**INVESTIGATION AND EVALUATION OF
GEOPRESSURED-GEOTHERMAL WELLS**

FINAL REPORT

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Date Published--September 1980

**Prepared for the
U.S. Department of Energy
Division of Geothermal Energy
Under Contract No. DE-AC08-77ET28460**

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EXECUTIVE SUMMARY

Under contract no. EG-77-C-08-1528 with the U.S. Energy Research and Development Administration, Gruy Federal, Inc. was responsible for screening, identifying, negotiating for, acquiring, completing, and testing wells penetrating geopressured-geothermal formations, and for analyzing the test data obtained.

Over the life of the project, 1,143 wildcat wells were screened for possible use. Although many did not meet the program's requirement for sand development, a surprisingly large number were abandoned because of downhole mechanical problems. Only 94 of these wells were completed as commercial hydrocarbon producers.

During the term of the contract, five "wells of opportunity" were funded for testing. Of these, two were evaluated for their hydraulic energy, thermal energy, and recoverable methane, and three were abandoned because of mechanical problems.

Early progress in acquiring wells was slow. The idea of intentional production of salt water with its dissolved methane, even on an experimental basis, proved to be so unconventional that the time frame for acceptance by industry was underestimated. The limited initial response appeared to stem from a number of reasons:

1. Gruy Federal was asking to take over wells and actively produce salt water from zones that had been always regarded as one of the foremost hazards of deep drilling.
2. Operators were reluctant to turn over geological failures to a rank outsider, even a consulting firm.
3. There was no established policy and no precedent for reply. As a result, very few replies were received in the early stages. Many responses were oral and not recorded. Some operators who did not respond initially or who responded negatively later became willing to consider cooperating with the program.

Increased industry acceptance was manifested when the operator was offered a cash inducement in the \$50,000 to \$100,000 range, plus purchase of mud inventory and various rentals and assumption of the responsibility for plugging the well and restoring the location.

Because of slow initial response to the well-of-opportunity concept, and in an effort to provide test data at the earliest possible time, Gruy Federal recommended and DOE approved a departure from the original concept in the first quarter of calendar 1978. This involved reentry, recompletion, and testing of abandoned wells, most of them on open (unleased) acreage. Program modification appeared to offer a number of advantages, and after a sequence of recommendations and tentative approvals, refusals from mineral owners, permitting difficulties, and other problems, two reentry projects were recommended and approved by DOE.

The first reentry project, the Alice C. Plantation No. 2 well in St. Mary Parish, La., proceeded without unusual mechanical difficulty until the mud column became unbalanced and a flow of salt water ensued just before casing could be run to contain the lowermost portion of the hole. This was in large measure the responsibility of the well supervisors under contract to Gruy Federal. After the saltwater flow was contained by natural bridging, it was found that the intermediate casing had collapsed and the operation was abandoned.

The Gladys McCall No. 1 well in Cameron Parish, La., was the second approved reentry attempt. This project failed because the 7-inch casing could not be entered; it had been severed by explosives at one or more places, not by mechanical cutting as reported in the records filed with the State of Louisiana.

The costly failure of these two attempts precluded consideration of other reentry prospects, irrespective of their individual conditions and merits. Even before the difficulties with the two reentry attempts, DOE instructed Gruy Federal to renew its efforts to obtain conventional wells of opportunity.

The first successful test of a geothermal aquifer under the program was the Fairfax Foster Sutter No. 2 well in St. Mary Parish, La. Gruy Federal assumed operations on the site on March 8, 1978, when the operator, Neuhoﬀ Oil and Gas Company, abandoned the well as a dry hole at a total depth of 16,340 feet. Completion was successful and all test objectives were accomplished, yielding data which will contribute to the assessment of the geopressured-geothermal resource in the Upper Gulf of Mexico basin. The gas solubility, 22.8 scf/bbl, was as expected for the temperature, pressure, and salinity of the brine. The produced water was more saline than expected (190,000 mg/l); this high concentration of dissolved solids creates a serious scaling problem that must be addressed in future tests.

The second successful test was made on the Beulah Simon No. 2 well in Vermilion Parish, La. This well was drilled by Southport Exploration, Inc. to 15,625 feet and temporarily abandoned by Gruy while awaiting approval for geopressured-geothermal completion. All objectives of the project were accomplished, and good test data were obtained on the flow rates of gas and water. Methane solubility was 24 scf/bbl, only slightly higher than that measured in the Fairfax Foster Sutter No. 2, even though the total dissolved solids content was less than half that in the Sutter well.

The Beulah Simon test also showed that the shallow Pliocene sands of south Louisiana are suitable for the disposal of large amounts of hot water. The disposal well accepted the full wellhead stream at temperatures as high as 255°F (124°C). Over the 10-day flow period the hot brine did not appear to adversely affect the clay minerals in the disposal aquifer. As one result, no cooling system was included in the design of the fifth well of opportunity tested.

Table 1 summarizes the results of the two successful tests.

TABLE 1
SUMMARY COMPARISON OF GEO² TESTS

	<u>Fairfax Foster Sutter No. 2</u>	<u>Beulah Simon No. 2</u>
Formation tested	Marginulina Ascensionensis - Lower Miocene	Camerina A - Frio
Date test started	May 25, 1979	Oct. 28, 1979
Date test completed	July 9, 1979	Dec. 29, 1979
Total depth drilled, feet	16,340	15,223
Size production tubing, inches	2-7/8, 3-1/2	3-1/2
Depth production tubing, feet	15,573	14,191
Size casing liner, inches	5-1/2	5-1/2
Depth production packer, feet	15,510	none used
Total depth cleaned out, feet	16,302	15,218
Depth to top of casing liner, feet	14,130	11,555
Size production casing, inches	7-5/8	7
Thickness of test zone, feet	420	220
Perforated zone, feet	15,916-15,781	14,770-14,674
Initial bottomhole static temperature, °F	270	266
Initial bottomhole static pressure, psia	12,220	13,015
Final bottomhole flowing pressure, psia	7,800	11,146
Final bottomhole buildup pressure, psia	10,240	12,920
Initial static tubing pressure, psi	4,680	5,991
Final flowing tubing pressure, psi	940	3,221
Final buildup tubing pressure, psi	4,247	6,020
Total time for buildup after flow, days	19.3	20
Total drawdown ΔP, psi	1,980	1,869
Maximum brine production rate, B/D	9,166	11,324
Maximum gas production rate, Mcf/D	126	239
Tubing pressure at maximum rate, psi	1,067	4,875
Total flow time, hours	369.66	253.25
Estimated total brine produced, bbl	86,695	125,209
Estimated total gas produced, Mcf	1,933	2,542
Average gas/brine ratio, scf/bbl	22.3	20.3
Brine conductivity, μmho	250,000	115,000
Brine pH	6.18	6.61
Brine specific gravity	1.0932	1.066
Gas specific gravity (air = 1)	0.6435	0.7481
Brine viscosity, Sus at 95°C	31.3	51.3
Bubble-point pressure, psia	11,750	12,500
Gas solubility, scf/bbl	22.8	24.0
Energy content of produced gas, Btu/cu ft (wet)	933	847
Formation porosity, percent	19.0	18.7
Permeability, millidarcies	14.3	12.0
Nearest barrier, feet	860	556
Aquifer geometry	two parallel sealing faults	two parallel sealing faults

The last well in the program, the Tenneco Fee "N" No. 1, was the first case in which a major oil and gas company participated in the well-of-opportunity program. Tenneco assisted in the preparation of the well prognosis and completion design and supplied on-site supervisory and operating personnel.

The well was originally drilled to 17,276 feet and a 4-1/2 inch liner was run to total depth. Several geopressured-geothermal sands were penetrated that met DOE selection criteria for testing. The test was designed for higher flow rates (20,000 to 30,000 B/D) and a longer test period (60 to 90 days) than had been standard in the program. A barge rig was moved to the location on January 9, 1980. Subsequent reentry operations could not be completed because of the difficulty of obtaining a cement seal around the 4-1/2 inch liner. A hole later developed in the liner at 13,920 feet, allowing shale, gas, and salt water to enter the well bore, and since it was not practical to attempt further remedial operations inside the small liner, the decision was made to abandon. The drilling barge was released on April 22 after having plugged the well in accordance with state regulations.

