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*Hot Dry Rock Geothermal Energy
Development Program
Annual Report
Fiscal Year 1987*

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Produced hot water, flashing to steam, confirms the creation of the second hot dry rock geothermal energy reservoir at Fenton Hill.

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**HOT DRY ROCK GEOTHERMAL ENERGY
DEVELOPMENT PROGRAM
ANNUAL REPORT
FISCAL YEAR 1987**

by

M. C. Smith, R. H. Hendron, H. D. Murphy, and M. G. Wilson

ABSTRACT

During Fiscal Year 1987, emphasis in the Hot Dry Rock Geothermal Energy Development Program was on preparations for a "Long-Term Flow Test" of the "Phase II" or "Engineering" hot dry rock energy system at Fenton Hill, New Mexico. A successful 30-day flow test of the system during FY86 indicated that such a system would produce heat at a temperature and rate that could support operation of a commercial electrical power plant. However, it did not answer certain questions basic to the economics of long-term operation, including the rate of depletion of the thermal reservoir, the rate of water loss from the system, and the possibility of operating problems during extended continuous operation. Preparations for a one-year flow test of the system to answer these and more fundamental questions concerning hot dry rock systems were made in FY87: design of the required surface facilities; procurement and installation of some of their components; development and testing of slimline logging tools for use through small-diameter production tubing; research on temperature-sensitive reactive chemical tracers to monitor thermal depletion of the reservoir; and computer simulations of the 30-day test, extended to modeling the planned Long-Term Flow Test.

However, the discovery in November 1986 that the casing in the production well of the Phase II system had collapsed at a depth of about 3200 m (10,500 ft) delayed initiation of the Long-Term Flow Test. Attempts to mill through the damaged region were unsuccessful, and the decision was made to sidetrack the well at a higher level and redrill it through the fractured reservoir. A target for redrilling was selected, using the newly developed three-point method of identifying flow paths through the reservoir by analyzing the source locations of microseismic signals generated by fracturing events. Detailed plans for well repair, sidetracking, and redrilling were prepared. A drilling contract was negotiated. The site was prepared, and the necessary equipment, material, and services were procured. By the end of the fiscal year, the abandoned lower part of the production well had been plugged with sand and cement; casing leaks at higher levels had been plugged with cement; lightweight cement had been injected behind the casing to support it during subsequent operations; a window for sidetracking had been milled through the casing at a depth of 2960 m (9710 ft); and a cement base had been provided for the whipstock that will be used for sidetracking through the window.

Site maintenance and other support activities continued throughout the year. Environmental monitoring detected no undesirable effects of Fenton Hill operations in or around the site.

EXECUTIVE SUMMARY

Naturally heated rock at accessible depths in the earth's crust represents one of the largest supplies of energy that is accessible to man. At Los Alamos in 1970, a concept was originated for extracting thermal energy from this essentially inexhaustible resource and bringing it to the surface, where it could either be used directly or, at higher temperature, be the energy supply for an electrical power plant. The proposed method was to drill two holes from the surface deep enough to reach crustal rock at a usefully high temperature; connect the two holes through the hot rock by large cracks created by fluid pressure ("hydraulic fracturing"); pump cool water down one hole to be heated as it circulated through the cracks; recover the hot water through the other hole under sufficient pressure to keep it from boiling; at the surface, extract its useful heat through heat exchangers; and reinject the cooled water through the first hole to recirculate through the underground loop and recover more heat. (This "recirculating pressurized-water heat-extraction loop" is similar in principle to the cooling system in an automobile engine.)

Between 1970 and 1974, background studies and field investigations were encouraging with regard to the practicality of constructing and operating such a system. In 1977 the world's first energy system of this kind was completed at Fenton Hill in the Jemez Mountains of Northern New Mexico. In 1979 it was enlarged and operated successfully for more than a year with no detectable environmental effect, producing heat at a temperature and rate that could have heated several hundred homes or served a variety of other useful purposes in a populated area. This "Phase I" or "Research" system accomplished the original objective of the Hot Dry Rock (HDR) Geothermal Energy Development Program: it demonstrated the technical feasibility of extracting useful heat from the earth's crust and bringing

it to the surface for conversion to a more useful form of energy.

However, the Phase I system did not produce heat at a temperature or rate that, in competition with fossil fuels or nuclear energy, would support economical operation of a commercial electrical power plant. Therefore the Program was extended to meet those more demanding requirements. For that purpose, a deeper, hotter "Phase II" or "Engineering" HDR system was constructed at Fenton Hill. Its major components were 1) an injection well, EE-3A; 2) a production well, EE-2; 3) a set of hydraulic fractures or a fractured region connecting the two wells, through hot granitic rock at a depth of about 3600 m (12,000 ft); and 4) a surface system to pump cool water into EE-3A, recover the superheated water from EE-2, extract the useful heat from the water through heat exchangers, and reinject the cooled water through EE-3A.

A successful 30-day "Initial Closed-Loop Flow Test" (ICFT) of this system indicated that the technology developed in the HDR Program was near commercial usefulness for supporting operation of a power plant. However, the economics of using such a system as the energy supply for an electrical power plant remained in question, primarily because of the long lifetime required of such a plant. The major uncertainties were the rate of thermal depletion of the HDR reservoir, the rate of water loss from the system, flow impedance or the pumping power required to overcome it, and the possibility of operating problems resulting from such things as corrosion, scaling, plugged fractures, and short-circuiting of cool fluid through the fracture system. It was generally agreed that a well-instrumented and well-documented one-year flow test could answer these and more fundamental questions about HDR systems. Accordingly, a one-year "Long-Term Flow Test" (LTFT) of the Phase II system was scheduled.

Program activities during FY87 were directed primarily toward preparations for that

test. These included background and engineering studies that would permit it to be planned and executed efficiently; collecting the information that would increase understanding of system behavior and would be useful to future HDR energy developments elsewhere; and preparing the site and its underground and surface facilities for continuous long-term operation.

Fatigue failure of the connection between an injection flow line and a wellhead flange terminated a massive hydraulic-fracturing operation in well EE-2 in 1983. This resulted in an uncontrolled, high-velocity vent to the atmosphere of a large volume of superheated water, which damaged the 245-mm (9-5/8-in.) well casing. Resulting leaks in the lower part of the casing were successfully sealed with cement, but the cement had deteriorated and the leaks had reopened by the time of the ICFT. Further, attempts to log the well at that time encountered an unidentified obstruction in the 178-mm (7-in.) liner at a depth of about 3200 m (10,500 ft). In November 1986, removal of several sections of the liner showed that it had partially collapsed at that depth. Caliper logs and impression-block runs showed that the casing had collapsed around the liner — presumably as a result of the pressure reduction in the well that accompanied the rapid vent, which was described above.

Two attempts to mill out the obstruction and re-enter the liner at greater depth were unsuccessful, apparently because the collapsed upper end of the liner forced the mill to one side where it penetrated the casing and entered the reservoir rock. A short flow test showed that the milling operations had not significantly affected fluid circulation through the reservoir or up the EE-2 wellbore. However, the condition of the well was obviously precarious and represented a serious risk that it would not survive a one-year flow test. At this point repair operations were suspended. Several options were considered with regard to preparing EE-2 for the LTFT.

Further attempts to mill through the collapsed region appeared unlikely to succeed and would be expensive for rig time. Use of the well in its existing condition involved the risk of premature termination of the critically important LTFT and would make it impossible to collect

information on reservoir behavior in the uncased production zone below the region of casing collapse. Minor repairs could be made by cementing behind the casing to seal leaks and improve casing support. Finally, the well could be sidetracked above the collapsed region and redrilled through the fractured reservoir, bypassing not only the known trouble spot but the entire lower part of the well — where the condition was doubtful.

A Reservoir Damage Evaluation Panel of drilling and reservoir experts was convened by the US Department of Energy (DOE) to consider these options. Its recommendations were to sidetrack and redrill the well and to repair it above the kickoff point for sidetracking by cementing behind the casing from that point to the surface. This involved some risk of casing damage during redrilling and of poor connections to the major flow channels in the reservoir; its high cost could not be covered by the FY87 budget except by reducing staff, terminating various support activities, and scheduling the work so that it would be completed in FY88; and it delayed starting the LTFT. However, it represented complete repair of well EE-2, and so the Panel's recommendations were accepted.

Preparations for the repair of EE-2 and for the ensuing LTFT required a great deal of planning, field investigations at Fenton Hill, procurement of equipment and materials, site preparations, contract negotiations, and instrument development, in addition to routine support and maintenance operations and environmental monitoring.

Planning for the repair of well EE-2 required, first of all, a thorough investigation of its current condition and interactions with the reservoir formation and fracture systems around it. This involved a careful review of its history, detailed downhole logging — including repeated temperature surveys, evaluation of the subterranean geology through re-examination of cores and cuttings, and limited pressurization and flow tests.

The recommendation of the Reservoir Damage Evaluation Panel that the new wellbore trajectory remain within 15 to 30 m (50 to 100 ft) of the existing well to maximize the probability that it would intersect the major flow paths connected to that well imposed a

constraint on selection of a redrilling target. Pressure analysis of the effects of the bypassed lower section of EE-2 on subsequent reservoir performance confirmed the desirability of maintaining that relatively close spacing. Within this limit, target selection was based on application of the newly developed three-point method to the source locations of the microseismic signals produced by the fracturing events that created flow paths through the reservoir. Those source locations were determined more rigorously with improved techniques, and the three-point method was then used to identify the probable locations and orientations of planes within the fractured reservoir that were the major paths of fluid flow to the production well. Confidence in the method increased when the most statistically significant of the planes thus identified was found to intersect the EE-2 wellbore in the region in which temperature logging indicated the greatest inflow of hot water from the reservoir during flow tests. Accordingly, the primary target selected for redrilling was a point on that plane — within the distance limit noted above — which was densely populated with source locations of microseismic signals. Attempts were then made to develop a redrilling trajectory that would also intersect planes above and below the plane that, from the three-point analysis, also appeared most likely to represent significant flow paths.

Design of the drilling trajectory also involved selecting a kickoff point in a competent section of rock above the region of casing collapse, minimizing directional drilling (especially in the deeper, hotter part of the reservoir), and avoiding severe doglegs (sharp changes of direction) in the new wellbore. Detailed plans for redrilling and well repair included specifications for the hardware and materials required and the procedures to be used and also design of cementing operations that would avoid interactions with the old wellbore, provide a base to support the whipstock to be used for sidetracking, and seal and support the well casing. A drilling contract was negotiated, necessary components (such as the whipstock) were ordered, and appropriate cement formulations were tested and their constituents procured and stored.

Actual repair of well EE-2 began with mobilization of the drilling rig on September 8, 1987. By the end of FY87 on September 30, the bottom of the well had been plugged with cement up to the point at which it was to be sidetracked; casing leaks had been sealed with high-strength cement; the annulus behind the casing had been filled with lightweight cement from below the kickoff point up to a lost-circulation zone at a depth of 735 m (2410 ft); and a window for sidetracking had been milled through the casing in the depth interval 2953 to 2971 m (9688 to 9747 ft) — with good cement below it to support a whipstock. Preparations had begun to install the whipstock and sidetrack the well.

In the meantime, preparations continued for the LTFT. Detailed plans were made for test procedures, for special experiments to be conducted during the test, and for the instrumentation and analyses required to derive as much useful information as possible from the entire operation. A PERT chart was generated covering design, procurement, and construction schedules. The surface system for the test was designed, long-lead-time items were identified, specifications for them were developed, and items that were well defined were purchased and installed. The 5-million-gallon water-storage reservoir was cleaned and repaired. A prefabricated metal building was acquired to house some components of the makeup-water and fluid-circulation systems. In preparation for logging through 114-mm (4-1/2-in.) production tubing, a slimline cablehead and several slimline logging tools were designed, built, and tested. The borehole acoustic televiewer was modified to improve its reliability, software algorithms were developed to reduce and analyze data from it, and the improved instrument was tested successfully in Fenton Hill well GT-2. A small shop/office trailer was added to expand the data acquisition system.

Development of the three-point method of fracture mapping, used to select the target for redrilling well EE-2, is an important extension of the microseismic fracture-mapping technique. It involves identification of all planes in the fracture system determined by any three points in the mapped array of the source locations of the microseismic signals produced by fracturing

events. Those planes whose orientations appear most commonly are assumed to represent pre-existing joints or zones of weakness in the formation; and specific planes having those orientations along which there are significant clusterings of source locations are considered to be hydraulically stimulated paths for fluid circulation through the reservoir. Correlation of the results of this analysis of the Phase II fractured reservoir with the major zone of fluid entry into well EE-2 during the ICFT is a significant indication of its usefulness. However, the critical test of the method will be in the success of intersecting fluid-flow paths during the redrilling of well EE-2.

Computer simulations of EE-2 performance during the ICFT were made using the wellbore heat- and mass-transfer code (WBHT). Comparison of predicted production temperatures with measured values showed a disparity that increased with time. It was determined that this resulted from use during the ICFT of a volumetric flowmeter whose measurements of outlet flow rate were erroneously high because of the presence of gases in the liquid produced. A similar discrepancy was observed when the subsequent venting of the system through EE-2 was modeled, for the same reason. For accurate measurement of production flow rates during future operations, it will evidently be necessary either to add a gas separator upstream of the point of flow measurement or to maintain fluid pressures high enough to keep the gases in solution.

A geochemical model of the first five days of the ICFT identified individually the changes in dissolved-species concentrations in the produced fluid that resulted from displacement of *in situ* pore fluid, from dissolution reactions, and from adsorption on rock surfaces or other rock-water interactions. In addition, a new geochemical-equilibrium model was developed that accounts for all major dissolved species and relevant equilibrium reactions. It will be used to improve chemically reactive tracer tests and to design and analyze a silica-dissolution experiment that should lead to better understanding of reservoir temperature patterns, rock-surface area, and flow distribution.

Tracer techniques using reactive chemicals are being developed to track thermal fronts in fractured reservoirs as they are cooled by fluid

circulation through them. Early laboratory experiments identified tracers with chemical kinetics suitable for reservoirs in the temperature range 75° to 100°C. During FY87 kinetics studies have focused on the hydrolysis of bromobenzene derivatives. This class of reactions can be used in reservoirs ranging in temperature from 150° to 275°C, which is of greater interest to geothermal operations. The preferable tracers in this group have been identified.

A three-dimensional finite-element model was developed and matched to hydraulic, thermal, tracer, and water-loss data from the ICFT. It was then used to simulate long-term performance of the production well under the conditions that existed during the ICFT and for two proposed trajectories of the redrilled well.

A heat-transfer model based on inert-tracer data has also been developed. It uses a tracer-determined residence-time distribution and an estimate of fracture porosity to predict the long-term thermal performance of an HDR reservoir. It predicts a broad range of thermal responses for the Phase II system depending on the value of fracture porosity assumed — which emphasizes the need to develop better *in situ* methods of determining fracture porosity (or, more fundamentally, the rock volume bathed by the heat-extraction fluid). The model does, however, indicate that measurable thermal drawdown should occur during the one-year LTFT.

