Conf-8210125
UC66, UC66a through
UC66j

CONF-8210125-Suppl.-3

CONF-8210125--Suppl.

DE83 009736

GEOTHERMAL PROGRESS MONITOR

Special Supplement

Proceedings of the Geothermal Program Review
October 25-26, 1982
Washington, D.C.

U.S. Department of Energy
Assistant Secretary for Conservation and Renewable Energy
Division of Geothermal and Hydropower Technologies
Washington, D.C. 20585

APPENDIX B - Presentation 2

Topic: Reservoir Stimulation

Speaker: Bob Hanold (LASL)

DISCLAIMER

GEOTHERMAL WELL STIMULATION PROGRAM

R. J. Hanold, Los Alamos National Laboratory

Introduction

The stimulation of geothermal production wells presents some new and challenging problems. Formation temperatures in the 275-550°F range can be expected and the behavior of fracturing fluids and fracture proppants at these temperatures in a hostile brine environment must be carefully evaluated in laboratory tests. To avoid possible damage to the producing horizon of the formation, the high-temperature chemical compatibility between the _in situ_ materials and the fracturing fluids, fluid loss additives, and proppants must be verified. In geothermal wells, the necessary stimulation techniques are required to be capable of initiating and maintaining the flow of very large amounts of fluid. This necessity for high flow rates represents a significant departure from conventional oil field stimulation.

The objective of well stimulation is to initiate and maintain additional fluid production from existing wells at a lower cost than either drilling new replacement wells or multiply redrilling existing wells. The economics of well stimulation will be vastly enhanced when proven stimulation techniques can be implemented as part of the well completion (while the drilling rig is still over the hole) on all new wells exhibiting some form of flow impairment.

Proppants

Proppants are an important aspect of hydraulic fracturing because they help retain the fracture conductivity created by the injected high-pressure fracturing fluids. To obtain this high conductivity, a large granular proppant is injected along with the fracturing fluid and deposited in the fracture. This material must be strong enough to maintain a high permeability when subjected to the formation closure stresses. Although sand is generally used as a proppant, it is not strong enough to withstand the conditions in geothermal wells at elevated temperature. Figure 1 shows the effect of temperature and closure stress on common Brady frac sand (20/40 mesh). Crushing starts below 4,000 psi at room temperature and begins between 2,000 and 3,000 psi at elevated temperatures. At 10,000 psi closure stress, only

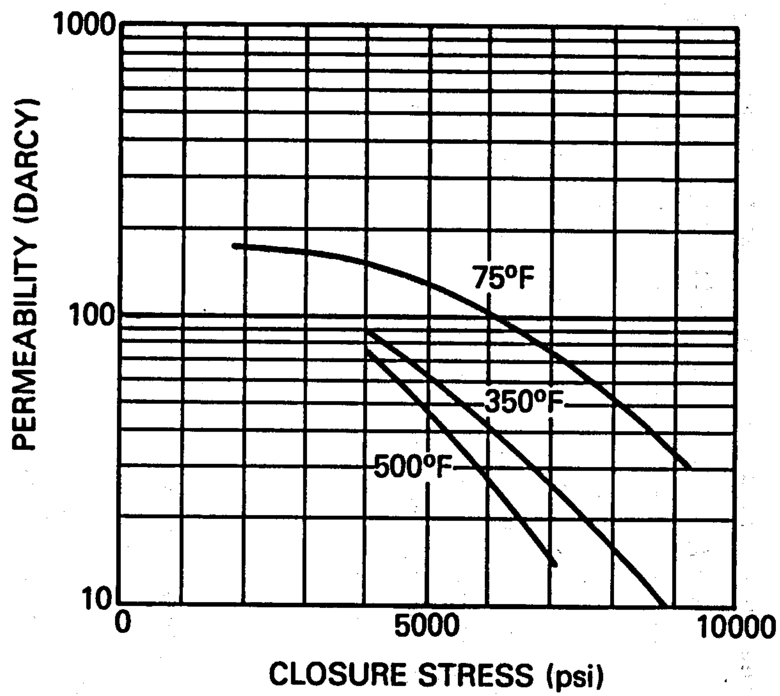


Figure 1. Temperature and Closure Stress Effects on 20/40-mesh Brady Frac Sand.

a fine powder is left and this can damage a high closure stress well rather than stimulate it.

