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Open-File Report # NM/Baca-34

BACA PROJECT  
DATA AND REPORTS

PRODUCTION

<u>No.</u>	<u>Transfer Date</u>	<u>Release Date</u>	<u>Title</u>
1.	A	A	Geothermal Power Plant Feasibility Report - Rogers Engineering Company - 1974.
2.	A	A	Baca Well No. 11 - Scale Evaluation, by Union Oil Company, Santa Rosa District, 1975.
3.	A	A	Effects of Turbine Power Cycle on Development Well Requirements in Redondo Creek, J.D. Hartz, 1977.



V. E. SUTER

APR 24 1975

April 24, 1975

TO: Vane E. Suter

FM: Olin D. Whitescarver *ODW*

Attached for your information is the Scale Evaluation  
on Baca Well No. 11.

ODW/jd  
Enc.

cc: Del Pyle  
Roland Kruger  
Tom Minette  
Jerry Jones

B A C A W E L L N O . 1 1

SCALE EVALUATION

UNION OIL COMPANY OF CALIFORNIA  
Santa Rosa Geothermal District

April 23, 1975

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## INTRODUCTION

Erratic flow characteristics of Baca Well No. 11 in the latter part of August and September of 1974 necessitated a thorough inspection of surface and subsurface facilities. This inspection disclosed the presence of scale in both locations. Scale had been noted prior to this on the coils of the test heat exchanger which were in contact with the wellbore fluids.

This report has been prepared to consolidate all information relating to the scale problem for purposes of information, analysis of the problem, possible effects on the project, and to provide a basis for recommendations for further evaluation.

## CONCLUSIONS & RECOMMENDATIONS

The formation scale has been verified downhole in the bore of Baca Well No. 11, at the New Mexico Project. The scale was primarily Calcium Carbonate, with possibly some silica associated. This situation along with the scale experience in the Philippines, indicates that scaling tendencies may be present in all hot water geothermal wells. An economical and practical solution for the problem must be found in order to have a viable project.

The following recommendations form a consensus of opinion of research and operations personnel as to the best methods to attack the problem. Most testing will be done in New Mexico because of better logistics.

1. A program is being developed to compute dynamic temperature-pressure wellbore profiles.
2. Solubility calculations are being developed for CO<sub>2</sub> in low pressure - high temperature geothermal fluid.
3. Combination of steps 1 & 2 should enable the prediction of the point of CO<sub>2</sub> evolution, which would coincide with the scale point. These predictions should be made for Baca Well No. 4, 6, 11 and 13. The scale point has been physically determined in Baca 11, no scale was found in Baca 6. Gauge runs can be made in Baca 4 and 13 to determine if the predictions are accurate.



4. When the scale point prediction technique has been verified and can be used with some assurance of reliability, mechanical differences can be entered into the program to determine the effect. Examples of those differences could be well-head flowing pressure or casing design. The goal of those changes would be to cause the scale point to occur in surface facilities which are more readily accessible for cleanout.
5. An adjustment of flowing wellhead pressure of Baca Well No. 13 will be used to test this theory during the interference flow test if the predictability technique has been verified.
6. Scale inhibitor has been developed and is ready for field testing. This inhibitor must be injected continuously into the wellbore below the scale point. Pressure of sufficient magnitude to prevent flashing must be maintained on the injection tube to prevent the inhibitor from gunking. The inhibitor will poison and thereby prevent the formation of  $\text{CaCO}_3$  crystals.

A 5000' string of 2-1/16" intergal joint tubing is proposed to be run in Baca Well No. 11. The string will be equipped with a back pressure valve and either a differential valve or an orifice. Inhibitor will be injected into the tube at a rate of 24 gallons per day (20 ppm total mass flow). The inhibitor may be diluted with water up to 1 bbl/gal. A total of 44 drums of chemical, at a cost of \$30,000, will be required for a 100 day test.

Surface facilities will be required in addition to the well modifications for the inhibitor test. These include chemical and water pumps, power to operate them, and surface storage and handling facilities for chemical and water.

One unresolved problem remains to be considered with the use of inhibitor and that is the possible effect on the injection wells.

7. Mechanical cleanout is a viable option, however it may be costly and damaging to the wellbore casing. Cleanout service rigs are available along with possibly other more sophisticated methods. See Figure XIX of the Appendix. Simple surface scraping devices are felt to be unworkable because of the hardness of the scale.
8. The use of acid to dissolve the scale is not recommended because of corrosive attack on the casing. A predictable corrosion inhibitor is not available for service above 300°F.
9. A removable liner or flow tube may contribute to the solution of the problem. The liner could be designed to streamline the flow path by utilizing one size casing top to bottom. This would eliminate the turbulent area at the liner lap and would probably raise the scale point due to wellbore friction loss. The liner could be pulled and changed in the event of mechanical damage during cleanout. The disadvantage is that the liner may restrict flow rates in some high volume wells.

10. The injection of CO<sub>2</sub> concentrated in the offstack gasses has been considered and eliminated due to the complexity of the chemistry and the potential of induced corrosion.
11. The use of downhole pumps to keep the system pressured above the flash joint does not appear to be feasible at temperatures above 350°F.

## DRILLING HISTORY

Well Baca No. 11 was drilled to 6,925' T.D. in 41 days. Water base fluid was used for a circulating medium and provided excellent hole stability. The drilling program was designed to accommodate three different sets of hole conditions corresponding to surface, intermediate and production intervals.

The surface interval consisted of Caldera Fill and the upper section of Bandelier Tuff. A 17-1/2" hole was spudded and drilled to 207'. The hole was then opened to 26" and 20" casing was run and cemented to the surface. A 17-1/2" hole was then drilled thru the remaining Caldera Fill and 150'+ into the Bandelier Tuff. Fresh water, low solids mud was used for a circulating medium. Typical properties were 66-72 P.C.F., 29-49 sec./qt. funnel viscosity and 12-15 cc/30 min. API filtrate. Properties were controlled by small treatments of Ben Ex, Bentonite, and frequent cleaning of shaker tank. No lost circulation occurred below 20" casing, and 13-3/8" casing was run and cemented to the surface at 1,336'.

The intermediate interval consisted entirely of Bandelier Tuff. A 12-1/4" hole was drilled to 3,381', a point within the Tuff where formation temp. was approximately 450°F. This point was determined geologically and verified by a temperature survey. The temp. recorder was run after allowing drilling fluid to remain static for 10 hours. Recorded temp. was 374°F after the recorder had been on the bottom 10 minutes. Return flow line temp. at this depth was 105°F.

This interval was drilled using fresh water as a circulating medium. The water was treated with sodium sulfite to remove oxygen, and cottonseed hulls to control occasional loss of returns. The sodium sulfite treatment was added at the pump suction, and adjustments were made to control residual of 20-40 ppm sodium sulfite at return flow line. Cottonseed hulls were dumped in suction pit, and any that returned were screened out at shakers. The drilling fluid properties were 8.35 P.C.F., and 26 sec/qt. No hole problems were encountered and 9-5/8" liner was hung and cemented from 1,219' to 3,380'. Good circulation was maintained while cementing, but float collar and float shoe, both metal flapper type, failed to hold. The liner lap was pressure tested and squeezed with cement to 1300 psi with 137 cu. ft. of cement outside liner.

The production interval consisted of the remainder of the Bandelier Tuff, a volcanic section, a sandstone section, and ended in a red bed section. An 8-3/4" hole was drilled thru this interval using aerated water as a circulating medium. The fluid was fresh water treated with 4+ PPB lignite, caustic to maintain ph of 9.5, and cypan in concentration of approximately .1 PPB. This fluid had to be aerated before circulation could be established below 9-5/8" liner.

Aerating of the drilling fluid was started using 10/1 air/water ratio with the pump output at 5 BPM. One gallon of Unisteam and 1 pound of graphite was injected into the drilling fluid for each 100 bbl. of fluid output. When the first productive

interval was penetrated, circulation was lost with the 10/1 air/water ratio. The ratio was gradually increased until circulation was regained with a ratio of 20/1. When circulation was reestablished, the flow line temp. was 120-140°F. Penetration of the productive interval and subsequent increase in wellbore temp. complicated the basic problem of circulating fluid without permitting reservoir fluid entry into the wellbore. The balance point between circulating and fluid entry into the wellbore was not easily distinguishable with the surface equipment on this job. Casing pressure, below the rotating head, varied between 40 and 100 psi while circulating.

It was discovered that pump output had to be increased each time the air/water ratio was increased. When total depth was reached, the air/water ratio was 35/1 and pump output was 8.5 BPM. Flow line temp. was 192-194°F. The greatest damage to drill pipe occurred as a result of addition of KCl to the drilling fluid. The KCl was added to drilling fluid as a precaution prior to drilling into the Santa Fe Sand. When the Santa Fe Sand was not encountered, the KCl was diluted out.

## PRODUCTION HISTORY

Baca Well No. 11 was completed November 11, 1973, and shut in waiting installation of a test separator. Installation of the separator was completed late in December, 1973, and the well was opened for initial flow test January 2, 1974. (No record of W.H.P. prior to initial flow test.) The well was put thru the separator immediately, and sand production cut out the level control valve and water line. Flow test #1 terminated January 3, 1974. Flow rates calculated from 2 phase flow orifice indicated approximately 650,000 PPH total mass flow.

Flow test #2 started January 11, 1974, S.I.W.H.P. of 850#. The well was opened and flowed thru bypass until January 16, 1974. Sand production had declined visually, and well was put thru the separator on January 16, 1974. All pressure sensing ports were plugged, so the separator vessel was opened for inspection. Sand was approximately 1' deep on bottom of vessel, and 1" deep in water flow line upstream of meter. The sand sample from the separator consisted of sand-sized fragments of pumicious tuff with common pieces of pyrite and traces of hematite. The material was correlated with the permeable zone in the Bandelier Tuff at 3950'-3960'.

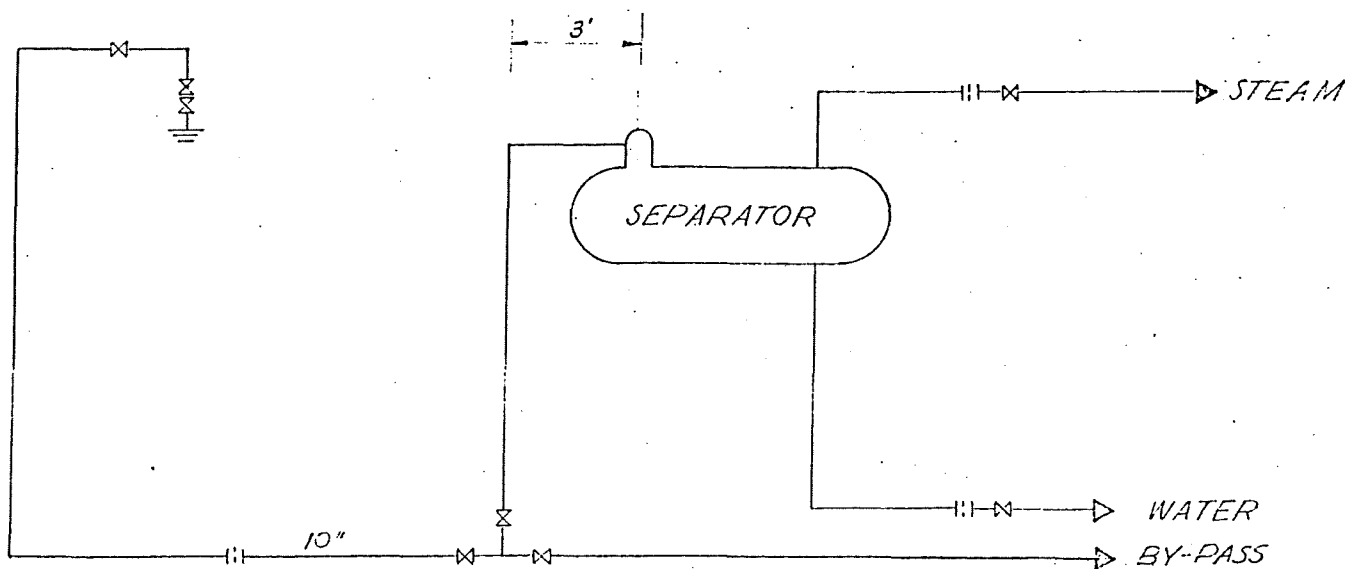
All ports and lines were cleaned, orifice plates were inspected, and flow test #3 was started thru bypass January 29, 1974. There is no record of S.I.W.H.P. prior to F.T. #3, but memory recalls it being approximately 500 psig. The flow line cut out and the well was shut in January 30, 1974.

Flow test #4 was opened thru the bypass on February 1, 1974, S.I.W.H.P. approximately 500 psig. During opening of the well, dry ice temporarily plugged the flow line, but evaporated within seconds. The well was put thru the separator February 3, 1974 and the initial heat exchange test was attempted. Sand production continued intermittently, and considerable fluctuations resulted as result of both sand production and heat exchanger withdrawals. Separator pressure during this time varied between 90 and 103 psig. After 8 days, on February 11, 1974, the well headed, the flow rate increased from 250,000 #/hr. to 304,000 #/hr. and separator pressure increased to 172 psig. Over the next 14 day period the separator pressure declined to 117 psig and the flow rate decreased to 270,000 #/hr. The well was shut in February 25, 1974 terminating flow test #4.

Tests were terminated at this time due to thaw and subsequent transportation problems due to run off. Prior to initiation of flow test #5, the flow lines, valves, and separator were broken down for inspection, repair and replacement. The flow lines and separator had approximately 1" of sand in the bottom, and approximately 1/8" of white powdery material on the mist extractor pads, upstream side of valves and orifice plates, and inside of separator vessel. See Photo No. 1. Mufflers and muffler pits were also replaced and repaired, and cleaned out.



Flow test #5 was started June 1, 1974 thru the bypass. Sand production was monitored and reached a nondetectable level after 24 days. Flow was turned into the separator on June 25, 1974, and flowed continuously on test until September 25, 1974. A reasonable constant decline was recorded until the heat exchanger test was resumed August 17, 1974, then the rate data became erratic. The production rate declined +20% on August 29, 1974 and did not recover. The well was put thru the bypass September 9, 1974 and the separator and lines were broken down for inspection. Scale 1-1/2" thick was found in the inlet to the separator, on the deflection plate inside the dome, and in 3' of the piping before entering the dome. This scale was almost insoluble in HCl acid. See Photo No. 2.



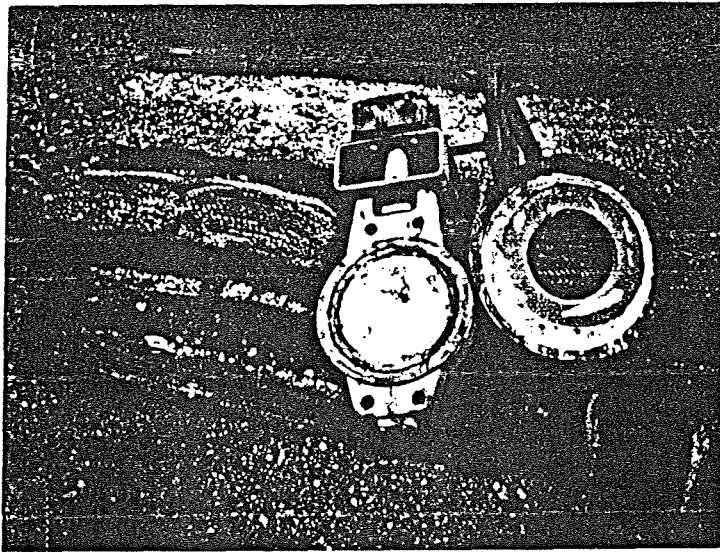


Photo No. 1  
1/4" or less White Powdery Scale on Inside of Separator  
Mist Extractor Pads  
7" Water Orifice  
8" Steam Line Valve

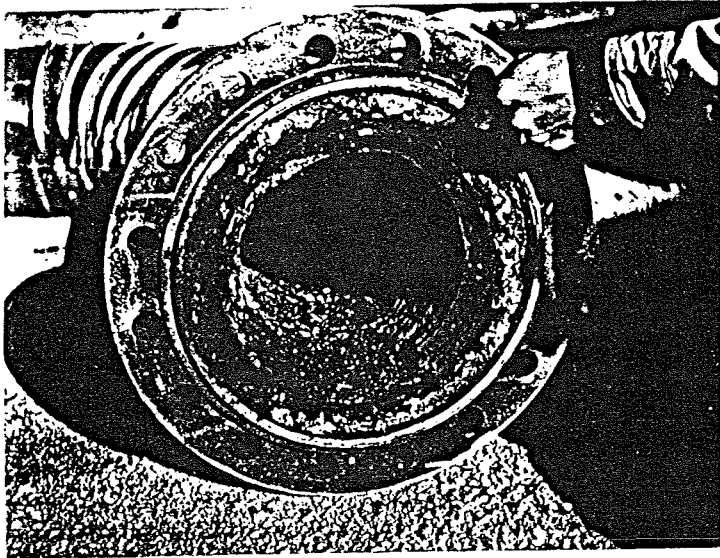


Photo No. 2  
1-1/2" Hard Varicolored Scale  
Inlet Pipe to Dome on Top of Separator

No scale was evident upstream of the 3' piping section leading into the dome of the separator. The interior of the separator and both steam and water lines had approximately 1/8" of white powdery material like that first observed following flow test #4. No sand was found in the vessel or lines. Research analysis of this material indicated it to be primarily Silica. See Appendix III.