1.0 INTRODUCTION

Since the mid-1970's the demand for conventional energy in the United States has exceeded the supply from domestic sources. This shortfall was compounded by a decline in oil and gas productivity, reserves, and exploratory drilling; disruptions in the foreign supply followed by major price increases; and delays in the development of alternative power sources under existing economic, sociological, and environmental constraints. Any appraisal of the energy choices facing this country cannot fail to conclude that all alternate sources must be assessed, evaluated, and if economically viable, developed.

One such potential energy source consists of the porous geopressured sandstone reservoirs of Tertiary age encountered at depths generally below 10,000 feet in the Gulf Coast region of Texas and Louisiana. Several estimates have been made of the energy content of these reservoirs and of the energy recoverable under certain development scenarios.^{1-5*} Such estimates are highly speculative, since no commercial or even experimental utilization of this potential energy source has ever been made. The U.S. Department of Energy (DOE) is conducting an extensive investigation of the thermal, hydrokinetic, and dissolved methane energy potentially available from such aquifers.

This report covers the acquisition, completion, and testing of geopressured-geothermal (Geo²) wells by Gruy Federal, Inc. under a contract with the U.S. Department of Energy, Division of Geothermal Energy.** The contract, as extended, was in effect for the fiscal years 1978 and 1979. It provided for the "identification, qualification, acquisition, planning and conducting of geothermal-geopressured formation tests in up to six oil or gas wells, about to be drilled, being drilled, or being abandoned. . ." The program is known as the "Well-of-Opportunity" (WOO) Program because the original concept was to take advantage of dry holes drilled by industry to obtain short-term test data on the methane content of the brines and the flowing characteristics of well-aquifer systems specifically designed to produce from rather than to avoid geopressured aquifers. At least 50 percent of the cost of drilling a new Geo² test well can be saved by taking over a well already drilled by others.

*References are listed in Section 6.

**Original contract No. EG-77-C-08-1528 between U. S. Energy Research and Development Administration (ERDA) and H. J. Gruy and Associates, Inc. dated September 14, 1977.

2.0 PROGRAM OVERVIEW

The Well-of-Opportunity program was implemented to utilize existing non-productive oil and gas wells for geopressured-geothermal testing at a lower cost than the alternative of drilling and completing a well. The objective was to obtain data from short-term tests that would aid in the evaluation of the resource base, specifically:

1. Determine the in-situ rock and reservoir properties: porosity, permeability, distances to boundaries, elastic properties, and net thickness contributing to flow.
2. Sample the aquifer fluids and measure the chemical composition of the water and gas, assess the methane solubility, and establish the pressure-volume-temperature relationships of the two-phase system.
3. Monitor the behavior of the fluid-rock system at moderate flow rates to detect any physical or chemical changes in the effluent.
4. Assess the disposal problems to be encountered in the development of the resource and evaluate the most appropriate method for brine disposal.

Preliminary summaries of well screening and evaluation under this contract are found in previous reports.^{6,7}

2.1 Screening Criteria

To accomplish the objectives of the program, a detailed plan was devised to identify potential test wells, monitor their progress, and contact operators to solicit cooperation. The priority areas for geopressured-geothermal testing along the Texas Gulf Coast were delineated by Bebout⁸ (Fig. 1), but no similar study had been published for Louisiana.

Screening criteria (Table 2) were established to identify areas in south Louisiana in which the search could be focused. Initially, the lower limit on the aquifer temperature was set at 300°F (149°C). A review of logs from the deep wells in the area showed that the 300°F isotherm was deeper in south Louisiana than in south Texas. In addition, it was learned that the AAPG correction factor consistently overestimated the aquifer temperature and that the maximum recorded bottomhole temperature more closely approximated the true temperature. Consequently, the minimum temperature constraint was relaxed to 250°F (121°C).

At the beginning of the program operators were naturally reluctant to cooperate on takeover proposals, particularly since there was no economic incentive to do so. After several months of unsuccessful attempts to take over new wells, emphasis was shifted to abandoned wells; hence the addition of criterion 8. Reentry attempts on two wells, the Alice C. Plantation and the Gladys McCall, were unsuccessful, and reentry prospects were never again considered.

A thorough review of the existing logs on deep wells in south Louisiana produced the target areas shown in Fig. 2.

Figure 1

TEXAS

- FRIO GEOTHERMAL FAIRWAYS
- WILCOX GEOTHERMAL FAIRWAYS

0 25 50 Miles
SCALE

TABLE 2
PRIMARY PARAMETERS FOR
GEO² WELL SELECTION

1. At least 250°F temperature at datum, derived from maximum mud temperature plus AAPG correction.
2. Pressure at least 4,500 psi greater than normal (calculated from gradient of 0.465 psi per foot), derived from reported mud weight at datum less 1,000 psi allowance for safety differential.
3. Minimum of 100 feet of net porous sand exhibiting good quality SP, with apparent 100% water saturation.
4. Location readily accessible by land (primarily).
5. Wells that appear to have penetrated qualified sand aquifers underlying at least 1,280 acres, with no tendency for porosity pinchout limits so far as can be determined from available geological data.
6. Wells currently off production or abandoned, besides those wells of opportunity that may be drilling in known Geo² areas that will likely contain water.
7. Wells equipped with casing of weight and grade adequate to permit completion of the desired test.
8. Wells reportedly abandoned, or those not abandoned in which mechanical conditions offer reasonable expectation of successful reentry and repair at moderate cost.

LOUISIANA

- No sand development at geo-temperature depths in Miocene.
- Region of good Miocene and Frio prospects requiring inland water operations to be reviewed, if necessary.
- Regions of good Miocene and Frio accessible by land that have been reviewed.
- Area where Miocene Geo² formations not penetrated by existing wells.
- Region of Geo² Tuscaloosa prospects under active development.

Figure 2.--Target areas for Geo² testing in Louisiana.

2.2 Monitoring Candidate Wells

Two weekly subscription services were utilized to screen potential "Well-of-Opportunity" (WOO) locations: Petroleum Information Service for South Louisiana and the Texas Gulf Coast and F. & A. Reports for South Louisiana. A comparison of the locations listed in the two reports showed nearly identical coverages. Sometimes one publication or the other was a week late in listing a newly permitted location.

Once a drilling operation began, it was followed in the "Drilling Progress" section of either report. This information was sufficient for the early stages of a lengthy operation, but it was frequently more than two weeks old and could not be trusted when a well approached critical depths. Nevertheless, this provided a means of tracking operations without the nuisance inflicted by frequent calls to an operator's representative.

Extensive investigation of Geo² trends gave the Gruy Federal staff independent knowledge of pressure-temperature occurrences in a large number of previously drilled wells, particularly while the search was concentrated on abandoned wells that might be reentered. In many instances this background permitted instant ranking of the area in which a location was announced.

An additional early screening step eliminated operators who had consistently declined to participate in the program and whose attitude was unlikely to change.

Whenever possible, the initial contact with an operator who was not familiar with the program was made by someone personally acquainted with a key man in the operator's organization. Two senior landmen of long experience assisted the Gruy Companies' staff in making these contacts. As the program became better known and more widely accepted, contacts concerning specific wells were made with offices, functions, or persons designated by the operator.

During the term of the contract, 1,143 wells of opportunity were screened for possible geopressured-geothermal testing in the Gulf Coast area of Texas and Louisiana. Of these, 94 were eventually completed as commercial producers and 36 were abandoned because of mechanical problems before they reached the geopressured-geothermal zones. Only a few wells were eliminated because the operator or the landowner refused to cooperate. The two major factors which eliminated wells from eligibility were lack of adequate sand development in the geopressured zones and poor mechanical condition. Over 65 percent of the wildcat wells drilled into the geopressured zones never reached their objectives in the original hole; i.e., they were forced to sidetrack. Five wells were eventually selected and approved for testing.

2.3 Manpower Utilization

Figure 3 shows the monthly and cumulative total well-of-opportunity candidate monitoring for the contract period.

Figure 3--Activity and milestone history of Gruy Federal Well-of-Opportunity contract.

Figure 4 displays the cumulative and monthly man-hours expended throughout the contract. A total of 13.5 man-years of effort went into the management, technical screening, and field activities. These data reflect only the utilization of Gruy personnel and do not include the contributions of third-party consultants.