A semi-analytical reservoir model is being developed that solves for both pressure distribution and heat transfer in the reservoir while avoiding the need for two-dimensional discretization of the reservoir region. For the region surrounding the production well, the hydrodynamics are solved assuming a bounded, stratified, porous system with flow across the layers. The two-dimensional pressure-diffusion equation is solved analytically subject to zero far-field pressure, a prescribed production flow rate, and a time-dependent pressure at the interface of the production region and the discrete flow channels. Provisions are made for orthotropic permeability distributions as well as transient boundary conditions. The effect on the pressure distribution due to the flow in the third dimension is included by using a lumped approximation. For heat transfer, correlations are obtained for transient heat conduction in

rock blocks of arbitrary sizes, which are then used to model thermal depletion. When the final model is completed, its results will first be compared with data from the 30-day ICFT.

Since 1974 water and soil samples from the geothermal site and from nearby groundwater and surface and discharge areas have been analyzed to identify any changes resulting from Fenton Hill operations. Only seasonal fluctuations were noted during FY87. Vegetation and soil samples from the canyon below the GT-2 mud pond, which receives occasional effluent releases from the on-site storage ponds, actually showed a decrease in chemical uptake with time.

During FY87 wastes from the GT-2 pond area were analyzed, found nonhazardous, and removed. The pond was filled and graded as nearly as possible to its original surface contours. It will be replanted with seedlings provided by the Forest Service.

With DOE funding, Bechtel National and Chevron Resources have undertaken an assessment of possibly developing a commercial HDR system in the geothermal area west of the Roosevelt Hot Springs hydrothermal reservoir in Utah. Initial results of the study are encouraging. Los Alamos has provided background information on the proposed site and on the appropriate technology developed at Fenton Hill, and it serves the partnership in an advisory role.

Two meetings of the Executive Committee of the National Hot Dry Rock Program Development Council were held during FY87. The committee received reports on the progress, status, and plans of the HDR Program and gave special attention to the problems of repairing and redrilling Fenton Hill well EE-2.

1. INTRODUCTION

1.1. The HDR Concept

The objective of the HDR Program is to develop the technology required for economical commercial recovery of useful thermal energy from naturally heated rock at accessible depths in the earth's crust. Although other methods of energy recovery are potentially useful in other geologic environments, the Program has so far

concentrated on the common case of hot crystalline rock of low initial permeability; the use of fluid pressure downhole (hydraulic fracturing) to create flow passages and heat-transfer surface within the rock; and operation of a recirculating pressurized-water loop to extract heat from the rock and transport it to the surface. The useful heat is removed at the surface through heat exchangers, and the cooled water is reinjected to recirculate through the fractured rock and recover more heat from it.

This heat-extraction concept, conceived and being developed at the Los Alamos National Laboratory (LANL), is illustrated schematically in Fig. 1. It is designed to utilize the largest and most broadly distributed energy resource that is available to man — the natural heat in the earth's interior. Because it is completely contained and produces no combustion or nuclear reaction products, its development and utilization present minimal risk to the environment and, at usefully high temperatures, its essentially inexhaustible energy supply is accessible almost everywhere.

1.2. Synopsis of the HDR Program through FY86

This HDR geothermal energy concept originated at LANL in 1970. Background and field investigations between 1970 and 1974 were encouraging with regard to the practicality of developing hydraulically fractured HDR systems. An area about 35 km (21 mi) west of Los Alamos appeared to be well suited for large-scale HDR field experiments. At Fenton Hill, a convenient location within that area, the world's first HDR energy system was completed in 1977. It was enlarged in 1979 by additional hydraulic fracturing and operated successfully for more than a year. This "Phase I" or "Research" system extracted heat from hydraulically fractured granitic rock at a depth of about 3000 m (9850 ft), where the initial rock temperature was around 185°C (365°F), and brought it to the surface in pressurized water at 135° to 140°C (275° to 285°F) and rates up to 5 MW_t (thermal megawatts; about 17 million Btu/hr). Some of the heat was used to operate an experimental binary cycle power plant, which produced 60 kW (kilowatts) of electricity that was

Fig. 1. HDR concept.

used at the site. System operation was essentially trouble-free, and there was no detectable scaling, plugging, corrosion, or environmental effect.

Successful completion and operation of the Phase I system at Fenton Hill accomplished the original goal of the HDR Program. In a populated area, it could have heated several hundred homes for many years, and it demonstrated the engineering feasibility and commercial usefulness of HDR energy systems. However, it did not produce heat at a temperature or rate that would support economical operation of a commercial electrical-generating power plant in competition with fossil-fuel-fired or nuclear energy plants. Because higher-temperature HDR systems had the potential to do so and a worldwide need existed for clean alternative energy supplies, the HDR Program was extended to attempt to meet those more demanding requirements.

Under this new directive, construction of a larger, deeper, hotter "Phase II" or "Engineering" HDR system began at Fenton Hill in 1979. Two new wells were drilled, about 50 m (150 ft) apart at the surface, the deeper one to a vertical depth of 4390 m (14,400 ft) where the rock temperature was 327°C (620°F). From hydraulic-fracturing theory and experience in creating the Phase I system, hydraulic fractures produced in the Phase II system were expected to be substantially planar and vertical, with an approximately north-northwest strike. Therefore, to provide the horizontal separation needed for thermally isolating a series of such fractures, the bottom 1000 m (3280 ft) of the first well was drilled toward the east-northeast and inclined at 35° to the vertical — as illustrated in Fig. 2. The second well was then directionally drilled with its inclined section 380 m (1250 ft) vertically above that of the first well.

Hydraulic-fracturing experiments were conducted at various depths in these two wells during 1982, 1983, and 1984. Unexpectedly, the fracture systems produced were three-dimensional rather than planar, inclined rather than vertical, and did not meet each other or connect the two wells hydraulically. (This unusual fracturing behavior is probably the result of a joint pattern in the reservoir rock, related to the presence of a cooling magma

Fig. 2. Phase II conceptual design.

body underlying a volcanic caldera a few kilometers east of Fenton Hill.) Because it appeared unlikely that further hydraulic fracturing would establish the required connection, it was concluded that a more promising approach would be to redrill one of the wells directionally through a fracture system created from the other well.

The largest of the potential redrilling targets was the fractured volume produced in December 1983 by the Massive Hydraulic Fracture (MHF) Experiment, during which 21,300 m³

(5.63 million gallons) of water were pumped at 48-MPa (7000-psi) pressure into an isolated section of the deeper well, EE-2, in the depth interval 3529 to 3550 m (11,580 to 11,650 ft).

Accordingly, during the spring of 1985, the upper well, EE-3, was sidetracked at a measured depth of about 2830 m (9285 ft) and completed at a final depth of 4018 m (13,182 ft), where the rock temperature was about 265°C (510°F). The sidetracked well, now identified as EE-3A, did intersect several of the fractures produced by the MHF operation, which provided good flow connections to well EE-2 — from which they had been produced. These fractures and the two wells, EE-2 and EE-3A, constituted the Phase II underground heat-extraction loop.

After several preliminary experiments, the ICFT of the Phase II system was conducted over a period of 30 days in May and June 1986. A total of 37,000 m³ (9.76 million gallons) of cool water was injected through well EE-3A, of which 66% was recovered through the production well, EE-2, during the test, and an additional 20% was recovered during a subsequent vent of the system — from temporary storage in the pressurized fracture system. Pumping rates were usually either 10.6 or 18.5 l/s (168 or 294 gpm), at surface pressures around 26.9 MPa (3900 psi) and 30.3 MPa (4400 psi) respectively. To prevent boiling and carbon dioxide evolution downhole, a back pressure of about 3.5 MPa (500 psi) was maintained on the production well, resulting in fluid-production rates of 6.3 to 13.9 l/s (100 to 220 gpm). Temperature of the produced fluid increased throughout the 30-day test, to a maximum of 192°C (378°F), and the rate of energy production increased correspondingly, to 10 MW_t (34 million Btu/hr). Overall flow impedance through the fractured reservoir decreased throughout the test.

Leaks in the 245-mm (9-5/8-in.) casing of the production well were discovered at depths of 2865 to 3110 m (9400 to 10,200 ft), and the casing had partially collapsed at 3200 m (10,500 ft) — preventing well logging below that depth. Accordingly, a draft procedure was prepared for repairing well EE-2 in FY87.

Construction of HDR systems is based on oil-field technology in drilling, hydraulic fracturing, and well logging, and commercial

drilling and service companies have, under contract to the HDR Program, performed most of these functions. However, the high-temperature hard-rock environment, the precision required in directional-drilling and fracturing operations and in well-logging and system monitoring, and the new types of experiments and measurements undertaken have all required improved or new equipment, instrumentation, techniques, and analyses. Much of the necessary research and technology development has been done in cooperation with or by contract to commercial organizations, universities, other laboratories, and individual consultants, but much has also been done by the HDR staff at LANL. These supporting activities have been an essential part of the HDR Program throughout its history. They are continuing, and many of their results are reported in the pages that follow.

1.3. FY87 Objectives

The major objectives of the HDR Program for FY87 were the following:

- complete the repair of Fenton Hill well EE-2 to increase its pressure capability, reduce fluid loss from it, and provide for logging through the reservoir's fluid-producing zone during the LTFT;
- continue development and improvement of flow connections between the fractured reservoir and the injection and production wells;
- continue field experiments that will include brief flow tests, tracer studies, and acquisition of well logs and microseismic data needed for reservoir diagnosis to characterize the Phase II fractured reservoir, extend the results of the ICFT, and confirm modeling results;
- continue geochemical studies relating to mineral deposition and scaling, carbon dioxide evolution, stress-corrosion modes, cement chemistry, and development of chemical techniques for assessment of reservoir characteristics and rate of thermal depletion;
- reduce, analyze, and document data from reservoir testing;
- continue the analysis and design effort needed to model the Phase II reservoir

thermally and fluid dynamically and to plan for its modification, testing, and long-term operation;

- establish final criteria for design and construction of the surface loop for the LTFT;
- begin procurement, assembly, and check-out of surface-system components and construction of the surface system;
- insure acquisition, storage, and management of a water supply adequate to operate the Phase II system continuously during the LTFT;
- complete development and testing of the prototype high-temperature digital borehole acoustic televiwer and use it to survey the EE-3A wellbore;
- continue development of one-tool and two-tool hodographic techniques of fracture mapping;
- continue support services and environmental monitoring at Fenton Hill;
- support the Electric Power Research Institute (EPRI) in completing its economic study of HDR energy systems; and
- continue and extend the technology exchange with industry and with other organizations involved or interested in HDR development.

2. INDUSTRIAL RELATIONS

2.1. Bechtel/Chevron Study of HDR at Roosevelt Hot Springs

The Roosevelt Hot Springs geothermal area in southwestern Utah extends westward from the Mineral Mountains into the Milford Valley. The geothermal area is crossed by a major north-south structure, the Opal Mound Fault, about 3.5 km (2 mi) west of and roughly parallel to the Mineral Mountain Range. A productive high-temperature hydrothermal reservoir has been developed in the hot-springs area between this fault and the base of the mountains and has been the energy supply for an electrical power plant since 1984. However, deep exploratory holes drilled into the granitic basement rock in the Milford Valley west of the Opal Mound Fault have been very hot but essentially dry.

Investigations by the Los Alamos HDR staff of two of these "dry holes" in the Milford

Valley have indicated that a large area west of the fault is promising for HDR development. (In many respects, it is similar to the Fenton Hill area.) Further, a Los Alamos investigation of the aquifer in the alluvial sediments overlying the basement rock showed that it represents an abundant supply of water that is naturally contaminated by geothermal fluids leaking out of the hydrothermal reservoir. Its chemical content makes it unsuitable for consumption by man or domestic animals or for irrigation, but it is usable as the water supply for an HDR energy system.

With DOE funding support, Bechtel National, Inc., and Chevron Resources Company have undertaken an assessment of the area west of the Opal Mound Fault as a possible site for a commercial HDR system to generate electricity. (Los Alamos personnel have served in an advisory role.) Initial results of this study are encouraging and indicate that a 50-MW_e (megawatts electric) HDR facility could generate electrical power at a cost competitive with that of coal-fired plants. This, however, is contingent particularly on the thermal productivity and depletion rate of the fractured HDR reservoirs.

The Bechtel/Chevron study proposes drilling and casing the injection well; fracturing from it at a series of depths within the hot basement rock; intersecting the fractures with the production well; circulating water through the fractures; and — at the surface — using a two-stage flash process to produce steam to drive the power-plant turbine. The study recommends federal support for an industrial HDR experiment at this site, which could be generating electric power by 1997. However, this is contingent on positive results concerning well-pair productivity and reservoir-depletion rate from the LTFT of the Phase II system at Fenton Hill.

2.2. Evaluation of the Clear Lake Area for the City of Clearlake, California

The Geysers-Clear Lake geothermal area is located in the northern coast ranges of California, about 150 km (90 mi) north of San Francisco. The Geysers area contains an extremely productive vapor-dominated hydrothermal reservoir; natural steam from the reservoir

supplies the energy requirements of the world's largest complex of geothermal power plants. To the northeast, separated from The Geysers area by the Collayomi fault zone, is the Clear Lake volcanic field, which has been active within the last 10,000 years. Geothermal prospecting there has discovered a few small water-dominated hydrothermal systems and has produced a large number of very hot dry holes. It is an area of obvious interest for possible HDR development, and in the past the Los Alamos HDR staff has studied the geology of the area and collected and analyzed much of the available information on existing wells, including their lease status.

The California Energy Commission and the City of Clearlake are interested in exploring the feasibility of HDR development in the volcanic area northeast of The Geysers steam field. With funding provided by the California Energy Commission, the city proposes that Los Alamos evaluate the data from existing dry holes in the area to select a well for experimental investigation. This initial study will involve no field work.

2.3. Meetings of the HDR Program Development Council

The National Hot Dry Rock Program Development Council (PDC) consists of an Executive Committee, which meets twice a year, and various subcommittees, which meet on call for limited periods to consider, in depth, specific technical aspects of the HDR Program. The Executive Committee reviews the progress, current status, plans, and financial situation of the overall Program and advises its management concerning its future activities.

No PDC subcommittees were active during FY87.

The Executive Committee met in Albuquerque, New Mexico, on February 5 and September 15, 1987. Its present members are

Stanley Bazant, Plains Electric Generation and Transmission Cooperative;

Bob Greider (Chairman), Geothermal Resources International;

Robert Lacy, San Diego Gas and Electric Company;

Parker Mathusa, New York State Energy Research and Development Agency;

Shigeyoshi Oba, New Energy Development Organization, Japan;

Martin Robbins, Colorado School of Mines;

Vasel Roberts, Electric Power Research Institute;

Randall Ward, California Department of Conservation; and

Daniel Yueh, Stone & Webster Company.

A few nonmembers are customarily invited to attend such meetings, including representatives of the DOE, LANL, and other organizations involved or interested in HDR-related activities. The latter are often asked to report on their own programs. Such reports were given by Janet Owens on the Bechtel/Chevron study described above and by Michio Kuriyagawa on the Japanese HDR Program, which is closely associated with the US HDR Program. Bob Greider also reported on a workshop held at Los Alamos in July 1987 on possible uses of the Fenton Hill facilities after completion of the LTFT of the Phase II system.

As it has previously, the Committee emphasized the crucial importance of a long-term flow test to industrial interest in and future development of HDR energy systems. Therefore, at both of its 1987 meetings, the Committee gave particular attention to the condition and proposed repair of EE-2, the production well of the Phase II system, and its effect on initiation and conduct of the LTFT.

