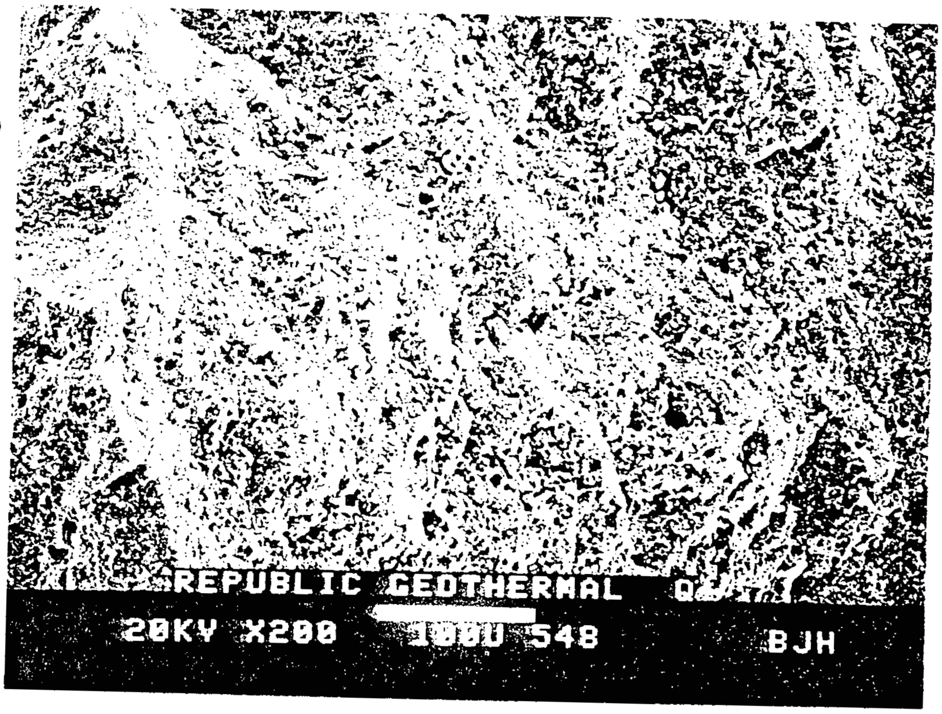
REPUBLIC P -
KV=20.0 TILT=30.0 TKOFF=2
BKG PT1= 1.0 BKG PT2= 9.0
ECON ANALYSIS
MOST
22-JUL-83

	CONCENTRATION		
	WT.%	AT.%	% S.E.
NAK	0.08	0.11	67.94
MGK	0.86	1.06	5.30
ALK	2.56	2.83	1.97
SIK	74.41	79.09	0.25
S K	7.02	6.53	1.28
K K	4.22	3.22	1.76
CAK	5.59	4.16	1.47
TIK	1.98	1.23	3.94
FEK	3.27	1.75	3.57
	100.00		

SAMPLE P, MICROGRAPH 536; 200X. A fine-grained, platy siltstone. Visual porosity is primarily through fractures or layers of the platy texture. Clay mineral particles or silt fragments heavily coat rock surface.



SAMPLE P, MICROGRAPH 541; 1000X. Micrograph showing platy surface and fine particles attached to surface. Visual microporosity is present because of natural fractures.

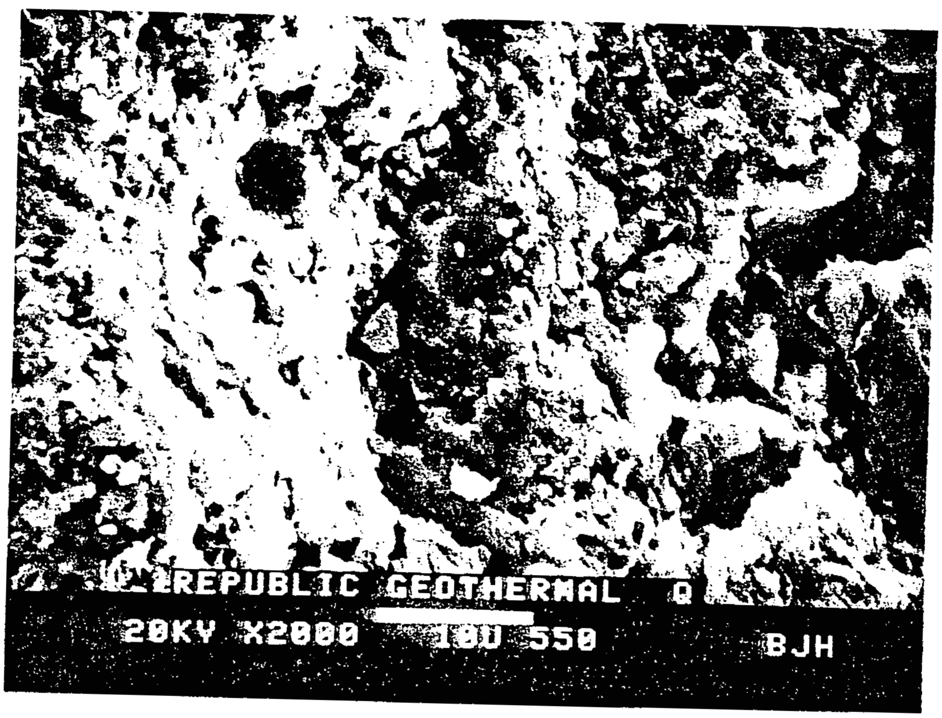


REPUBLIC Q
KV=20.0 TILT=30.0 TKOFF=29
BKG PT1= 1.0 BKG PT2= 9.0
MOST
22-JUL-83

CONCENTRATION

	WT.%	AT.%	% S.E.
NAK	0.00	0.00	0.00
MGK	0.45	0.57	23.07
ALK	3.54	3.99	3.05
SIK	69.16	74.80	0.42
S K	9.02	8.54	1.76
K K	6.17	4.79	2.26
CAK	3.79	2.87	3.39
TIK	1.84	1.17	7.72
FEK	6.03	3.28	3.79
	100.00		

SAMPLE Q, MICROGRAPH 547; 100X. A very fine-grained siltstone. Visual porosity is from pores which have been enlarged into solution cavities and cavernous voids. Fine clay mineral particles coat the surface.



SAMPLE Q, MICROGRAPH 552; 2000X. Looking into a void with clay mineral (montmorillonite) coating the walls. Some individual calcite particles are seen also.