2.4 Summary of Wells Proposed

Gruy Federal's initial survey resulted in the selection of 10 reentry candidates, which were submitted to DOE/NVO early in 1978.^{9,10} Over the course of the program 28 wells were formally proposed for geopressured-geothermal testing, 12 reentry proposals and 16 takeovers. Table 3 is a summary of these wells and the estimated properties of the potential test aquifers.

Figure 4--Monthly and cumulative total Well-of-Opportunity candidate monitored.

TABLE 3

WELLS OF OPPORTUNITY FORMALLY RECOMMENDED TO DOE

Well	County/Parish, State	TD, feet	Formation	Net sand thick- ness, ft	Est. poros- ity, %	Est. BHT, °F	Est. BHP, psia	Ultimate Disposition Reasons for Rejection
U.S. Oil of Louisiana Mecom No. 1	Cameron, La.	15,144	Abbeville	110	*	309	11,300	DOE rejected "out of hand"
Superior Oil Co. W. Miller No. 1	Cameron, La.	18,226	Planulina	310	15.8	311	14,000	Gladys McCall took priority
Getty-Buttes Gladys McCall No. 1	Cameron, La.	15,598	Marg. Asc.	610	15.8	313	12,500	Reentry attempt failed
Sun Oil Co. Dorothy Sturlese No. 1	Cameron, La.	18,970	Marg. Asc.	90	*	358	16,680	Gladys McCall took priority
Pan. Am. Pet. Co. State Lease 4183 No. 1	Cameron, La.	16,920	Lower Mio.	275	*	329	13,575	Wildlife preserve--no permit
Inexco, C. B. Hamill No. 1	Matagorda, Tex.	16,200	*	250	*	360	*	No operator cooperation
Falcon-Seaboard Baer Ranch A-3	Matagorda, Tex.	15,811	Frio-Tex-Miss	140	26.1	292	12,781	Pressure depleted, low permeability
Tenneco Fee "N" No. 1	Terrebonne, La.	17,276	Textularia warreni	486	25	290	14,860 15,550	Reentry attempt failed
Milton Cooke, Jr. et al. Louis Lobit No. 1	Galveston, Tex.	14,500	Frio	*	*	*	*	Withdrawn--not drilled
Union Oil Pan Am. Fee No. 2	Cameron, La.	18,891	Camerina	305	*	306	12,000	DOE rejected "out of hand"
J. P. Owen et al., L. H. Hardee No. 1	Vermilion, La.	18,932	Mio-Frio Hackberry	140	*	360	16,200	Poor mechanical condition
Superior Oil Hazel Sawyer No. 1	Vermilion, La.	19,808	Camerina	120	*	328	14,450	Alice C. Plantation took priority
Sun Oil Alice C. Plantation No. 2	St. Mary, La.	19,000	Low. Marg. Asc.	315	21.5	305	14,650	Reentry attempt failed
Union Oil Dr. M. O. Miller No. 1	Cameron, La.	18,132	Marg. Asc.	800	15	318	15,800	Impossible landowners
TOTAL Petroleum Means No. 1	Wharton, Tex.	16,800	Wilcox	120	25	365	12,780	Well junked while logging
Slapco Joyce Foundation No. 1	Tangipahoa, La.	22,000	Low. Tusc.	*	*	390	*	Well was blowing out when offered
Forest Oil et al. J. Carter Thomas	DeWitt, Tex.	14,500	*	*	*	*	*	Poor sand development

*Insufficient data.

TABLE 3 continued

Well	County/Parish, State	TD, feet	Formation	Net sand thick- ness, ft	Est. poros- ity, %	Est. BHT, °F	Est. BHP, psia	Ultimate Disposition Reasons for Rejection
Great Basin Pet. Co. Gutierrez No. 1	Jim Hogg, Tex.	15,280	Wilcox	*	*	350	*	Poor sand development
Sabine Prod. Co. et al. Gaudeau No. 1	St. Landry, La.	18,000	Low. Tusc.	*	*	*	*	Pressure regression and well was junked
Texaco No. 1 Fee (A. R. Rucks)	Brazoria, Tex.	*	Frio	*	*	*	*	Impossible landowner
Arco Crews No. 1	Brazoria, Tex.	22,000	Wilcox	*	*	*	*	Insufficient sand development
Superior Willis Hulin No. 1	Vermilion, La.	21,000	*	*	*	*	*	Producing well
Adobe Oil & Gas et al. Stubbs G. U. No. 1	Galveston, Tex.	*	Frio	*	*	*	*	Required deepening
Williams Matilda Gray Stream No. 1	Calcasieu, La.	*	Planulina	*	*	*	*	Poor mechanical condition
Enterprise Lucien J. Richard et al. No. 1	Lafourche, La.	16,000	Mid-Miocene	70	30	290	12,500	One interest balked
Alcorn Fairfax Foster Sutter No. 1	St. Mary, La.	15,800	MA5, MA6	100	20	291	12,000	Multiple-pay producer
Neuhoff Fairfax Foster Sutter No. 2	St. Mary, La.	16,340	MA6	272	19	303	13,000	Well completed and tested
Southport Beulah Simon No. 2	Vermilion, La.	15,265	Camerina	266	17.4	285	13,000	Well completed and tested

*Insufficient data.

3.0 PROJECT OPERATIONS

3.1 Alice C. Plantation No. 2

The first saltwater disposal well for the Alice C. Plantation test was abandoned after casing stuck at 643 ft. A second disposal well was spudded on July 16, 1978, and drilled to a total depth of 4,575 ft. Conductor pipe (13-3/8 in.) was driven to 121 ft and 9-5/8 inch casing was cemented from 1,057 ft to the surface. After a core was taken from 4,355 to 4,375 ft, the hole was drilled to 4,575 ft with an 8-3/4 inch bit and logged. A string of 5-1/2 inch casing was run to 4,557 ft and cemented to the surface. After block squeezing through perforations from 4,432 to 4,435 ft to achieve a cement bond, the 5-1/2 inch casing was cleaned out to 4,522 ft and the rig moved off location.

Reentry operations on the test well started on July 26, 1978. The 13-3/8 inch casing was extended to the surface and a casing head and blowout preventers were installed. The 13-3/8 inch casing was cleaned out to 3,273 ft with a 12-1/4 inch bit. A cement plug at 3,273 ft was drilled to 3,275 ft and a mill and junk basket were used to clean out to 3,428 ft (top of 9-5/8 inch casing). An 8-3/8 inch bit was used to clean out the 9-5/8 inch casing to 3,503 ft. The 9-5/8 inch casing was cut off at 3,446 ft and the cut portion was pulled. A 9-5/8 inch tieback overshot was run and the 9-5/8 inch casing extended to the surface. A set of 10,000-psi blowout preventers was installed on the 13-3/8 x 11 inch casing spool and tested.

The 9-5/8 inch casing cement plug was cleaned out from 3,503 to 3,522 ft and the casing was cleaned out to the cement retainer at 16,000 ft. After the cement retainer and cement were drilled from 16,000 to 16,211 ft, the mud weight was increased to 17.2 lb/gal. The cement in the open hole was drilled and the hole was washed to 18,100 ft (total depth drilled). Numerous shows of gas were circulated up while cleaning out to total depth. Schlumberger ran an ISF-caliper log from 18,100 to 16,230 ft.

Two trips were made to condition the hole before running 7-inch casing. While drill pipe was being pulled out of the hole and laid down, the well started flowing. The BOPs were closed and a safety valve was installed on the 4-1/2 inch drill pipe. The bit was at 559 ft.

A snubbing unit was moved on location and used to clean 9 bridges out of the 9-5/8 inch casing between 574 and 4,750 ft, while the mud weight was increased to 17.7 lb/gal. Three joints of drill pipe were pulled, a TIW safety valve installed on the drill pipe, and the pipe set down on the pipe rams. The snubbing unit was rigged down and released and the drilling rig was used to clean out from 4,750 to 5,053 ft. Upon pulling the bit it was determined that the 9-5/8 inch casing had collapsed at a depth of 5,053 ft.

Halliburton was rigged up and set a 400-ft cement plug from 5,050 to 4,650 ft. The 9-5/8 inch casing was cut at 3,469 ft and salvaged. A 123-sack cement plug was spotted at 3,652 to 3,850 ft and a 20-sack plug at 20 to 6 ft on October 20, 1978, and the well was abandoned.