As has been mentioned, leaks were discovered in the EE-2 casing in the depth interval 2865 to 3110 m (9400 to 10,200 ft), together with partial collapse of the casing and 178-mm (7-in.) liner at 3200 m (10,500 ft). This resulted in fluid loss from the well, a restriction in the flow path through it, and a barrier to logging down into the fractured reservoir. Use of the well in that condition would greatly reduce the amount of information that could be collected on reservoir behavior during the LTFT and would risk further casing collapse that could terminate the LTFT prematurely.

Therefore, as a first step in well repair, an unsuccessful attempt was made to fish out the liner and mill out the obstruction at 3200 m. However, a short flow test showed that this attempt had not increased either flow impedance or the rate of water loss, although the condition of the well was obviously precarious. Because of the severe limitations on Program funding and the importance of initiating the LTFT as soon as possible, LANL proposed to accept the disadvantages and risks of using the well in substantially its existing condition, with only minor cementing operations to seal and stabilize the casing.

Because of the importance of a successful LTFT, the DOE convened a Reservoir Damage Evaluation Panel — a group of experts on drilling and well completion — to review and assess this decision and the other possible options for repair and use of well EE-2. The Panel recommended that EE-2 be completely repaired by sidetracking it above the damaged region and redrilling along a trajectory close to and substantially parallel to the existing well.

At its February meeting, the PDC Executive Committee instead recommended that the Program proceed with the lower-cost, quick, partial repair of EE-2 so that the LTFT could begin in FY88 and the money otherwise spent on more extensive repairs could be used to preserve the existing HDR staff and continue most of its other activities. Nevertheless, after a series of further meetings among DOE, LANL, and members of the Reservoir Damage Evaluation Panel, a firm decision was reached to proceed with sidetracking and redrilling — in spite of the high cost and programmatic delay that would result.

This decision and its implications were discussed at length at the PDC Executive Committee meeting in September. Opinions were divided. Concerns were expressed about both the high cost of redrilling and the large reduction in staff and other programmatic activities required to pay for it; the risk to the existing well and to the underground circulation loop of sidetracking and redrilling operations; the possibility that a new well trajectory would miss the main flow paths through the reservoir; and the long delay in initiating the LTFT that would result. However, there was also support for the redrilling option since the risk to

the underground loop appeared acceptable; the production well must be in condition to survive a long-term flow test; and the ability to log that well through the uncased reservoir section is important to collecting the information required to understand and evaluate reservoir behavior. Successful completion of a long flow test and good data on reservoir characteristics are essential to future industrial interest in commercial development of HDR energy systems.

A firm decision having already been made that EE-2 would be sidetracked and redrilled, the PDC Executive Committee could only urge that Los Alamos proceed with it as quickly as possible so that the LTFT could begin as soon as possible.

3. REDRILLING FENTON HILL WELL EE-2

3.1. Initial Repair Attempt

The ICFT of the complete Phase II heat-production system was conducted during May and June 1986 and is discussed in the FY86 HDR Annual Report and LA-11498-HDR. It involved 30 days of continuous circulation of water through the fractured reservoir, with EE-3A as the injection well, EE-2 as the production well, and an air-cooled heat exchanger at the surface to remove the useful heat from the recirculated fluid and provide cool water for reinjection. After the ICFT was completed, the two wells were shut in until late September to observe the slow decay of fluid pressure in the reservoir. Then the remaining fluid was vented to the surface through well EE-2.

The 245-mm (9-5/8-in.) casing in well EE-2 was badly damaged during an uncontrolled vent in 1983 (which resulted from fatigue failure of a connection between an injection flow line and a wellhead flange). Resulting leaks through the lower part of the casing were successfully sealed by two squeeze-cementing operations, but by the time of the ICFT there were again indications of leaks in the depth interval 2865 to 3110 m (9400 to 10,200 ft) — indicating deterioration of the cement. Further, attempts to log the well encountered an obstruction in the 178-mm (7-in.) liner at about 3215 m (10,550 ft).

To evaluate the condition of the well, the 140-mm (5-1/2-in.) production tubing was removed from the well together with the casing packer at its lower end. Three attempts were made to fish out the 178-mm (7-in.) transition liner that extended downward from the casing packer at 3170 m (10,400 ft). On the third attempt, the tie-back sleeve and two joints of the liner were removed. The lower joint was found to have partially collapsed at 3200 m (10,500 ft). Caliper logs and impression-block runs showed that the 245-mm (9-5/8-in.) casing had also collapsed around the liner.

Two attempts were made to mill out the obstruction and re-enter the remaining 178-mm (7-in.) liner. Neither was successful. Apparently the collapsed upper end of the liner acted as a whipstock, forcing the mill to the side, i.e., out through the casing and into the rock.

Additional attempts to re-enter the lower part of EE-2 would have required an extensive and expensive fishing operation, with high mechanical risk. In addition, there was the possibility that additional casing and liner collapse had occurred at greater depths. Therefore, the drilling rig was furloughed and the condition of the well was investigated further.

A short flow test — pumping water into EE-3A while venting EE-2 — showed that flow impedance and rate of water loss were about the same as they had been during the ICFT, indicating that the fishing and milling operations described above had not plugged EE-2 or the flow paths through the reservoir.

Several options were considered for preparing well EE-2 for the LTFT. (1) Continue milling and fishing operations to clean out the well, then cement in a liner. The probability of success of this option appeared to be small. Additional milling operations would further damage the already weakened casing, and cost was unpredictable — but probably very high. (2) Sidetrack the well above the region of casing collapse and redrill it through the fracture system. This would provide a clean new well through the reservoir and permit logging through the fractured region. Technically, this was the most attractive option, although some risk would be involved — both mechanical and with regard to achieving good connections to the major flow paths through the reservoir.

However, the estimated cost of about \$1.4 million could not be covered by the current HDR budget. (3) Use the well in its existing condition. This would accept the risk of further casing collapse and increased water loss and would not permit logging instruments to enter the fractured reservoir. (4) Cement behind the casing in the region where leaks had been discovered, then use the well in that condition.

In view of budget limitations and to minimize delay in initiating the LTFT, LANL proposed to undertake only minor cementing operations to seal and stabilize the casing and then to use the well in substantially its existing condition.

3.2. The Reservoir Damage Evaluation Panel

Following the initial attempt to repair well EE-2, the Geothermal Technology Division of the DOE convened an advisory panel to help evaluate existing conditions and make recommendations. The group met in Los Alamos on December 19, 1986, and included a panel of reservoir specialists and a panel of drilling experts. Los Alamos presented the history and known conditions to the panels with options for sidetrack redrilling or continuing with flow experiments with little or no further repair. Further fishing efforts were considered to be too costly. The group recommended sidetrack redrilling to re-enter the existing reservoir. This would allow logging into the reservoir region for complete studies and eliminate any difficult-to-evaluate effects of the damaged wellbore. A second meeting with the group was held in Washington, DC, in April to review details of the plans developed in response to the December recommendation. The drilling panel agreed with the proposed plans in general and added three strong recommendations based on the options presented: (1) place lightweight cement around the existing 245-mm (9-5/8-in.) casing from existing cement top to surface; (2) redrill near the existing EE-2 wellbore to a depth below the concentration of microseismic events defining the main reservoir; and (3) install a 178-mm (7-in.) liner from the reservoir region to surface.

Plans for redrilling proceeded accordingly.

3.3. Redrilling Plans

The repair and sidetracking of well EE-2 at Fenton Hill had these primary objectives:

- increase both its capability to withstand high pressures — in reservoir-stimulation and high-back-pressure operations — and the probability that it would perform satisfactorily throughout a one-year flow test;
- reduce water loss by sealing both the annulus behind the casing and leaks in the casing;
- permit logging through the uncased reservoir section below the casing;
- reduce flow impedance in the production well, increasing rates of flow and energy production at constant fluid pressure in the reservoir; and
- accomplish all this without increasing flow impedance within the reservoir, either by reducing the number of fractures intersected by the well or by blocking those flow paths.

Plans for repairing EE-2 by cementing, sidetracking, redrilling, and recompleting the well were prepared by LANL staff and consultants, reviewed by another consultant, and then presented to DOE's Reservoir Damage Evaluation Panel. After minor revisions in accordance with the Panel's recommendations, the overall plan included the following major activities:

- Select a drilling target and well trajectory that will maximize the probability of intersecting the principal fractures in the reservoir (as discussed in Section 6 of this report), while staying within 15 to 30 m (50 to 100 ft) of the original EE-2 wellbore — as recommended by the Reservoir Damage Evaluation Panel. Plan a drilling program to sidetrack the well at about 3000 m (9800 ft), above the region of casing collapse, and drill a 216-mm (8-1/2-in.) hole directionally to a final depth of about 3800 m (12,500 ft).
- Plug back the old wellbore below the proposed kickoff point at 3000 m (9800 ft) with cement to prevent cross flow of water at various temperatures or depths between the fractures intersected by that well and

to eliminate the effect that would have on reservoir performance. This will also reduce uncertainties in the results of later tests intended to measure such reservoir characteristics as volume, flow impedance, rate of water loss, and response to high back pressure in the well.

- Perforate the 245-mm (9-5/8-in.) casing at 2985 m and 3155 m (9800 ft and 10,350 ft) and squeeze-cement the annulus behind it to shut off flow to a low-pressure leakoff zone at about 2985 m and to provide support for the casing in the region of the sidetracking operations.
- Perforate the 245-mm (9-5/8 in.) casing above the present top of cement at about 1980 m (6500 ft) and squeeze-cement the annulus to the surface to reduce damage to it during redrilling. As recommended by the Reservoir Damage Evaluation Panel, use lightweight cement followed by high-strength cement to cover the perforations.
- Mill an 18-m (60-ft) section through the casing at about 2985 m (9800 ft).
- Install an oriented Packstock (a whipstock that is locked in place mechanically) just below the milled-out section to kick out of the well to the west and slightly upward.
- Use a special rotary drill-off assembly to start the sidetrack hole from the milled-out section and to extend it to a distance of 5 to 6 m (15 to 20 ft) from the old well. Correct the hole direction using a bent sub above a downhole motor. Then use normal rotary drilling toward the target, with downhole-motor runs as needed to keep the hole substantially parallel to the old EE-2. So far as possible do the directional drilling in the cooler upper part of the hole and restrict dogleg severity to 2°/30 m (100 ft). Use a sepiolite drilling-fluid system to provide good cuttings removal and reduce wear on the casing and drilling assemblies.
- Pump water continuously into well EE-3A during redrilling to maintain a fluid pressure of about 14 MPa (2000 psi) in the fractured reservoir. This will cause water to flow into the redrilled well (now identified as EE-2A) when it intersects fractures in the reservoir, indicating that a hydraulic connection has been made to EE-3A and

preventing drilling mud and cuttings from entering and plugging those fractures.

- Cement in a 178-mm (7-in.) liner from 3500 m (11,500 ft) upward, reaching at least 90 m (300 ft) into the 245-mm (9-5/8-in.) casing to isolate the whipstock and the casing to above the top of the window. [Final permanent completion using a 178-mm (7-in.) liner cemented-in to the surface was still being considered when this plan was completed.]

The redrilling plan also included specifications for much of the hardware and materials needed and discussions of many of the supporting activities required.

3.4. Repair Progress through September 30, 1987

Big Chief Drilling Company Rig No. 47 was used in 1985 to redrill Fenton Hill well EE-3 and again in 1986 in the attempt to repair well EE-2 described above. The contract for its use was extended to include the final repair, sidetracking, redrilling, and completion of well EE-2A. Preparations for those operations having been completed, the rig was mobilized over well EE-2 on September 8, 1987.

With the drill string and drilling tools in the hole, water was circulated and temperature logs were run to verify the well-temperature code to be used for predicting temperatures as functions of depth and time during cementing operations. Then the well was cooled at depths below 3178 m (10,428 ft) by injecting water into the formation, and this part of the well was plugged with cement.

The 245-mm (9-5/8-in.) casing was perforated in the interval 3115.2 to 3116.4 m (10,221 to 10,225 ft), and water was pumped through the perforations to cool the formation outside the annulus surrounding the lower part of the casing. Then cement was displaced through the perforations to seal the annulus.

The 245-mm casing was perforated again in the interval 2909.5 to 2910.7 m (9546 to 9550 ft), the formation was cooled by pumping water through the perforations, and the void behind the casing was filled with cement.

After the cement left in the well had been drilled out to a depth of 3014 m (9889 ft),

a window for sidetracking the well was produced by milling out the 245-mm casing from 2952.8 m (9688 ft) to 2970.7 m (9747 ft). Then the well was cleaned out to the top of the cement and cooled by circulating water through it.

In preparation for cementing the annulus outside the 245-mm (9-5/8-in.) casing to the surface, the well was filled with sand to a depth of 2969.2 m (9742 ft) and the sand was topped with a 2.77-m³ (17.4-bbl) cement plug. The casing was perforated between 1972 and 1973.8 m (6470 and 6476 ft), and the annulus cooled by pumping water through the perforations. Finally, 76.5 m³ (481 bbl) of lightweight cement followed by 3.8 m³ (24 bbl) of high-strength cement tail slurry were pumped down the well, and the cement volume required to fill the annulus to the surface was displaced through the perforations. On September 30, 1987, preparations began to install a Packstock and sidetrack the well.

3.5. Cementing Operations

As described above, preparation for the sidetracking and redrilling of well EE-2 involved five cementing operations designed to plug and abandon the lower part of the well, seal off flow behind the casing to a low-pressure leakoff zone at about 2985-m (9800-ft) depth, support the casing throughout its length, and provide a base for setting a whipstock. These cementing operations were carried out with only minor difficulties, and their results were evaluated by means of a cement-bond log and limited reservoir testing.

For several years, the cement formulation used in the geothermal wells at Fenton Hill consisted, by weight, of 60% Class H Portland cement and 40% D-66 silica flour, plus variable amounts of Dowell-Schlumberger's D-121 tri-functional additive — depending on downhole conditions. Several times it formed sheaths in the pipe or tubing used to place it, and in one case it set prematurely. Whether these difficulties arose from variations in the ingredients or from changes in downhole conditions during placement of the cement is not known. In any case, a new free-water test specified by the

American Petroleum Institute (API) that simulates downhole conditions instead of being carried out under surface conditions showed that this formulation produced a cement with excessive free water. Therefore the mix was adjusted to contain about 45% finely divided silica and to have zero or very low free water. Additional requirements such as density, thickening time, and batch-mixing time were specified for each individual job. Dowell-Schlumberger reserved supplies of cement and additives, and all laboratory tests were run using samples of the reserved materials and Fenton Hill well water.

The formulation used to plug back EE-2 below the proposed sidetrack was 55% Class H cement and 45% D-66 silica flour, plus 0.25% D-65 dispersant and 0.7% D-28 retarder. The volume of cement placed was 5.49 m³ (34.5 bbl). Limited reservoir testing indicated that the well was plugged successfully below a retainer set at 3178 m (10,428 ft).

The same cement formulation was used to seal the annulus behind the lower part of the casing by displacing 11.1 m³ (70 bbl) of slurry through casing perforations in the depth interval 3115.2 to 3116.4 m (10,221 to 10,225 ft). The cement extended from 3139 m to 2812 m (10,300 ft to 9225 ft), and reservoir testing showed that it eliminated upward flow through the annulus from the reservoir to the leakoff zone at about 2985 m (9800 ft).

To fill a void in the annulus behind the casing at a higher level and to provide good casing support for milling a window, setting a whipstock, and sidetracking the hole, 4.41 m³ (27.75 bbl) of the same cement slurry were injected through perforations in the depth interval 2910 to 2911 m (9546 to 9550 ft). A cement-bond log showed 47 m (155 ft) of cement fill between 2888 and 2935 m (9475 and 9630 ft) with good to excellent bond from 2895 to 2920 m (9500 to 9580 ft).