The strongest and highest permeability proppant tested to date is Resin Coated Bauxite. The core of this proppant is composed of many small particles of bauxite sintered together at high temperature to allow some deformation before crushing. The core is covered with an uncured resin that polymerizes at elevated temperatures to form a cohesive high strength outer layer. This cohesive layer bonds the proppant pack together and minimizes sand and proppant flowback during subsequent well production. This proppant exhibits almost no temperature sensitivity or permeability decrease under load. Sintered Bauxite proppant, supplied by the Carborundum Company, yielded a permeability only slightly lower than that of the Resin Coated Bauxite. Temperature sensitivity was also very low and only a slight decrease in permeability is noted at the highest closure stresses resulting from particle repacking and slight crushing. These experimental results are presented in Figure 2 as a function of closure stress at 350°F along with the data from Resin Coated Sand proppants. Resin Coated Sand uses a conventional frac sand core covered with an uncured resin analagous to the Resin Coated Bauxite. The Resin Coated Sand has low temperature sensitivity, a permeability approximately 40% lower than that of the Carborundum Company-supplied Sintered Bauxite, and relatively little permeability change over the range of closure stresses. The superior permeability of all these man-made proppants at high temperatures and high closure stresses makes them the logical choice over conventional frac sands for geothermal well service.

Permeability retention as a function of time must also be considered in evaluating a proppant's ultimate downhole performance. Using a modified linear flow cell, 50-hr tests were performed at a temperature of 350°F with a constant closure stress of 5,000 psi. Sintered Bauxite, Resin Coated Sand, Ottawa frac sand, and Brady frac sand of 20/40 mesh were tested under these conditions. Upon completion of the 50-hr tests, an examination of the proppants showed no change in the Sintered Bauxite or Resin Coated Sand, but both frac sands contained over 30% fines and were obviously not suitable as proppants under these conditions. These results are summarized in Figure 3 where dynamic permeability loss with time indicates crushing, chemical degradation, or movement of fines within the proppant pack.

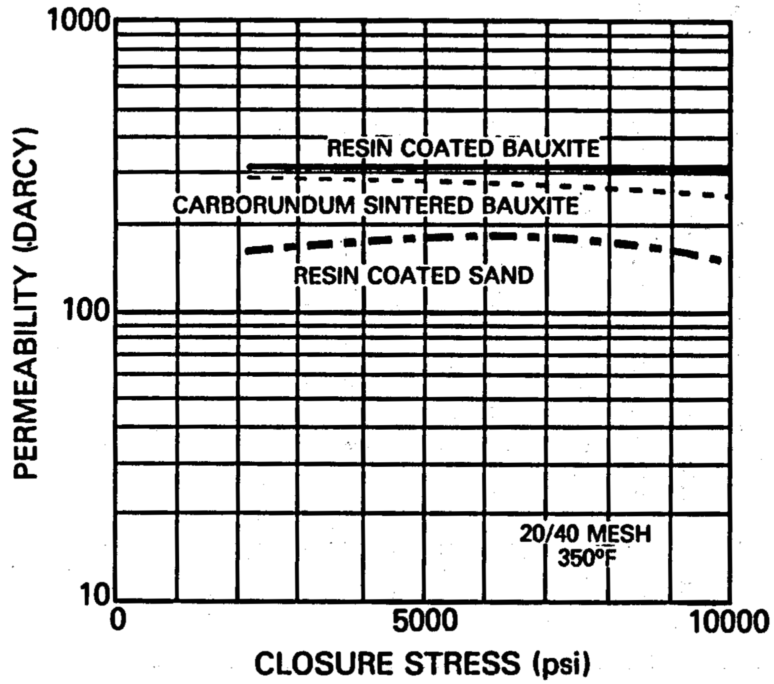
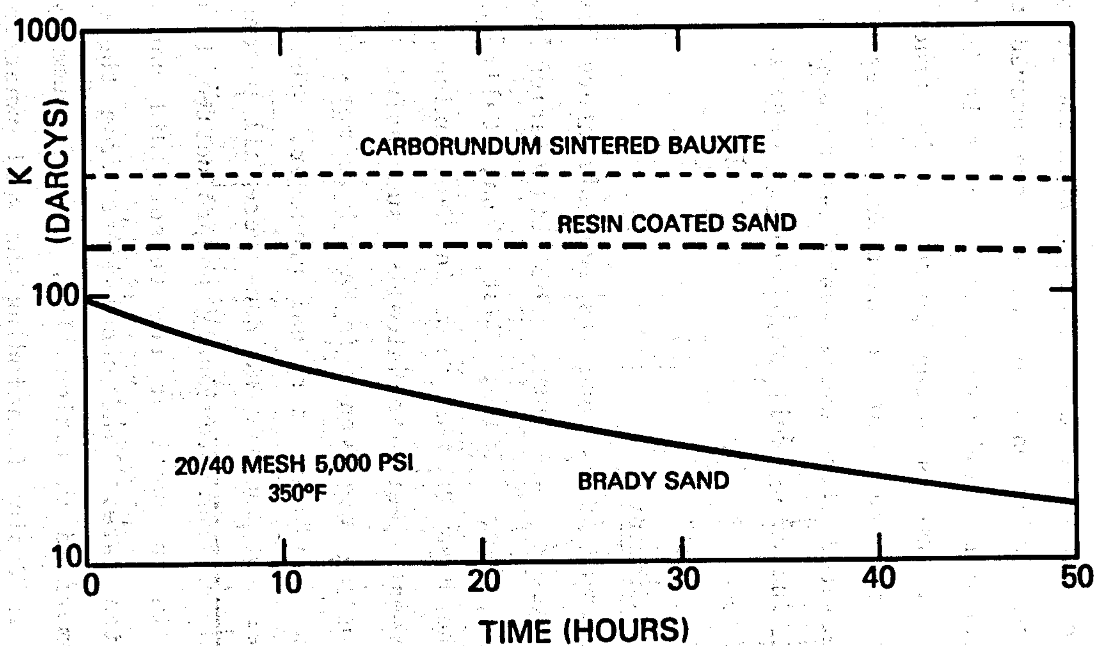