A complete account of operations is found in the final report for this well.¹¹

3.2 Gladys McCall No. 1

To prepare for reentry operations on the Gladys McCall No. 1 well, Cameron Parish, La., repairs were made to 2.3 miles of board road and five bypasses in addition to a 40,000-square-foot turnaround and the ring levee around the location.

The disposal well was drilled to 1,509 ft on a turnkey contract. A string of 9-5/8 inch casing was driven to 119 ft and 5-1/2 inch casing was cemented to the surface from 1,484 ft.

Reentry operations began on November 8, 1978. The 10-3/4 inch casing was extended to the surface and a casing housing and blowout preventers were installed and tested. Cement plugs were drilled from 36 to 47 ft and from 64 to 71 ft. While washing to bottom, the bit encountered cement plugs from 2,268 to 2,871 ft and 3,062 to 3,137 ft. At this depth the bit broke through and returns were lost. The mud weight was reduced to 10 lb/gal and circulation established after adding 10 lb of lost circulation material per barrel of mud. The hole was then washed to 3,511 ft, to what was thought to be the top of the 7-inch casing.

An inspection log run on the 10-3/4 inch casing from 3,511 ft to the surface showed it to be in good condition.

In the reentry prognosis it was intended to locate the top of the 7-inch casing, dress it to receive a tieback overshot, and extend the 7-inch casing to the surface. After difficulties were encountered in locating the top of the 7-inch casing, numerous configurations of fishing tools were used in attempts to open the 7-inch casing so that it could be dressed to receive the tieback overshot and allow unrestricted entrance into the 5-inch liner at 13,954 ft. It is questionable whether at any time any of the tools entered the cut-off 7-inch casing. From the available information it was concluded that the bottom of the 10-3/4 inch casing was damaged when the 7-inch casing was cut using an explosive charge. The 7-inch casing top was flared and the hole possibly enlarged at this point, allowing some of the reentry attempts to go alongside the 7-inch casing. Even though deviation surveys indicated that the hole from 3,000 to 5,000 ft was only 1-1/4 degrees off vertical, none of the tools entered the 7-inch casing. Thirty different fishing assemblies were used to try to find the top or clean out the casing, and the use of hooks failed to engage the 7-inch casing so that it could be entered. After fishing for 30 days without positive indication that the top of the 7-inch casing had been located, permission was requested and received from DOE to abandon the reentry attempt. The hole was abandoned in accordance with Louisiana Conservation Department regulations on December 18, 1978.

A detailed account of the reentry operations is contained in the final report on this well.¹²

3.3 Fairfax Foster Sutter No. 2

This well, located in St. Mary Parish, La., was drilled by Neuhooff Oil and Gas Corporation to a total depth of 16,340 ft, logged, and found to be nonproductive of hydrocarbons. Well developed geopressured-geothermal

sands existed in the open hole below the 7-5/8 inch casing shoe, which was set at 14,375 ft. While awaiting approval from DOE for Gruy Federal to assume operations, the operator circulated the hole 24 hours with the drill bit at 14,289 ft.

On March 9, 1978, operations were resumed after approval was obtained from the landowner, the Louisiana Department of Conservation, and DOE. The drill bit was used to clean out and condition the hole to total depth. Bridges were encountered and washed out, with large quantities of shale accumulating on the shaker. It was necessary to spot oil-base mud to free the drill pipe, which became stuck while making a short trip. The bit was run to 18,340 ft without encountering any obstruction and pulled with no detectable drag.

The 5-1/2 inch casing liner was hung with its top at 14,130 ft and bottom at 18,340 ft and cemented. Thirty minutes were required to release the liner-setting tools from the liner top, and after pulling the seals out of the polished bore receptacle a surface pressure of 2,500 psi would not reverse-circulate the excess cement from around the drill pipe. Ten stands (900 ft) of drill pipe were pulled and the hole was circulated clear of cement.

Upon going in the hole to clean out the cement in the 7-5/8 inch casing, firm cement was encountered at 9,208 ft. While drilling firm cement at 11,550 ft it was necessary to make a trip for a new bit. A tight spot was found between 9,989 and 10,890 ft, and while reaming the bit backed out of the drill collars and was left in the hole.

The drilling fluid was in poor condition at takeover and worsened while drilling cement; hence extra time was needed to remedy this condition. This reconditioning was accomplished while recovering the drill bit and cleaning out the 7-5/8 inch casing to 14,137 ft (top of the 5-1/2 inch liner) and 3 ft into the 5-1/2 inch liner. After cleaning out the 5-1/2 inch liner to 16,288 ft, cement bond, variable density, gamma ray/neutron, and collar locator logs were run from 16,288 to 13,500 ft. A casing inspection log was run on the 7-5/8 inch casing above the liner top. The seal at the liner top was tested and held. The cement bond log, however, indicated that better cementation of the 5-1/2 inch liner was required, both above and below the Geo² sands.

The liner was perforated above the Geo² sand (15,678 to 15,680 ft) with four shots per foot. A retrievable squeeze tool was run and set at 15,545 ft. Using surface pump pressure of 3,500 psi the formation would not take fluid, but with a differential pressure to the wellbore the well started flowing. Since the upper perforations could not be squeeze-cemented, preparations were made to complete the well for testing.

A 3-3/8 inch casing gun was used to selectively perforate seven zones (94 ft total) between 15,781 and 15,930 ft. A wireline production packer was set at 15,500 ft. Four feet of seals were made up on the work string and run in the hole to test the packer. With a work string, 15,000 lb of weight was set on the packer. A pressure of 1,500 psi was applied to the bottom side of the packer. Both tests were satisfactory and the seals were pulled and the work string laid down.

The production tubing was picked up and run, but when the seals entered the packer and weight was applied, the packer moved down the hole. After pulling the tubing, a 4-1/2 inch bit was run to shove the packer down the 5-1/2 inch liner to 15,884 ft. The mud was displaced with oil-base mud, and after the bit was pulled, another wireline packer was set and tested at 15,510 ft and the 3-1/2 inch tubing was run and seated in the packer. After displacing the oil-base mud from the surface to 14,000 ft, a back-pressure valve was installed in the Canfield bushing, the blowout preventers were removed, and the christmas tree was installed.

While work on the test well proceeded, an injection well was drilled on a turnkey basis. Conductor pipe (13-5/8 inch) was driven to 108 ft and a 12-1/4 inch hole was drilled to 1,200 ft. A string of 9-5/8 inch casing was run to 1,219 ft and cemented to the surface. An 8-inch bit was used to drill to 3,964 ft and 5-inch casing was run to 3,692 ft and cemented to the surface. A cement bond-gamma ray-collar locator log was run from 3,912 to 700 ft and indicated good bonding between casing and formation throughout. The 5-1/2 inch casing was perforated after displacing the drilling fluid with produced brine while holding a 500-psi pressure as the first gun was fired. After each run with the perforating gun, injectivity rates were measured. A total of 60 ft (3,609 to 3,669 ft) was perforated, and after treating with a combination of HCl and HF acid the injection pressure was less than 400 psi at 11,000 B/D. On production testing the injection pressure was 90 psi at 7,000 B/D.

Production testing of the Fairfax Foster Sutter No. 2 started on May 25 and continued until July 10, 1979. The well was then killed by pumping 16.8 lb/gal oil-base mud down the tubing, and the tubing was recovered by cutting at 14,952 ft. A bridge plug was set at 14,950 ft and 15 ft of cement placed on top of it. The blowout preventers were rigged down and a 10-inch flange was placed on top of the casing head housing. The test well and the disposal well were returned to the custody of Neuhoof Oil and Gas on August 20, 1979, in accordance with the agreement.

A complete description of all phases of the operation is given in the project report.¹³

Detailed cost analyses of the estimated versus actual costs for the completion operation and the saltwater disposal well are shown in Tables 4 and 5.

3.4 Beulah Simon No. 2

The Beulah Simon No. 2 was drilled by Southport Exploration, Inc., to a total depth of 15,265 ft. Geothermal-geopressured zones were encountered below 14,700 ft but since no hydrocarbon zones were penetrated, the well was temporarily abandoned. Cement plug were spotted in the 7-5/8 inch casing on top of the retainer set at 13,782 ft, and from 49 to 44 ft inside the 9-5/8 inch casing. The 13-3/8 inch and 9-5/8 inch casings were cut 3 feet below ground level and the drilling rig was moved to another location.