After the sidetracking section had been milled in the casing, the well was filled with sand to a depth of 2969 m (9742 ft) and the sand was topped with a 2.77-m³ (17.4-bbl) cement plug, which extended to above the top of the section. The cement formulation was the same as that described above except that only 0.6% instead of 0.7% D-28 retarder was used. Subsequent drilling operations showed that this cement provided a good base for the whipstock.

The final cementing operation in FY87 was an attempt to fill the annulus behind the casing from a depth of about 1981 m (6500 ft) to the surface, to strengthen and support the casing. Two cement formulations were used, pumped through perforations in the depth interval 1972 to 1974 m (6470 to 6476 ft). The lead slurry, pumped first to fill the upper part of the annulus, was 76.5 m³ (481 bbl) of a lightweight formulation consisting of 65% by weight of a one-to-one (by volume) mixture of Class G Portland cement and perlite and 35% D-66 silica flour, plus 2.0% prehydrated D-20 bentonite, 5.0 ml D-75 sodium silicate per kilogram of cement (0.056 gal/sack), 0.5% D-65 dispersant, and 0.3% D-28 retarder. The tail slurry, pumped immediately following the lead slurry, was 3.8 m³ (24 bbl) of a mix containing 55% Class H cement and 45% D-66 silica flour plus 0.75% D-20 bentonite, 0.35% D-65 dispersant, and 0.20% D-28 retarder. Because of breaks in the 340-mm (13-3/8-in.) intermediate casing in a lost-circulation zone at 735-m (2410-ft) depth, the lightweight cement filled the annulus only to that level and did not reach the surface. [A considerable volume — perhaps as much as 40 m³ (250 bbl) — evidently was pumped into the cavernous limestone formation that overlies the crystalline basement.] The cement-bond log showed fair to excellent cement bond from 1975 to 735 m (6480 to 2410 ft) except for two short sections of poor bonding at 1645 to 1651 m (5396 to 5416 ft) and 1605 to 1610 m (5265 to 5281 ft).

4. PREPARATIONS FOR THE LONG-TERM FLOW TEST

4.1. Test Objectives and Plans

The overall objective of the Long-Term Flow Test (LTFT) is to develop a comprehensive understanding of the structure, flow characteristics, geochemistry, and thermal-power potential of the multiply-fractured Phase II HDR reservoir; and, while doing this, to demonstrate that HDR geothermal energy is a technically viable source of thermal energy at a temperature high enough to support operation of a commercial power plant. The last part of the LTFT will include a series of two-hole

cyclic-production experiments that will approximate a potential load-peaking application of HDR for a commercial power plant.

The goals of the LTFT are to

- 1) determine the thermal characteristics of the reservoir (power versus time, extractable heat, and thermal-stress effects);
- 2) determine the time-varying hydraulic characteristics of the reservoir (water loss, flow impedance, and tracer-derived reservoir volume);
- 3) study the operating characteristics of the flow system (materials corrosion, scaling, reservoir geochemistry, borehole stability, and environmental acceptability);
- 4) confirm reservoir diagnostic techniques (temperature-sensitive chemically reactive tracers, radioactive tracers, microseismic-event monitoring, wellbore temperature and flow distributions from wireline logging, geochemical methods including geothermometry, and cross-well acoustic tomography);
- 5) verify analytical reservoir models; and
- 6) provide a data base and experimental analytical techniques for assessment of the feasibility of future HDR reservoirs at other sites.

The present plan for the LTFT is shown schematically in Fig. 3. The essential operations during this one-year test are as follows:

- 1) Perform an initial sequence of 30-day flow steps, incrementally inflating the reservoir while at the same time establishing pressure- and flow-rate-dependent reservoir parameters.
- 2) Near the end of each flow plateau, conduct a tracer test to determine the pressure-dependent reservoir volume.
- 3) After apparent maximum flow is established, vary the injection pressure — and therefore the reservoir pressure — to determine the maximum injection pressure that just precludes reservoir growth by fracturing (i.e., aseismic reservoir operation).
- 4) Perform a series of high-back-pressure experiments at 10.3, 17.2, and 22.1 MPa (1500, 2500, and 3200 psi) to assess the

Fig. 3. Experimental plan for the LTFT.

effect of back pressure on reservoir flow impedance.

- 5) During the subsequent long, constant-pressure flow test, at the injection pressure determined in 3) above, conduct a sequence of four stress-unlocking experiments (SUEs). These experiments will be conducted with full seismic coverage and will involve injection pressures approaching that of the previous MHF test, 41.4 to 48.3 MPa (6000 to 7000 psi) with the production well shut in. The high-pressure pumping phases of these SUEs would last no longer than eight hours each. The objectives of these experiments are to
 - a) briefly relax the confining earth stresses at the boundary of the cooled region, allowing the natural joints to realign and open — thereby, it is hoped, reducing the reservoir flow impedance, and
 - b) seismically map the boundary of the cooled region.
- 6) Conduct reservoir-tracer studies before and after each SUE to assess changes in effective reservoir volume.
- 7) At the end of the long, constant-pressure flow plateau, decrease the flow in steps — replicating the initial flow steps used in 1) above.

- 8) At the end of the decreasing flow steps, the reservoir will be tested in a cyclical injection-vent (huff-puff) mode for up to 30 days. As now envisaged, EE-3A will be pressurized on a 12-hour-per-day cycle, with EE-2A shut in. At the end of each 12-hour EE-3A pressurization cycle, EE-2A will be vented for 12 hours. If warranted, the injection pressure at EE-3A may be allowed to approach that used during the SUEs.

4.2. Loop Design, Construction Schedule, Component Procurement, and Site Preparation

4.2.1. Loop Design. The LTFT surface-loop design is based on the flow loop used during the ICFT conducted in the summer of 1986. A schematic of the LTFT surface system is shown in Fig. 4. This loop is designed to provide both maximum flexibility for experiments and maximum continuous on-line operation. All critical items are backed up on-line where possible, and spare parts will be available for quick repair elsewhere throughout the system. All functions that can be simply and cheaply automated will be; however, the actual control of the loop will be the responsibility of a team of operators who will control the system from the data acquisition trailer on an around-the-clock basis.

The purpose of the surface system is simply to control the flow from the production well, record the power produced, cool the fluid, add and record makeup water as necessary, then inject the combined streams back into the reservoir. The surface system must also be flexible enough to accommodate the many reservoir experiments planned, purge the production fluid of carbon dioxide if it rises above 0.5 wt%, provide a total-water inventory, and protect the wellbores from oxygen corrosion. (Oxygen-corrosion protection will be by the addition of the oxygen-scavenger sodium sulfite.)

Besides providing analysis of the carbon dioxide concentration in the production stream, the surface system will incorporate corrosion coupons for corrosion studies and provide for radioactive-tracer, chemically reactive tracer, and fresh-water-flush experiments.

4.2.2. LTFT Design and Construction Schedule. Figure 5 is a PERT chart that was generated late in the fiscal year, showing the target design, procurement, and construction schedule for the LTFT. The schedule was generated under the guidelines that the LTFT would follow the redrilling of EE-2 scheduled for the first quarter of FY88; major procurements and construction of the loop would occur during the second and third quarters of FY88; and the test would start in the fourth quarter.

4.2.3. Component Procurement and Site Preparation. With this schedule in mind and with a very limited budget available until redrilling was completed, we proceeded as follows.

The experience gained from the ICFT was examined, and a basic system design was conceived. Long-lead-time items were identified and specifications for these items were started, the major item being the main circulating pumps. Parts of the surface system that were well defined were purchased and installed. (This was confined primarily to the makeup-water system.)

A prefabricated metal building was purchased to house the makeup-water pumps, the oxygen-scavenging equipment, the main control valves, the control instrumentation, an air compressor, and some critical valves and instrumentation that were not protected from freezing during the ICFT but will have to be protected during the year-long LTFT.

Two frac tanks were procured to replace a water-storage tank that had deteriorated beyond repair. They will be used in the LTFT surface system to hold and mix makeup water.

Two 206-mm (8-1/8-in.) high-temperature/high-pressure open-hole packers, two spare packer elements, and two redress kits were ordered for possible use in up to four well-stimulation tests during the redrilling of well EE-2. Later, a decision was made to order two extra packer elements and associated hardware that would allow the packers to be run as production packers during the LTFT. When hot water is produced through them, they will be heated to above the temperature at which they were set — which is the reverse of the cooling

Fig. 4. Schematic showing the LTFT surface system.

Fig 5. PERT chart for design, procurement, and construction of the LTFT surface system.

that occurs when they are used for well stimulation. Calculations showed that, for use as production packers, they could be set at 3.5 MPa (500 psi) and no modification would be needed when fluid pressure was later increased.

Several piping-spool pieces were fabricated after our welder was recertified. All welds during the summer and fall were given an API inspection, including radiography, by an independent shop. This has given us the level of confidence necessary to assure a safe system.

A piping-stress-analysis program was located and purchased, and plans were made for a complete stress and flexibility analysis of the surface piping.

In-house studies on gas separators, oxygen scavenging, and hydrogen sulfide treatment were made. Independent outside studies were considered necessary to complement the hydrogen sulfide and gas-separator studies. The hydrogen sulfide study was done by Dr. M. Gopala Rao *et al.* of Howard University, Washington, DC. The gas-separator study will be done by Dr. John Byeseda of NATCO in Houston, Texas.

The final activities centered around the plans to filter the water in the 1-million-gallon pond, clean the pond after drilling operations, and line it with bentonite, all to be done in compliance with New Mexico state water-quality regulations.

4.3. Instrumentation

The data acquisition complex was expanded with the addition of a small shop/office trailer. This addition permitted the removal of a large amount of equipment from the Data Acquisition Trailer (DAT), which provided a vacant area in the DAT for installation of the MASSCOMP Seismic-Data System.

The EE-3A-to-EE-2 30-day flow test (ICFT) provided an important learning opportunity for the instrumentation section. The philosophy and techniques for the LTFT control and instrumentation design were re-evaluated. Now automatic control techniques will be integrated with manual control. This control design should require minimum operating and scientific personnel and still provide a low-cost, reliable system.

Work on site preparation has progressed on schedule. The hydrogen sulfide monitor/alarm system was completed; the Precambrian seismic net was repaired and is fully operational; and an emergency radio was added that communicates directly with the Laboratory's Security Headquarters.

5. FENTON HILL TEST-SITE ACTIVITIES

5.1. Site Maintenance and Improvements and Field-Operations Support

Clean water for loop operations is stored at Fenton Hill in a 5-million-gallon reservoir that is protected from airborne debris by a floating plastic cover. In preparation for the LTFT, the reservoir was emptied and cleaned and the cover was repaired. Activities in advance of these operations included a health and safety review that received the appropriate approvals, a chemical analysis of sludge in the bottom of the reservoir, Scott Air Pack training and certification for personnel who would work in the reservoir, and filling over 200 sand bags that would be needed to hold down parts of the cover while other parts were raised by air pressure in the reservoir. Operations then included emptying the reservoir, removing sludge from the top of the cover, cleaning the reservoir under the inflated cover, inspection of the liner (which was in good shape), inspection and repair of the cover and floats, and installation of three additional skylights in the cover to facilitate access to the reservoir for inspection, inflation, and egress. The remainder of the FY87 water allotment was then pumped from the Fenton Hill water well and stored in the pond. During this operation, the water was treated with calcium hypochlorite as a final step in the cleanup operation.

Wellhead Master valves and downhole-tool pressure locks have been added to wells EE-1 and GT-2, the injection and production wells of the Phase I system. A nine-day flow test was run to investigate a leak thought to exist in the EE-1 casing. Water was added to keep the casing filled to the top, and under this hydrostatic head, the rate of water loss declined steadily from an initial 15 ℓ/min (4 gpm) to about 5.7 ℓ/min (1.5 gpm) at the end of the

test. However, this continuing water loss from the well was evidence that the condition of its casing was such that deepening EE-1 was not an acceptable alternative to repairing well EE-2 for use as the production well of the Phase II system.

Site preparations for skidding the Big Chief drilling rig from well EE-3A to EE-2 included hauling, compaction, and grading of base-course material to insure an adequate foundation for the rig. Reserve pits were dug after the rig was spotted and erected.

The unsuccessful initial attempt to repair EE-2, described above, was made in November 1986. The 140-mm (5-1/2-in.) TAC-1 tubing string removed from the well was laid down, inspected, and stored. (In general, it was in good shape; about 10% of the joints needed rethreading.) Fishing runs then removed two of nine joints of the 178-mm (7-in.) transition liner, and the lower of the two joints was found to have collapsed. Caliper logs and impression-block runs showed that the 245-mm (9-5/8-in.) casing had also collapsed around the liner. Attempts to re-enter the liner with mill runs were unsuccessful, and the rig was furloughed while the situation was investigated.

A short pump test, Experiment 2070 — pumping into EE-3A while venting and temperature logging EE-2 — showed that neither EE-2 nor the flow paths through the fractured reservoir had been plugged by this repair attempt. Other information obtained contributed to the repair plan that was then developed.

In preparation for its final repair, temperature, caliper, cement-bond, and casing-wall-thickness logs were run in EE-2 to evaluate the condition of the 245-mm (9-5/8-in.) casing. This information was used in planning the remedial-cementing, redrilling, and well-completion operations.

Four water-cooled, single-pass heat exchangers, obtained as excess from the East Mesa Geothermal Demonstration Project, were modified for use in cooling drilling fluids, pressure tested, and assembled on a portable skid. They have operated satisfactorily in subsequent drilling operations. A gas separator for rig operations was also modified and installed.

5.2. Water Supply

5.2.1. Water Rights. On June 29, 1987, the New Mexico State Engineer's Office issued a permit [RG-24834-Temp (2)] to appropriate underground waters of the State of New Mexico for use in the HDR Program. This permit was amended on August 4, 1987. It allows a diversion of water not to exceed 3 acre-feet per annum through Calendar Year 1991. The diversion may be increased to a maximum of 15 acre-feet per annum if a number of conditions are met. Most of these conditions are already being complied with to satisfy our previous permit. However, a new condition requires that water rights will be leased according to a schedule set out in the permit extending to the year 2001-2. The process of leasing these rights must be completed by June 1, 1988.

A purchase request for the leasing of rights was issued on July 21, 1987, and at the end of FY87 this request was being pursued by LANL Group MAT-9 and by the LANL legal office.

5.2.2. NPDES Permit Renewal. On May 20, 1987, the Environmental Protection Agency (EPA) was asked to reissue the National Pollutant Discharge Elimination System (NPDES) Permit No. NM0028576 for Fenton Hill.

The EPA has proposed to reissue the permit, but in the meantime it has sent copies of the proposed permit to various interested parties for their comments and approval before the reissuance becomes final. The New Mexico State Environmental Improvement Division (NMEID) had not yet certified the proposed reissuance as of September 30, 1987.

5.2.3. Groundwater Discharge Plan. On April 27, 1987, the Los Alamos Area Office of the DOE requested in a letter to William LeMay of the New Mexico Oil Conservation Division (NMOCD) that the Groundwater Discharge Plan (GW-31) be modified to allow for the use of reactive tracers in our geothermal reservoir.

The NMOCD approved this modification on September 8, 1987.