The well was again turned into the separator on September 11, 1974, and the production continued to decline at accelerated rate until September 18, 1974, when total mass flow was approximately 149,000 PPH. The steam line valve was used as choke to increase wellhead pressure from 100 pounds to 143 pounds, and an apparent increase in total mass flow was observed. Between September 18, 1974 and September 25, 1974 four attempts were made to run flowing pressure and temperature surveys without success. Bombs stopped at 3209', which was approximately the top of the 7" liner, on all four attempts. The well was shut-in, terminating flow test #5 on September 25, 1974. Subsequent attempts to run wireline tools under static conditions were futile, with the tools stopping at 3209'.

Following the termination of flow test #5, and the unsuccessful attempts to run wireline equipment, a service rig was moved in and rigged up on Baca No. 11. An 8-3/4" bit and 9-5/8" casing scraper were run on tubing. Scale was first detected at 3068'. Water would circulate at this depth. Light scale was cleaned out to 3194' where a 1-2' bridge was drilled out,

and circulation was lost. Heavy scale was continuous to the top of the liner at 3209'. Ran a 6-1/8" bit and cleaned out hard scale to 3813', light scale to 3937', and apparently no scale to 6605'. Attempts to drill out fill were unsuccessful because of inability to remove fill from hole. Attempted to clean out with sand pump and melted rope socket leaving sand pump in hole. Recovered sand pump and kicked well off. Flowed well four hours at 180 # W.H.P. Ran in hole with tubing and found E.T.D. 6620'.

Scale samples were collected from flow line during the clean out operation. Field examination showed scale to be soluble in HCl. Samples of scale were sent to Union Research for analysis, which revealed them to be primarily  $\text{CaCO}_3$ . See Appendix Figure III.

The diagrammatic sketch of Baca Well No. 11 completion, Appendix Figure I, indicates the location of the scale cleaned from the casing. Figure II of the Appendix is a graphical presentation of the well's production history. Figure III is the results of the analyses of separator scale by Max Ellis, Figure IV is Paul Fishers' report on the analysis of the scale removed from the casing. Figure V is a memo from Dick Dondanville advising of a possible Silica precipitation problem in the produced geothermal waters.

COMPARISON WITH OTHER WELLS

To date, scale deposition has not been detected in the flow tests on other wells. However, Baca Well No. 11 was flowed at higher rates, and produced approximately three times the cumulative production of other wells. The liner was pulled from Baca No. 6 and was found to be essentially free of scale; see Carl <sup>Cron's</sup> Croin's report, Appendix Figure V. The reason for the absence of scale could be one of the following:

1. Scale precipitated in formation.
2. Scale precipitated at surface.
3. Fluid chemistry not susceptible to scale precipitation.

Gauge runs have not been made in either Baca 4 or 13 in search of deposition on the casing walls. The following is cumulative production tabulated by well.

<u>Well</u>	<u>No. Days Produced</u>	<u>Cumulative Production (lbs)</u>
Baca No. 4	73	301,270,000
Baca No. 6	86	299,869,000
Baca No. 11	139	812,112,000
Baca No. 13	77	585,178,000

The percent flash on Baca No. 11 was higher on the first flow tests than expected, based on data from other wells. The initial flash was 56%, but gradually declined to 33% just before the sharp drop in production. This decline in flash was accompanied by an essentially constant water production rate, and a declining steam rate.

When the well was shut-in for a pressure buildup test, the pressure built up slower than in other wells. Pressure and temperature surveys run in the well showed that during the buildup period, fluid was flowing from the lower zones to the upper zone at 3950'. The bottom hole pressure suddenly increased to its original value, and static pressure surveys showed that the flow between zones had stopped.

The higher than normal quality and the flow between zones suggests that the zone at 3950' was producing all or mostly steam, but it was depleted as the well was produced. When the well was shut-in, the upper zone was filled back in with fluid from the lower zone. Figures VII and VIII show the pressure buildup behavior.

Figures IX through XIV of the Appendix show comparative water analyses from wells Baca 4, 5A, 6, 8 and 11 respectively. The waters from various wells appear to be similar in nature. Baca No. 11 did exhibit slightly more calcium (20 ppm) than others. The water analysis information presented is inconclusive but at this time would seem to indicate that scale deposition is possible in other wells. Figures XV through XVIII of the Appendix are non-condensable gas analyses data for Wells Baca 4, 6, 11 and 13.

TABLE 1  
 COMPARATIVE ANALYSES  
 GEOTHERMAL FLUIDS, BACA PROJECT

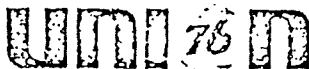
	<u>BACA 4</u>	<u>BACA 5A</u>	<u>BACA 6</u>	<u>BACA 8</u>	<u>BACA 11</u>	<u>BACA 13</u>
WATER ANALYSES						
PH	8.6	9.5	6.5	8.8	8.3	8.5
HCO <sub>3</sub>	63	244	28	84	24	281
CO <sub>3</sub>	108	75	93	41	48	97
Cl <sup>3</sup>	2700	1500	2980	3310	3550	2890
SO <sup>4</sup>	33	29	30	275	76	250
B <sup>4</sup>	20	30	22	15	30	23
A <sup>5</sup>	1.9	2.5	4.2	3.9	4.6	
Ca	6.5	Nil	11	.6	32	5
Fe	<3		<10	.22	.4	
Mg	<.5	Nil	<10	<.1	.2	.2
K	311	115	319	565	360	278
Na	1400	1100	1770	2170	1920	2000
Si			1133		350	750
SiO <sub>2</sub>	227	270	160	50	749	
F	.06	10.2	9.5	21.2		
NO <sub>3</sub>	<1	Nil	0.7			

NON-CONDENSIBLE GAS ANALYSIS (PPM wt.)

CH <sub>4</sub>	3.4				0	2.8
C <sub>2</sub> H <sub>6</sub>	26		10			20
H <sub>2</sub>	1.4		.6		2.9	0
N <sub>2</sub>	0				219	109
CO <sub>2</sub>	30390		10070		28892	37584
NH <sub>3</sub>			1.6		2.8	2.6
H <sub>2</sub> S	152		71		241	197
Wt. %					2.86	3.67
Vol. %					1.18	1.54

HEAT EXCHANGER TEST





CAREL OTTE

MAR 10 1975

To: G. D. Cheadle  
 From: D. G. Samuelson  
 Division: Engineering & Development  
 Subject: NEW MEXICO GEOTHERMAL  
 PILOT PLANT - REPORT NO. 1

Memo: PD-152M 74  
 Date: October 31, 1974  
 Project: 555-83403  
 PP-414  
 Supervisor: G. D. Cheadle

cc: Library (2)

Patent

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OBJECTIVE

A skid-mounted heat exchanger pilot plant was installed at the Baca Ranch No. 11 geothermal well-site in New Mexico to determine the following:

- (1) The overall heat transfer coefficients for both the steam and hot brine solution.
- (2) Establish the amount of inert gas in the steam under dynamic operating conditions.
- (3) Determine the degree of fouling and/or silica deposition on the heat transfer surfaces.
- (4) Establish the degree of corrosiveness of the steam and hot brine solution on various types of tubing alloys.

SUMMARY

The initial shakedown operation of the pilot plant was made in New Mexico during February 1974. The pilot plant was modified in the field during July and flow operation started on August 12, 1974. The pilot plant was operated for 38 days through September 25, 1974.

Because of mechanical problems with the cooling water pump and flow problems associated with the well, the pilot plant operation was not continuous. Heat transfer coefficients tended to decrease with time until a forced shutdown. Immediately after a shutdown, the heat transfer coefficients would increase appreciably and then start to decrease again with additional on-stream operating time until the next shutdown. The increased rate of heat transfer probably resulted because of spalling of surface deposits when sudden tube wall temperature changes occur on loss of cooling water or process streams.

The use of the higher efficiency binary cycle heat exchange with the New Mexico hot brine stream appears to be impractical at the present time because of heavy silica deposition on the exchanger tube surfaces wherever heat transfer occurs. A multi-stage flash system with an extra flash vessel on a rotating time-cycle to allow periodic off-line physical removal of silica deposits may be technically feasible although economically more expensive than a simple two-flash system. The possible use of silica seeding in the flash vessels may keep the silica in suspension in the brine for removal in a filter prior to reinjection.

The corrosion data from this pilot plant was reported in a separate memo, CORR 74-225M, December 20, 1974, entitled "Corrosion Results of Second Heat Exchanger Test Conducted at Baca 11."

#### RECOMMENDATIONS

An additional period of 30-60 days of continuous operation (probably next spring) will be necessary to firmly establish the rate of decline in heat transfer coefficient due to fouling and/or silica deposition. Parallel sparing of new-condition control valves on the Well-head Separator and a back-up pump for the cooling water system will be necessary to insure that continuous operation of the next test can be achieved. Because of manual valve operation at the Well-head Separator, it will also be necessary to employ a man on both the evening and midnight shifts to control the separator liquid level and monitor the cooling water pump operation to insure relatively constant operating conditions for the pilot plant.

#### INTRODUCTION

The management of Union Oil Company has set a goal of maintaining and improving the Company's present leadership in the utilization of geothermal energy. A Research Department Task Group consisting of Associate Directors R. S. Crog, Arnold Kelley, and Joe Walker, was established in March of 1973. A Working Committee, reporting to the Task Group, comprises H. Hennig, Chairman, and Messrs. J. M. Fraser, J. A. Klotz, B. Kouzel, G. A. Marsh, and D. G. Samuelson.

In order to properly evaluate the practical problem of exploiting geothermal energy for power generation, an essential first step was the determination

of the physical and chemical nature of the geothermal steam and/or hot water under flowing conditions. Our present knowledge and tools limit our ability to predict scaling and/or corrosion at a specific reservoir location. A portable heat exchanger pilot plant consisting of two skid-mounted banks of double-pipe exchangers was built at the Research Center during the summer of 1973. The pilot plant was shipped to the New Mexico Baca Ranch site in October of 1973. Because of field operating problems, connected with the well, the pilot plant was not hooked up to the Well-head Separator until later in January, 1974.

A ten-day shakedown run was terminated on the pilot plant on February 25, 1974 because of difficulty in maintaining continuous cooling water circulation during the severe cold winter weather. Based on the results of this shakedown operation, the pilot plant was modified primarily on the brine exchanger side. The modifications were made at the site during late July and early August, 1974.

This memo covers the 38 days of intermittent operation of the pilot plant in New Mexico from August 12 through September 25, 1974.

## EXPERIMENTAL PROCEDURE

### Equipment

Figure 1 is a simplified schematic flow diagram of the skid-mounted heat exchanger pilot plant. The pilot plant was purposely designed for rugged service in remote locations. Because of the probable lack of available electricity and sophisticated instrument service facilities, all instrumentation is mechanical in nature. Bimetallic thermometers, pressure gauges, ball float mechanical liquid drain valves, spring loaded back pressure control valves, manual flow-throttling valves, orifice plates with  $\Delta P$  cells, and gas and water meters are used as measuring and/or controlling devices.

The exchangers are simple double pipe design with 3/4" O.D. exchanger tubing inside of a carbon steel pipe jacket. The exchangers were made for relatively easy and quick removal of the inside tubing specimen for visual observation of surface deposits. Unions were liberally used throughout the pilot plant for quick disassembly or modifications in the field with a minimum of tools and technical personnel.

The pilot plant consists of both steam and hot brine exchangers plus allied piping and measuring equipment each mounted on their respective skids. Figure 2 is a drawing of the double pipe design used for all the exchangers. Those exchangers used for measuring overall heat transfer coefficients have a 3/4" O.D. - 20 gauge Titanium tube inside the pipe jacket. The exchangers used for corrosion studies have ten 1-foot long sections of various alloy 3/4" O.D. tubing connected in series with tubing connector unions inside of the pipe jacket. The tubing unions have Teflon ferrules for quick field assembly prior to a test and then relatively easy disassembly after the test.

## Steam Skid

This skid has three 12-1/2 foot long primary exchangers labeled as follows:

- (1) Clean Steam Corrosion Exchanger
- (2) Clean Steam Heat Transfer Exchanger
- (3) Dirty Steam Corrosion Exchanger

The so-called "Dirty Steam" exchanger uses steam directly off of the Well-head Separator which very probably has a small amount of entrained hot brine. Corrosion data from this exchanger will show the relative effect of the entrained brine on the steam corrosion rates resulting from either poorly designed separators or temporary commercial plant upsets. The so-called "clean steam" exchangers use steam that has passed through a Teflon demister pad to remove any entrained brine from the steam.

Steam is admitted to jacket side of the exchangers from both ends and the condensate is drained out at the center of the exchanger to prevent stagnant inert gas pockets from developing if the exchanger was not perfectly level. A ball float trap with a thermostatic vent element is used to drain off only the condensed steam plus inert gases if any. This type of steam trap prevents live steam from draining out of the exchanger for more accurate measurement of steam and inert gas quantities.

The cooling water rate is controlled at approximately 6 gpm ( $\sqrt{6}$  ft/sec tube velocity). The cooling water rate flowing through a mechanical water meter is timed and then reset if necessary by manually adjusting the water globe valve at the outlet end of the exchanger. Cooling water temperature rise is measured using dial thermometers at both the inlet and outlet end of the exchanger. The calculated quantity of heat transferred to the cooling water is used to determine the overall heat transfer coefficient for the steam exchanger.

The liquified steam condensate-inert gas mixture from the heat transfer exchanger trap flows to a CO<sub>2</sub> Separator. The inert gas and liquid condensate are separated hot at approximately 40 psig. The inert gas flows overhead through a spring-loaded back-pressure control valve. The gas is then cooled in a water-cooled exchanger to approximately 100°F. Equilibrium moisture from the cooled gas drops out in a knock-out pot and is drained on level control. The water saturated 100°F gas then flows through a dry test gas meter to a stack.

The steam condensate flows out of the CO<sub>2</sub> Separator on mechanical ball float control through the Condensate Cooler where the condensate temperature drops to 120°F. The condensate then flows through a rotameter and/or water meter into the brine pond drain line. Approximately 270 pounds per hour of steam condensate passes through each exchanger. A 5-gallon condensate sample is timed and weighed each hour as an additional check on steam condensate rate.

With a relatively constant cooling water rate and steam supply pressure, a drop in the calculated overall heat transfer coefficient with time is an indication of fouling on the heat transfer surface either from corrosion and/or silica deposition.

### Brine Skid

This skid has four heat exchangers plus allied piping and a 10" diameter flash vessel. The four exchangers are labeled as follows:

- (4) Brine High Temperature Corrosion Exchanger
- (5) Brine Low Temperature Heat Transfer Exchanger
- (6) Brine High Temperature Heat Transfer Exchanger
- (7) Brine Low Temperature Corrosion Exchanger

The so-called "high temperature" exchangers use the approximately 345°F brine directly off the Well-head Separator. The so-called "low temperature" exchangers use an approximate 235°F concentrated brine from the low pressure flash vessel.

The 100 psig brine feed rate to the low pressure flash vessel is controlled manually by throttling the inlet globe valve in conjunction with a  $\Delta P$  cell and orifice plate. Approximately 11 percent steam is flashed overhead to the atmosphere through a 2" spring-loaded back pressure control valve.

The concentrated cool brine ( $\sim 235^\circ\text{F}$ ) flows out the bottom of the flash vessel by differential pressure flow. The flash vessel pressure is set to maintain the desired rate of brine flow through exchangers Nos. 5 and 7 (hooked-up in series flow) by counter-balancing the pressure drop through the exchanger train. The effluent from these exchangers flows through a separate low pressure 3" drain line to minimize the back pressure effect on the brine flow rate.

Cooling water rates are determined by noting hourly water meter readings and manually adjusting a globe valve at the outlet end of the exchangers. Brine flow rates for the high temperature brine exchangers are manually adjusted with a gate valve on the outlet end of the exchanger to maintain a given differential pressure drop across an orifice plate in the exit line.

## RESULTS & DISCUSSION

### Data Presentation

#### Tables

1. New Mexico Geothermal Pilot Plant Log
2. A Sample Set of Computer Calculated Output Data for the Seven Exchangers.

### Figures

1. Simplified Schematic Flow Diagram of the Geothermal Pilot Plant
2. Double E - Pipe Heat Exchanger Detail Drawing
3. Computer Calculated Heat Transfer Coefficients for the New Mexico Baca Geothermal Field
4. Photograph of Silica Scale Deposited on Titanium Tubing in the Low Temperature Brine Exchanger (No. 7)

### DISCUSSION

The Baca Ranch Well No. 11 Well-head Separator was operated at approximately 120 psig with manually throttled control valves. The hot brine and steam slipstreams to the pilot plant were approximately 110 and 102 psig respectively at the exchangers. The steam exchangers were put on-stream on August 12, 1974. The first two-three days operation were plagued with mechanical leaks and balky steam trap operation. Subsequent pilot plant equipment operation was good except for occasional cooling water pump failures. The steam exchangers operated intermittently for 38 days between August 12 and September 25, 1974. Table 1 is a summary log of the pilot plant operations.

The brine exchangers were put onstream two days later on August 14, 1975. The two high temperature brine exchangers operated for a total of 36 days before shut down on September 25, 1974.

The two low temperature brine exchangers each operated for approximately 2-1/2 days with the brine flow rate reduced from 6 gpm initially to less than 2 gpm at shutdown because of silica deposits on the tube wall reducing the annular area between the outside diameter of the tube and the inside diameter of the double pipe wall. Upon dismantling these two exchangers a serrated silica deposit as shown in the photograph in Figure 4 was noted. A second set of alloy tubing specimens were installed and this particular exchanger test repeated. The second test was shut down after approximately 2-1/2 days because of reduced brine flow rate due to silica deposition.