Figure 2. Permeability vs. Closure Stress for Temperature-Insensitive Proppants.



<u>Figure 3</u>. Permeability Retention with Time at $350^{o}F$ and 5,000 psi Closure Stress.

Site Selection

In selecting candidate reservoirs and wells, the Geothermal Well Stimulation Program was influenced by many contributing factors. In addition to the obvioius technical considerations, the program evaluated cost-sharing arrangements provided by the well owner to conserve program funds and the potential impact that effective stimulation could have on the future commercial development of the field. The reservoirs chosen for field stimulation treatments are listed in Table I along with the primary considerations for their selection. While each of these sites proved to be an excellent choice from a technical stand-point, it did result in five of the seven field stimulation treatments being performed in fracture dominated reservoirs. Only the two treatments at East Mesa addressed the very significant problems associated with low permeability regions in matrix-type producing formations, including well skin damage resulting from drilling and completion operations.

Field Stimulation Treatments

Republic Geothermal, Inc., and its subcontractors have planned and executed seven stimulation treatments. Well stimulation treatments have been performed at Raft River, Idaho; East Mesa, California; The Geysers, California; and the Baca Project Area in New Mexico. Six of the seven stimulation experiments were technically successful in stimulating the wells. The two fracture treatments in East Mesa more than doubled the production rate of the previously marginal producer. The two fracture treatments at Raft River and the two at Baca were all successful in obtaining significant production from previously nonproductive intervals. The acid etching treatment in the well at the Geysers did not have any material effect on production rate. The conclusions from these well stimulation treatments are summarized in Tables II-V. A cost summary for these treatments is presented in Table VI including the well owner/operator contributed cost-sharing funds. These cost-sharing funds, totaling in excess of one million dollars, substantially improved the quality of the field treatments that were performed.