5.2.4. Purification of Water in EE-1 Pond. Methods of treating the water in the

EE-1 service pond were investigated. The purpose of the water treatment is to allow water in the EE-1 pond to be clarified and freed from organic contaminants so that it can be stored in the 5-million-gallon pond. Methods of flocculating the pond and filtering the supernatant liquid through various types of filters were tested. Flocculation of pond water containing SiO_2 dissolved from the HDR reservoir can be successfully carried out using lime, $\text{Ca}(\text{OH})_2$, or lime plus aluminum-ion solution.

Of several cartridge-type filters that were tested, some were effective. Such cartridge filters are quite expensive, so a pilot-plant-sized sand and activated charcoal filter was constructed and tested. This filter was not as effective as certain of the cartridge filters, but it seems certain that with some modification the sand filter will perform satisfactorily.

5.3. Environmental Monitoring

Since 1974 samples from the geothermal site and from nearby surface and groundwater sources have been studied to determine any changes due to Fenton Hill operations.¹ During FY87 the storage ponds and the domestic well were sampled at regular intervals and after any procedure that could result in a change. In November 1986 samples were collected from 13 surface-water and 19 groundwater stations (Fig. 6) near the site and in the major drainages of the Jemez River and Rio Guadalupe downgradient from the site. Vegetation and soil specimens from the canyon below the GT-2 pond, which receives intermittent effluent releases from the storage ponds, were compared with earlier samples.

Analyses of the fluids and sludges in the storage ponds reflected their major sources. The EE-1 pond received most of its fluid from water circulated through the HDR reservoirs and the sludge from drilling. Conductivities of EE-1 pond fluids were near $11,000 \mu\text{mho}/\text{cm}$ with seasonal dilution and concentration. The sludge from this pond contained drilling clays, cuttings, and insoluble compounds precipitated from the reservoir fluid. EPA toxicity tests² on the sludge showed no contaminant value above the maximum allowable concentration limit. The GT-2 pond received no water other than that from rain and snow during FY87,

Fig. 6. Locations of sampling stations.

and analysis yielded much lower values than in the past. Wastes from this area were tested and removed, and the site was filled and graded as nearly as possible to the original contours. The Forest Service will provide seedlings for replanting the area. The 5-million-gallon pond was completely emptied and cleaned in October and November of 1986. The sludge was checked for contaminants with the EPA toxicity procedure and fell well below allowable concentration values. It was also checked for bacteria and algae, with the main emphasis on those types that could create health or corrosion problems. Water from the on-site well was used to refill the pond.

Over the past few years the well has shown little change in chemistry, with the water-level decline being as anticipated under current pumpage.¹ However, after pumping continuously for about 11 weeks to fill the 5-million-gallon pond, there was a slight increase in the total dissolved solids (TDS) in the domestic water, with the analyses giving values still well

within those set for safe drinking-water criteria. Since this incident, the well has been sampled weekly and has shown no further change.

Surface and groundwater samples taken downgradient from TA-57 (the Fenton Hill site) in 1986 indicated no significant changes that could be attributed to HDR activities.¹ Results of analyses done on the samples were compared with data collected since 1974, and only seasonal fluctuations were noted.

Chemical uptake in the soil and vegetation was monitored in the canyon below the GT-2 pond, where intermittent dumping of the storage ponds occurs. Water from dumping infiltrated the alluvium of the canyon within 300 m (1000 ft) and did not reach or contribute to the natural stream flow in the canyon. The chemical concentrations found in soil, roots, and foliage as the result of effluent release have shown a decrease in concentration down-canyon and a decrease with time since the larger releases that took place in the late 1970s and early 1980s.¹

Cleanup of the storage ponds resulted in an occasional release of fluid below the GT-2 pond. The fluid was analyzed before and sampled during dumping in compliance with the discharge requirements.³

6. RESERVOIR ENGINEERING

Of the several HDR Program objectives for FY87, the one most directly pertaining to the reservoir engineering task is that of developing a sound technology base. This task involves the physical, thermal, hydraulic, and geochemical characterization of the Phase II reservoir in such a way that the methods and analytical models can be applied to future HDR reservoirs developed at other sites. In FY87 part of the reservoir engineering effort was directed toward preparations for redrilling EE-2 and in analyzing past flow tests and otherwise characterizing the Phase II reservoir.

6.1. Preparations for the Redrilling of EE-2

These preparations included the selection of a wellbore trajectory intersecting a number of fracture planes derived from the MHF Experiment (Expt 2032) microseismic data, the development of a plan to interrogate the

Phase II reservoir region during redrilling using a variety of techniques, numerical analyses of wellbore temperatures as a function of water injection (in preparation for a suite of predrilling remedial cementing operations), and supporting geological studies.

6.1.1. Selection of the Redrilling Trajectory. The predominant fracture planes in the Phase II reservoir region, as determined from the microseismic-event-location data recorded during Expt 2032 (using the three-point method discussed below), were used for selecting the redrilling trajectory for EE-2A.

For better definition of the principal joints in the vicinity of old EE-2, which had been stimulated during the very high pressure injection that created the Phase II seismic region during Expt 2032, the early-time seismic data were reanalyzed in a more consistent and complete fashion. The fracture planes that were developed early during this flow test strongly influenced the final trajectory selection for EE-2A.

6.1.1.1. Fracture Planes. A new method, called the "three-point method," was developed for determining the orientations and locations of planar regions along which statistically significant clusterings of the source locations of the microearthquakes occur during hydraulic injections.⁴ The planes determined by application of this method are considered to be fluid-flow paths that were stimulated during high-pressure fluid injections. Fehler⁵ argues that these planes are pre-existing joints or zones of weakness in the rock.

Application of the three-point method to the 844 best-quality microseismic events initially located during Expt 2032 (first data set) resulted in the determination of 5 different sets of planes of different orientations,⁴ with most orientations comprising multiple planes. Dreesen *et al.*⁶ have examined the locations in the reservoir at which these planes intersect the various wellbores to determine whether wellbore-temperature anomalies exist that indicate the presence of fluid-conducting fractures. Table I shows the correlations of significant temperature anomalies with these seismic planes. (Multiple planes with similar orientations were labeled with an identical number

TABLE I
SIGNIFICANT FEATURES CORRELATED WITH WELL INTERSECTIONS

<u>Plane</u>	<u>Seismically Active Region</u>	<u>Aseismic Extension of Plane</u>
1(A,B)	Main EE-2 injection intervals preceeding MHF test (Expts 2018 and 2020).	Borehole breakout zones close to three of four wellbore intersections (from caliper logs).
2	Deep seismic target for EE-3A redrilling trajectory; unable to establish flow to EE-2 from EE-3A intersection region during deeper injection (Expts 2061 and 2066).	NONE
3(A,B)	Seismic activity was almost all associated with the post-MHF EE-2 casing failure and the resulting pressurization of the upper Phase I (low-pressure) region.	Intersections are near the low-pressure injection intervals of Expts 2032 and 2052, as shown on temperature logs.
4(A,B,C)	Main injection interval during reservoir circulation from EE-3A to EE-2 (Expts 2059, 2062, and 2067).	The upward extension of Plane 4A intersects EE-2 near the low-pressure injection zone for Expt 2052 at 2985 m (9800 ft).
	Planes 4A and 4C have no EE-2 intersections in seismic regions.	
5(A,B)	Plane 5A was an injection interval for Expts 2018 and 2020. It was the only seismic plane connected to both EE-2 and EE-3A during Expt 2067. Plane 5B has no seismic intersections.	Plane 5A intersects EE-3 near Expt 2042 injection interval. (No seismic planes with this orientation were located within the Expt 2042 microseismic-data set using the three-point method.)

followed by a unique letter for each plane, the letter increasing alphabetically with depth. Thus, planes 3A and 3B are nearly parallel, with plane 3A lying above plane 3B.) Correlations with both the seismically active portions of the planes and the aseismic portions are given. The table shows that there are significant correlations between the locations of planes predicted by the three-point method and temperature-log data.

A deterministic model of the fracture system within the Phase II reservoir was constructed using the orientations of planes determined from Expt 2032 seismic locations. A perspective view of this model is shown in Fig. 7. In this model, only the seismically active portions of the individual planes are drawn. In addition, the locations of wellbores EE-2, EE-3, and EE-3A are shown. There is a clear indication of a fracture network connecting wellbores in EE-2 and EE-3A.

For further definition of the flow paths, a model was made of the flow paths through the reservoir that were active during the ICFT (Expt 2067). In this qualitative model water flows from one fracture to another along lines where planes intersect. The ability of water to

Fig. 7. Perspective view of wellbores EE-2A, EE-3, and EE-3A, together with the seismically active portions of the planes found by applying the three-point method to microearthquake locations found for Expt 2032.

Fig. 8. Schematic showing the interconnections between the various seismic planes and wellbores that comprised the reservoir during the ICFT (Expt 2067). The thicknesses of lines connecting the various features are proportional to how easily fluid is estimated to flow between the features.

flow from one fracture to another is taken as proportional to the length of the line of intersection of the two planes in their seismically active regions. The resulting model is shown in Fig. 8 where the connectivity of the fractures, determined as just described, is shown by the line thickness joining two intersecting planes. The locations during the ICFT where water left EE-3A and entered the reservoir, as well as where water entered EE-2, are shown by arrows.

6.1.1.2. Reanalysis of Expt 2032 Microseismic Data. During FY87 we began to reanalyze and extend the seismic data recorded on analog tape during Expt 2032. The purpose of this effort was to extend coverage of the data beyond the 2000 events that were collected with the manually keyed Biomation digitizing

scheme used during the experiment. By extending our analysis to cover many more seismic events, we hoped to obtain a more representative sample of the microearthquakes induced during the experiment, revealing the fine-scale seismic structure of the Phase II reservoir. This information may prove valuable in assessing the performance of the reservoir during subsequent long-term flow testing.

The effort began by digitizing events from analog tapes using the MASSCOMP/RAVEN data acquisition system. We are currently undertaking to pick event-arrival times to locate these events. The reanalysis is yielding approximately 30 times more locations than were determined with the original Biomation system. Some events have been located using both the old data and the new data. A comparison of the locations made for the same event using the old scheme and the new scheme shows that the locations are slightly different, but most are within 50 m (160 ft) of each other. However, some differences in locations should be expected owing to slight differences in the arrival-time picks made from the two sets of data. In most cases, the locations determined using the newly digitized data are more tightly clustered than the locations determined from the old data. This encourages us to conclude that the new locations are more precise than the old locations.

6.1.1.3. Redrilling Trajectory for EE-2A. Some of the most promising work in reservoir analysis has been the recent development of the three-point method for detecting planar features in the large "clouds" of microseismic-event locations that accompany massive hydraulic-fracturing operations. This section discusses the application of the method in determining the new wellbore trajectory. One important feature of the method is that it identifies planes from the seismic data in order of the decreasing probability that they were discovered by chance.

The microseismic data used in this study were from Expt 2032, in which 21,200 m³ (5.6×10^6 gallons) of water were injected into the Phase II reservoir at Fenton Hill. The microseismic events were distributed throughout a rock volume of 42×10^6 m³ (1.5×10^9 ft³). When the microseismic sources were first located by identifying each microseismic event

TABLE II
STRIKE AND DIP OF 10 PLANES
FOUND IN THE HAND-PICKED
EXPT 2032 DATA SET
(all angles in degrees)

<u>Plane</u>	<u>Target Plane</u>	<u>Strike</u>	<u>Dip</u>
1A	X	N29W	76E
1B	X	N29W	76E
2		N88E	27W
3A		N29W	67W
3B		N29W	67W
4A		N6E	67E
4B	X	N5E	64E
4C		N8E	67E
5A		N33E	60W
5B		N34E	56W

by hand from the Biomation-system data, a total of 844 high-quality events was found in the records of the 3 days of the experiment. From these events, the three-point method identified 10 planes as shown in Table II, although some of these differ in orientation by only a few degrees — so that this may actually represent only 5 planes. A second, more rigorous, examination of the first 10 hours of seismic data by a computer-based system found well over 1000 acoustic events, from which 3 planar features in the developing reservoir were initially determined using the three-point method. These planes are listed in Table III. Because of the decreased error associated with the computer-based method, the planes found in this second data set have a greater degree of confidence associated with them.

Sets of planes (i.e., 1A and 1B) are listed in order of decreasing probability of existence. Multiple planes in any set are parallel, but spatially separated, and all have the same probability of existence. "X" indicates those planes selected as target planes for the redrilling trajectory.

Again, the 1 and 2 planes are listed in order of decreasing probability of existence.

NOTE: The set of planes 1A and 1B above has almost the same orientation as the

TABLE III
STRIKE AND DIP OF THREE PLANES
FOUND IN THE COMPUTER-BASED
EARLY-TIME EXPT 2032 DATA SET
(all angles in degrees)

<u>Plane</u>	<u>Target Plane</u>	<u>Strike</u>	<u>Dip</u>
1A	X	N4W	74E
1B	X	N2W	75E
2	X	N3E	61E

set of planes 4A, 4B, and 4C in the first data set given in Table II. This suggests that these planes were much more active seismically early in the experiment (the first set of joints to be stimulated), but over the entire 62 hours of injection, this set of planes was statistically not as significant as other sets of planes stimulated later.

In planning the trajectory for EE-2A, one of the goals was to intersect as many of the three-point planes as possible. Because intersecting all the planes would have been prohibitively complicated and expensive, certain planes were given preference over others. The most desirable planes had to meet one of two criteria: 1) be among the first few planes identified by the three-point method, since these planes were more probably real features, or 2) show some correlation with other data which suggested that they were hydraulically active. An example of the second criterion would be a plane's intersection coinciding with a known injection or production zone in the wellbore as shown on temperature logs.

The primary target for the EE-2A trajectory was a region on the first plane densely populated with microseismic source locations, identified in the early-time computer-based data set. This plane was chosen for three reasons. First, owing to the greater degree of confidence associated with the source locations of these microseismic events, all 3 of the planes found in the computer-based data set were given priority over the 10 planes determined by the hand-picked method. Second, it was also the first plane extracted from its data set and

thus most statistically significant. Third, and most importantly, its intersection with the old production well EE-2 correlated with the most prolific production zone in EE-2 as determined by temperature logging. It was reasoned that since this plane appeared to carry most of the flow to the old production well, intersecting it with the new well would result in a similarly good connection. The seismically dense region of this plane was preferred as a target since evidence suggests that pressurized fluid triggers the microseismic events.

Attempts were made to fine-tune the trajectory to intersect other planes that also met one or both of the two criteria mentioned above.

6.2. Reservoir Interrogation During Redrilling

During the redrilling of EE-2A, the newly accessed reservoir region will be evaluated using a variety of geophysical, geochemical, and hydrologic techniques. As a part of this reservoir evaluation, we hope to identify the intersections with the wellbore of the shear planes that have been identified by a statistical evaluation of Expt 2032 microearthquake event locations — the three-point method discussed above.

Before redrilling EE-2A through the Expt 2032 seismic region, the Phase II reservoir will be pressurized through EE-3A by continuous high-pressure pumping to provide flow-connection information. Primarily, we will be looking for indications of fracture intersections during redrilling as shown by

- increased drilling-fluid outflow relative to the mud-pump circulating rate,
- pressure response at EE-3A,
- sudden increase in carbon dioxide evolved from the drilling fluid, and
- change in the wellbore temperature profile indicating a significant reservoir flow into EE-2A.