Before a drilling rig moved to the location to complete the geothermal-geopressured well, the 13-3/8 inch casing was extended to ground level and 13-3/8 inch casing housing installed. After the rig was rigged up on September 15, 1979, the 9-5/8 inch casing was extended to the surface

TABLE 4

ESTIMATED AND ACTUAL COSTS
COMPLETION OPERATIONS, FAIRFAX FOSTER SUTTER NO. 2

Description		Estimated	Actual
Drilling contractor		\$ 109,500	\$ 74,460.33
Site preparation		60,000	37,399.67
Equipment & tool rental		66,000	41,072.32
Freight & transportation		15,000	21,658.89
Insurance		26,500	838.50
A - GR & CB logging	12,500		
B - Casing logging	<u>7,000</u>		
Subtotal A + B		19,500	8,468.86
Perforating		45,000	73,885.41
Cementing		25,000	27,824.40
Miscellaneous		10,000	1,059.95
Contingencies		85,200	27,779.60
Spec. Cont. Tools & Equip.		16,400	4,184.87
C - Mud inventory & costs	20,000		
D - Pressure test tubing	30,800		
E - Float equip. & hanger	17,000		
F - Mud & chemicals	15,000		
G - Completion fluids	<u>36,000</u>		
Subtotal C - G		118,800	113,536.12
Outside services		15,500	2,680.45
Contract labor		42,000	25,345.34
Tubular - tangibles		34,600	187,229.01
H - Operator's fee	75,000		
I - Landowner's fee	<u>35,000</u>		
Subtotal H + I		110,000	28,784.80
Communications		---	472.55
Office copying		---	178.08
Conference		---	194.12
Travel - allowable		---	15,188.04
Automobile		---	1,489.05
Other		---	- 562.23*
Misc., subcontract		---	<u>-6,007.89*</u>
TOTAL		\$799,000	\$687,160.24

*Negative amounts transferred or corrected from this cost summary--not in total.

TABLE 5

ESTIMATED AND ACTUAL COSTS
SALTWATER DISPOSAL WELL, FAIRFAX FOSTER SUTTER NO. 2

Description		Estimated	Actual
Site preparation		\$ 10,000	\$ 6,088.66
Drilling contractor		102,000	54,632.95
A - Conductor pipe	2,400		
B - 9-5/8" casing	14,200		
C - 5-1/2" casing	21,300		
D - Wellhead equipment	<u>5,000</u>		
Subtotal A - D, tangibles		42,900	15,463.20
E - Float equipment	3,000		
F - Mud & chemicals	<u>5,000</u>		
Subtotal E + F, expendables		8,000	
G - Perforating	8,700		
H - Logging	<u>10,600</u>		
Subtotal G + H		18,700	11,824.28
Supplies & rentals		9,500	40,664.33
Trucking		5,000	8,869.14
I - Cementing	15,000		
J - Stimulation	<u>2,500</u>		
Subtotal I + J		17,500	16,090.34
Supervision		5,000	8,182.42
Contingencies		32,800	2,250.00
Travel - allowable		---	1,381.00
Legal fees & consultants		---	1,000.00
Expendables		---	11,425.95*
Evaluation		---	4.78
Minor outside services		<u>---</u>	<u>184.75</u>
TOTAL		\$251,400	\$155,210.01

*Negative amount transferred or corrected from this cost summary--not in total.

and hung off on the 13-3/8 inch casing housing, and the blowout preventers were installed. The 9-5/8 inch casing was cleaned out to 11,882 ft; the 7-5/8 inch liner was cleaned from 11,882 to 13,800 ft; and the 6-1/2 inch open hole was conditioned to 15,231 ft. The bit then was pulled and a 5-1/2 inch liner run to bottom (15,233 ft), hung off in the 9-5/8 inch casing, and cemented in place.

The liner-setting tools were pulled and, while going in the hole with a 8-3/4 inch bit to clean out to the top of the 5-1/2 inch liner, the well started to flow with the bit at 3,522 ft. The blowout preventers were closed and 18.0 lb/gal mud was displaced down the drill pipe to reduce the flowing pressure so that the drill pipe could be stripped through the bag preventer in order to lower the bit to 11,536 ft. The mud weight was increased to 18.5 lb/gal and the flow was killed.

A squeeze tool was run to 11,042 ft in order to squeeze cement outside the 5-1/2 inch liner. An 8-3/4 inch bit was used to clean to the 5-1/2 inch liner top. The seal around the 5-1/2 inch liner was pressure tested to 2,000 psi and differentially tested with 3,500 psi.

A 4-1/2 inch mill cleaned out the 5-1/2 inch liner to 15,208 ft. A CBL/CNL/GR run from 15,218 to 11,550 ft (electric log measurements) showed good bonding above and below the objective sands.

The tieback sleeve was cleaned out and the 7-inch casing with a tieback seal on bottom was picked up and stabbed into the top of the 5-1/2 inch liner. The seal was pressure-tested and a 75,000 lb pull was exerted on the latch prior to setting the 7-inch casing slips. A 4-1/2 inch mill was used to clean out the 5-1/2 inch to 15,208 ft and the drill pipe was laid down.

A string of 3-1/2 inch tubing (14,930 ft) was picked up and run in the hole to displace all of the 18.5 lb/gal mud with 10.0 lb/gal salt water. The tubing was then raised to 14,191 ft. The bottom master valve of the christmas tree was installed and a backpressure valve installed in the 3-1/2 inch "R" nipple at 2,751 ft.

The drilling rig was released and moved off location on October 19, 1979.

After the top portion of the christmas tree was installed, a work platform, a kill line, and a chemical injection line were installed. A corrosion inhibitor was circulated down the tubing and up the tubing annulus, leaving 50 gallons in the bottom of the tubing.

The 5-1/2 inch liner was perforated from 14,647 to 14,770 ft with a 2-7/8 inch hyper-dome gun with zero phasing using four shots per foot. Upon making the first run with the gun the tubing surface pressure increased to 6,500 psig and remained at this pressure while the perforating operation was completed.

The injection well was drilled while the test well was being completed. A string of 13-3/8 inch conductor casing was driven to 105 feet below ground level. A 12-1/4 inch hole was drilled to 1,226 ft and 9-5/8 casing was run and cemented to surface with its bottom at 1,226 ft. After rigging up on

the 9-5/8 inch casing a 8-3/4 inch hole was drilled to 2,702 ft. ISF-Sonic and electric logs were run from 2,708 to 1,228 ft, and the hole was conditioned. A string of 5-1/2 inch casing was then run to 2,708 ft and cemented to the surface.

The 5-1/2 inch casing was cleaned out to 2,653 ft and the drilling fluid displaced with produced salt water. Cement bond, variable density, and gamma-ray logs were run after laying down the drill pipe. The CBL indicated good bonding over the injection zones. The wellhead was installed and the rig released on October 2, 1979. After perforating the 5-1/2 inch casing from 2,464 to 2,524 ft, the perforated zone was acidized and injectivity tests were made on October 26. The injection pressure while pumping 9 bbl/min was 90 psig.

Detailed cost analyses of the actual versus estimated costs for the completion operation and the saltwater disposal well are shown in Tables 6 and 7.

A complete review of all phases of the operation on the Beulah Simon well is given in reference 14.

3.5 Tenneco Fee "N" No. 1

The Tenneco Fee "N" No. 1 well, located in Terrebonne Parish, La., was drilled to a depth of 17,276 ft and a 4-1/2 inch liner was set from 17,276 to 13,148 ft. After cementing the liner and starting out of the hole with the liner setting tools, the well started flowing with the tools at 12,200 ft. The well flow was partially killed by displacing 1,500 sacks of cement down the drill pipe. The drill pipe was then stripped to a depth of 12,937 ft and another 500 sacks of cement displaced below the tools. The well was temporarily abandoned and the rig moved off. This was the condition at the time of takeover for completion as a geopressured-geothermal well.

The 9-5/8 inch casing was cleaned out to the top of the 7-inch liner at 12,327 ft. Cement was then drilled out of the 7-inch liner to a depth of 13,040 ft, at which time the well started flowing.