Prior to dismantling these exchangers, 210°F hot water was run through the exchangers for 24 hours to see if the deposits could be washed out. The deposits after the hot water wash appeared to be identical to the previous test deposit. Subsequent laboratory analysis of the deposits showed 99+ percent amorphous silica.

The amount of silica deposited in the relatively short time of 2-1/2 days would preclude the use of a binary cycle process where additional heat is recovered from the hot brine by heat exchange with a secondary working fluid like iso-butane. A multi-flash process with an extra flash vessel on a rotational basis being cleaned off-line might be practical. Seeding of the brine with silica nuclei in the flash vessels (similar to salt crystallizer operation) may prevent silica deposition on the flash vessels per se. If successful, the silica nuclei would grow larger and stay suspended in the high velocity brine fluid until filtered out prior to brine reinjection.

A computer program (R5GEOTST) has been written and debugged to calculate hourly log mean temperature differences, overall heat transfer coefficients, and tube-stream linear velocities for each of the individual exchangers. The quantity of heat transferred is calculated from the temperature rise of a measured quantity of cooling water passing through a given exchanger during a specified time interval. The program automatically corrects the raw data to a 60 minute hourly basis in the event that the raw data is obtained over varying time intervals.

The program also calculates the weight percent CO<sub>2</sub> inert gas in the steam from calculated values of CO<sub>2</sub> and steam processed by the clean steam exchanger (No. 2). A sample set of the computer output data for each of the seven exchangers is included in Tables 2A-2G in the Appendix.

Figure 3 is a plot of overall heat transfer coefficients vs operating time for each of the high temperature exchangers. It will be noted that the heat transfer coefficients decreases with time and then suddenly increases and repeats this cycle periodically. These periodic increases occur after a forced temporary shut down due primarily to the cooling water pump failure. Apparently the abrupt changes in tube wall temperature as a result of loss of cooling water caused surface deposits to spall off exposing clean metal surfaces for improved heat transfer. It will be necessary to repeat this pilot plant exchanger test next spring for 30-60 days of uninterrupted operation to obtain good heat transfer data. Past operation has included one man collecting data during the day and allowing the unit to run unattended during the night. In the light of past experience, the writer recommends an additional man (local hire) on both the evening and midnight shifts primarily to maintain the Well-head Separator water level and restart the cooling water pump, if necessary.

Prior to the next test, it is imperative that the Well-head Separator manual control valves be replaced with brand new valves to prevent loss of control due to erosion during the test. The Well-head Separator installation should also have spared control and block valves to transfer control without shut-down in the event that a single valve failure occurs.

*D. G. Samuelson / DGS*  
D. G. Samuelson  
Senior Research Engineer

DGS:am

Attachments

Table 1

New Mexico Geothermal Pilot Plant  
Report No. 1Log

<u>Date</u>	<u>Days Operation</u>	<u>Well-Head Separator Pressure</u>	<u>Overall Heat Transfer Coefficient (High Temperature)</u>		<u>Remarks</u>
			<u>Steam</u>	<u>Brine</u>	
8/13	1	112	461	-	4 hours of data
8/16	4	108	584	678	coolant pump down
8/17	5	111	447	589	low water rate
8/18	6	109	477	558	
8/19	7	108	458	538	
8/20	8	102	520	510	coolant pump down
8/21	9	100	536	474	coolant pump down
8/22	10	99	532	623	
8/23	11	101	503	584	
8/24	12	106	491	541	
8/25	13	106	482	507	
8/26	14	106	493	516	high sep. level liq. carryover
8/27	15	102	488	502	" " " " "
8/28	16	103	460	491	" " " " "
8/29	17	99	504	610	
8/30	18	95	440	564	sep. steam valve losing control due to erosion
8/31	19	87	416	515	
9/1	20	79	412	491	
9/2	21	122	412	485	pinched down on steam valve trying to control pressure
9/3	22	121	440	502	
9/4	23	115	430	508	
9/5	24	116	399	528	
9/6	25	123	433	491	
9/7	26	117	461	515	
9/8	27	117	500	567	
9/9	28	107	518	541	down to change sep. valves
9/12	29	110	498	537	
9/13	30	107	489	567	coolant pump down
9/14	31	105	497	579	" " "
9/15	32	103	499	570	" " "
9/16	33	101	505	540	
9/17	34	113	456	498	
9/18	35	130	475	486	
9/19	36	112	485	492	
9/23	37	116	554	509	
9/24	38	123	528	560	

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Table 2A

GECTHERMAL PILOT PLANT DATE 8/15/74 TIME 845  
CONSTANTS AND GENERAL DATA

BAROMETER READING, PSIA 10.66  
STEAM ENTHALPY, BTU/LB 884.

EXCHANGER, NO 1 - CLEAN STEAM CORK TEST

DATE	TIME	TEMPERATURES, F		PRESS PSIG		COOLING WATER			VEL FT/S	CALCULATED VALUES			STEAM LB/HR		
		PROCESS IN OUT	COOLANT IN OUT	PROC	COCL	METER RDG	GPH	GPM		LMTD F	QC BTU/HR.	U			
8/15/74	845	337.	0.	84.	140.	112.	59.	35129.	0.	0.0	0.0	224.	0.	0.	0.0
8/15/74	945	333.	0.	85.	154.	107.	59.	35485.	356.	5.93	5.83	212.	204618.	434.	231.5
8/15/74	1045	333.	0.	85.	158.	108.	59.	35650.	365.	6.08	5.97	209.	221953.	475.	251.1
8/15/74	1145	331.	0.	85.	158.	105.	59.	36213.	363.	6.05	5.94	207.	220737.	477.	249.7
8/15/74	1245	332.	0.	86.	157.	106.	58.	36573.	360.	6.03	5.89	208.	212915.	458.	240.9
8/15/74	1345	333.	0.	89.	157.	107.	59.	36936.	363.	6.05	5.94	208.	205618.	443.	232.6
8/15/74	1445	333.	0.	89.	151.	108.	59.	37305.	369.	6.15	6.04	211.	190574.	404.	215.6
8/15/74	1545	335.	0.	89.	153.	111.	59.	37676.	371.	6.18	6.07	212.	197788.	418.	223.7
AVERAGES	8	333.	0.	87.	154.	108.	59.	2547.	364.	6.06	5.96	210.	207743.	444.	235.0

## EXCHANGER NO. 2 - CLEAN STEAM C TEST

Table 2B

DATE	TIME	TEMPERATURES, F		PRESS PSIG	PSIG	COOLING WATER			CO <sub>2</sub>		CALCULATED VALUES					STEAM WA		
		PROCESS	COOLANT			METER	GPH	GPM	CO <sub>2</sub> RDG	FT <sup>3</sup> /H.	LMTD	QC	U	CO <sub>2</sub>	WT%		LB/HR	FT
		IN	OUT	PROC	COOL	RDG	GPH	GPM	CO <sub>2</sub> RDG	FT <sup>3</sup> /H.	F	BTU/HR		LB/HR	WT%	LB/HR	FT	
8/15/74	845	335.	0.	84.	165.	109.	42.	63978.	0.	0.0	803.0	0.0	208.	0.	0.	0.0	0.0	0.0
8/15/74	941	334.	0.	86.	165.	107.	42.	64291.	341.	5.69	962.0	173.5	205.	227545.	497.	13.66	5.04	257.4
8/15/74	1046	334.	0.	87.	167.	103.	42.	64671.	351.	5.85	1132.0	156.9	204.	233752.	513.	12.29	4.44	264.4
8/15/74	1141	333.	0.	87.	165.	107.	42.	64992.	350.	5.84	1287.0	169.1	204.	230444.	507.	13.24	4.82	260.7
8/15/74	1246	333.	0.	88.	165.	106.	41.	65390.	375.	6.25	1471.0	169.8	204.	240361.	528.	13.30	4.66	271.9
8/15/74	1341	333.	0.	91.	165.	106.	41.	65798.	393.	6.55	1631.0	174.5	203.	242085.	535.	13.57	4.72	273.9
8/15/74	1446	333.	0.	90.	165.	103.	41.	66185.	394.	6.57	1822.0	176.3	203.	246248.	543.	13.71	4.69	278.6
8/15/74	1541	333.	0.	90.	165.	107.	41.	66548.	396.	6.60	1983.0	175.6	203.	247401.	546.	13.66	4.65	279.9
AVERAGES	8	334.	0.	88.	166.	107.	42.	2570.	371.	6.19	1180.0	170.8	204.	238265.	524.	13.35	4.72	269.5

Table 2C

## EXCHANGER NO 3 - DIRTY STEAM CORR TEST

DATE	TIME	TEMPERATURES, F				PRESS PSIG		COOLING WATER			CALCULATED VALUES			STEAM LB/HR	
		PROCESS		COOLANT		PROC	COOL	METER RDG	GPH	GPM	VEL FT/S	LMTD F	QC BTU/HR		U
8/15/74	847	335.	0.	84.	152.	106.	0.	46426.	0.	0.0	0.0	215.	0.	0.	0.0
8/15/74	947	334.	0.	85.	154.	105.	0.	46776.	350.	5.63	5.73	213.	201169.	424.	227.6
8/15/74	1047	334.	0.	87.	153.	105.	0.	47144.	368.	6.13	6.02	212.	202319.	427.	228.9
8/15/74	1147	334.	0.	87.	154.	105.	0.	47518.	374.	6.23	6.12	212.	200733.	442.	236.1
8/15/74	1247	334.	0.	88.	154.	106.	0.	47885.	367.	6.12	6.01	211.	201709.	428.	228.2
8/15/74	1347	334.	0.	91.	157.	106.	0.	48254.	369.	6.15	6.04	208.	202369.	437.	229.5
8/15/74	1447	334.	0.	90.	156.	106.	0.	48627.	373.	6.22	6.10	209.	205068.	439.	232.0
8/15/74	1547	334.	0.	90.	155.	105.	0.	48997.	370.	6.17	6.06	209.	203419.	436.	230.1
AVERAGES	8	334.	0.	88.	155.	106.	0.	2571.	367.	6.12	6.01	211.	203621.	433.	230.3

Table 2D

## EXCHANGER NO 4 - URINE HIGH TEMP CORR TEST

DATE	TIME	TEMPERATURES, F				PRESS PRUC	PSIG CCCL	COOLING WATER			BRINE		CALCULATED VALUES			
		IN	OUT	IN	OUT			METER RDC	GPH	GPM	VEL FT/S	CALC GPM	VEL FT/S	LMTD F	QC BTU/HR	U
8/15/74	848	342.	310.	85.	163.	111.	0.	99412.	0.	0.0	0.0	0.0	201.	0.	0.	
8/15/74	948	340.	310.	87.	164.	111.	0.	99771.	359.	5.98	5.88	15.36	3.67	199.	230266.	520.
8/15/74	1048	341.	309.	88.	165.	111.	0.	100151.	360.	6.00	5.89	14.44	3.45	198.	230908.	524.
8/15/74	1143	341.	310.	88.	166.	113.	0.	100484.	353.	5.88	5.78	14.80	3.54	198.	229358.	521.
8/15/74	1243	341.	310.	89.	167.	112.	0.	100829.	345.	5.75	5.65	14.47	3.46	197.	224160.	511.
8/15/74	1343	341.	310.	92.	169.	112.	0.	101172.	343.	5.72	5.61	14.20	3.39	194.	220004.	508.
8/15/74	1443	341.	310.	91.	168.	112.	0.	101513.	341.	5.68	5.58	14.12	3.37	195.	218721.	503.
8/15/74	1543	341.	310.	91.	169.	112.	0.	101854.	341.	5.68	5.58	14.30	3.42	195.	221561.	511.
AVERAGES	8	341.	310.	89.	166.	112.	0.	2442.	349.	5.81	5.71	14.53	3.47	196.	224997.	514.

## EXCHANGER NO 5 - BRINE LOW TEMP Q TEST

DATE	TIME	TEMPERATURES, F				PRESS PSIG		COOLING WATER			BRINE			CALCULATED VALUES		
		PROCESS		COOLANT		PROC	COOL	METER	ROG	GPH	GPM	VEL FT/S	CALC VEL GPM	FT/S	LMTD F	QC BTU/HR
8/15/74	849	245.	212.	35.	106.	17.	0.	56993.	0.	0.0	0.0	0.0	0.0	133.	0.	0.
8/15/74	949	244.	212.	86.	106.	17.	0.	57545.	552.	9.20	4.79	5.75	5.65	132.	91963.	401.
8/15/74	1049	243.	209.	86.	108.	17.	0.	58030.	535.	8.92	4.65	5.77	5.67	129.	98044.	437.
8/15/74	1149	245.	211.	86.	108.	18.	0.	58633.	553.	9.22	4.80	5.95	5.86	131.	101343.	445.
8/15/74	1249	243.	209.	87.	108.	17.	0.	59182.	549.	9.15	4.77	5.65	5.55	128.	96037.	430.
8/15/74	1349	243.	209.	90.	111.	17.	0.	59738.	550.	9.27	4.83	5.56	5.46	125.	97261.	448.
8/15/74	1449	243.	209.	90.	110.	17.	0.	60295.	557.	9.28	4.84	5.46	5.36	126.	92796.	424.
8/15/74	1549	242.	209.	90.	110.	17.	0.	60856.	561.	9.35	4.87	5.07	5.56	125.	93463.	428.
AVER AGES	8	244.	210.	88.	108.	17.	0.	3863.	552.	9.20	4.79	5.69	5.59	128.	95844.	430.

Table 2F

## EXCHANGER NO 6 - BRINE HIGH TEMP Q TEST

DATE	TIME	TEMPERATURES, F				PRESS PROC	PSIG COOL	COOLING WATER			BRINE			CALCULATED VALUES		
		PROCESS		COOLANT				METER	VEL	CALC	VEL	LMTD	QC	U		
		IN	OUT	IN	OUT			RDG	GPH	GPM	FT/S	GPM	FT/S	F	BTU/HR	
8/15/74	850	345.	308.	86.	141.	114.	0.	76746.	0.	0.0	0.0	0.0	0.0	213.	0.	0.
8/15/74	950	345.	307.	87.	142.	114.	0.	77289.	543.	9.05	4.72	13.10	12.86	211.	248775.	676.
8/15/74	1050	345.	307.	88.	143.	115.	0.	77832.	543.	9.05	4.72	13.10	12.86	210.	248775.	680.
8/15/74	1150	345.	303.	88.	143.	115.	0.	78575.	543.	9.05	4.72	13.45	13.21	211.	248775.	678.
8/15/74	1250	345.	303.	88.	144.	115.	0.	78911.	536.	8.93	4.55	13.52	13.28	210.	250033.	683.
8/15/74	1350	344.	308.	92.	146.	115.	0.	79450.	539.	8.98	4.68	13.47	13.23	207.	242453.	674.
8/15/74	1450	345.	303.	91.	145.	115.	0.	79972.	542.	9.03	4.71	13.18	12.95	208.	243602.	672.
8/15/74	1550	344.	309.	92.	145.	115.	0.	80536.	544.	9.07	4.72	13.73	13.48	208.	240171.	664.
AVERAGES	8	345.	303.	89.	144.	115.	0.	5790.	541.	9.02	4.70	13.37	13.12	209.	246112.	675.

Table 2G

## EXCHANGER NO 7 - BRINE LOW TEMP CORR TEST

DATE	TIME	TEMPERATURES, F				PRESS PROC	PSIG COOL	COOLING WATER			BRINE		CALCULATED VALUES			
		PROCESS IN	PROCESS OUT	COOLANT IN	COOLANT OUT			METER RDG	GPH	GPM	VEL FT/S	CALC GPM	VEL FT/S	LMTD F	QC BTU/HR	U
8/15/74	851	211.	170.	83.	107.	8.	0.	47237.	0.	0.0	0.0	0.0	0.0	105.	0.	0.
8/15/74	951	212.	190.	85.	107.	8.	0.	47654.	427.	7.12	6.99	7.12	1.70	105.	78252.	334.
8/15/74	1051	210.	187.	85.	107.	8.	0.	48094.	430.	7.17	7.04	6.86	1.64	103.	78802.	345.
8/15/74	1151	212.	191.	85.	108.	8.	0.	48522.	428.	7.13	7.00	7.81	1.87	105.	82001.	350.
8/15/74	1251	209.	189.	87.	109.	7.	0.	48937.	415.	6.92	6.79	7.61	1.82	101.	76053.	338.
8/15/74	1351	208.	183.	89.	110.	7.	0.	49340.	411.	6.85	6.73	7.19	1.72	99.	71896.	327.
8/15/74	1451	209.	187.	91.	109.	7.	0.	49762.	414.	6.90	6.78	6.21	1.48	99.	62075.	281.
8/15/74	1551	209.	189.	89.	109.	7.	0.	50187.	425.	7.08	6.90	7.08	1.69	100.	70805.	318.
AVERAGES	8	210.	189.	87.	108.	7.	0.	2950.	421.	7.02	6.90	7.13	1.70	102.	74269.	328.