As presently planned, there will be one major pause during drilling to evaluate the known fracture zone that intersects EE-2 at a depth of about 3280 m (10,750 ft). Presently available information suggests that this region is part of the high-pressure (Phase II) reservoir

created during the MHF test, but it is essential to our completion strategy that the nature of this fracture connection be clearly established while it can be easily isolated from the deeper EE-2 fracture connections into the high-pressure reservoir.

6.3. Wellbore-Temperature Variations During Cooling

Before the start-up of the EE-2A redrilling operations, Wellbore Heat-Transfer (WBHT) code runs were made to simulate wellbore cool-down profiles before and during cementing operations. This information was then provided to drilling personnel to aid in planning cement formulations. A flow schedule of all circulation and injections projected to occur before and during cementing was input to the code, and wellbore cool-down was projected. Figure 9 illustrates the planned workover flow

Fig. 9. Projected flow schedule for plug-back operations below 3170 m (10,400 ft).

schedule for the plug-back operations below 3170 m (10,400 ft). Figure 10 shows the resulting estimate of cool-down at 3160 m (10,375 ft), whereas Fig. 11 provides wellbore-temperature profiles preceding and following cement injection. Simulations were performed for all four remedial cementing operations planned in EE-2.

Before the actual sidetracking of EE-2A, day-to-day rig operations were simulated to monitor wellbore performance during cementing. An early circulation test with Kuster (mechanical) temperature gauges in the hole indicated more effective cooling was being obtained

Fig. 10. Estimated cool-down at 3160 m (10,375 ft).

than was projected by the WBHT simulations. Input heat-transfer parameters were then modified, but the simulation still predicted temperatures about 12°C (21°F) warmer than those actually measured.

6.4. Re-examination of EE-2 Cuttings

Core and cuttings from EE-2 were re-examined to identify features that might affect the success of the sidetracked redrilling operation. One of the most notable features of the EE-2 cutting samples was the high content of

Fig. 11. Wellbore-temperature profiles preceding and following cement injection.

carbonate-clay material in several samples, interpreted by Laney *et al.*⁷ as representing abundant alteration along shear zones in the granitic rocks. This interpretation, if correct, might have had implications relevant to the planning of the redrilling operation. For example, the postulated shear zones might support the identification of certain transmissive fracture systems from seismic-data analysis and influence the choice of the redrilling trajectory.

Cuttings from the postulated alteration zones were re-examined in thin section. Upon re-examination, the carbonate-clay material was identified as contamination derived from Paleozoic metasedimentary rocks overlying the Precambrian crystalline rocks. This conclusion is strongly supported by comparison with core samples of Paleozoic rock from drill hole VC-1 located about 8 km (5 mi) southeast of Fenton Hill. The carbonate fossil fragments in the EE-2 "Precambrian" cuttings eliminate any possibility that this material could represent alteration zones in granitic rock.

Newly cleaned EE-2 cuttings from the drilling depth interval 3110 to 3480 m (10,190 to 11,400 ft) reveal one major alteration zone from about 3150 to 3480 m (10,340 to 11,400 ft), with the most intense alteration from 3167 to 3180 m (10,390 to 10,430 ft). This closely resembles the previously identified EE-3A alteration zone from about 3180 to 3260 m (10,430 to 10,700 ft). However, the anticipated higher-quality cuttings material from EE-2A should be very helpful in establishing geologic correlations with EE-3A.

6.5. Phase II Reservoir Characterization

In addition to preparing for the redrilling of EE-2A, considerable effort was directed toward a continuing characterization of the Phase II reservoir region using geophysical, geochemical, geological, and numerical modeling techniques.

6.5.1. Geophysical Studies. During FY87 geophysical studies focused principally on analysis and interpretation of the microseismic events that were detected during a number of pressurization and hydraulic-fracturing experiments conducted in the Phase II reservoir.

Fig. 12. Lower-hemisphere, equal-area projection showing poles to planes found by application of the three-point method to locations accompanying hydraulic injections carried out within or adjacent to the Phase II reservoir. Each pole is plotted with a letter. Contours show ratio of shear to normal stress acting on planes with a given pole, calculated using stress tensor described in the text.

6.5.1.1. Three-Point Method. The three-point method described earlier was also applied to microearthquakes accompanying several previous Fenton Hill pressurization experiments (Expts 2042, 2061, 2062, and 2066). Numerous planes were identified for each experiment. The poles (normal vectors) to the planes found from these data are shown in Fig. 12, each letter representing one plane found during one experiment. It is noteworthy that one particular plane orientation occurred during all experiments. This plane is marked with a bold letter D in Fig. 12. Many experiments, particularly those in which injections were carried out deep in the reservoir, were completely dominated by planes with poles parallel to D.

If joints with poles parallel to D are seismically activated by changes in the normal stress as a result of increases in reservoir pressure, there must be some relationship between the

orientations of such joints and the *in situ* stress field. We can model this by considering the ratio of shear to normal stress acting along all possible orientations of planes in the rock. If joints of all orientations exist in the rock comprising the Phase II reservoir, this ratio is a rough measure of the likelihood of a joint of a given orientation slipping when the stress field is perturbed.

As a rough estimate, we take the ratio of effective stresses in the Phase II reservoir to be (Don Brown, Los Alamos National Laboratory, personal communication)

$$\sigma_1/\sigma_2 = 2$$

$$\sigma_2/\sigma_3 = 1.5$$

where σ_1 is the maximum principal stress, σ_2 the intermediate principal stress, and σ_3 the least principal stress.

In addition, we take the vertical stress to be the maximum principal stress. Barton *et al.*⁸ analyzed borehole-breakout data and interpreted the results using the method of Zoback *et al.*⁹ to determine the orientation of the least compressive stress. They concluded that the orientation of the least compressive stress is horizontal and N104E. Using the information about the stress field given above, we can calculate the ratio of the shear stress to the normal stress acting on planes of any orientation. This ratio has been calculated and is contoured on an equal-area net of poles to planes in Fig. 12. Slip is more likely to occur along planes that have a large value of this ratio. It is clear from Fig. 12 that the largest value of the ratio of shear-to-normal stress occurs along planes whose poles are in the direction labeled D in the figure, the same plane orientation that dominated many of the hydraulic injections at Fenton Hill. From this result, we conclude that planes whose poles are parallel to direction D are pre-existing zones of weakness (i.e., joints) that slipped when the *in situ* effective stress was perturbed by the fluid pressure.

6.5.1.2. Fault-Plane Solutions. For better understanding of how the induced microearthquakes relate to *in situ* stresses and pre-existing joints, a systematic study of fault-plane solutions was undertaken. This study represents the most reliable and complete study

Fig. 13. Plot of P-axes obtained from fault-plane solutions. Plot is lower-hemisphere, equal-area projection. P-axes are derived from earthquake fault-plane solutions (see the text). Center of plot (indicated by +) is vertical down; circle enclosing plot is horizontal, with azimuths ranging from north (top of plot), east (to right), south (bottom of plot), and west (to left).

done to date on the Expt 2032 data. Earlier efforts were reported by Kaieda¹⁰ and by House *et al.*¹¹ A total of 110 earthquake fault planes have been analyzed, which is about one-half of all the microearthquakes in this data set suitable for analysis using this approach. Fault-plane solutions were obtained solely from P-wave first motions as recorded by the downhole sensors (the so-called Precambrian network) and by the network of surface stations. First motions at the surface stations are required for adequate lateral coverage of the earthquake focal sphere. The pattern of P-wave first motions is divided into four quadrants by two nodal planes. The quadrants alternately contain compressional (P) and dilatational (T) first motions. P- and T-axes are drawn that bisect the first-motion quadrants. Both P- and T-axes are approximate estimates of the maximum and minimum principal-stress directions that acted to produce the earthquakes.

To summarize the results obtained, we have plotted the P-axes from all fault-plane solutions obtained thus far in Fig. 13. Note that despite the large scatter of P-axis orientations, the average orientation of the P-axes is nearly horizontal and trends about northwest-southeast, in variance to the stress orientation given above in Section 6.5.1.1. The average orientation of the P-axes is nearly parallel to the strike of the distribution of microseismic-event locations from this injection test (Expt 2032). The fault-plane solutions show a distribution of orientations that does not always agree with the orientations of the planes identified by the three-point method, given previously in Tables II and III. Perhaps the fault-plane solutions are more indicative of the stresses in the rock, while the event locations are more indicative of the actual joint orientations stimulated by high-pressure fluid injection. We anticipate completion of the fault-plane-solution work soon and will more fully interpret the results then.

6.5.2. Geological Studies. More detailed analyses of cores and cuttings from the Fenton Hill wells have increased our understanding of the physical and mineralogical nature of the reservoir formations there and have modified some of our earlier conclusions about them.

6.5.2.1. Core Analyses. Cuttings and cores from drill hole EE-3A were analyzed to provide information on the distribution of geologic units, fractures, and alteration. The cuttings from this hole are both larger and less contaminated than those from holes drilled earlier at Fenton Hill because drilling mud, rather than water, was used as the circulating fluid. This has made it possible to achieve much better characterization of rock types, fracture abundance, and alteration. Figure 14 shows the generalized geology of EE-3A. The cores contain several features, described below, that have helped clarify questions of geologic interpretation.

Core 1. 2880 to 2882 m (9450 to 9455 ft): a medium-grained amphibolite schist cut by veins of light-colored granite. From the side-tracked upper end of EE-3A, the amphibolite extends downward to about 2950-m (9680-ft) drilling depth. The main mineral constituents

Fig. 14. Generalized geology of well EE-3A.

of the amphibolite are quartz, plagioclase, hornblende, and biotite. Granitic dikes cutting the amphibolite contain microcline, quartz, plagioclase, with minor biotite, epidote, and sphene. Dike boundaries are very indistinct owing to substantial amphibolite recrystallization associated with the intrusion of K-rich felsic magmas. Near the dike boundaries, hornblende has recrystallized to aggregates of epidote, biotite, and quartz.

Core 2. 3315 to 3316 m (10,875 to 10,880 ft): a light-colored monzogranite dike rock that is itself cut by a small dike of pink granite. The monzogranite has a distinctive mottled red color from hematite in prominent fractures and along grain boundaries. Mineral constituents, in order of decreasing abundance, are plagioclase, quartz, microcline, hematite, muscovite, chlorite, and epidote. Plagioclase crystals with core composition $Ab_{86-88}Or_{0.6-0.8}An_{11-13}$ have rims of composition $Ab_{97.5-98}Or_{0.5}An_{1.5-2}$ derived from subsolvus unmixing of adjacent microcline crystals.

Texturally older fractures are filled with plagioclase, sericite, and quartz, whereas younger fractures and reactivated fractures are filled with calcite and hematite. Figure 15 shows two examples of plagioclase fracture fillings. In Fig. 15A both the older main portion of the plagioclase crystal and the optically continuous fracture filling have a pitted appearance resulting from deuteric alteration. The plagioclase fracture filling in Fig. 15B has a clear appearance like that of the outer rim on the host crystal. This rim was derived from the subsolvus unmixing of an adjacent microcline crystal during the late-stage crystallization of the dike magma. The clear plagioclase fracture filling and the fracture itself may therefore be about the same Precambrian age as the clear rim on the host crystal.

Core 3. 3536 to 3540 m (11,600 to 11,615 ft): contains a variety of light-colored granitic dikes cutting biotite granodiorite. Because relatively few intact dike contacts were recovered, some cross-cutting relationships are conjectural. The granodiorite is medium grained and gray, with a very slight to slight foliation defined by alignment of mafic mineral segregations. The dikes range in composition from essentially

Fig. 15. Photomicrographs of plagioclase-filled fractures in core 2. Arrows point to fractures.

mafic-free quartz-feldspar rock to monzogranite with 5% biotite. The question of metamorphic versus plutonic origin for the granodiorite and related rocks has not received much formal discussion and earlier workers have stated that the granodiorite is of metamorphic origin.^{7,12} Feldspar textures in granodiorite from this core include a number of features more suggestive of plutonic than metamorphic origin: highly irregular crystal outlines, variable crystal size, and complex twinning. Large microcline crystals with relic Carlsbad twinning must have formed by inversion of orthoclase upon cooling. Additional evidence for plutonic origin is described in the following section (Core 4).

Fig. 16. Scanning electron microscope photograph, back-scattered electron image. Prehnite incompletely fills the fracture in amphibolite, leaving some porosity.

Core 3 contains very few fractures. Rare hematite-coated fractures cut some of the light-colored dike rock. A single epidote-coated, slickensided fracture is also present in the dike rock.

Core 4. 3791 to 3800 m (12,438 to 12,468 ft): longest core obtained from Fenton Hill and one of the most significant. Lithologic and textural features revealed in this core and adjacent cuttings samples have made it possible to revise earlier geologic interpretations of Fenton Hill Precambrian cores.

The principal rock type is medium-grained amphibolite schist of metamorphic origin, composed mainly of plagioclase (An_{36-45}), hornblende (hastingsite), and biotite. This rock is similar to the amphibolite of core 1, but it contains almost no quartz and appears to be less affected by metasomatism. The amphibolite contains a few natural, partly open fractures with prehnite filling (Fig. 16). Partly open fractures with prehnite have also been observed in a junk-basket amphibolite sample from EE-2. If this type of fracture is confined to amphibolite xenoliths, it may have been isolated from communication with younger, more connected fracture systems in the surrounding plutonic rocks. The amphibolite is cut by dikes of medium-grained, variably foliated tonalite.

Above and below the amphibolite is fine-

grained mafic rock (major minerals are plagioclase, quartz, biotite, epidote, microcline, and ferrohastingsite hornblende) similar to the rock in EE-2 core 2 [3916-m (12,850-ft) drilling depth] that was labeled "metavolcanic" in Ref. 7. A petrographic comparison of the amphibolite and the fine-grained mafic rock shows that the two rock types have highly contrasting plagioclase textures (Figs. 17 and 18). Plagioclase crystals in the amphibolite are xenoblastic (irregular) and equant. By comparison, plagioclase crystals in the fine-grained rock surrounding the amphibolite are moderately to extremely elongate, with a few large blocky crystals. There is some preferential alignment of plagioclase and biotite crystals.

The textural differences are significant because they indicate that the fine-grained rock does not belong to the metamorphic suite of which the amphibolite was originally part but is a separate unit with a different origin. The amphibolite has a typical metamorphic texture with no preservation of the premetamorphic texture. The fine-grained rock has a generally igneous texture, although it does show signs of recrystallization. The alignment of elongate crystals may be primary flow lineation. Based on texture, mineralogy, and position relative to the amphibolite and surrounding felsic plutonic rocks, the fine-grained rock is tentatively

Fig. 17. Photomicrograph of amphibolite, core 4, crossed polarizers. Plagioclase crystals (center of photo) have simple boundaries and equant shapes. Long dimension of photo is 1.2 mm.

Fig. 18. Photomicrograph of reaction rock at 3740-m (12,270-ft) drilling depth, crossed polarizers. Plagioclase crystals (left-center and right-center) are very elongate (and highly altered). Long dimension of photo is 1.2 mm.

interpreted as a reaction or hybridization zone formed between felsic magma and the amphibolite xenolith.