TABLE I

CANDIDATE RESERVOIR SELECTION

FACTORS:

- Technical Considerations
- Potential Impact on Future Commercial Development
- Cost-Sharing Arrangements

RAFT RIVER - Requested by DOE to Support 5 MW Powerplant

EAST MESA - Program Selection to Support Intense Development Activities in the Imperial Valley

THE GEYSERS - Program, Union and Halliburton Interest - Cost Sharing - Importance of the Field

BACA PROJECT - Support DOE/Union/PNM Demonstration Plant - Cost Sharing - Very High-Temperature

- Excellent Choices from a Technical Standpoint
- 5 of 7 Treatments in Fracture Dominated Reservoirs

TABLE II

WELL STIMULATION TREATMENTS AT RAFT RIVER, IDAHO

Well RRGP-4 (Treatment performed on August 20, 1979)

Well RRGP-5 (Treatment performed on November 12, 1979)

CONCLUSIONS

Both fracture stimulation treatments at Raft River were successful in establishing production from previously nonproductive zones. In the case of RRGP-4, the fracture apparently communicated with a highly productive zone but the fracture was of insufficient conductivity. The more conventional fracture treatment in RRGP-5 established commercial producing rates; however, the low produced fluid temperature made it subcommercial.

TABLE III

WELL STIMULATION TREATMENTS AT EAST MESA, CALIFORNIA

Well 58-30 (Deep interval treatment performed on July 3, 1980)

Well 58-30 (Shallow interval treatment performed on July 6, 1980)

CONCLUSIONS

The two stimulation treatments in East Mesa well 58-30 more than doubled production from the well and constituted an economic and technical success. The lower zone treatment stimulated production from a tight sandstone formation. The upper zone treatment successfully penetrated mud and cement damaged high permeability sands around the wellbore. The produced fluid temperature was also increased because of the additional fluid from the deeper, hotter portion of the well.

TABLE IV

WELL STIMULATION TREATMENT AT THE GEYSERS, CALIFORNIA

Well OS-22 (Treatment performed on January 15, 1981)

CONCLUSIONS

The acid etching treatment of the Ottoboni State 22 well in The Geysers failed to increase production. It is believed that the treatment fluids were dissipated into multiple natural microfractures and therefore failed to penetrate deep enough into the formation to enhance communication with the major fractures. The steam producing formations at The Geysers represent a significant departure from conventional hydrothermal reservoirs and this stimulation attempt was a pioneering effort in such formations.

TABLE V

WELL STIMULATION TREATMENTS AT THE BACA PROJECT, NEW MEXICO

Well Baca 23 (Treatment performed on March 22, 1981)

Well Baca 20 (Treatment performed on October 5, 1981)

CONCLUSIONS

Large hydraulic fracture treatments were successfully performed on both Baca 23 and Baca 20. Production tests indicated that high conductivity fractures were propped near the wellbore, communication with the reservoir system was established, and fluid production has been obtained from previously nonproductive zones. Productivities of Baca 23 and Baca 20 have declined to 70,000 and 50,000 lb/hr, respectively, since the fracture treatments. The probable cause is permeability reduction associated with two-phase flow effects in the formation, although partial closing of the fractures during drawdown is possible and should be further evaluated.

TABLE VI

GEOTHERMAL WELL STIMULATION PROGRAM

FIELD EXPERIMENT COST SUMMARY[1]

Experiment No.	1	2	3	4	5	6	7	
Experiment Site	Raft River RRGP-4	Raft River RRGP-5	East Mesa 58-30 Lower Zone	East Mesa 58-30 Upper Zone	Geysers OS-22	Baca 23	Baca 20	Total
Program Field Costs								
Budget[2]	275.0	310.8	462.0		220.1	524.4	580.8	2373.1
Actual	312.6	390.4	674.6		195.4	403.1	585.9	2562.0
Operator Cost-Sharing	N/A[3]	N/A[3]	N/A[3]		113.0[4]	359.7[4]	566.5[4]	

Footnotes

(1) Field costs in ($000), not including RGI labor and subcontractor charges.

(2) Cost estimate from experiment proposal.

(3) Operator contributed testing facilities and labor for partial support of operation, but estimates of dollar value are not available.

(4) Amounts shown are estimates from the experiment proposals. Actual operator contributions averaged more than the estimates, but exact cost figures are not available.

FY83 Objectives

Based on the results from the seven stimulation treatments that have been conducted, the primary technical areas of interest to the program are outlined in Table VII. The field treatments that would be performed to address these technical areas are listed in Table VIII.

TABLE VII

FY-83 CONTINUATION OF STIMULATION PROGRAM

WHAT WOULD WE EXPECT TO LEARN?