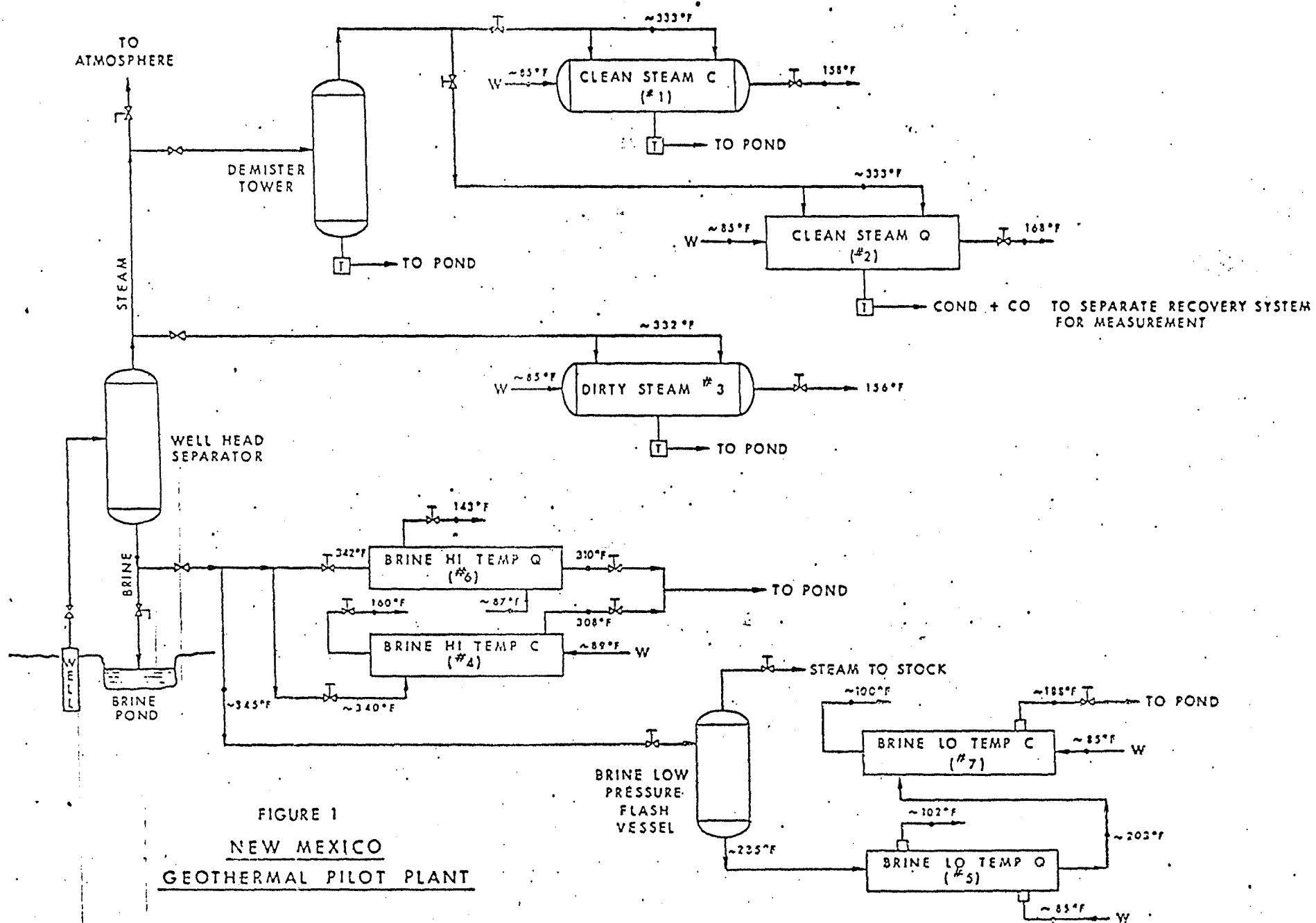


FIGURE 1  
 NEW MEXICO  
 GEOTHERMAL PILOT PLANT



GEOTHERMAL ENERGY

Figure 2

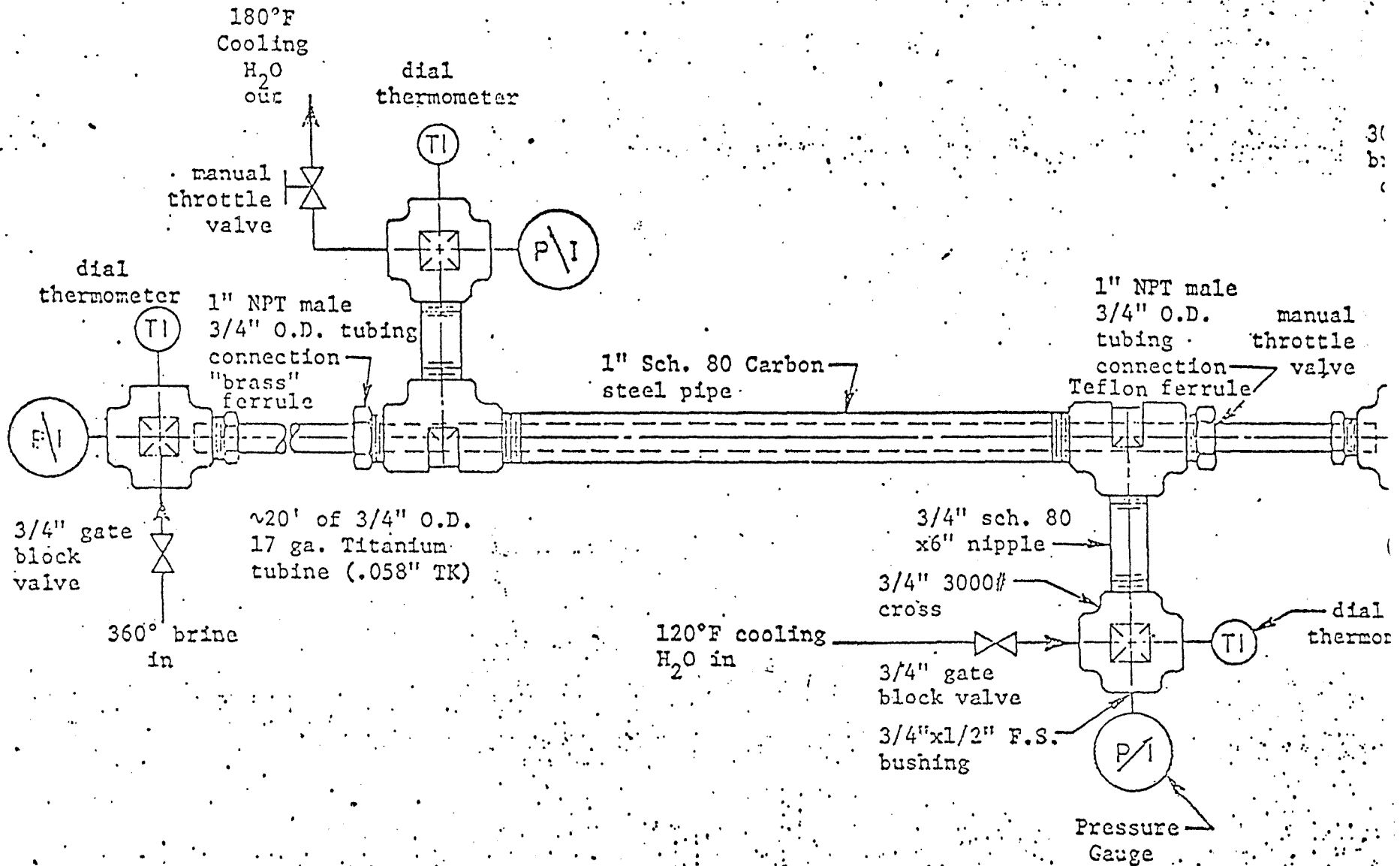
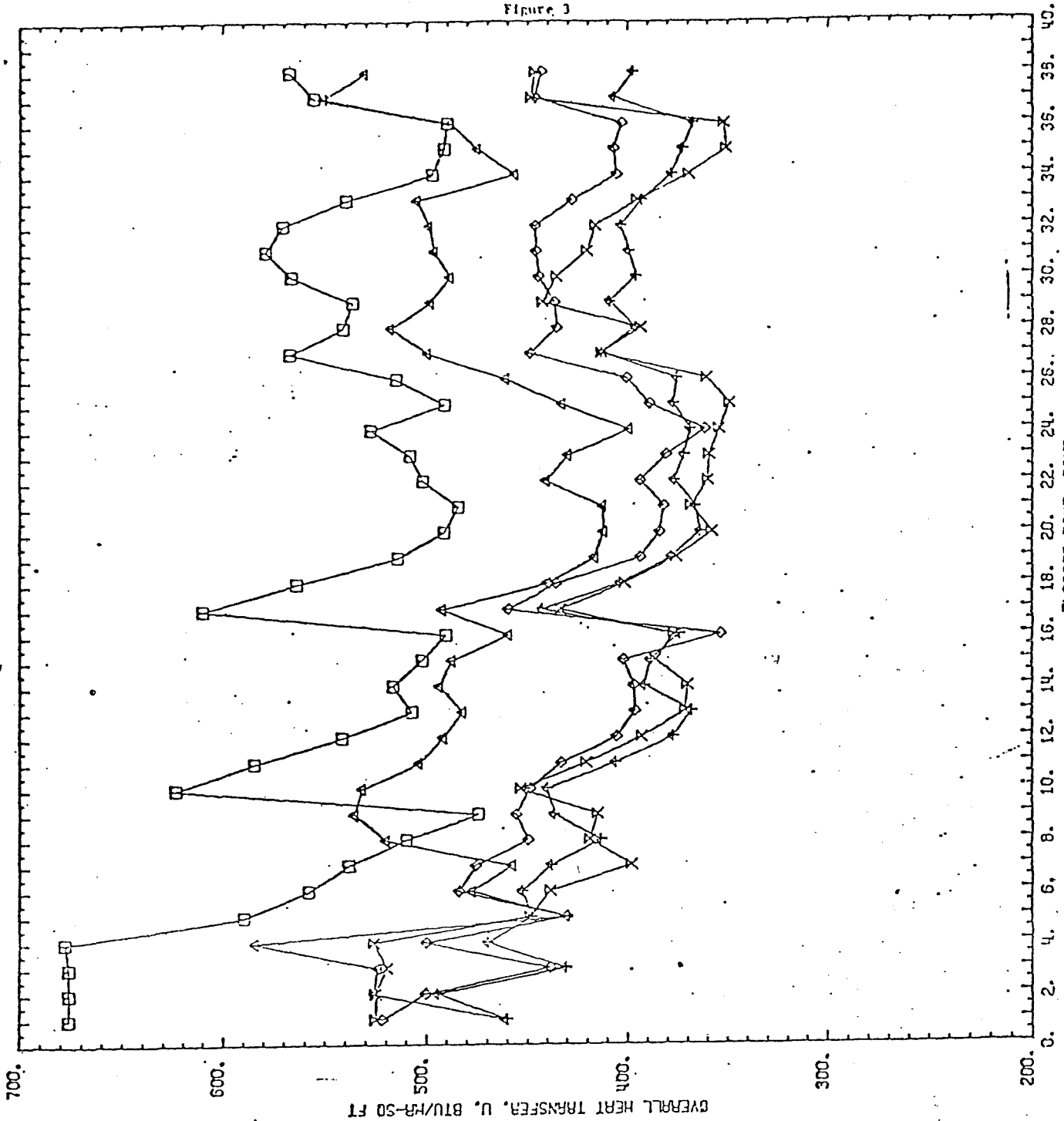


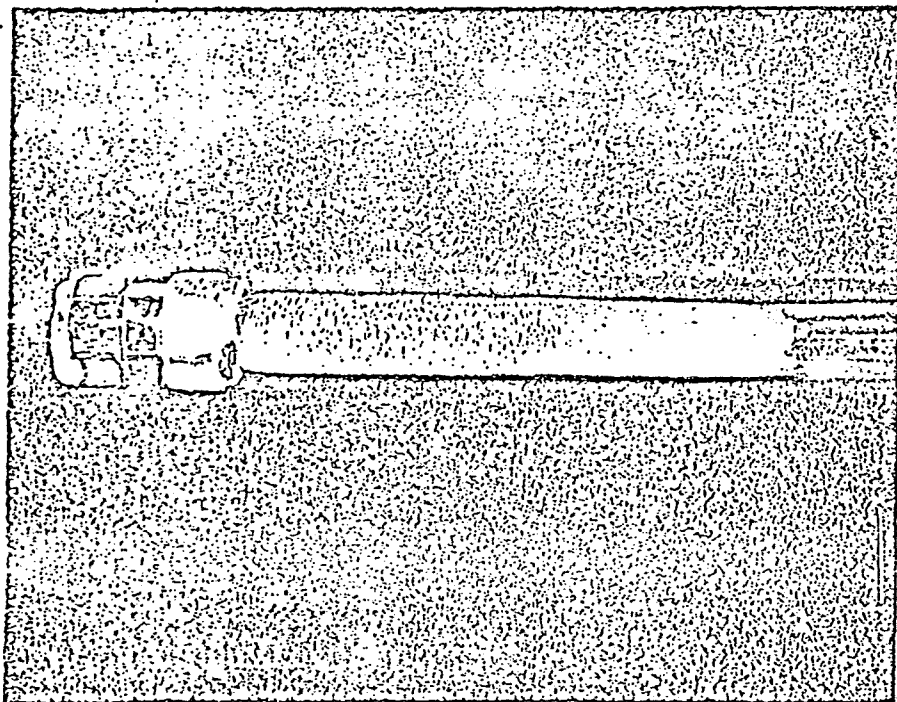
Figure 3



- NO 2 - STEER 0 -  $\square$
- NO 1 - STEER CORROSION -  $\diamond$
- NO 3 - OJATY STEER C -  $\triangle$
- NO 4 - BRINE HI TEMP C -  $\times$
- NO 5 - BRINE HI TEMP O -  $\circ$

NEW MEXICO GEOTHERMAL PILOT PLANT

Figure 4





To: H. Hennig

Memo: CORR 74-225M

From: C. J. Cron

Date: Dec. 20, 1974

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 282-83403

Subject: CORROSION RESULTS OF SECOND HEAT  
EXCHANGE TEST CONDUCTED AT BACA 11

Supervisor: G. A. Marsh

cc: Library (2)

Patent  
G. D. Cheadle  
Arnold Kelley

D. G. Samuelson  
R. P. Vaell  
J. Walker

### Summary

The titanium, Carpenter 20-CB3, Incoloy 825, Inconel 600, and Carpenter 7 Mo alloys experienced no corrosion in clean steam, dirty steam, or brine of Baca 11. The copper base alloys, namely Monel 400, 70/30 CuNi, aluminum bronze, and admiralty brass, suffered measurable corrosion rates, although not severe, in all three environments with the steam being more aggressive than the brine. The carbon steel suffered considerable corrosion on the inside and outside surfaces in all environments. From a corrosion standpoint the following alloys would be acceptable for geothermal heat exchanger service: titanium, Carpenter 20-CB3, Incoloy 825, Inconel 600, and Carpenter 7 Mo.

### Introduction

A combination heat exchange and corrosion test was conducted at our New Mexico geothermal project. My report will discuss the results of the corrosion portion of the test.

Tubular corrosion coupons (12" x 3/4") were exposed to three environments: clean steam, dirty steam, and brine. The clean steam designation refers to steam from the separator that has been passed through a demister pad while the steam directly from the separator has been labeled dirty steam.

The steam tests ran for 38 days and the brine test ran for 36 days. The steam and brine were on the shell side, and cooling water passed through the tubes. The alloys tested were: titanium, Carpenter 20-CB3, Incoloy 825, Monel 400, Inconel 600, 70/30 CuNi, Carpenter 7 Mo, aluminum bronze, admiralty brass, and mild steel.

### Discussion

The corrosion rates of each alloy in the three environments are given in the following table:

<u>Alloy</u>	<u>Clean Steam</u>	<u>Dirty Steam</u>	<u>Brine</u>
Titanium	0 mpy	0 mpy	0.2 mpy
Carpenter 20	0	0	0.1
Incoloy 825	0	0	0.1
Inconel 600	0	0	0.2
Carpenter 7 Mo	0	0	0.1
Monel 400	2.1	2.3	1.3
Admiralty	2.6	3.4	1.7
70/30 CuNi	5.5	5.4	2.8
Al Bronze	6.4	6.5	3.5
Mild Steel	42	24	31

As the data indicate there are several alloys that have virtually zero corrosion rates in all three environments. The corrosion rate of the mild steel was excessive and it would not be considered for heat exchanger service. It was included in the test more or less as a benchmark to demonstrate that alloying is necessary to maintain sufficient corrosion resistance. One should not interpret the corrosion rates for mild steel to mean that the well head and casing materials are suffering the same amount of corrosion. A considerable amount of the corrosion of the carbon steel tube occurred on the cooling water side of the tube.

### Observations on Scaling

In the clean steam, the titanium, Carpenter 20, Inconel 600, Incoloy 825, and Carpenter 7 Mo alloys were clean with some slight black discoloration of the Inconel and Incoloy alloys. The Monel 400, 70/30 CuNi, aluminum bronze, and admiralty alloys were covered with a black scale which flaked off in some areas and adhered tightly in others. The carbon steel tube was covered with a rusty, black scale.

In the dirty steam, the titanium, Carpenter 20, Inconel 600, Incoloy 825, and Carpenter 7 Mo alloys were all clean, no discoloration. The Monel 400, 70/30 CuNi, aluminum bronze, and admiralty alloys were covered with a thin black scale. The carbon steel tube had a slight rust scale, not as bad a scale as in the clean steam.

Of course the scaling is more severe and varied in the brine phase and the observations are probably best presented in a table, as below.