This is the only Fenton Hill core that shows the relationship between amphibolite and felsic dikes. Medium-grained granodiorites, with a very slightly to moderately developed foliation defined by the crude alignment of mafic mineral segregations, in cores 1 and 6 from EE-2 have been described in Ref. 7 as metamorphic gneisses, perhaps on the basis of the foliation. The variable development of the foliation in this and other cores (including EE-3A core 3) and the inconsistent orientation of foliation in different dikes suggest an igneous rather than metamorphic origin. In some examples from core 4, the tonalite foliation is parallel to the dike walls and bears no consistent relationship to the amphibolite schistosity. Because the tonalite is clearly younger than the amphibolite, any metamorphic fabric imprinted upon the tonalite should also be present in the amphibolite. Therefore, the lack of correspondence between the foliations within the tonalite dikes and the metamorphic fabric in the surrounding (older) amphibolite is best explained by a primary igneous origin for the tonalite foliation. If this interpretation is correct, the majority of the rock intersected by drill hole EE-3A is also probably igneous rather than metamorphic.

This is not meant to imply that there has been no modification of the plutonic rocks following emplacement, but rather that most textural and mineralogic features reflect igneous origins.

6.5.2.2. Alteration and Fractures.

Most of the rock in EE-3A is relatively unaltered. The granitic rocks commonly show the effects of minor deuteritic (late-stage cooling) alteration, such as chloritization of biotite and sericitization of plagioclase. Amphibolite xenoliths have been variably metasomatized by reaction with K-rich felsic magmas, as described above.

The most highly altered rock is in the 3149- to 3304-m (10,330- to 10,840-ft) drilling-depth interval. There is no core from this interval. Based on cuttings, the rock is strongly oxidized; feldspars are deep orange, biotite is chloritized, and interstitial hematite is common. Fractures filled with hematite, chlorite, epidote, quartz, feldspar, or calcite are abundant, as described below. Microbreccia zones, with irregular boundaries, are up to at least 2 mm wide. The microbreccias are very fine grained and usually dark red or green; this material comprises up to 5% of some cuttings samples.

The relative amounts of joint surfaces intersected by the drill hole in each 3-m sample interval have been crudely estimated from detailed cuttings examination in the 2925- to 3316-m (9597- to 10,880-ft) drilling-depth interval. The values shown in Fig. 19 represent the equivalent number of cuttings containing complete fractures (both fracture walls) in samples approximately equivalent in volume to a 5000-cutting sample with 2-mm cutting size. The cuttings numbers have not been corrected to account for cuttings sizes other than 2 mm. For a rough comparison, a single 0.5-mm-wide filled fracture running through the center of the borehole trajectory parallel to the borehole would be represented by about 50-130 cuttings per sample (cuttings in the 1- to 2.5-mm size range). Fractures without mineral coatings or altered borders would not be detectable but are probably rare (based on core examination). The fracture counts do not distinguish between potentially transmissive fractures.

As shown in Fig. 19, zones of abundant fractures are present at 2969 to 2972 m (9741 to 9751 ft), 3054 to 3057 m (10,020 to

Fig. 19. Values for fracture-surface abundance (not corrected for cutting size) in cuttings samples from well EE-3A.

10,030 ft), 3185 to 3197 m (10,450 to 10,490 ft), 3225 to 3228 m (10,581 to 10,591 ft); and 3298 to 3301 m (10,821 to 10,831 ft). These zones, especially the 3185- to 3197-m and 3225- to 3228-m intervals, generally correspond to the alteration zones described above.

6.5.3. Geochemical Studies: Reactive Tracers. Los Alamos is developing tracer techniques using reactive chemicals to track thermal fronts in fractured geothermal reservoirs. If a nonadsorbing tracer, flowing from the injection well to the production well, chemically reacts, its reaction rate will be a strong function of temperature. Thus, the extent of the tracer's chemical reaction will be greatest early in the lifetime of the system and less as the reservoir cools and the thermal front progresses toward

the production well. Early laboratory experiments identified tracers with chemical kinetics suitable for reservoirs in the temperature range of 75° to 100°C (170° to 210°F). In the past year, kinetics studies have focused on the hydrolysis of bromobenzene derivatives. This class of reactions can be used in reservoirs ranging in temperature from 150° to 275°C (300° to 530°F), which is of greater interest to the geothermal industry in general and for the Phase II reservoir at Fenton Hill.

Table IV lists the kinetics parameters for all tracers tested. The second-order rate law used to compile the data is

$$\frac{dC}{dt} = -k [\text{OH}^-] C$$

where C is the concentration of the tracer, $[\text{OH}^-]$ is hydroxide-ion concentration, and k is the rate constant, given by

$$k = A_r^{-E_a/RT}$$

where E_a is the activation energy, A_r is the pre-exponential factor, R is the universal gas constant, and T is temperature in kelvins. Figure 20 plots the half-life of reaction, $\tau_{1/2}$, at pH 5.6 versus temperature for the tracers listed in Table IV. Practical usage requires that $\tau_{1/2}$ should roughly equal the tracer residence time in the reservoir. Figure 20 shows that appropriate tracers have been identified for a wide variety of temperatures and residence times at pH 5.6. (Similar figures have been produced for other pH values.)

The work done on the tracer-adsorption study during 1987 involved verification of calculated pore volume by using sodium fluorescein as a conservative (i.e., a nonsorbing and non-reactive) tracer. In adsorption-column experiments, the conservative tracer yielded a value of 438 ml, which is very close to the calculated value of 446 ml. Once this was obtained, sodium fluorescein was replaced by sodium bromide as the baseline tracer.

Next a set of reactive tracers that were considered to be the best candidates for use at Fenton Hill was tested. The first compound tested at room temperature was 1-bromo-2-nitrobenzene. When compared to sodium bromide, the breakthrough occurred at around two

TABLE IV
KINETICS PARAMETERS FOR CHEMICALLY REACTIVE TRACERS

<u>Compound</u>	<u>Number in Fig. 20</u>	<u>A_r ($\ell/\text{mol}\cdot\text{s}$)</u>	<u>E_a (kJ/mol)</u>
<i>Esters</i>			
ethyl acetate	1	1.23×10^6	39.2
ethyl propionate	2	1.09×10^6	39.9
isopentyl acetate	3	1.67×10^7	49.3
hexyl acetate	4	1.13×10^7	48.6
ethyl pivalate	8	9.65×10^9	89.5
<i>Amides</i>			
acetamide	7	8.93×10^8	78.7
butyramide	9	3.33×10^7	69.2
benzamide	10	2.40×10^5	49.2
<i>Aryl Halides</i>			
4'-bromoacetophenone	15	4.85×10^{11}	130
p-bromobenzaldehyde	14	7.70×10^{10}	117
1-bromo-2-nitrobenzene	12	2.87×10^{10}	107
1-bromo-3-nitrobenzene	16	3.80×10^{16}	181
1-bromo-4-nitrobenzene	13	2.13×10^{10}	108
1-bromo-2,4-dinitrobenzene	5	1.00×10^{14}	110
1-fluoro-2-nitrobenzene	6	1.35×10^{14}	119
1-iodo-2-nitrobenzene	11	1.18×10^{11}	110

pore volumes, indicating only moderate sorption. Hence, it became a possible candidate for use at Fenton Hill. Since the column experiments were time consuming, emphasis was shifted to shorter, batch-adsorption studies for quickly ruling out the tracers that exhibited strong adsorption on granite.

The compounds tested in batch experiments were bromobenzaldehyde, 1-bromo-2-nitrobenzene, 1-bromo-3-nitrobenzene, 4'-bromoacetophenone, and para-toluenesulfonic acid (which is a conservative tracer). The extent of adsorption at room temperature for 4'-bromoacetophenone and p-bromobenzaldehyde was minimal; 1-bromo-2-nitrobenzene and 1-bromo-3-nitrobenzene exhibited somewhat more

adsorption; and para-toluenesulfonic acid exhibited no adsorption. Based on these adsorption experiments, none of these tracers will be excluded from the list of tracers to be run through the adsorption column; however, the preferable tracers are now known.

6.5.4. Reservoir Modeling. Modeling of the chemical, hydraulic, and thermal behavior of the Phase II reservoir continued throughout FY87.

6.5.4.1. Geochemical. Geochemical modeling was carried out using data obtained in the ICFT conducted in May and June 1986. A geochemical model was developed to understand the first five days of this flow test when

Fig. 20. Tracer-reaction half-life versus temperature at pH=5.6 for all tracers tested. (See Table IV for the list of tracers.)

the downhole pore fluid, with a high concentration of dissolved solids, was being swept from the reservoir. The model identified three types of behavior (Fig. 21): 1) simple displacement of dissolved species with fluid of lower concentration (inert species such as B, Br, Cl, K, Li, and Na); 2) constant concentration owing to a continuous source of mineral from dissolution reactions (Si); and 3) concentrations that drop lower than their injection values due to rock-adsorption or other rock-water interactions (Mg, Ca).

In addition, a new geochemical-equilibrium model was developed for the Fenton Hill reservoir. The model accounts for all major species and relevant equilibrium reactions. This is an improvement over the previous models in which only carbonate and water equilibria were considered. The new model calculates H_4SiO_4 - H_3SiO_4^- - NaH_3SiO_4 , $\text{B}(\text{OH}_3)$ - $\text{B}(\text{OH})_4^-$, and HSO_4^- - SO_4^{2-} equilibria as well as H_2CO_3 - HCO_3^- - CO_3^{2-} and H^+ - OH^- - H_2O equilibria.

Analysis of future chemically reactive tracer tests will be improved with the new

model because calculation of $[\text{OH}^-]$ is necessary for interpretation of the test results. The model can also be used to design and analyze a silica-dissolution experiment. The geochemical model shows that the addition of 0.1 moles of NaOH per liter of injection fluid will result in a tenfold increase in the *in situ* total dissolved silica. However, this change in silica concentration will not be seen in the production fluid until the reservoir has been sufficiently penetrated with NaOH. Tracer data from the ICFT show that if 90 barrels of NaOH were injected over a five-day period, half of the production flow would contain the added NaOH. Therefore, the total dissolved silica in the production fluid would increase by a factor of 5. Modeling the transient silica equilibrium will lead to better understanding of the reservoir temperature patterns, surface area, and flow distribution.

6.5.4.2. Numerical Models. A three-dimensional model of the ICFT has been developed assuming porous-equivalent flow (flow through a porous medium equivalent to a fractured reservoir). The model matches hydraulic, thermal, and tracer data, including

Fig. 21. Characteristic concentration-time behavior for different dissolved species during the initial sweep of pore fluid from the reservoir.

Fig. 22. Production temperatures for 20-year simulations of the ICFT match, close-in and stepped-out cases.

water loss. Wellbores were placed in the finite-element mesh at approximately their known relative positions. The data match was used to make long-term simulations for the production-wellbore performance as it existed during the ICFT and for the close-in and stepped-out redrilling proposals. [The term close-in refers to a redrilling trajectory that was no more than 30 m (100 ft) from the old EE-2 wellbore, and stepped-out refers to a trajectory 125 m (410 ft) from old EE-2.]

Twenty-year simulations of the production temperatures are shown in Fig. 22 for an injection flow rate of 18 kg/s. The close-in and stepped-out cases show initial production temperatures that are higher than the ICFT owing to flow through deeper parts of the reservoir. All three cases have the same reservoir volume, yet thermal performance differs from case to case because of the different flow patterns. In this model, flow diverges from the cooled flow paths because of increased fluid viscosity in the cooled region. However, fracture opening owing to thermal contraction of the rock mass may lessen or preclude this effect. In either redrilling scenario, thermal drawdown is slowed in the redrilled (EE-2A) case because the longer production (open-wellbore) interval anticipated in EE-2A enlarges the reservoir volume accessed by fluid.

A heat-transfer model based on tracer data has also been developed. This model uses a tracer-determined residence-time distribution

and estimates of fracture porosity (the void volume in open fractures and dilated joints) to predict the long-term thermal performance of an HDR reservoir. The model consists of a number of parallel, interacting flow paths with flow rates and fluid volumes set to be consistent with the tracer data. Each path is a network of evenly spaced fractures, and the outlet temperature is the mixed-mean-average temperature from the individual paths.

Figure 23 shows the predicted thermal behavior for different values of the fracture porosity, ϕ , expressed as a fraction of total rock volume. In effect, fracture porosity sets the reservoir size since the fluid volume (determined from tracer measurements), divided by ϕ , gives the reservoir rock volume. The figure indicates a large range of possible thermal responses for the Phase II system, highlighting the need to develop better *in situ* tests to determine fracture porosity, or more fundamentally, the rock volume bathed by fluid in a circulating HDR system. Nonetheless, the predictions indicate that some thermal drawdown will be experienced during the upcoming LTFT.

Fig. 23. Predicted produced-fluid temperature versus time, using the tracer-based heat-transfer model for different assumed values of the fracture porosity.

6.5.4.3. Pressure Analyses. There were two separate efforts this year in the area of pressure analysis. The first dealt with determining the degree of interference caused by the close proximity of an unused wellbore. The second was a semi-analytical reservoir model that solves for both pressure distribution and heat transfer. This latter work is still under way.

As discussed in detail in Section 2.3, the decision was made early in the year to sidetrack and redrill the bottom 600 m (2000 ft) of EE-2 in order to bypass a section of damaged wellbore casing. However, the question remained as to how best to reaccess the Phase II reservoir and still provide the optimum reservoir-production capability for future reservoir-evaluation tests.

When EE-2A is sidetracked and redrilled, we will leave behind an abandoned section of the old EE-2 wellbore below the sidetracking point. Our concern is that the abandoned section of old EE-2 may be inadequately plugged with cement, a real possibility at high downhole temperatures and with collapsed casing and tubing. If this occurs, the abandoned wellbore below the EE-2A sidetracking point could act as an unwanted flow conduit, bypassing water from the deeper Phase II reservoir to the upper Phase I reservoir. This situation is depicted in Fig. 24. Because the upper Phase I reservoir readily accepts water at pressures 15 MPa (2200 psi) lower than the deeper reservoir, the potential for high water losses was of concern.

There were two aspects to this study:

- 1) the flow interference that would be caused by the proximity of an open lower section of old EE-2, and 2) the reservoir enlarged by increasing the spacing between injection and production wells had to be balanced against the greater reservoir-body flow impedance that accompanies a larger reservoir. Therefore, a model was devised that predicts reservoir flow performance while taking into account any interference the old wellbore might create.

Because the reservoir normally will be operated in a steady-state mode, the model was based on Muskat's relationship between pressure and the log of distance, which assumes steady-state, two-dimensional Darcy flow in a homogeneous reservoir. Although the Phase II reservoir is known to be highly fractured, the assumption of homogeneity was made because

Fig. 24. Idealized view of the two reservoirs (not to scale).

the high operating pressures acting on the numerous fractures make the system act like a porous medium. Despite its simplicity, results of this first study were quite informative. In particular, the model indicated that if the abandoned section of EE-2 could not be adequately plugged, then the EE-2A wellbore should be drilled as close as possible to EE-2 to avoid significant water losses to the upper Phase I reservoir. The explanation for this recommendation becomes clearer when it is recalled that normally EE-2A will be operated as the production well, at a fairly low back pressure. As the reservoir cross flow approaches the EE-2 and EE-2A wellbores, the EE-2A wellbore would present a more effective sink [at a back pressure of say 3 MPa (435 psi)] than would EE-2, flowing into the Phase I reservoir [at a pressure of about 8 MPa (1200 psi)]. If these two wellbores are in close proximity, the flow into EE-2A will predominate; however, if the two wellbores are widely separated, EE-2 would be exposed to higher reservoir pressures and could accept a larger proportion of the reservoir cross flow. The model indicated that the new wellbore should be drilled no more than 15 to 30 m (50 to 100 ft) from the EE-2 wellbore to provide effective isolation from water losses to the upper Phase I reservoir — assuming a series of failures in the isolating cement plugs —

and was the recommendation followed in the redrilling of EE-2A.