- What is the best technique for eliminating low permeability regions around a wellbore that have resulted from either mud or cement invasion during well drilling and completion operations or the accumulation of formation materials and scale damage during sustained fluid production and injection operations?

- Will stimulation treatments performed in reservoirs which produce or accept fluid as a result of matrix permeability be inherently more successful and productive than equivalently designed and executed treatments performed in fracture dominated reservoirs?

- Is it possible to economically produce flow channels between a geothermal reservoir (either producing or injection) and a wellbore which have a significantly higher flow conductivity than a properly designed and executed propped hydraulic fracture using a gelled acid or acid fingering technique?

- Is the rapid decline and resulting reduced production from apparently adequately propped hydraulic fractures (such as those at Baca) a result of proppant embedment and loss of flow conductivity from formation closure stresses during well drawdown?

TABLE VIII

SCENARIO OF EXPERIMENTS

EXPERIMENT NO.	TYPE OF EXPERIMENT
(1) & (2)	Matrix acid and hydraulic fracture treatment in a matrix-permeability dominated formation (impaired production because of near-wellbore damage)
(3) & (4)	Matrix acid and hydraulic fracture treatment in matrix-permeability dominated formation (impaired injectivity because of near-wellbore damage)
(5)	Acid fracturing (gelled acid) treatment in either a production or an injection well in a naturally fractured formation

EFP SYSTEM FOR CARBONATE SCALE CONTROL

R. J. Hanold, Los Alamos National Laboratory

Introduction

Many geothermal hot-water (brine) wells experience calcite precipitation and plugging of the wellbore and surface equipment when the wells are allowed to produce by "flashing flow." The wells experience plugging because carbon dioxide gas, which is in equilibrium with the hot water in the reservoir, escapes from solution with the steam when the hot water is allowed to flash.

At reservoir conditions, the carbon dioxide gas partial pressure maintains the carbon dioxide in solution in the soluble bicarbonate form. But evolution of carbon dioxide gas causes a shift in chemical equilibrium from the soluble bicarbonate to the insoluble carbonate. The carbonate ion formed reacts with calcium in the hot water to form calcium carbonate. The calcium carbonate is deposited in the wellbore above the gas bubble (flash) point as hard crystalline calcite. The deposits grow and restrict well flow until flow ceases entirely. In extreme cases the cessation of well flow can occur in a matter of weeks. These chemical reactions are illustrated in Table I.

EFP Process

The Equilibrium Flash Production System (EFP) is a proprietary process that applies a different principle and technique for preventing calcite deposition. The process controls the shift in chemical equilibrium from bicarbonate to carbonate by controlling the amount of CO_2 gas that is liberated from the reservoir brine. The control is accomplished by recycling and injecting the liberated CO_2 gas back into the wellbore to maintain the desired CO_2 gas partial pressures. This will prevent any further liberation of CO_2. The point of CO_2 injection in the wellbore is selected below the depth of the gas bubble point and optimized for maximum brine production versus recycle gas compressor horsepower. The injected CO_2 also serves as a gas-lift pump. The EFP System has the advantage of mechanical simplicity and operating reliability. There are no moving mechanical parts in the well; only a recycle gas injection pipe. Mechanical drives are at the surface, accessible for maintenance.

TABLE I

CHEMICAL REACTIONS

AT RESERVOIR CONDITIONS:

$$CO_2 + H_2O \rightleftharpoons HCO_3^- + H^+$$

WITH EVOLUTION OF CO_2:

$$2HCO_3^- \rightleftharpoons CO_2\uparrow + CO_3^{=} + H_2O$$

CARBONATE ION REACTS WITH CALCIUM:

$$CO_3^{=} + Ca^{++} \rightleftharpoons CaCO_3\downarrow$$

CALCIUM CARBONATE DEPOSITS ON WELLBORE AS HARD CRYSTALLINE CALCITE.

Field Demonstration Program

The Department of Energy (DOE) evaluated the merits of the EFP System and agreed to sponsor a field demonstration of the system. EFP Systems, Inc. contacted the Geothermal Division of Phillips Petroleum Company about the use of one of their geothermal wells at Desert Peak, Nevada. Phillips confirmed that the Desert Peak wells were experiencing calcite plugging in the wellbores. Phillips offered the use of Well B21-2 for the field demonstration of the EFP System.