Scaling in Brine

Alloy

Observations

Titanium	Thin silica scale, tightly adherent.
Carp 20 CB3	Silica scale, tightly adherent.
Incoloy 825	Heavy silica scale, tightly adherent.
Monel 400	Not much silica scale, black flaky deposit.
Inconel 600	Silica scale, some flakes off, remainder adheres tightly.
70/30 CuNi	Black flaky deposit, loosely adherent, doesn't look like silica.
Carp 7 Mo	Black silica scale, some flakes off, remainder adheres tightly.
Al Bronze	Black silica deposit, tightly adherent.
Admiralty	Silica scale, tightly adherent.
Carbon steel	Heavy black silica scale, tightly adherent.

Conclusions

A number of alloys showed virtually a zero corrosion rate in all three geothermal fluids: clean and dirty steam and brine. Even those alloys, copper base, that did suffer measurable corrosion rates, did not corrode at excessive rates. The data from these tests (36-38 days) agree well with the data collected in a shorter test which were reported in CORR 74-126. The black scales that formed on the copper base alloys are a result of H<sub>2</sub>S attack.

CJC:mb

Carl J. Cron

APPENDIX

26" HOLE  
20", 94" CASING @ 207'  
CEMENTED W/600 CU.FT.

17 1/2" HOLE

9 5/8", 36" CASING (TIE BACK) @ 1219'  
CEMENTED W/565 CU.FT.  
13 3/8", 54.5" CASING @ 1336'  
CEMENTED W/600 CU.FT.

9 5/8", 36" CASING, 1219 - 3380'  
CEMENTED W/1965 CU.FT.

3068'-3194' LIGHT SCALE

3194'-3813' HEAVY SCALE

3813'-3937' LIGHT SCALE

557'  
312'

PALIZA CANYON ANDESITE  
5440' - 6565'

7", 26" SLOTTED LINER  
HUNG 3320' - 6926'  
SLOTTED: 3483' - 4245' (16-2-6-250)  
4283' - 6617' (6-12-24-250)  
6699' - 6928' (15-2-6-40)

TERTIARY SEDIMENTS  
6565' - T.D.

TOTAL DRILLED DEPTH 6931'

U.S. GEOLOGICAL SURVEY - REGIONAL DIVISION

D. PYLE  
G. GRIFFEY  
2-15-74  
NONE

BACA-II CASING SCHEMATIC

FIGURE 1



THOUSANDS OF LBS/HR

WELLHEAD PRESS - PSIG

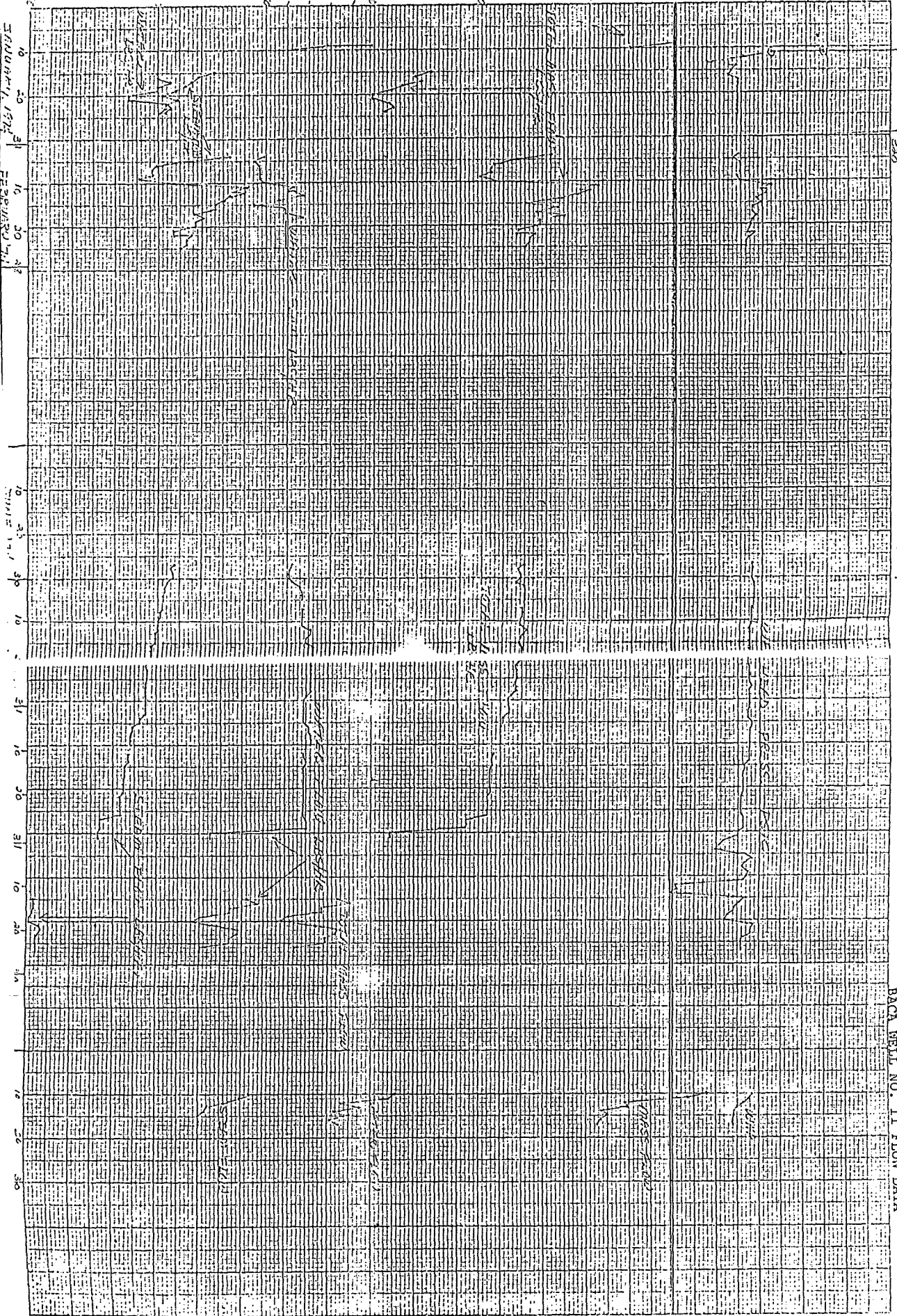


FIGURE II  
BACA WELL NO. 11 FLOW DATA



E&PP-75-75

O. WHITESCARVER

February 28, 1975

MAR 5 1975

Mr. O. D. Whitescarver  
Santa Rosa

ANALYSES OF SCALE SAMPLES  
WELL BACA #11, NEW MEXICO

Attached are analyses of scale samples from various locations in the steam separator installed on Well Baca #11, New Mexico. These samples were analyzed by two methods, X-ray diffraction and emission spectroscopy.

X-ray diffraction (XRD) determines mineralogical species by characteristic diffraction patterns. Some materials appear amorphous to X-rays and yield no pattern. In this series of samples, Numbers 1 and 6 yielded no X-ray diffraction pattern, Numbers 2, 3, and 4 showed only Maghemite ( $\gamma$  Fe<sub>2</sub>O<sub>3</sub>), and Number 5 showed Illite and Quartz in addition to Maghemite.

Emission spectroscopy (ES) shows metal constituents irrespective of mineralogy. Iron, aluminum, and silicon are the major constituents of samples taken within the separator. Calcium also appears in the sample from the exit water line. Lesser amounts of other constituent were found as listed.

In a general sense these analyses are consistent with what can be expected from a hot water system. Calcite will precipitate at the flash point where carbon dioxide is evolved. This is usually in the formation or wellbore. Thus, it is not surprising that little or none was found in the separator. Calcium could be expected to precipitate again at the pressure drop at the exit water line orifice.

Amorphous silica scale is one major constituent in these samples. It forms as a result of supersaturation caused by temperature drop or steam flashing. Thus, it is more prevalent in surface facilities.

The iron and aluminum may be peculiar to your geologic formation. I am not aware of reports of major concentrations in other geothermal scales. Although the iron may come from corrosion downhole, the red beds drilled also seem like a reasonable source.

Please let us know if we may be of further assistance to you.



M. M. Ellis

NME:ms  
Att.

FIGURE III

SCALE SAMPLES FROM SEPARATOR  
Well Baca #11

---

1. Dome Inlet to Separator

XRD No diffraction.

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Silicon	Copper	Potassium	Lead
	Iron	Sodium	Calcium	Tin
		Aluminum	Manganese	Magnesium
			Silver	

2. Separator Wall

XRD Maghemite ( $\gamma$  Fe<sub>2</sub>O<sub>3</sub>)

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Iron	Potassium	Manganese	Chromium
	Silicon	Calcium		Nickel
	Aluminum	Sodium		Molybdenum
				Silver
				Copper
				Titanium
				Lead

3. Mist Extractor Pads

XRD Maghemite

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Iron	Potassium	Manganese	Magnesium
	Aluminum	Sodium		Copper
		Silicon		Nickel
		Calcium		Chromium
				Molybdenum
				Lead
				Titanium

4. Pressure Sensing Tap - Side of Separator

XRD Maghemite

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Iron	Zinc	Copper	Magnesium
		Lead	Potassium	Nickel
		Silicon	Manganese	Molybdenum
				Silver
				Chromium
				Calcium

## 5. Bottom Sight Glass Tap

XRD Maghemite

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Silicon	Sodium	Molybdenum	Lead
	Iron	Potassium	Calcium	Magnesium
	Aluminum			Tin
				Vanadium
				Silver
				Manganese
				Copper
				Titanium
				Chromium

## 6. Water Line from Separator at Orifice

XRD No diffraction

ES	<u>Major</u>	<u>Moderate</u>	<u>Slight</u>	<u>Trace</u>
	Calcium	Copper	Manganese	Magnesium
	Silicon	Sodium	Silver	Tin
	Iron	Potassium		Nickel
	Aluminum			Molybdenum
				Strontium

UNION

November 22, 1974

E&PP 74-408

Mr. D. E. Pyle  
Los Angeles

SCALE REMOVED FROM WELL BACA NO. 11

The samples of scale removed from downhole Well Baca No. 11 in New Mexico have been analyzed by X-ray, emission spectrograph and quantitative flame-spectral analysis. The analytical results are appended.

We found the major component in each sample to be calcite. In the 3160' and 6600' samples, substantial amounts of iron oxide were identified. In all samples, except the sample at 3500 ft depth, the concentration of acid soluble calcite and iron oxide is between 75 and 81%. However, the sample at 3500 ft was only 25% acid soluble calcite, 36% was acid-insoluble quartz, and an unidentified concentration was feldspar. We conclude that the majority of scale in all but the one sample could be removed by acid wash.

If we can be of further help, please let us know.

*P. W. Fischer*  
P. W. Fischer

PWF:ec  
Attach

cc: J. C. Jones  
R. F. Dondanville  
V. E. Suter

3320 - 74-408  
3320 - 74-408  
3320 - 74-408

ANALYSIS OF SCALE SAMPLES OBTAINED FROM WELL BACA 11

Sample Depth, ft	Crystalline Compounds Found by X-Ray	Emission Spectrograph			Quantitative Analysis, % by Wt.			Estimated Acid Solubles % by Wt.
		Major	Moderate	Slight	Calcite	Iron Oxide	Quartz	
3160	Calcite	Calcium Iron	Manganese Aluminum Potassium Silicon	Sodium (a)	58	20		78
3500	Calcite; quartz	Calcium Silicon Aluminum	Iron Potassium Sodium Manganese	None (a)	26	-	36	26.2
3813	Calcite	Calcium	Manganese Potassium Iron Aluminum	Silicon Sodium (a)	78	-		78
3950	Calcite	Calcium	Manganese Iron Potassium	Aluminum Silicon Sodium (a)	81	-		81
6600	Calcite Quartz Feldspar	Calcium Iron	Silicon Aluminum Manganese Potassium	Sodium (a)	62.0	13		75
6620	Calcite	Calcium	Iron Manganese	Potassium Silicon Aluminum Sodium (a)	81.2	-		81

(a) Trace concentrations in each sample of silver and copper.

UIM 76 M

DEL PYLE

MAR 31 1975

To: D. E. Pyle  
From: C. J. Cron  
Memo: CORR 75-43M  
Date: March 26, 1975  
Division: Petrochemical, Analytical  
and Corrosion Research  
Project: 282-72805  
Subject: CORROSION INSPECTION OF 7 INCH  
PRODUCTION LINER FROM BACA #6  
Supervisor: G. A. Marsh

cc: Library (2)

Potent

D. L. Ash

R. S. Crog

M. M. Ellis

J. C. Jones

E. Schaschl

J. Walker

### Summary

An inspection showed that very little corrosion has occurred in the production liner of Baca #6. The liner had been in place about 3-1/2 years and the well had flowed about 60 days. From the inspection it does not appear that down-hole corrosion will be a serious problem. However, conditions may change when the well is flowed for a long period of time.

### Introduction

I recently made a corrosion inspection of the 7" production liner which was pulled from Baca #6. Baca 6 was drilled in July-August of 1971. It has been flowed for approximately 60 days and it has been used as an injection well for about 30 days. The production liner had been pulled so that Baca 6 could be deepened. The inspection for corrosion damage was performed because this was the first opportunity we've had to inspect casing that had been in service in New Mexico.

### Discussion

The wall thicknesses of almost all of the 73 joints were measured with an ultrasonic device. The wall thickness data appear in the following table:

FIGURE IV

<u>Joint #</u>	<u>Thickness</u>	<u>Joint #</u>	<u>Thickness</u>	<u>Joint #</u>	<u>Thickness</u>
1	0.345"	32	0.355	53	0.358
2	0.395	33	0.345	54	0.375
3	0.350	34	0.370	55	0.360
4	0.370	35	0.370	56P	0.320
5	0.360	36	0.390	57P	0.285
6	0.345	37	0.365	58P	0.330
7	0.375	38	0.375	59P	0.325
8	0.365	39	0.360	60P	0.300
9	0.380	40	0.373	61	0.350
10	0.365	41	0.370	62	0.365
11	0.395	42	0.373	63	0.360
12	0.335	43	0.370	64	0.375
17	0.350	44	0.380	65	0.370
18	0.345	45	0.363	66	0.360
19	0.340	46	0.357	67	0.375
21	0.370	47P*	0.345	68	0.365
22	0.380	48P	0.320	69	0.370
28	0.380	49	0.350	70	0.355
29	0.360	50	0.370	71P	0.350
30	0.360	51	0.390	72P	0.320
31	0.360	52	0.370	73P	0.350

\*P means perforated joint.

The joints making up the liner were two different weights, 23 lb/ft and 26 lb/ft. These weights correspond to nominal wall thicknesses of 0.317" and 0.362", respectively. With the exceptions of joints 57 and 60 all of the joints had a wall thickness greater than one of the nominal thicknesses mentioned above. Mill specifications for wall thickness are generally  $\pm 12.5\%$  of the nominal wall thickness. These data indicate that the 7" production liner did not suffer any serious general corrosion. Perhaps a qualifying statement should be made at this point. Although the liner had been in place 3-1/2 years most of that time the well had been idle and it is difficult to know exactly the environment of the liner. A flowing well would be a different environment than a static one.

A visual inspection of the outside surface of the liner revealed no pitting type corrosion damage. The perforated joints were checked carefully for any cracking associated with the perforations and there was none. The perforations were all mill cut as opposed to torch cut which can result in residual stresses and a brittle phase in the heat affected zone of the cut which is susceptible to cracking for a variety of reasons.



The amount of scaling inside the liner was minimal, generally less than 1 mm. However, the scale that was present was sampled at various depths and submitted for a qualitative analysis to our emission spec lab. It should be noted that joints 1 through 10 were very clean and there wasn't enough scale to collect samples. In general all of the analyses were very similar with the major elements (>10%) being Fe and Si and the moderate elements (1-10%) were Al and Na. Probable origins of the elements mentioned are: Fe - corrosion products, Si + Al - formation dirt (silica and silicates), Na - formation water. There were numerous elements mentioned as traces which are not listed here.

### Conclusions

The Baca 6 production liner had been in place long enough (3-1/2 years) to provide reasonable data on the corrosion conditions downhole at our New Mexico site, albeit the flowing time of the well was a small fraction of the exposure time. From the information gathered in this inspection it does not appear that downhole corrosion would be a problem. There does not appear to be any problem with scaling in the well bore. I think the well has been flowed a sufficient length of time to make that observation.

CJC:mb

Carl J. Carr

July 24, 1974

W. E. SUTER  
JUL 26 1974

TO: A. J. Chasteen

FROM: R. F. Dondanville

SUBJECT: Precipitation of Silica and Loss of Permeability  
in Injection Wells - Baca Location - New Mexico

### PURPOSE

The purpose of this memo is to alert concerned individuals that the silica content of injected water is sufficiently high that precipitation and deposition of silica is probably occurring in injection wells. The urgency of the problem is not known, but the long-term effect will be destruction of injection permeability.

### THE PROBLEM

Hydrothermal systems contain silica dissolved from the reservoir rock. The separator water during the Baca #4 test in 1973 contained about 700 ppm dissolved silica. The silica is concentrated during flashing in the separator; the unflashed reservoir fluid probably contains 550-600 ppm silica.

The solubility of silica is temperature dependent. At room temperature the solubility is about 120 ppm. At reservoir temperature of 200°C the solubility is in the order of 700 ppm. When a well is flowed into a cond, much of the silica precipitates immediately to give the pond water a milky appearance due to suspended silica. The water with dissolved and suspended silica in the order of 200 ppm is injected back into the reservoir where the solubility at reservoir conditions is 550-600 ppm silica. Some silica must be deposited in the fractures of the reservoir.

This is a borderline problem. The hydrothermal system is not being so overloaded with silica that fracture plugging is imminent, and possibly the suspended silica may not settle out until it is far away from the well bore. We may never have a real problem. On the other hand, the consequences of a plugged injection well require that some consideration be given to methods of silica reduction.