Four squeeze jobs using a total of 1,300 sacks were used to effect a seal around the top of the 4-1/2 inch liner. Cement bond, variable density, and gamma ray logs were run from 12,304 to 6,500 ft and an electromagnetic thickness log was run from 12,304 ft to surface, all inside the 9 5/8-inch casing.

A 3-1/2 x 5-3/32 inch polish mill was used to dress the polished bore receptacle (PBR) on top of the 4-1/2 inch liner. A combination 5 x 7-inch tieback casing string was run to surface. This tieback casing would not seat inside the 4-1/2 inch liner; it was cemented with 375 sacks to effect a seal between it and the 7-inch liner.

Cement was cleaned out of the 5 x 7-inch tieback casing and the 4-1/2 inch liner was cleaned out to 17,226 ft. While cleaning out the 4-1/2 inch liner, tight spots were reamed at 13,700+ ft and firm cement was drilled from 14,447 to 15,435 ft. After conditioning the mud, a cement bond log was run on the 4-1/2 inch liner from 17,226 to 12,000 ft. This log

TABLE 6
ESTIMATED AND ACTUAL COSTS
COMPLETION OPERATIONS, BEULAH SIMON NO. 2

Description		Estimated	Actual
Drilling contractor		\$319,330	\$298,627.84
Site preparation		4,620	99,028.75
Well, land, and lease		75,000	28,078.35
Tubulars & christmas tree		102,391	323,002.99
Cement & pumping		56,274	32,541.64
A - Drill bit & shoes	8,788		
B - Mud & chemicals	95,000		
C - Downhole equipment	10,970		
D - Corrosion inhibitor	<u>25,000</u>		
Subtotal A - D, expendables		139,758	90,973.28
Rental tools & equipment		11,541	46,449.13
Transportation		29,300	18,793.21
E - Open-hole logs	12,398		
F - Cased-hole logs	14,561		
G - Perforating	<u>31,153</u>		
Subtotal E - G, test & evaluation		58,112	48,213.22
Insurance		24,813	27,096.82
Wireline work		800	79,901.34
Contract labor		19,627	30,962.73
Miscellaneous supplies		5,065	2,212.11
Communications		1,496	-0-
Travel, allowable		---	7,453.48
Automobile		---	179.92
Miscellaneous		<u>---</u>	<u>54,770.95</u>
TOTAL		\$848,127	\$1,188,285.76

TABLE 7
ESTIMATED AND ACTUAL COSTS
SALTWATER DISPOSAL WELL, BEULAH SIMON NO. 2

Description		Estimated	Actual
Drilling contractor		\$ 80,000	\$ 60,604.00
Tubular goods		19,299	38,120.94
Cement & pumping		19,247	17,659.69
Drill bits & shoes		1,050	28,024.99
Rental tools & equipment		2,553	2,591.60
Transportation		6,182	34.44
A - Open-hole logs	3,345		
B - Cased-hole logs	<u>1,940</u>		
Subtotal A + B, evaluation		5,285	3,872.20
Perforating		15,350	24,958.67
Contract labor		3,165	5,218.22
C - Stimulation	10,379		
D - Communications	764		
E - Miscellaneous supplies	<u>490</u>		
Subtotal C - E		11,633	9,523.80
Travel - allowable		---	1,204.46
Automobile		---	5.25
Legal fees & consultants		---	2,026.65
Site preparation		<u>---</u>	<u>731.58</u>
TOTAL		\$163,764	\$194,576.49

indicated very poor bonding.

Preparatory to running a bridge plug to seal off the 4-1/2 inch liner bottom, a 3-5/16 inch mill was run. Obstructions were encountered at 13,683 to 13,720 ft and 13,978 to 13,980 feet. To determine if the 4-1/2 inch liner was leaking, the PBR in the 5 x 7 inch tieback casing was dressed and the seals for it were run on drill pipe. Since it was possible to pump through the drill pipe, it was assumed that the bottom was leaking. A 300-sack cement mixture was displaced so that its top would be at 16,990 feet. A slick line was rigged up and run into the hole through the drill pipe. The indicated top of the cement plug was at 13,162 feet, confirming that there was a leak around the top of the 4-1/2 inch liner. Another 300-sack cement mixture was displaced down the drill pipe so that its top would be at 12,650 feet.

The seal assembly was pulled from the PBR and a 3-3/4 inch mill was used to clean the 5-inch tieback from 12,510 to 13,148 feet. The seal between the 4-1/2 inch liner and the 5-inch tieback was tested with 1,500 psi and held for 15 minutes.

A 3-5/16 inch mill was used to clean out the 4-1/2 inch liner. Tight spots were reamed at 13,700, 14,500 and 14,706 ft. With the mill at 17,276 ft the BOP's were closed, and when a pressure of 1,000 psi was applied, it bled off. It was again assumed that the 4-1/2 inch liner shoe was leaking. A gauge ring was run to see if a bridge plug could be run. This was lost in the hole while trying to work past the liner top at 13,146 feet. The gauge ring was fished after pushing it to 13,839 feet. Another 3-5/16 inch mill was run and reamed through tight spots at 13,742 to 13,746 ft, 13,865 to 13,870 ft and 13,935 to 14,005 ft. When bottoms were pumped to the surface, they were contaminated with gas and salt water. Eleven stands of drill pipe were pulled and the BOP's were closed; it was possible to pump into the formation with 1,250 psi. With the pump shut down there was 600 psi on the drill pipe at the surface.

With the 3-1/4 inch mill at 12,566 ft, a 250-sack cement mixture was displaced so that its top would be at 12,950 ft. A pressure test was made on the 4-1/2 inch liner, and held both 2,000 psi static and differential pressure.

While going in the hole with a 3-5/16 inch mill a pin from the safety clamp was dropped in the hole and recovered with a bailer. The mill was rerun and drilled cement from 13,144 ft to 13,920 ft, after a tight spot had been reamed from 13,760 ft to 13,763 ft. There was a void below the cement at 13,920 ft but it was necessary to ream from 13,910 to 13,960 ft because of drill pipe torque while rotating.

When bottoms were circulated up there was a show of gas and formation shale. The mud weight was increased from 17.6 to 17.8 lb/gal to control the entry of gas.

The quantity of mud required to keep the hole full while pulling the bit was less than the volume of the drill pipe displacement, so the mill was run back to bottom. A bridge was found at 13,804 ft which was reamed to 13,960 ft. The mill was pulled to 13,424 ft to allow the hole to heal

and then run back to bottom. A 6-foot fill was noticed during the time required for the short trip. This confirmed that there was a hole in the 4-1/2 inch liner.

A gamma-ray casing collar log, a 3-arm casing caliper log, and a gyro were run to determine the size and configuration of the hole, but none of the instruments was able to get below 13,922 feet.

Permission was granted to abandon the well in accordance with Louisiana Department of Conservation rules. Cement plugs were set, the casing was cut off below canal bottom, and all piling removed. This work was completed on April 29, 1980.

A complete account of operations on the Tenneco Fee "N" No. 1 is contained in reference 15.

3.6 C. D. Hopkins et al. No. 2

On December 8, 1977, Gruy Federal took over the C. D. Hopkins et al. No. 2 well, located near Jessup in Wayne County, Georgia, to be deepened and used for geothermal temperature gradient measurements. The well was drilled from 4,009 to 4,341 ft, then diamond-cored to 4,371 ft to obtain 28 ft of core for analysis. After logging by the USGS district groundwater officer in Atlanta, the well was terminated with 3-1/2 inch tubing to 4,386 ft.

Scientists from Virginia Polytechnic Institute and State University determined the bottomhole temperature to be 140°F at 4,365 ft. Over the interval 154 to 4,365 ft, the temperature gradient was determined to be 1.61°F/100 ft.

On March 17, 1980, a pulling unit moved to the location, rigged up, and pulled the 3-1/2 inch tubing. Cement plugs were placed from 3,300 to 3,100 ft and from 2,400 to 2,200 ft. The wellhead was modified so that the well could be used by the state of Georgia and the USGS for a groundwater observation well. The spotting of the plugs completed the geothermal temperature measurement operations on this well.

An account of operations on this well is found in reference 16.