Evaluation of well and resource characteristics by EFP Systems, Inc. showed Well B21-2 to be a suitable well for the demonstration. An agreement was entered into between Phillips and EFP Systems, Inc. for use of Well B21-2. EFP Systems, Inc. and Rogers Engineering Co., Inc. in turn entered into a contract with the Los Alamos National Laboratory for the field demonstration program.

Process Operation

The overall flow process for the field demonstration is illustrated in Figure 1. The CO_2 Recycle Compressor delivers the compressed CO_2 to the well. The wellhead is equipped with a tubing hanger and 1900 ft of 3-1/2" OD tubing, which is hung from the hanger and stabilized with centralizers. The CO_2 is injected into the wellbore through perforations in the tubing. The CO_2 recycle gas together with geothermal brine flows up the annulus and is delivered to the Well Production Flash Separator. The brine flows out of the bottom of the separator under level control. The flow rate is measured by a venturi meter and the brine is discharged to the brine pond through a rock-type silencer. The steam-CO_2 mixture flows through the overhead line to the air-cooled condenser, which condenses the steam and cools the CO_2 recycle gas. The condensate is separated from the recycle gas in the Compressor 1st Stage Suction Drum. The condensate is metered and flows out from the suction drum under level control. The CO_2 gas flows overhead to the suction of the compressor to complete the gas recycle loop. The major process flows involved in the EFP system are shown in Table II.

EFP System Operation

The EFP System was operated over a range of conditions. To prove that the system was an effective pump as well as a calcite preventer, the unit