RECOMMENDATIONS

Of first priority is the determination of the urgency of the problem. If possible, injectivity tests should be designed to determine if Baca #5, the injection well, is progressively accepting fluid with more or less ease.

Secondly, consideration should be given to both short-term and long-term methods of reducing the amount of injected silica. One short-term solution is additional surface residency time before reinjection. Meager data from Baca #11 indicate that effluent water in the pond near the well contains 820 ppm silica while the same water in the settling pond near the injection inlet at the Baca #5 location contains about 730 ppm silica. The silica is slowly settling out of the water during its course through the settling ponds. Perhaps pond design can be improved.

Jim Baur, Union Research, suggests that simple filtering through a sand or gravel may be effective in removing suspended silica. I am also told that the Broadlands field in New Zealand will be developed by treating the effluent with lime to remove silica and arsenic prior to disposal into a nearby river. I have written to the New Zealand people, requesting more information.

RDF:tb

cc: Carel Otte  
H. J. Stefanides  
V. F. Suter  
R. C. Lindwall

FIGURE VII

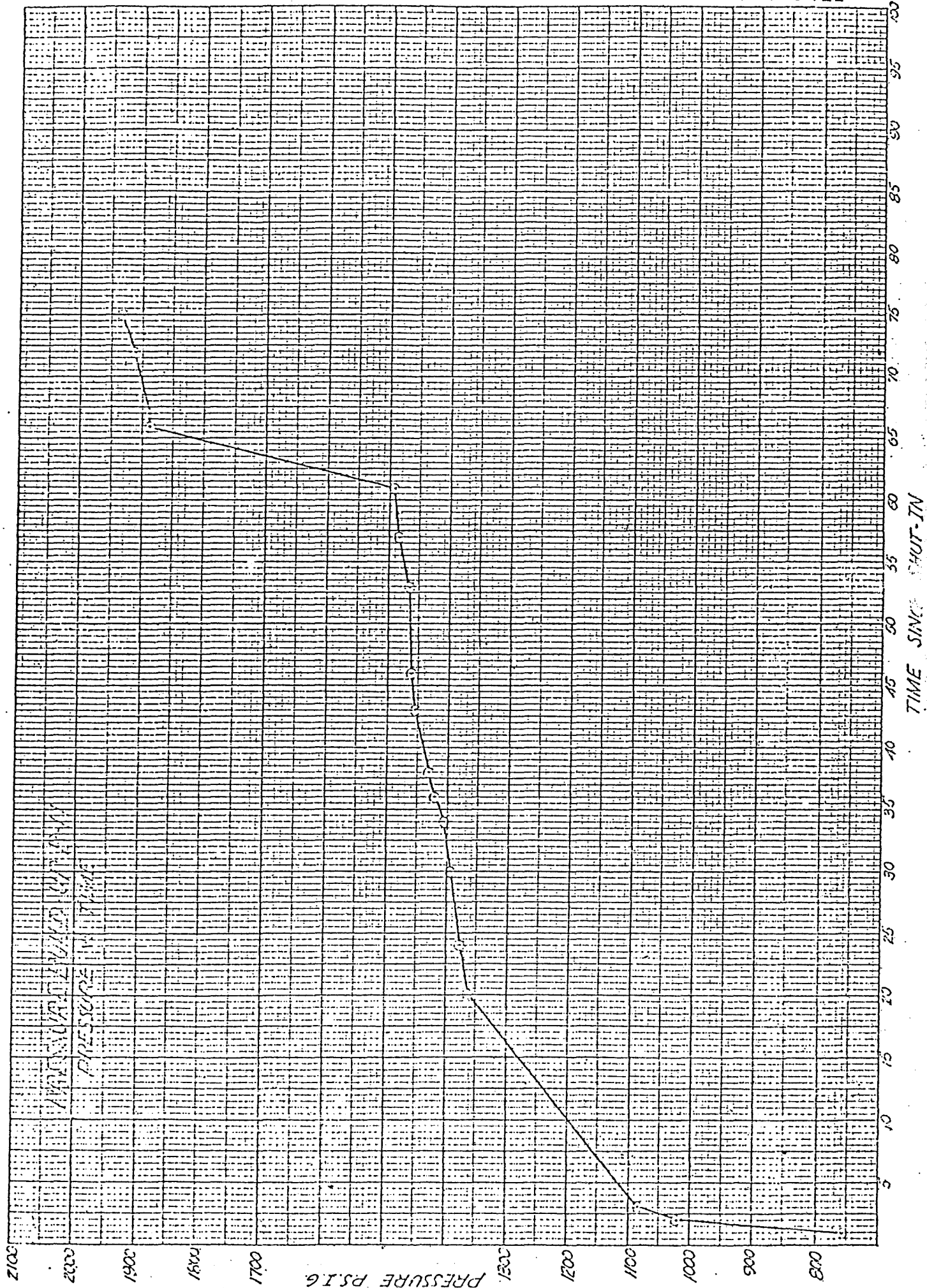
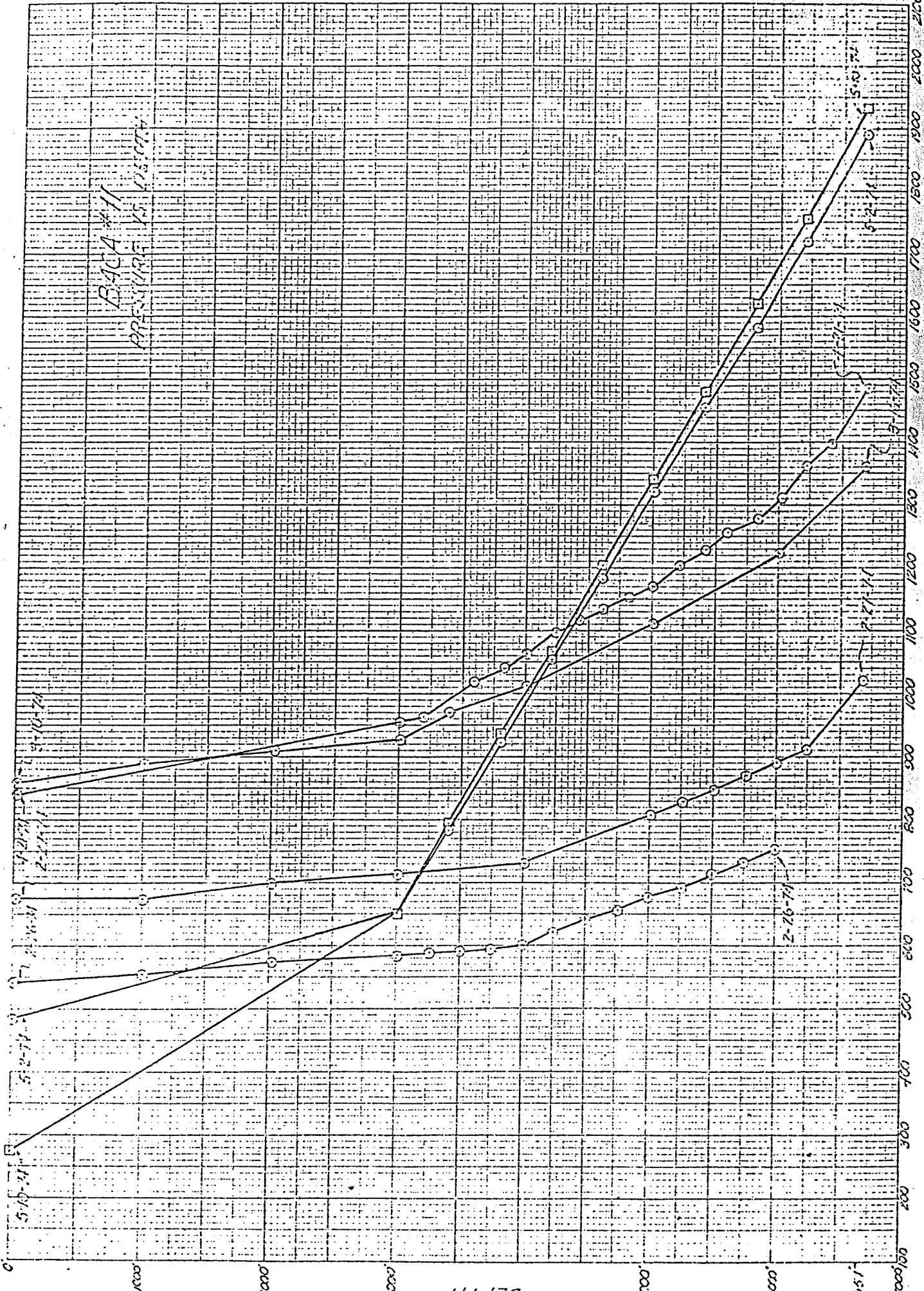


FIGURE VIII



PRESSURE P.S.I.G.

**UNION**

ARCA #

Source	pH	HCO <sub>3</sub> <sup>-</sup> CO <sub>3</sub> <sup>=</sup>	Cl <sup>-</sup>	SO <sub>4</sub> <sup>=</sup>	S <sup>=</sup>	B	As	Ca	Fe	Mg	K	Na	Si	SiO <sub>2</sub>	Li	Cu	Mn	Mo	Ti	S	NH <sub>3</sub>	F	Be	I	Mg
Well	9.0		1618.3	65.7		37	6.6							227	<1.0						15.0				
"			256											125											
"			226											125											
"			257											125											
"			257											135											
"			260											135											
"			236											140											
"			2400	52			2.6				375	1100		375											
Waterline			2300	30		21	12	7	0.2	<1	300	1220		260											
Waterline	7.2	0	180			25	3.6	11	18	0.4	372	180		857											
Waterline	2.2	2	141			<2	0.02	0.2	0.7	0.3	<5	1.0													
Waterline	4.2	0	<1			19	2.6	5.4	0.3	0.2	292	1335													
Waterline	6.5	0	2480																						
Waterline	S ec		74	1200	(JAN. 14, 1977)	20	1.9	6.5	<3	<4.5	312	1400		227											
"	8.6	4.5	2700	35																					

Refer to E.F. #3357, Sept 27, '73

DATA ON 14 SAMPLES

**UNION**

DATE	Source	pH	HCO <sub>3</sub> <sup>-</sup>	CO <sub>3</sub> <sup>2-</sup>	Cl <sup>-</sup>	SO <sub>4</sub> <sup>2-</sup>	S <sup>2-</sup>	B	As	Ca	Fe	Mg	K	Na	Si	SiO <sub>2</sub>	Li	Cu	Mn	Mo	Ti	Se	NH <sub>3</sub>	F	Br	I	NO <sub>3</sub> <sup>-</sup>	Sr
1/5/71		9.5	1924	78	1330	1500		4600	1.5	N.I.	--	N.I.	20	1650		360							15.5				N.I.	
1/18/71		9.4	1345	48	1490	2000		1571	5.5	N.I.	--	N.I.	120	1680		4100							18.0				N.I.	
1/18/71		9.5	2450	75	1500	2880		3000	2.5	Trace	--	N.I.	110	1000		2700							15.5				N.I.	
1/18/71		8.8	549	24	2930	2880		2330	3.5	13.3	--	5.3	210	1830		450						19.3				N.I.		

1/5/71  
1/18/71  
1/18/71  
1/18/71  
1/18/71

FIGURE XI  
UNION



1311  
Water

DATE	Source	P#	MO3	CO2	CI	SO4	S	B	A	Ca	Fe	Mg	K	NO3	Si	Li	Cu	Mn	Ni	Zn	F	Cl	Br	I	NO2	Se
10/17/72	Well	27	400	5710	200	12	12	12	12				280	1400	37						7.20					
"	Steam	74	239	3160	40	127	127	127	3.94				105	1800	207						7.1					
"	Pipe	150	253	2400	40	144	144	144	3.9				115	2000	37						7.20					
"	See head	300	680	2755	30	112	112	112	3.7	0.1	<0.1	<0.1	235	1600	100						7.20					
"	Water line			2800	30					0.6	0.1	0.1	10	100	6											
"	Condenser			13.2	4					1.0	0.37	0.1	25	250	30	10.5					4.23					
11/9/72	Well	6.5	2223	1100	9	9.3	9.3	9.3	1.4				0.3	100	6											
10/26-11/11/72	See ARS 72-35579																									
10/27/72	Separation		93	2280	30	22	22	22	4.2	11	<10	<10	319	1770	1133											
"	"		80	3060	30	21	21	21	3.5	11	<10	<10	331	1780	1264											
"	"		90	1390	10	10	10	10	1.2	6	<10	<10	<1	18	176											
11/7/72	Condenser			3340	10																					
12/20/72	Water line			910																						
1/13/73	Pond			3050																						
"	Condenser			3460																						
"	Water line			3050																						
"	Pond			3440																						
1/13/73	Water line			3440																						
"	Water line			1080																						

Fourth is tested (indicated X)  
<10

\*SILICA may be high. See ARS 72-35579 TABLE 2

<10  
NDC  
NDC  
NDC  
NDC  
NDC  
<10  
<10  
<10



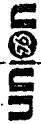
FIGURE XII  
UNION T. H. COMPANY OF CALIFORNIA



DATE	SOURCE	PH	HCO <sub>3</sub> <sup>-</sup>	CO <sub>3</sub> <sup>=</sup>	Cl <sup>-</sup>	SO <sub>4</sub> <sup>=</sup>	S <sup>=</sup>	B	As	Ca	Fe	Mg	K	Na	Si	SiO <sub>2</sub>	Li	Cu	MN	MA	Ti	SR	NH <sub>3</sub>	F	Br	I	NO <sub>3</sub> <sup>-</sup>
1/11/73	Water	8.78	842	414	3310	275		149	3.85	0.6	0.22	4.01	535	2179	50									21.5			
1/11/73	Well	6.35	700	1083	3460	205		160	4.9	1.7	1.85	0.8	500	2160	167								3.9				

CI 7A

FIGURE XIII Union Oil Company of California



DATE	SOURCE	pH	Hardness (ppm)	Ca (ppm)	Mg (ppm)	Fe (ppm)	Al (ppm)	Cl (ppm)	S (ppm)	SO <sub>4</sub> (ppm)	Na (ppm)	Si (ppm)	SO <sub>3</sub> (ppm)	K (ppm)	Cu (ppm)	Mn (ppm)	Ti (ppm)	Sr (ppm)	NH <sub>3</sub> (ppm)
2/22/73	Steam	4.7	C	C	105	0.9	.061	1	0.7	0.1	12	38	21	5					
"	Steam	4.6	C	C	50	0.6	.023	0.4	0.4	0.1	5	25	4.4	5					
"	Water	8.3	54	4.4	3550	30	4.4	3.8	0.4	0.2	262	1963	350	749					
"	"	8.4	55	4.1	3550	27	4.5	3.8	0.3	0.2	348	1950	346	428					
9/16/74	Water	6.9	150	0	3590	24	4	23	<0.1	0.1	483	1905							
9/20/74	Water	6.9	141	0	2850	25	4	25	<0.1	0.1	483	5800							

BACA-13 WATER SAMPLE

12/7/75

pH	8.5
Silica	750 mg/l.
K	278 mg/l.
Na	2000 mg/l.
Mg	<0.2 mg/l.
Ca	5 mg/l.
Sulphates	250 mg/l.
Cl <sup>-</sup>	2890 mg/l.
<u>Alkalinity</u>	
BiCarb.	281 mg/l.
Carb.	97 mg/l.
Boron	23 mg/l.
*Conductivity	9250 micro mho's/cm
Suspended Solids	340 mg/l.
**TDS	8684 mg/l.

\* High conductivity correlates to TDS.

\*\* Majority Na, moderate K.

Incomplete: Needs settleable solids analysis and  
F1<sup>-</sup> analysis.

URC 3 D

To: K. J. Stracke, Santa Rosa

Memo: ARS 73-341M

From: R. N. Wheatley

Date: October 19, 1973

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: BACA 4 (NEW MEXICO) WELL  
WATER AND STEAM ANALYSIS

Supervisor: L. W. Burdett

cc: Library (2)

Patent

A. J. Chasteen

D. J. Christoffersen

J. M. Fraser

H. Hennig

Carl Junker, Big Geysers

G. A. Marsh

Carel Otte, UOC

J. Walker

Non-condensable gas samples and water samples taken at Baca Well No. 4 and dated August 16, 1973, were received at the Research Center on October 1, 1973 for analysis.

These samples represent the steam production line and the water line from the separator. These samples were taken by Mr. Junker into containers prepared by us. Results are shown in the attached table.

### Discussion

The 4.14% CO<sub>2</sub> found in the non-condensable gas phase of the steam line is several times greater than the CO<sub>2</sub> anticipated in the well. (Baca 6 ran about 1%.) Because of this unusually high amount of CO<sub>2</sub>, the sampling capacity of the caustic collection system apparently was exceeded resulting in a low value of 3.84% for total CO<sub>2</sub> which is lower than the value obtained from the non-condensable gas samples. In the future when sampling Baca, the amount of condensate collected in the CO<sub>2</sub> (C-1) sampling bottle should be kept under 100 grams to assure an ample excess of caustic. (100 grams is about a 3/4-inch increase in height of liquid level in the 1-quart bottle.) In the case of this sample, however, the 4.14% non-condensable CO<sub>2</sub> value probably represents most of the carbon dioxide in the stream as the pH was only 4.4 which is low enough to discharge most of the CO<sub>2</sub> into the gaseous phase.