4.0 TEST RESULTS

The tests on the Fairfax Foster Sutter No. 2 well and the Beulah Simon No. 2 well were designed to obtain the maximum amount of information about the Geo² reservoir rock and fluid properties within the time and funds allotted. These properties were:

- Gas solubility
- Well deliverability
- Formation flow capacity
- Wellbore damage
- Aquifer geometry
- Distance to existing boundaries
- Chemical composition of the water and gas
- Physical properties of the water and gas

The performance of downhole and surface equipment exposed to these high-pressure, high-temperature brines was unknown. For example, the maximum temperature to which the Hewlett-Packard quartz crystal gauge is calibrated is 302°F (150°C), which is near the expected bottomhole temperature. Similarly, the injectivity performance of shallow Miocene sands subjected to this temperature and injection rate had not been previously studied. All of these factors were considered when designing the test procedures.

4.1 Surface Testing Facilities

Figure 5 is a schematic drawing of the test facilities used for testing both wells.

All mainline surface piping was 3-inch, API (5L), Schedule 80, butt-welded line pipe rated to 1,850 psi at temperatures up to 250°F (121°C). The valves in the system were trimmed with T-24 steel with high-temperature packing.

The test separator was a conventional three-phase, 3-1/2 × 10-foot horizontal separator in which the standard 2-inch dump valves were replaced with 3-inch valves. The working pressure rating of the vessel was 1,440 psi; however, operating pressures never exceeded 280 psi. The liquid-level float was fabricated from Teflon to withstand the high temperatures. The fluid retention time was approximately 30 seconds at the maximum design throughput of 10,000 B/D.

The liquid drain from the separator was split into two streams, each containing a 10,000 B/D HOWCO turbine meter with digital readout. A 100-bbl calibration tank was provided for periodic calibration of each meter. The gas production from the separator was measured using a 3-inch flange-type orifice meter with a 1/2-inch orifice plate and a Barton recorder.

A fan-type air-cooled heat exchanger capable of transferring heat at a rate of 23,400,000 Btu/hr was installed in the system. It was necessary to cool the produced brine below its saturation temperature at atmospheric pressure in order to measure liquid volumes using the calibration tank on the Sutter well.

Figure 5.--Surface facilities for testing.

Furthermore, the compatibility of the disposal aquifers with these hot brines was unknown. The cooler contained two 120-inch diameter fans, each driven by a 25-hp electric motor, and was capable of reducing the water temperature from 350°F (177°C) to 190°F (86°C) at a throughput rate of 10,000 B/D per day when the ambient temperature was 100°F (38°C). The overall dimensions of the horizontal skid-mounted cooler were 32 × 11 × 7-2/3 ft. It was used only in the Fairfax Foster Sutter No. 2 well test.

Prior to disposal, the produced brine was filtered through a dual-tower replaceable cartridge filter. The cartridges retain particles 75 microns or larger in size and can withstand temperatures up to 250°F (121°C).

Downstream from the filters were diesel-driven centrifugal pumps capable of delivering 10,000 B/D at a pressure of 125 psi above suction pressure, manifolded in parallel with common suction and discharge. The pumps were intended for injecting the brine into the disposal well and transferring water from the calibration tank to the disposal well.

One low-pressure and three high-pressure sensors were installed in the surface flow lines to activate the safety valves on the wellhead in case pressure problems developed in the system. One high-pressure sensor was placed between the data header and the separator to detect any pressure rise resulting from sand erosion of the chokes; another was installed ahead of the cooler to shut the well in if scale buildup occurred in the cooler; and the last was placed ahead of the injection well to terminate production if the injection pressure rose above 400 psi. The low-pressure sensor was installed between the separator and the cooler to stop flow in case a serious leak in the surface facilities occurred.

A data header was assembled ahead of the separator to monitor and record data at a central site. This manifold contained a sonic sand detector, a continuous-recording thermometer, a scale coupon, and valving parts to collect full well stream samples. Pressure and temperature recorders were installed on both sides of the cooler to monitor inlet and outlet temperatures and to detect the occurrence of scale buildup in the cooler tubes if the pressure differential increased.

A dual-pen pressure recorder was attached to the tubing and casing annulus to detect any fluid communication which might occur outside the tubing or around the packer.

At the wellhead a 10,000-psi deadweight pressure gauge was installed to measure the surface flowing and shut-in tubing pressures periodically, and a continuous pressure recorder was attached to the injection well.

Throughout the entire cleanup and testing period the surface equipment performed exceptionally well. Early in the Sutter test the buildup of scale in most of the surface equipment became excessive and a scale inhibitor (NTC-S621, a phosphonate compound) was injected into the system upstream from the positive choke at an average rate of 10 gallons per day. This treatment prevented additional scale buildup but did not eliminate the scale already deposited.

The injection well took fluid at pressures equal to or less than the output pressure of the filters, and hence the booster pumps were never used for injection. They were utilized, however, to transfer water from the calibration tank to the disposal well after each meter calibration.

For the Beulah Simon test, several minor modifications of the surface equipment were implemented to ameliorate the scaling problem. A scale inhibitor was injected into the wellbore annulus to prevent scale buildup in all parts of the flow stream. The cooler was connected to the system as before, but proved to be unnecessary and never was utilized. Two 100-bbl calibration tanks were used to calibrate the meters daily.

The surface equipment performed exceptionally well throughout the test on the Beulah Simon well. The scale inhibitor was completely effective. At the end of the test, no scale was observed on any surface contacted by the water.

4.2 Aquifer Fluid Properties

Table 8 lists the chemical analyses of the produced brines from the two test wells. The chemistry department at McNeese State University analyzed two samples from the Fairfax Foster Sutter No. 2 well; their results are shown for comparison. The Institute of Gas Technology sampled the Beulah Simon No. 2 well and their analysis results are also shown. While the agreement between the ion concentrations is good, there is an appreciable difference between the total dissolved solids determined by Southern Petroleum Laboratories and reported by McNeese and IGT. These differences are believed to be attributable to the method of handling samples. SPL analyzed the samples on site immediately after sampling at the flowing temperature. The other two laboratories cooled the samples to ambient temperature before determining the total dissolved solids. The cooler samples should exhibit higher residues and lower total dissolved solids. The comparison of the total solids on the Beulah Simon support this hypothesis.

4.3 Gas Analysis

The analyses of the gas samples from both wells are compared in Table 9. In both cases, fairly high concentrations of CO₂ reduced the Btu content of the solution gas.

4.4 PVT Analysis

Gas and liquid samples were taken from the separator during both tests and recombined in the laboratory. The bubble-point pressures at reservoir temperatures of the two fluids were found to be near the initial bottom-hole pressures, confirming that the fluids were saturated with gas at initial reservoir conditions. The results of the PVT analyses are shown in Table 10.

4.5 Reservoir Analysis

The production/shut-in sequence on the two wells differed slightly because of the experience gained in testing the Fairfax Foster Sutter and because of certain operational problems.

TABLE 8

CHEMICAL ANALYSIS OF PRODUCED WATER
FAIRFAX FOSTER SUTTER NO. 2 AND BEULAH SIMON NO. 2 WELLS

Constituent	Fairfax Foster Sutter No. 2			Beulah Simon No. 2			
	McNeese SU (2 samples)	Southern Petrol. Labs (20 samples)		Southern Petrol. Labs (10 samples)		Inst. Gas Technol. (6 samples)	
	Milligrams per liter	Milligrams per liter	Standard Deviation	Milligrams per liter	Standard Deviation	Milligrams per liter	Standard Deviation
Total dissolved solids	155,880	190,904	10,000	103,925	8,016	91,533	1,524
Total solids		203,475	20,000	104,947	7,815	102,250	25,924
Calcium (CaCO ₃)		18,305	1,000	7,869	548	6,955	736
Calcium (Ca)	7,670						
Magnesium (MgCO ₃)		2,320	187	910	39	887	18
Magnesium (Mg)	623						
Bicarbonate (HCO ₃)		208	49	606	93	868	118
Carbonate		0	-	1	-	0	-
Chloride (Cl)	94,705	91,387	3,500	50,300	909	54,050	1,372
Total iron (Fe)	57	56	14	33	9.4	N.D.	-
Dissolved silicate (SiO ₂)	86	60	18	92	9.5	69	35.6
Copper (Cu)		0.33	0.07	0.152	0.019	N.D.	-
Zinc (Zn)	0.89	2.11	1.55	0.136	0.163	N.D.	-
Boron (B)		68.5	7.30	89.6	2.757	67.8	9.4
Arsenic (As)		0	-	0.002	-	< 0.01	-
Chromium (Cr)		0.16	0.03	0.086	0.014	N.D.	-
Mercury (Hg)		< 0.0005	-	0.005	-	N.D.	-
Lead (Pb)		0	-	7.73	10.646	N.D.	-
Cadmium (Cd)	0.2	0.77	0.22	0.269	0.077	N.D.	-
Sodium (Na)	44,850	48,281	2,000	32,190	1,521	28,150	2,620
Potassium (K)	900	988	100	454	68	470	15
Ammonia (NH ₃)				29.8	2.94	N.D.	-
Barium (Ba)				30.4	1.96	N.D.	-
Sulfate (SO ₄)		< 1	-	444	15	381	64
Uranium (U)		0.0003	-				
Radium (Ra)		1,765*	-				
Strontium (Sr)	597						
Density		1.0932 gm/ml		1.066 gm/ml	0.0023	-	-
pH		6.18		6.61	0.088	7.03	0.46
Sus viscosity at 95°C		31.3		28.55	0.314	-	-

*Disintegrations per minute per liter.