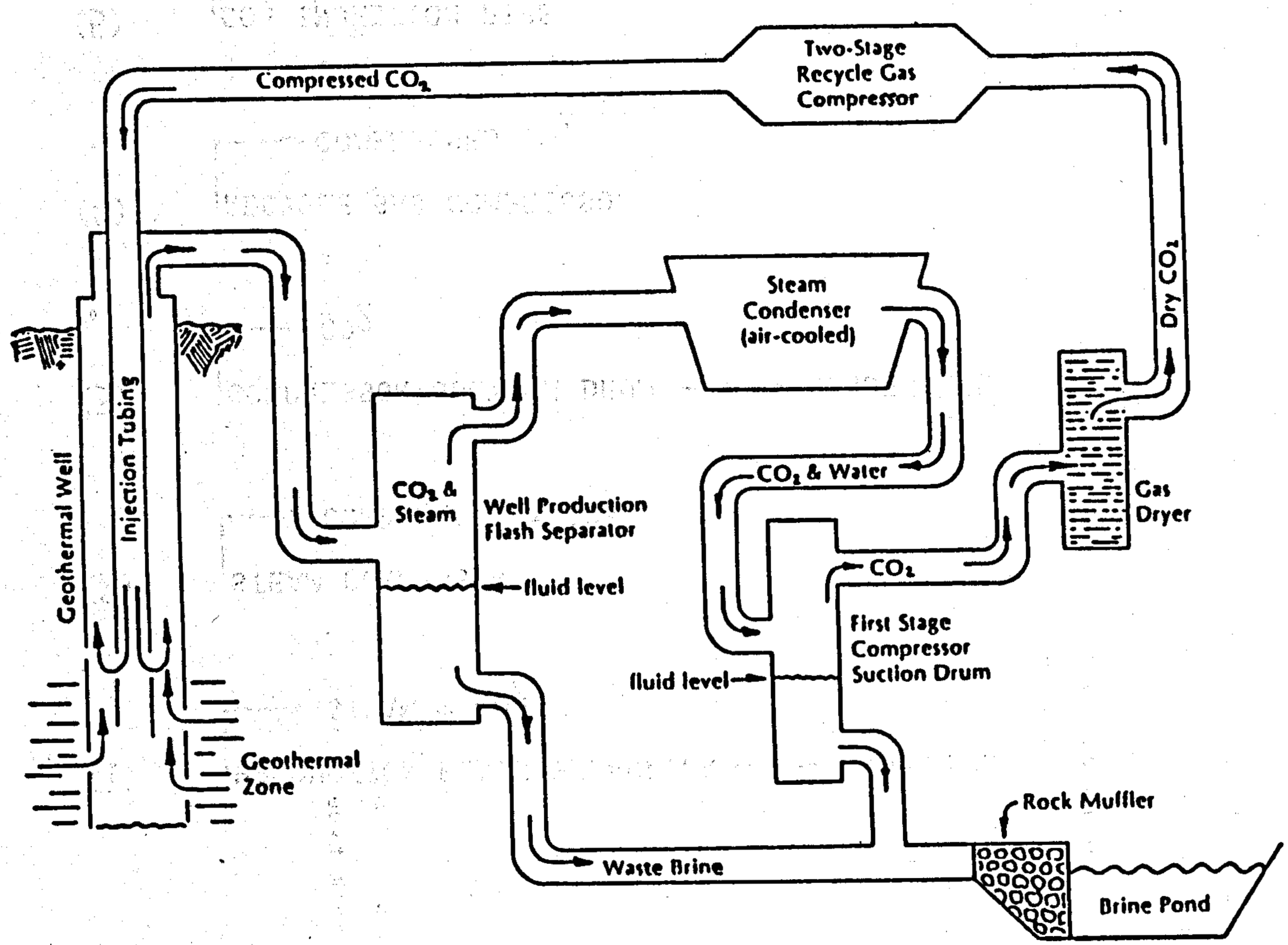


Figure 1 - SCHEMATIC PROCESS FLOW DIAGRAM.

TABLE II

EFP PROCESS

(1) PRODUCTION FLASH SEPARATOR → BRINE
 → STEAM + CO_2

(2) STEAM CONDENSER
 → CONDENSATE + CO_2

(3) COMPRESSOR SUCTION DRUM → CONDENSATE
 → CO_2

(4) RECYCLE GAS COMPRESSOR
 → COMPRESSED CO_2

(5) CO_2 INJECTION PIPE
 → PRODUCED BRINE + CO_2

was operated at a wellhead pressure of 200 psig with CO_2 injection rate to the well of 14,000 Lb/Hr. At this condition, the well produced as much brine as the well produced by straight flashing flow at a wellhead pressure of 65 psig. However, the operation could not be sustained at 200 psig without the addition of makeup CO_2 because the high CO_2 partial pressure increased CO_2 solubility losses in the brine leaving the separator.

The makeup CO_2 was shut off, and the system was allowed to seek its stable operating pressure. System stability was reached at a wellhead pressure of about 140 psig. The CO_2 injection rate to the well had to be decreased to prevent overloading the Condenser duty. The CO_2 injection rate was ultimately reduced from 14,000 Lb/Hr to about 8000 Lb/Hr when stable (no CO_2 makeup) operating conditions were achieved. The brine pH was 5.6. Over the final 30-day test period, the brine production averaged about 340,000 Lb/Hr, limited by condenser duty. At the 140 psig wellhead pressure operation, the gas injection rate was 8000 Lb/Hr, and the compressor horsepower requirement was about 180 BHp.

At the conclusion of the 30-day test, the tubing was removed from the well. The upper joints of pipe had a thin film of black sulfide while the lower joints were clean, and painted stenciling was still clearly visible on the tubing. The centralizers were in excellent condition. An 8-1/2" ring gauge easily traversed the well to bottom, whereas an 8" ring gauge was the maximum size that could pass through after the well was reamed out, but prior to commencement of the EFP System test. This clearly indicated that the EFP System not only prevented calcite deposits from forming in the wellbore, but also cleaned out the deposits left by the mechanical reamer.

Conclusions

The EFP System is an effective gas-lift pump in that it can increase wellhead pressure while maintaining a given well production rate, or it can increase well production rate while maintaining wellhead pressure. The EFP System is effective in preventing calcite deposits from forming in the wellbore, and it will also remove calcite deposits previously formed in the wellbore by "flashing flows."

The advantages of the EFP System are summarized in Table III. A photograph of the field demonstration equipment at the Phillips wellsite, as it was featured on the cover of the Geothermal Resources Council Bulletin, is shown in Figure 2.

TABLE III

EQUILIBRIUM FLASH PRODUCTION SYSTEM

- CONTROL CALCITE DEPOSITION IN WELLBORE.
- IMPROVE WELL PRODUCTIVITY BY GAS LIFTING.
- PROVIDE PH MAINTENANCE TO CONTROL HEAVY METAL SULFIDE DEPOSITION.
- REDUCE RATE OF SILICA POLYMERIZATION.
- ALLOW WELL TO FLOW AT LOW WELLHEAD PRESSURES.