K. J. STRACKE

NOV 14 1973

FIGURE XV

Because barometric pressure was not given with the sampling data, an approximate figure (23 inches of mercury) based on the 9000 foot elevation of the well site above sea level was used in making calculations.

P. M. Whitting

RNW:bjs  
attach. Table 1

Table 1

Baca Well No. 4  
8/16/73

	Steam Line (sampled between 1745 & 1915)	Water Line (sampled between 1745 & 1915)
Non-Condensibles*		
H <sub>2</sub> S, ppm by wt.	180	(gas collected
H <sub>2</sub> S, ppm by mole	99	too small to
CO <sub>2</sub> , % by wt.	4.14 ✓	measure)
CO <sub>2</sub> , % by mole	1.69	
Total Production		
NH <sub>3</sub> , ppm by wt.	2.9	0.6
NH <sub>3</sub> , ppm by mole	3.1 7	0.6
H <sub>2</sub> S, ppm by wt.	213	6.8
H <sub>2</sub> S, ppm by mole	112	3.6
CO <sub>2</sub> , % by wt.	3.84	0.042
CO <sub>2</sub> , % by mole	1.57	0.017
pH	4.4	6.5

\* Traces (<1 ppm) of ethane, propane and hydrogen detected.



To: T. N. Minette, Santa Rosa

Memo: ARS 74-9M

From: R. N. Wheatley

Date: January 7, 1974

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: ANALYSIS OF BACA #4  
STEAM WELL SAMPLES

Supervisor: L. W. Burdett *LB*

cc: Library (2)  
Patent

A. J. Chasteen, Santa Rosa  
D. J. Christoffersen  
J. M. Fraser  
H. Hennig

G. A. Marsh  
C. Otte, UOC  
K. J. Stracke, Santa Rosa  
J. Walker

Baca #4 Samples Taken in November 1973

On November 26, 1973 you submitted the following from the Baca #4 steam well:

<u>Samples</u>	<u>Tests Requested</u>
Water Line 11-9-73, 2:30 p.m.	Na, Fe, Mg, K, Ca, B, As, HCO <sub>3</sub> , CO <sub>3</sub> , pH, Cl <sup>-</sup>
Steam Line 11-9-73, 2:10 p.m.	Na, Fe, Mg, K, Ca, B, As, HCO <sub>3</sub> , CO <sub>3</sub> , pH, Cl <sup>-</sup>
Water Line 10-7-73, 10:45 a.m.	No tests (retain sample)
Steam Line 10-7-73, 10:45 a.m.	No tests (retain sample)
Scale from water muffler pipe, 11-18-73	Emission spect. analysis
Non-condensable gas, 10-7-73, 11-1-73, 11-8-73	Total non-condensable gases
Condensate, 11-9-73	NH <sub>3</sub> , H <sub>2</sub> S, CO <sub>2</sub>

Results of the above testing are shown in Tables 1 through 4. No CO<sub>2</sub> values are given for the condensate as the bottles were leaking and there was no satisfactory way to estimate total condensate collected on which to base CO<sub>2</sub> results.

Because no atmospheric pressure data was supplied at the time of sampling a nominal value of 23.05 inches of mercury, based on altitude, was used in making calculations.

R N Whately

RNW:lq  
Attachments



Table 3

Baca #4. Non-Condensable Gases

	<u>11-1-73</u> <u>12:50 p.m.</u>	<u>11-9-73</u> <u>10:50 p.m.</u>
Methane (ppm wt.)	3.4	2.2
Methane (ppm mol.)	3.8	2.5
Ethane (ppm wt.)	26	22
Ethane (ppm mol.)	16	13
Nitrogen (ppm wt.)	0	0
H <sub>2</sub> S (ppm wt.)	152	150
H <sub>2</sub> S (ppm mol.)	80	79
CO <sub>2</sub> (ppm wt.)	30,390	30,390
CO <sub>2</sub> (ppm mol.)	12,430	12,430
H <sub>2</sub> (ppm wt.)	1.4	1.4
H <sub>2</sub> (ppm mol.)	12.5	12.5

Note: Sample taken 10-7-73 contained mostly air and could not be accurately analyzed.

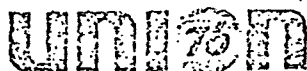
Table 4

Baca #4. Condensate 11-9-73, 10:30 a.m. to 1 p.m.

NH <sub>3</sub> (ppm wt.)	3.1
NH <sub>3</sub> (ppm mol.)	3.3
H <sub>2</sub> S (ppm wt.)	117
H <sub>2</sub> S (ppm mol.)	62

Note:

H<sub>2</sub>S values here are reported lower than in the non-condensable samples. As the condensate represents total H<sub>2</sub>S (condensibles and non-condensibles combined) in the production it appears there may have been some H<sub>2</sub>S lost in sampling or that the sample was not representative. It seems unlikely that the well composition fluctuated to any extent as the 11-1-73 and the 11-9-73 samples were nearly identical in all components.



To: Mr. A. J. Chasteen, Santa Rosa

Memo: ARS 72-315M

From: J. A. Baur

Date: October 26, 1972

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: ANALYSIS OF BACA #6  
NON-CONDENSABLE GASES

Supervisor: L. W. Burdett *LWB*

cc: Library (2)  
Patent  
C. F. Budd

J. M. Fraser *JMF*  
J. Walker  
R. N. Wheatley

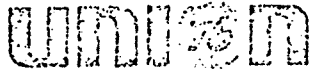
The sample of non-condensable gas from the Baca #6 steam well, New Mexico, dated 10/14/72, and submitted by you for analysis on 10/19/72 was analyzed by mass spectrometry with the following results:

<u>Compound</u>	<u>Mole %</u>
Methane, CH <sub>4</sub>	0.0
Ethane, C <sub>2</sub> H <sub>6</sub>	0.1
Hydrogen, H <sub>2</sub>	0.0
Nitrogen, N <sub>2</sub>	0.0
Hydrogen sulfide, H <sub>2</sub> S	0.6
Carbon dioxide, CO <sub>2</sub>	99.3

Average molecular weight = 42.0

The above results are calculated exclusive of air and water, both of which were very small.

JAB:bjs



To: Mr. K. J. Stracke, Big Geysers

Memo: ARS 72-355M

From: J. A. Baur & R. N. Wheatley

Date: December 22, 1972

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: BACA 6 GEOTHERMAL WELL SAMPLING

Supervisor: L. W. Burdett *lwb*

cc: Library (2)

Patent

A. J. Chasteen, Santa Rosa

D. J. Christoffersen

J. M. Fraser *JMF/lwb*

G. A. Marsh

Carel Otte, UOC

J. Walker

Summary

Tests 2 and 3 of the Baca 6 geothermal well showed the steam phase to contain about 1% CO<sub>2</sub>, about 70 ppm H<sub>2</sub>S and 2 to 3 ppm NH<sub>3</sub>. The water condensate from the separator consisted of about 0.5% solids composed primarily of Na, K, Cl and SiO<sub>2</sub>. Significantly, about 4 ppm arsenic was also present.

.....

The second flowing (Test 2) of Baca 6 geothermal well at Jemez Springs, New Mexico, was sampled on October 26-27, 1972. The samples were brought back to Brea for analysis. The third flowing of the same well was sampled by Mr. Carl Junker on November 7-11, 1972. These samples were sent to Brea for analysis shortly after sampling.

Samples of the condensed steam, water from the separator and condensate taken directly at the wellhead prior to separation were analyzed for % non-condensibles, pH, carbon dioxide, ammonia and H<sub>2</sub>S. In addition, condensed steam and water line samples from the separator were analyzed for metals, silica, and anionic constituents. Also, non-condensable gases were analyzed by the mass spectrometer. The low pH (~4.3) of the condensed steam can be attributed to the high amount of carbonic acid present.

Results are shown in Tables 1 & 2.

DiscussionHigh CO<sub>2</sub> Confirmed by  
Condensate Analysis

The high CO<sub>2</sub> content in the non-condensibles was confirmed by the values obtained by the analysis of the condensed steam which includes both the total and non-condensibles. The CO<sub>2</sub> total was generally higher than the CO<sub>2</sub> obtained in the non-condensibles because of the CO<sub>2</sub> distribution between the two phases which is considered to be a function of pH and temperature.

Non-condensable Gases Are  
Almost All CO<sub>2</sub>, Some H<sub>2</sub>S

In all non-condensable gas samples taken from the steam line the CO<sub>2</sub> was approximately 99.4 mol % with about 0.5% H<sub>2</sub>S and trace amounts of ethane and propane. A non-condensable gas sample taken at the wellhead also contained 0.16 mol % argon.

James A. Bair  
R N Whalley

JAB/RNW:bjs  
attach. Tables 1 & 2

Table 1

Analysis of Baca 6 Well

<u>Date</u>	<u>Time</u>	<u>Sample</u>	<u>pH</u>	<u>% Non-Condensibles</u>	<u>NH<sub>3</sub> ppm</u>	<u>H<sub>2</sub>S ppm</u>	<u>CO<sub>2</sub> ppm</u>
10/26/72	0940	Steam condensate		1.09			
10/26/72	1330	" "	4.3	1.06	2.7	69	10,716
10/26/72	1230	Water from separator			0.5	3.4	71
10/26/72	1630	" " "	7.7		0.3	5.4	93
10/27/72	0920	" " "	7.85		0.5	6.5	103
10/27/72	0950	Steam condensate		0.86	2.4	71	11,284
10/27/72	1030	" "	4.3	0.87	2.4	76	11,800
10/27/72	1050	Wellhead condensate	5.35	0.19	1.2	12.4	1,857
11/9/72	1505	Water from separator			0.4	3.4	78
11/9/72	1525-1537	Steam condensate			2.1	73	9,000
11/9/72	1548-1600	Wellhead condensate			1.8	43	6,080
11/11/72	0910-0925	<i>Still</i> " "			2.3	76	9,319
11/11/72	0950-1000	<i>Wellhead</i> " "			1.7	53	5,281
11/11/72	1012-1020	Water from separator			2.8	3.8	162

Table 2

Analysis of Dissolved Solids From Baca 6 Well  
(All Values Reported in mg/liter)

<u>Date</u>	<u>Time</u>	<u>Sample</u>	<u>Total Dissolved Solids</u>	<u>Na</u> <u>Sodium</u>	<u>K</u> <u>Potassium</u>	<u>Li</u> <u>Lithium</u>	<u>Si</u> <u>Silica*</u>	<u>As</u> <u>Arsenic</u>	<u>Ca</u> <u>Calcium</u>	<u>Cl</u> <u>Chloride</u>	<u>S</u> <u>Sulfate</u>	<u>CO<sub>3</sub></u> <u>Carbonate</u>	<u>CO<sub>2</sub></u>	<u>Boron</u>	<u>Filterable Solids</u>	
10/27/72	0850	Water from separator	5980	1770	319	26	1133	4.2	11	2980	30	93	-	22	-	Fe, Mg, Sr each <10
10/27/72	1000	Steam condensate	14										242			
11/7/72	1545	Water from separator	6230	1780	331	29	1084	3.5	11	3060	30	80	-	21	6100	Fe, Al, Sr, Mg each <10
11/7/72	1455	Steam condensate	18	0.3	<1					<3	<10		35			
11/7/72	1615	Wellhead condensate	2950	760	153	11	476	1.2	6	1390	10	90	-	10	2815	Fe, Al, Cr, Mg each <10

\* silica results may be high as samples were taken in glass bottles rather than plastic containers

UIM 76 M

To: Mr. K. J. Stracke, Big Geysers

Memo: ARS 73-74M

From: R. N. Wheatley

Date: March 7, 1973

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: BACA 6 GEOTHERMAL WELL  
SAMPLING ON 1/13/73

Supervisor: L. W. Burdett <sup>LWB</sup>

cc: Library (2)

Patent

A. J. Chasteen, Santa Rosa

D. J. Christoffersen

J. M. Fraser <sup>JM</sup>

Carl Junker, Big Geysers

G. A. Marsh

Carel Otte, UOC

J. Walker

Samples of non-condensable gases, separator water, wellhead water, and steam line condensate from Baca 6 (New Mexico) steam well were taken by Mr. Carl Junker on 1/13/73, and forwarded to the Research Center for analysis. Results are shown below.

Water and Condensate Samples

	<u>Wellhead</u> 1/13/73	<u>Separator Water</u> 1/13/73	<u>Steam Condensate</u> 1/13/73
CO <sub>2</sub> , ppm by wt.	5750	77.5	10,070
H <sub>2</sub> S, " " "	61	2.9	71
NH <sub>3</sub> , " " "	1	0.1	1.6

Non-Condensable Gases in Steam Line

	<u>ppm/wt</u>	<u>ppm on a mole basis</u>
Ethane	4.7	2.8
Propane	5.2	2.1
Hydrogen	0.6	5.4

K. J. Stracke

MAR 21 1973

R N Wheatley

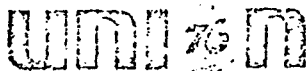
RNW:bjs



A. J. CHASTEEN

MAR 27 1974

Union Oil Company of California  
Union Research Center, Brea, California



To: T. N. Minette, Santa Rosa

Memo: ARS 74-82N

From: R. N. Wheatley

Date: March 19, 1974

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: COMPOSITION OF BACA #11  
12/22/73 SAMPLES

Supervisor: L. W. Burdett *LWB*

cc: Library (2)

Patent

A. J. Chasteen, Santa Rosa

D. J. Christoffersen

J. M. Fraser *JMF*

H. Hennig

G. A. Marsh

C. Otte, UOC

V. E. Suter, Santa Rosa

J. Walker

On February 11, 1974, two gas samples, four ammonia and H<sub>2</sub>S collection bottles, two steam condensates and four water line samples, all taken from Baca Well #11, were received for analysis. Results are shown below.

Since these samples were received at the Research Center about seven weeks after sampling, there has been ample time for their compositions to have changed. This would reduce the reliability and value of analytical results.

Sample: Baca #11, gas taken 1410, 12/22/73, ammonia & H<sub>2</sub>S sampled 1600-1645, 12/22/73.

Non-Condensable Gas Analysis

	<u>ppm (wt.)</u>	<u>ppm (mole)</u>
Methane	0.0	0.0
Hydrogen	2.9	25.5
Nitrogen	218.9	140.6
H <sub>2</sub> S	241.0	127.3
CO <sub>2</sub>	28,892.	11,817.
Argon	0.0	0.0

Total Compositional Analysis

	<u>ppm (wt.)</u>	<u>ppm (mole)</u>
NH <sub>3</sub>	2.8	3.0
H <sub>2</sub> S	305.1	161.2
CO <sub>2</sub>	(not sampled for total analysis)	
Non-condensable gas, wt. %	2.86	
Non-condensable gas, vol. %	1.18	

Water Line & Condensate Analysis  
(all values reported in mg/liter except pH)

<u>Test/Sample</u>	<u>Steam Line</u> 12/22/73 2:10 P.M. "Center Tap"	<u>Steam Line</u> 12/22/73 2:15 P.M. "Center Tap"	<u>Water Line</u> 12/22/73 1:07 P.M.	<u>Water Line</u> 12/22/73 3:10 P.M.	<u>Steam Line</u> 12/22/73 3:25 P.M.	<u>(No Ident.)</u> 12/22/73 4:00 P.M.
pH	4.7	4.6	8.3	8.4		
Na	58.	25	1920	1930		
Fe	0.7	0.4	0.4	0.3		
Mn	0.1	0.1	0.2	0.2		
Mg	12	5	360	340		
Ca	1	0.4	32	32		
B	0.9	0.6	30	27		
As	.061	.023	4.6	4.5		
HCO <sub>3</sub> <sup>-</sup>	0	0	24	35		
CO <sub>3</sub> <sup>=</sup>	0	0	48	41		
Cl <sup>-</sup>	105	50	3550	3550	50	150.
Si	10	4.4	350	340		
SiO <sub>2</sub>	21	9.4	749	728		

RN Wheatley

RNW:bjs

V. E. SUTER  
AUG 28 1974



To: V. E. Suter, Santa Rosa

Memo: ARS 74-265M

From: R. N. Wheatley

Date: August 23, 1974

Division: Petrochemical, Analytical  
and Corrosion Research

Project: 267-61011

Subject: BACA #11 SAMPLE OF 7/24/74

Supervisor: L. W. Burdett <sup>LWO</sup>

cc: Library (2)

Potent

A. J. Chasteen, Santa Rosa

D. J. Christoffersen

J. M. Fraser <sup>JWZ</sup>

J. C. Jones, Los Alamos

J. A. Klotz

Carel Otte, UOC

J. Walker

Samples taken from Baca well #11 on 7/24/74 were received at the Research Center for analysis about 8/9/74. These comprised one bomb containing non-condensable gases and five bottles of condensate for H<sub>2</sub>S, NH<sub>3</sub> and CO<sub>2</sub> analysis. Results are shown below.

Baca #11, 7/24/74, Total Compositional Analysis

	<u>ppm, wt.</u>	<u>ppm, mole</u>
Methane	2.6	2.9
Hydrogen	2.6	23.3
Nitrogen	381	245
Ammonia	2.9	3.1
Hydrogen Sulfide	486	257
Carbon Dioxide	43,470	17,780
Argon	0	0
Mol. wt. =	43.55	
Non-condensibles =	3.46%	

Because of the high amount of CO<sub>2</sub> in Baca samples it is recommended that a lesser amount of condensate be collected in the first CO<sub>2</sub> absorption bottle. In this sampling about 110g was collected which considerably taxed the system causing some carryover into the second bottle. About



To: T. N. Minette, Santa Rosa

Memo: ARS 75-61M

From: R. N. Wheatley

Date: February 20, 1975

Division: Petrochemical, Analytical  
 and Corrosion Research

Project: 267-61511

Subject: BACA WELL #13 CONDENSATE  
~~10/15/74~~

Supervisor: D. J. Christoffersen

1/15/75

cc: Library (2)

Patent

L. W. Burdett

J. M. Fraser

J. Jones, Jemez Springs, N.M.

Carel Otte, UOC

J. Walker

The compositional analysis of the steam from Baca Well #13 sampled on October 15, 1974 and received at the Research Center on January 24, 1975 is shown below.