TABLE 9

COMPOSITION OF GAS FLASHED FROM SEPARATOR LIQUID

<u>Constituent</u>	<u>Mol percent</u>	
	<u>Fairfax Foster Sutter No. 2 *</u>	<u>Beulah Simon No. 2[†]</u>
Nitrogen	0.52	0.35
Carbon dioxide	7.85	18.42
Methane	89.57	79.17
Ethane	1.78	1.55
Propane	0.20	0.34
Isobutane	0.06	0.09
n-Butane	0.01	0.05
Isopentane	0.01	0.02
n-Pentane	----	0.01
TOTAL	100.00	100.00
Specific gravity at 60°F (air = 1)	0.6430	0.7481
Calculated Btu/cu ft at 15.025 psia and 60°F:		
dry		862
wet		847
Calculated Btu/cu ft at 14.696 psia and 60°F:		
dry	947	
wet	930	

*Average of 7 samples.

†Result from one sample.

TABLE 10

RESERVOIR FLUID PROPERTIES OF WATER
FROM DIFFERENTIAL LIBERATION

Pressure psia	Formation volume factor vol/vol		Gas/water ratio* scf/bbl		Relative volume V/Vsat		Density gm/cc	
	F. F. Sutter	B. Simon	F. F. Sutter	B. Simon	F. F. Sutter	B. Simon	F. F. Sutter	B. Simon
13015 RP	-----	-----	-----	-----	-----	0.9985	-----	1.0262
12500 BP	-----	1.0403	-----	24.0	-----	1.0000	-----	1.0247
12220 RP	-----	-----	-----	-----	0.9989	-----	1.0758	-----
11750 BP	1.0348	-----	22.8	-----	1.0000	-----	1.0746	-----
11000	-----	-----	-----	-----	1.0020	-----	1.0725	-----
10000	1.0385	1.0430	18.3	18.0	1.0049	1.0072	1.0694	1.0174
9000	-----	-----	-----	-----	1.0077	1.0107	1.0694	1.0139
8000	1.0422	1.0455	14.1	13.4	1.0109	1.0137	1.0630	1.0109
7000	-----	-----	-----	-----	1.0141	1.0175	1.0598	1.0071
6427	-----	-----	-----	-----	-----	1.0194	-----	1.0052
6000	1.0460	1.0486	10.4	9.6	1.0175	-----	1.0562	-----
5000	-----	-----	-----	-----	1.0214	-----	1.0521	-----
4928	-----	-----	-----	-----	-----	1.0252	-----	0.9995
4000	1.0500	1.0528	7.0	6.0	1.0264	-----	1.0470	-----
3624	-----	-----	-----	-----	-----	1.0322	-----	0.9927
3000	-----	-----	-----	-----	1.0337	-----	1.0396	-----
2643	-----	-----	-----	-----	-----	1.0411	-----	0.9842
2000	1.0537	1.0588	3.6	2.6	1.0475	-----	1.0259	-----
1975	-----	-----	-----	-----	-----	1.0521	-----	0.9740
1538	-----	-----	-----	-----	-----	1.0645	-----	0.9626
1000	-----	-----	-----	-----	1.0897	-----	0.9862	-----
906	-----	-----	-----	-----	-----	1.1060	-----	0.9265
15	-----	1.0690	0	0	-----	-----	-----	-----

*Standard conditions = 60°F and 14.696 psia.

After an initial cleanup period, the Sutter well was flowed for 3 days and shut in for 6 days, after which it was flowed for 11 days and shut in for 20 days. Because of scaling in the adjustable choke wing of the tree, the production rate continually declined. The initial flow rate on the 11-day test was 7,700 B/D but fell to 5,000 B/D per day by the end of the test. The Beulah Simon was flowed for 10 days through both wings of the christmas tree at a relatively constant rate of 10,500 B/D. Because of mechanical difficulties associated with the wireline, the Hewlett-Packard quartz crystal gauge was not run during the flow period; it recorded the pressure only during the 20-day build-up.

The pressure data from both wells were analyzed using currently acceptable techniques.¹⁷⁻³¹

4.6 Permeability

Analysis of two pressure buildup curves and one pressure drawdown test yielded an estimated permeability of 14.3 md for the geopressured sand interval in the Fairfax Foster Sutter well. The Beulah Simon test gave only one set of drawdown and buildup data, but surface casing and tubing pressures were used to augment the pressure buildup analysis. The best estimate of the effective aquifer permeability in this well was 11.6 md, varying from 10.3 md to 18.5 depending on the source of the pressure data used.

4.7 Reservoir Geometry

Because both well tests were of such short duration, not all limits of the aquifers were reached during the flowing periods. The pressure transient tests on both wells detected linear barrier faults less than one section away. In fact, analyses showed that both wells were situated between two parallel linear discontinuities. In the case of the Fairfax Foster Sutter well, the pressure data suggests that the well lies equidistant between two faults approximately 880 feet away.

The analysis of the pressure data on the Simon well showed that the two faults are 556 feet and 731 feet from the well. The geological interpretations of both areas confirm the geometrical interpretation of both aquifers.

5.0 CONCLUSIONS

Successful completion tests of the Fairfax Foster Sutter No. 2 and Beulah Simon No. 2 have contributed a significant amount of interesting and important information concerning the production behavior of geopressured-geothermal aquifers. These and subsequent tests will provide the framework for assessing the commercial potential of geopressured-geothermal energy.

More specifically, the following characteristics of the reservoir rock and its contained fluids were determined and the following conclusions based on these data were reached:

1. The average dissolved gas content of the produced brine was less than 25 standard cubic feet per stock tank barrel of brine. Recombination studies of the separator gas and liquid samples confirmed that the brines were saturated with gas at the original reservoir conditions.
2. Gas-water ratios remained constant throughout the tests and were unaffected by changes in operating conditions (other than separator pressure) or pressure drawdown.
3. Chemical composition of the produced brine from each reservoir remained essentially constant throughout each test. All variations appear to be the result of sampling or random experimental errors.
4. Separator gas withdrawn from the flow streams consisted mostly of methane and CO_2 . The energy content of the dry gases in both wells was less than 950 Btu/cu ft.
5. High concentrations of calcium salts in the produced brine will cause severe scale deposition in both surface and subsurface equipment unless properly treated.
6. Downhole injection of scale inhibitor will eliminate scale deposition (approximate cost \$60/day for a production rate of 20,000 B/D).
7. Short-term injection of the hot brine into the shallow disposal sand did not alter the injectivity behavior of the disposal well.
8. Conventional two-phase horizontal separators, modified for higher flow rates and temperatures, satisfactorily separate the effluent.
9. The data-collection program established prior to the test was successful in collecting and integrating the data for test analysis.
10. If the downhole Hewlett-Packard quartz crystal pressure gauge is to be used for geopressured-geothermal operating conditions, a leakproof connector between the gauge and the wireline must be developed.

11. A redesigned high-pressure lubricator is needed that will allow the wireline to pass through it regardless of scale buildup on the line and still not leak while being used.
12. Short-term testing can evaluate all geopressured-geothermal reservoir characteristics except the areal extent.
13. Both aquifers tested had fairly low permeabilities, i.e., less than 20 md, and appeared to be limited in areal extent.

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