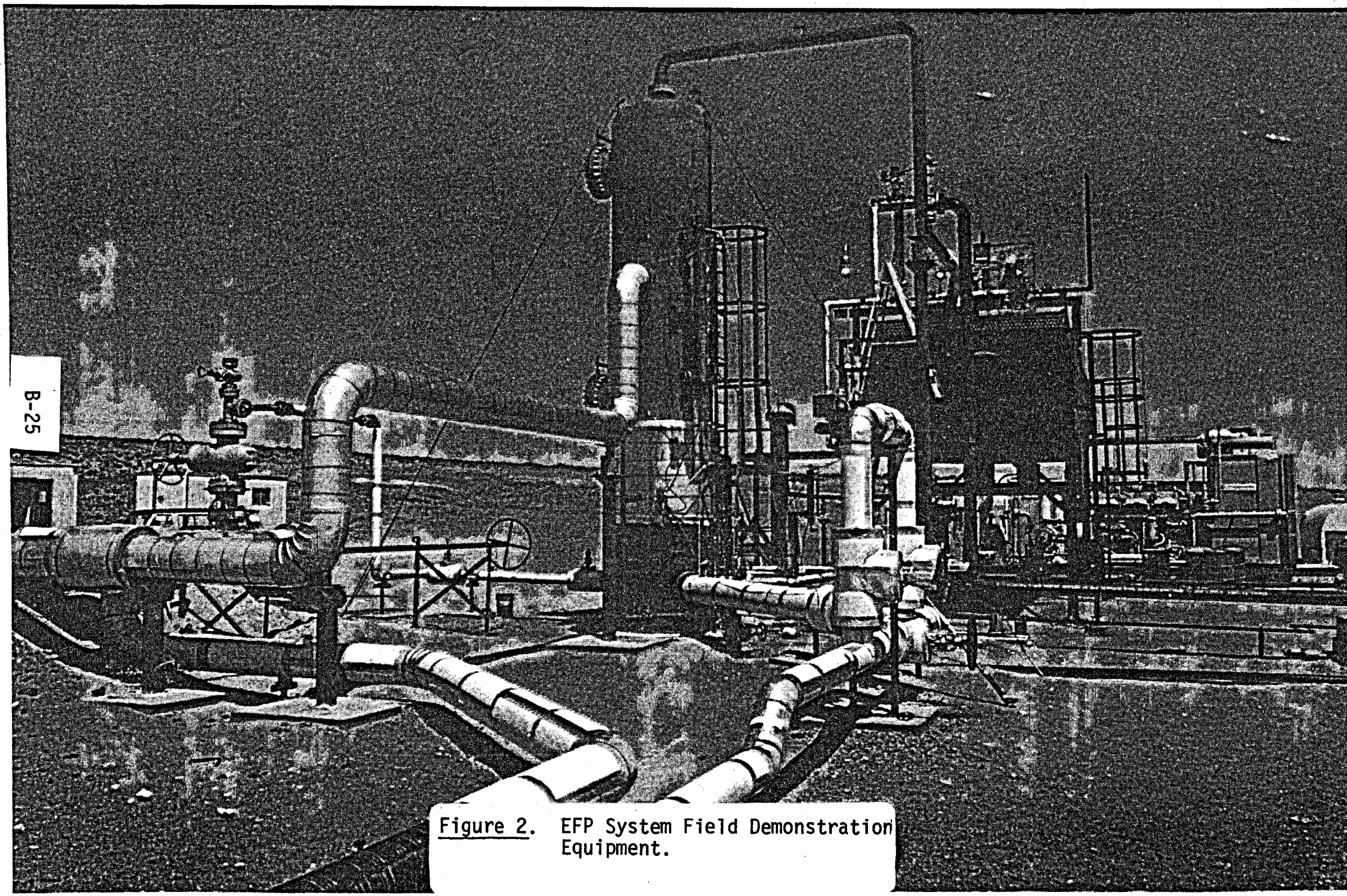


Figure 2. EFP System Field Demonstration Equipment.