Baca Well #13

~~10/15/74~~ 1/15/75

	Non-Condensable Gas Sample #1		Non-Condensable Gas Sample #2		Total Sample	
	ppm by wt.	ppm by mol	ppm by wt.	ppm by mol	ppm by wt.	ppm by mol
	CH <sub>4</sub>	2.8	3.1	10	11	
C <sub>2</sub> H <sub>6</sub>	20	12	40	24		
H <sub>2</sub>	0	0	0	0		
N <sub>2</sub>	109	70	0	0		
CO <sub>2</sub>	37,584	15,371	38,865	15,896		
Argon (in excess of air)	0	0	0	0		
NH <sub>3</sub>					2.6	2.7
H <sub>2</sub> S					197	104
Non-Condensibles, Wt. %	3.67		3.77			
Non-Condensibles, Vol. %	1.54		1.58			
pH of Condensate	6.4					

FIGURE XVIII

Discussion of Results

Total CO<sub>2</sub> is not reported as the values obtained were considerably lower than the non-condensable CO<sub>2</sub> figure. This indicates that the absorbing solution bottles did not have the capacity to handle all of the CO<sub>2</sub>. We note that about 90 gms of condensate was collected which was perhaps too much. About 40 to 50 gms or about 3/8" increase in sampling bottle level should be sufficient. Also, if there are reagent grade NaOH pellets available at the Baca laboratory, it would improve the absorbing capacity of the C-1 bottles to add 10.0 gms of NaOH to each. If this change is made, please note this fact on the work sheets with sampling data so that we may account for this additional bottle weight.

Because atmospheric pressure was not included on the sampling work sheet, we assumed a pressure of 21 inches of mercury, based on Baca altitude, in making the calculations.

~~The three-month interval between sampling time and available for analysis, we feel, is too long to obtain reliable data. The samples should be received within 2 to 3 weeks, at most, of the sampling date.~~

*Not correct*  
Sample was taken 1/15/75 ; analyzed 1/24/75

JOHN D. HARTZ

APR 16 1975

R. M. W. Licetty

RNW:bjs

O. WHITESCARVER

APR 5 1975

April 4, 1975

TO: D. E. Pyle  
Vane Suter  
C. F. Budd

FM: T. N. Minette *Tm*

RE: Well Bore Scale Removal

I have had some thoughts on well bore scale removal that should be expanded upon by someone here in the U.S. now that I am being transferred.

There are two possible techniques which can be looked at, both based on lubricating small continuous work strings into the well with relatively inexpensive and simple surface equipment that are now either available or can be made by modifying existing equipment to fit our specific needs.

#### CONTINUOUS SUCKER ROD

Originally I felt that we could lubricate in a continuous sucker rod, as manufactured by Corod, Inc., with some type of scraper attached that could cut out the scale using techniques used to remove well bore paraffin. This system should work if the scale is not allowed to grow too thick. Perhaps it could be run on a periodic cycle such as two weeks. There would be no need to shut the well in, however, reduced rates may be desirable.

Corod, Inc. is a Canada Company with U.S. headquarters in Odessa, Texas. The advertizing sheet from the Composite Catalog is attached. This company manufactures both the rods and the service unit. The rods are lubricated in and out using hydraulically operated gripper tracks. I do not know what the maximum pressure allowance is but it should be sufficient for geothermal work.

Union Oil used continuous rod systems on some problem wells in Wyoming with very good success. The problems they had were due to the lack of sufficient service units for routine pump changes.

FIGURE XIX

D. E. Pyle  
April 4, 1975

Page 2

Harold Simpson, the Operations Manager in Casper, is about the only one left in Casper that is familiar with the project. He could provide the names of engineers that were on the job.

My conception of the system would be to use a large diameter lubricator that would handle a scraper head large enough for 9-5/8" casing. The head would have retractable blades that would hinge up so they would pass through the scale and then cut coming up the hole. If the blades stuck then additional pull would allow them to fold down. This is similar to paraffin knives now being used. The cutting head would have to be hollow to allow flow through and still provide the necessary outside diameter.

I think this system has merit and should be considered. It is simple and inexpensive. The well would not have to be killed and perhaps not even restricted. A production field set up on a scheduled cutting routine could prevent severe problems from ever developing.

#### CONTINUOUS TUBING STRING

The second basic method and the one that provides for the most variations is the use of a continuous retrievable tubing string such as now used by Nowsco nitrogen well service. This tubing comes in both 3/4" and 1" in diameter and can be lubricated into the well in the same manner as the continuous sucker rod string.

This system has been used to kick off geothermal wells on numerous occasions with no problems. The tubing is retracted very easily. In case of damage it can be repaired with heliarc.

Nowsco is presently using this system along with a small dynamo drill to drill out plugged tubing. They are also using the tube to jet remove scale from tubing and to jet notch (with sand) casing. Incorporating nitrogen with water provides very high nozzle velocities; however, in our case, we may be able to utilize flashed clean water as the jetting fluid.

This system really allows one's imagination to run wild. Herb Maxom with Nowsco in Bakersfield is up to date on new ideas and has a lot of ideas on uses himself. He told me that the president of the company was its former chief engineer and really is an innovative man.

D. E. Pyle  
April 4, 1975

Page 3

Their running equipment is made by Bowen, their sister company, and sells for about \$100,000 without tubing. The unit is similar to Corod's but does not require a mast unless the height becomes too great in which case they are developing a telescopic mast unit. A Bowen ad is attached showing a drawing of the unit.

It is my feelings that one of the two systems can be developed to meet our requirements. Neither is complex nor expensive. I believe that they can be used either in the U.S. or in the Philippines with proper training of personnel. Nowsco, in fact, has overseas service and could be contacted about providing contract services in the Philippines.

These systems provide another method of scale control not previously considered and should be developed on parallel tracts with the chemical method. I see no reason why some method along these lines cannot be made to work.

TNM/jd  
Enc.

cc: Stephen Pye  
Jerry Jones  
Olin Whitescarver



# COROD®

IN U.S.A.:

COROD INCORPORATED  
P. O. Box 313,  
Odessa, Texas 79760.  
Phone (915) 332-2808

MANUFACTURING LTD.  
Box 5210, Postal Station C,  
Edmonton, Alberta, Canada.  
Phone (403) 474-1151

## CONTINUOUS ROD

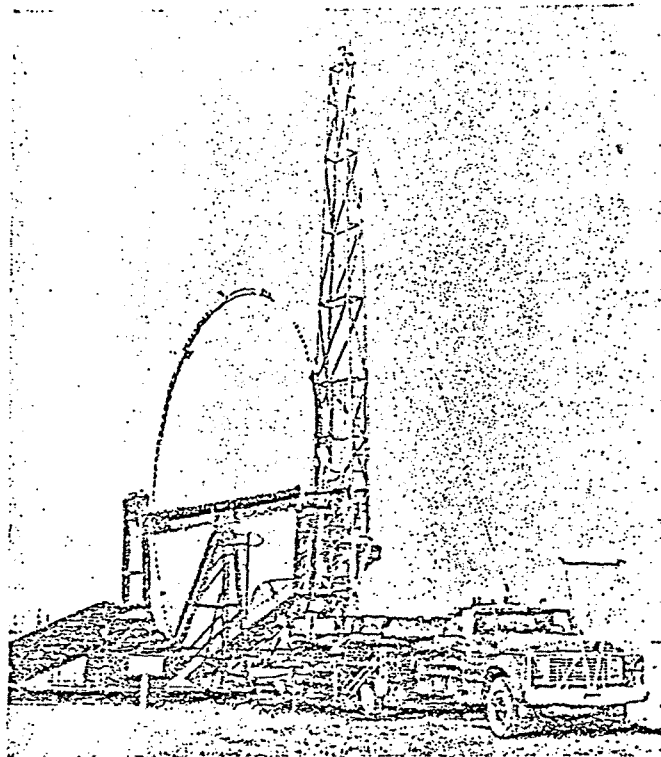
Corod is a one piece sucker rod, computer designed and manufactured to well lengths to meet particular well conditions, taking into account depth, well fluid, pump size, P.D., S.P.M., stroke length, corrosion and other relevant factors. Tapered strings are standard in Corod, in 1/16" increments.

Table 1 and 2 show typical mechanical properties and chemical analysis of the two grades of steel used for the manufacture of Corod.

Corod is transported to the wellsite coiled (without deformation or permanent set) in a transport reel. Servicing is handled by a portable folding service reel carried on Corod service rig.

Installation and servicing of Corod is handled by a Corod service unit. The service unit is basically a hydraulic driven unit of tracks with plastic-aluminum composite inserts which grip the rod or tubing by friction. The inserts are of a harder material than the rod or tubing, eliminating hard metal-to-metal contact. The pulling units are typically designed for a peak pull of 50,000 lbs., with normal pulling installation speeds of 80-125 feet per minute depending on field well conditions.

The Corod service units are designed in an interchangeable modular configuration. The configurations consist of a skid mount, a skid mount (with or without turn-table) or a turn-table configuration of skid mounted turn-table and skid mounted on a semi-trailer, or with additional subframe for off-shore operations. With all configurations, the units are standardized, (pumps, power pack, hydraulics, etc.)



Corod Service Unit at Wellsite

## ADVANTAGES OF COROD.

With Corod there are no couplings or pins to fail with increments and tapered string design the strings weigh less with increased strength (see Table 1 and 2) which results in reduced maximum polished rod loads with the advantages of couplings a larger rod can be used in small tubings (see Table 3). The use of smaller tubing provides for savings in new completions, as well as increased production in completed wells with small tubing.

The elimination of couplings reduces friction between the rod and tubing in both straight and directional wells. This results in higher velocity and facilitates faster pumping rates. The total system results in less tubing wear, no excessive torque makeup, ideally balanced tapers, minimal power and rig costs, reduced costs on new completions,

65-85% fewer failures, minimal horsepower requirements, reduced crooked hole problems, use of smaller tubing, elimination of paraffin scrapers (no couplings thus less turbulent flow more laminar flow).

Parted Corod can be repaired in the field using a specially developed shaped charge welding technique, without removing the rod from the wellsite.

Complete descriptive literature of system and equipment as well as case histories available upon request.

TABLE #1 TYPICAL MECHANICAL PROPERTIES—HIGH TENSILE (API GRADE D)

Grade	1000 PSI Yield	1000 PSI Tensile	%-2" Elongation	In Area Reduction	Hardness Brinell
CD-100	120	135	32	60	250
CD-100	120	135	30	60	255

TABLE #2 TYPICAL CHEMICAL ANALYSIS

Steel	C.	Mn.	P.	S.	Si.	Ni.	Mo.	V.
4150	0.29	0.75	0.016	0.022	0.25	1.70	0.26	0.003
1335	0.33	1.25	0.016	0.025	0.30	0.12	0.030	0.233

TABLE 3—ROD—TUBING COMBINATIONS

Maximum Corod Size	Maximum Sucker Rod Size	Tubing Size
3/8"	...	1.5" I.D.
1/2"	3/8"	2 1/8" O.D.
1 1/8"	3/4"	2 1/2" O.D.
1 1/2"	1"	2 3/4" O.D.
1 3/4"	1 1/4"	3 1/2" O.D.
1 7/8"	1 1/2"	4 1/2" O.D.

## BOWEN TUBING INJECTORS

**BOWEN CONTINUOUS STRING TUBING INJECTORS** are self-contained, speedy workover units which are designed to perform a variety of operations, in depths up to 15,000 feet. Units are available for ½" o.d. tubing thru 1.315" o.d. tubing.

These units are used for many service operations, including—perforating, drill stem testing, acidizing and fracturing, lost-circulation remedies, corrosion control and atomized acid techniques, nitrogen drilling, pressure testing of tubular goods and vessels, cementing, cleanout operations, sand bridge removal, storm valve recovery, insertion of kill strings, fishing for wire line tools, and many other applications.

Almost any fluid or gas required to work over or service wells can be pumped thru these units successfully.

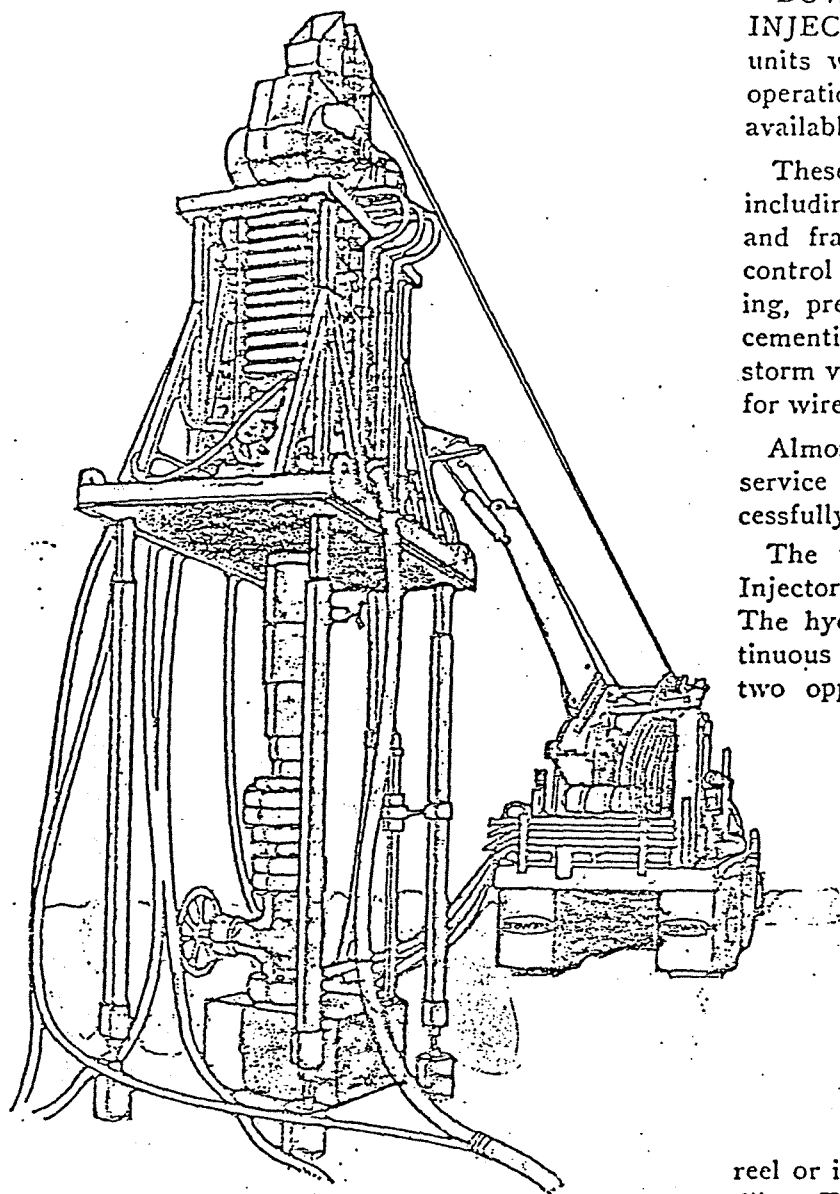
The two major components of Bowen Tubing Injectors are the Tubing Injector and the Reel Unit. The hydraulically powered Injector feeds the continuous work string into the wellhead by means of two opposed, endless, rotating traction members.

The powered reel holds the spooled work string. The inboard end of the string is connected to the hollow shaft of the reel which allows fluid or gas to be pumped thru the string via a swivel connection.

The two basic units; Injector and Reel may be mounted on a skid or trailer together or may be separately skid-mounted to facilitate offshore handling. The necessary power plant for the Reel and the Injector may be mounted on the same unit with the reel or it may be separately mounted for easy handling. The controls for both the Reel and Injector are usually grouped as a single unit with the power plant.

To operate, the Injector Unit is spotted on or above the wellhead and control equipment. The Reel is set some 15 to 50 feet from the wellhead. The tubing is brought from the reel in a smooth-arc loop and thence thru the Injector and into the well through appropriate pressure retention and control equipment.

Depending on the specific unit, workstring speeds up to 140 feet per minute may be attained, compared to the usual 10 to 15 F.P.M. using a conventional rig. Complete specifications and quotations will be sent on request.



**BOWEN CONTINUOUS STRING  
TUBING INJECTOR UNITS**

INJECTOR MODEL	5M	5M	8M	12M	30M
<b>TUBING:</b>					
O.D.—Inches	½	¾	¾	1	1.315
Wall Thickness—Inches	0.049	0.049	0.049	0.065	0.133
Weight—Lbs./1000 Ft.	236	466	456	648	1,530
Min. Tensile Strength—Lbs.	4,200	8,250	8,250	11,450	25,250
Min. Burst Press.—PSI	12,000	8,000	8,000	8,600	12,000
<b>TUBING INJECTOR:</b>					
Thrust Capacity—Lbs.	5,000	5,000	8,000	12,000	30,000
Max. Speed—Ft./Min.	135	135	140	100	75
Working Depth—Ft.	12,000	6,000	12,000	12,500	12,000
<b>REEL CAPACITY—Linear Ft.</b>	12,000	8,000	12,000	12,000	15,000