The second study was suggested by the observation that hydraulic, seismic, and tracer data from the ICFT run in the spring of 1986 (Expt 2067) indicate a heterogeneous reservoir, composed of several distinct regions. A simple model for such a reservoir would consist of a parallel set of discrete flow channels that originate near the injection well and then merge into a zone of more homogeneously fractured rock surrounding the production well. A semi-analytical procedure was used that solves for both pressure distribution and heat transfer, while avoiding the need for a two-dimensional discretization of the reservoir region.

The hydrodynamics for the region surrounding the production well are solved assuming a bounded, stratified, porous system with flow across the layers. The two-dimensional pressure-diffusion equation is analytically solved subject to a zero far-field pressure, a prescribed production flow rate, and a time-dependent pressure at the interface of the production region and the discrete flow channels. Provisions are made for orthotropic permeability distributions as well as transient boundary conditions. The effect on the pressure distribution due to flow in the third dimension is included by using a lumped approximation.

A set of pressure contours generated by an early version of the model is shown in Fig. 25. Because the production region is symmetric, a no-flow boundary is imposed on the line of symmetry (except, of course, at the production well), the production flow-rate input parameter is halved, and a half-space solution can be generated. The rest of the boundaries are set to zero pressure except at the interface, which has some constant nonzero value. For the example shown in Fig. 25, an interface pressure of 30 MPa (4350 psi) was assumed. In the final version of the model, the interface pressure will be determined by the pressure drop through the channeled region of the reservoir. Figure 25 shows a set of isobars that bunch together near the production well, indicating the high-pressure gradient that is to be expected in this region of the reservoir.

For heat transfer, correlations from numerical solutions are obtained for transient heat conduction in rock blocks of arbitrary

Fig. 25. Dimensionless pressure isobars in a homogeneously fractured half-space. Interface separates this region from region of discrete parallel fractures.

sizes, which are then used to model thermal depletion. The model accommodates internal-temperature gradients if the rock size is large and reverts to the traditional "lumped" approximation for small blocks. Approximate local fluid-temperature distributions are calculated by analytically solving a single integral equation. The model is then extended to include reactive and nonreactive tracers, with tracer-response curves predicted semi-analytically.

The final solutions for temperature, heat-flow-rate, pressure, and fluid-flow-rate distributions are obtained by matching all four quantities at the interface separating the production zone from the discrete flow channels. This is implemented using an interactive process. When the final model is completed, it will be compared against the data from the 30-day ICFT. The values to be matched are production pressure, hydrodynamic response, tracer response, and thermal depletion. Results will be computed for a range of parameters such as permeability, channel width, and reservoir size. Sensitivity analyses will be performed on the input parameters to determine their relative importance in the overall model.

6.5.5. Reservoir Flow Testing. Additional information on flow distribution, water loss, and temperature recovery in the Phase II reservoir was collected and analyzed during FY87.

6.5.5.1. Continuing Thermal Analysis of the ICFT (Expt 2067). Very little pumping was done in EE-3A during FY87, allowing a long period (from June 18, 1986, through October 15, 1987) for EE-3A to recover thermally following the ICFT. Five temperature surveys of the EE-3A wellbore injection region are compared in Fig. 26. The survey of January 19, 1982, depicts the original geothermal gradient. The May 15, 1986, survey, run two weeks before the start of the ICFT, illustrates the wellbore condition at the beginning of the test. Anomalies from earlier stimulations of the ICFT injection region (Expts 2059 and 2062) are still present, as is the residual cooling of the entire wellbore from Expt 2066 (January 31 through February 3, 1986), an injection into a deeper interval. During the ICFT, a total of 37,000 m³ (9.76 million gallons) was injected. The next survey on June 23, 1986, was conducted five days after the ICFT was terminated. The injection zone temperature had already rebounded 25°C from the 55°C minimum temperature recorded during injection. The August 28, 1986, survey followed two months of shut-in with no activity. As can be seen, the reservoir had recovered another 55° to 60°C. The two main EE-3A injection intervals are still well marked on the final survey of October 14, 1987, even though the wellbore injection region shows an additional 45°C of recovery. This survey, just before the start of redrilling operations at EE-2, was run 16 months after the ICFT and followed 9 months of relative inactivity in EE-3A. The only EE-3A activity, a short 24-hour injection during Expt 2070 (conducted on December 5 and 6, 1987, to determine post-ICFT injection pressures), should not have had a major impact on the progress of thermal recovery. A total of only 690 m³ (182,340 gallons) of water was injected at about 8.4 l/s (133 gpm), reaching a maximum pressure of 15 MPa (2200 psi) during this test.

Following completion of the ICFT, simulations of EE-2 performance were made using the WBHT code.¹³ The WBHT model solves the 2-D equations for heat transfer, accounting for forced convection in the wellbore and annulus, and conduction to the surrounding rock mass. EE-2 production was modeled using a reservoir-outlet temperature of 232°C (450°F), which corresponds to the original rock temperature at

Fig. 26. Pre- and post-ICFT temperature surveys of EE-3A showing thermal recovery with time.

3535 m (11,600 ft) and flow rate as measured at the EE-2 wellhead. A comparison of the predicted production temperatures with measured values indicated an increasing disparity with time. In general, the major discrepancies corresponded to the appearance of more gas in the production fluid. The largest discrepancies occurred after a 5100-kg (11,000-lb) slug of nitrogen was injected during a 30-minute interval on June 8, 20 days into the ICFT. The main purpose of the gas injection was to attempt to clean out the EE-2 production interval. It was felt that debris, which was filling and covering the near-wellbore fractures, could be removed by gas-lifting the production well to increase flow velocity. (Some sand and mud had previously been removed from EE-2 by surging the well.) Although a significant surge of flow occurred, little debris was seen. A review of production data showed that the outlet flow-rate measurements were erroneously high owing to the continuing presence of nitrogen in the production flow. (A volumetric flowmeter had been used.)

To improve the WBHT simulation, the model was first rerun using a production flow rate derived by summing the flow rates through the two heat exchangers, downstream of the outlet flowmeter. These measurements appeared to provide more reliable values and to

Fig. 27. Comparison of EE-2 production temperature with WBHT projections of production temperature: a) using wellhead-measured flow rates; b) using heat-exchanger flow rates; c) using flow rates with a correction, during early stages, for N_2 injection/production; and d) using flow rates corrected for N_2 injection/production through the end of the test.

be less susceptible to entrained gas. Projections of production temperature using the heat-exchanger flow rates, although still high, were in better agreement with experimental results. As a final step, two possible corrections to account for the error caused by nitrogen production were devised and the simulation was rerun again. The first correction applied only to the early stages of nitrogen injection/production, resulting in only a small difference from the previous simulation. The second correction (about a 10% decrease in flow) applied from the time nitrogen was first injected into the system through the end of the experiment. The best results were obtained from this simulation, but temperatures were still 2° to 5°C (4° to 9°F) high. A comparison of measured temperatures and model predictions for the four cases, following nitrogen injection to the end of the test, is shown in Fig. 27. Associated flow rates are given in Fig. 28.

Simulations of performance during the EE-2 vent-down (Expt 2068, described below) were also run. The same problem with poor flow-rate measurements occurred, this time because of the presence of carbon dioxide in the production fluid during the latter part of the vent. In

order to model the vent properly, it was necessary to reduce flow rates by up to 50%. This suggests much less fluid was recovered during the final stages of the EE-2 vent-down than was initially estimated; only an additional 3700 m^3 (10%) of water may have been recovered rather than the original estimate of 7400 m^3 (20%). It also points out the need for a gas separator upstream of the point of flow measurement or a higher back pressure to keep the carbon dioxide in solution during future operations.

6.5.5.2. Fluid Recovery after the ICFT (Expt 2068). During the fall of 1986, the Phase II reservoir was allowed to vent down at low pressure through the production well-bore, EE-2. The cumulative production for this 47-day vent, referred to as Expt 2068, is shown in Fig. 29. During this time, a total 7400 to 9800 m^3 (1.95 to 2.6 million gallons) of water was vented back from the Phase II reservoir, representing between 50 and 70% of the $14,000\text{ m}^3$ (3.7 million gallons) of water "lost" during the preceding 30-day flow test (the ICFT conducted from May 19 to June 18, 1986).

We conclude that most of the water "loss" during the ICFT was actually water storage

Fig. 28. Production flow rates used for WBHT simulations: a) wellhead-measured flow rates; b) sum of heat-exchanger flow rates; c) flow rates with a correction, during early stages, for N_2 injection/production; and d) flow rates corrected for N_2 injection/production through the end of the test.

Fig. 29. Cumulative production, Expt 2068.

within the reservoir region. This water, injected at high pressure — at up to 30 MPa (4400 psi) — into the fractured reservoir, was slowly returned to the surface during this long vent against an average back pressure of about 1.4 MPa (200 psi).

The measured EE-3A to EE-2 flow impedance during the vent was 11 to 12.5 MPa-ℓ/s (7 to 8 psi/gpm); this surprisingly low impedance is probably indicative of the near-EE-2 conditions only. This observation, coupled with previous Phase II venting experience and other supporting data, suggests that most of the reservoir water is stored in discontinuous, lower-opening-stress joints, which are essentially aseismic.¹⁴ Therefore, the low-pressure venting of the stored reservoir fluid was severely restricted by the flow impedance across the set of continuous but higher-closure-stress shear fractures connecting the fractured Phase II reservoir directly to the short [12-m (40-ft)] EE-2 production interval.

6.5.5.3. Twenty-Six-Hour Flow Test (Expt 2070). On December 4 and 5 of 1986, the Phase II reservoir was flow tested for 26 hours at an injection rate of 8.4 ℓ/s (133 gpm). The EE-3A injection-pressure profile for this brief pumping experiment is shown in Fig. 30.

The remarkable aspect of Expt 2070 is the very low EE-3A injection pressure as compared with that of Expt 2067 (the ICFT). The following table compares the early-time injection

pressures for these two flow tests, after equivalent pumping times (about one hour) and while pumping into a previously vented-down reservoir.

Flow Test	EE-3A	EE-3A
	Injection Pressure (MPa)	Injection Flow Rate (ℓ/s)
Expt 2067 (the ICFT)	30.2	8.4
Expt 2070	13.8	8.4

Because the reservoir-inlet flow impedance was reported¹⁵ to nearly vanish halfway through the ICFT, presumably owing to thermal dilation of the fractures connected to EE-3A, the above data suggest that the effects of the thermal cool-down of the EE-3A injection interval persisted some five and one-half months after the end of the ICFT. From Fig. 26 one can guess that the cooling near EE-3A was still about 100°C at this time.

Another significant conclusion can be drawn from the injection-pressure profile for Expt 2070. We were apparently opening — and filling — a joint network within the Phase II reservoir at surface-injection-pressure levels at or below 16 MPa (2300 psi). This is about one-half of the fracture-extension pressure — 30 MPa (4400 psi) — measured during the ICFT. Without the thermal dilation of the set of shear fractures connecting the EE-3A injection interval to the Phase II reservoir, we would not have observed this lower-opening-stress set of fractures within the reservoir. In

Fig. 30. Injection-pressure profile for 26-hour flow test.

other words, the flow impedance across the set of 30 MPa (4350 psi) extending shear fractures (joints) manifolding the EE-3A injection interval to the Phase II reservoir would normally have completely masked the presence of the set of discontinuous lower-opening-stress joints within the body of the reservoir.¹⁴

This, in turn, casts doubt upon our ability to measure the minimum earth stress in the presence of a pre-existing set of continuous shear joints that obviously exist within the Phase II reservoir (based on microseismic data).

7. TOOL DEVELOPMENT AND WELL LOGGING

7.1. Downhole-Instrument Development

Several "slimline" instruments were designed to make measurements in the EE-3A and EE-2A boreholes through the 114-mm (4-1/2-in.) completion tubing. Because many of the wellbore surveys performed during the LTFT require the downhole instruments to reside in the high-temperature fluids for extended periods of time, it was necessary to design the new slimline tools for continuous operation in the open-hole section of the wellbore during long-term measurements.

Given the above criteria, a new slimline 44-mm-diam (1.75-in.) cablehead was built first. This new design incorporates a pressure-balance system in the cable-termination chamber to equalize the pressure of the oil-filled cavity with the borehole fluid pressure (Fig. 31). The pressure-balance system will prevent borehole fluid from seeping into the termination chamber through the armor and will extend downhole lifetime.

A slimline 44-mm (1.75-in.) spinner-temperature-pressure (STP) tool was designed and fabricated (Fig. 32). This tool also includes a casing-collar locator (CCL), used primarily for wireline-depth correction. It is most useful in determining where geothermal fluids enter the production well and leave the injection wellbore. The STP measurements will also provide data to establish the mass-flow ratio in two-phase flow systems.

A slimline gamma-ray detector has also

been designed to provide accurate depth signatures in the borehole, used for placing open-hole packers in the predetermined packer-setting location. The slimline gamma-ray tool is deployed through the drill string when the open-hole packer is inserted. It may also be deployed through the completion tubing for subsequent radioactive-tracer experiments to analyze reservoir characteristics.

The high-temperature downhole fluid sampler, "Brine Sampler," (Fig. 33) was modified to obtain 4-ℓ fluid samples in the borehole. The tool also uses a temperature probe to measure the temperature of the fluid during the collection process. It has been used to obtain a series of downhole-brine samples at each production zone in four geothermal production wells, without any malfunctions.

7.2. Four-Arm Caliper

The new four-arm-caliper tool design has significant improvements over the old three-arm caliper. The new tool has independent readouts from each of the four arms plus the average borehole diameter. New linear-potentiometers provide the caliper data. The potentiometers, Model 7046, were purchased from Vernitron Corporation and tested to 300°C. This tool also incorporates the pressure-balance system that significantly increases reliability in the geothermal environment (Fig. 34). The tool design has provisions for field replacement of the caliper arms to accommodate any size borehole, thus providing maximum accuracy and resolution. The four-arm caliper is designed to incorporate a gamma-ray detector to provide wireline-depth correlations with background gamma-ray signatures.

The newly redesigned tool will operate continuously at borehole temperatures up to 300°C (520°F). It is 1.5 m (5 ft) long, 108 mm (4-1/4 in.) in diameter, and weighs about 77 kg (170 lb).

7.3. Borehole Acoustic Televier

The rotating acoustic subassembly of the Los Alamos borehole acoustic televier (BAT) has been modified to improve the reliability

Fig. 31. Cablehead.

Fig. 32. Spinner-temperature-pressure tool.

Fig. 33. Brine sampler.

Fig. 34. Four-arm caliper.

of the AC motor-drive circuit. The modification included the relocation of the pressure-balance system from the nose or front end of the tool to just behind the motor housing, thereby eliminating structural support of the pressure-balance housing and piston by the motor shaft. A description of the design and operation of the BAT is presented in some detail in Ref. 16. Most of the effort in FY87 concentrated on fielding the tool and developing the software algorithms to reduce and analyze the data.

On April 13, 1987, the BAT successfully collected borehole images from the entire open-hole region of GT-2. Two surveys were made of this open-hole region at logging rates of 3 m/min (10 ft/min). Since then other tests have been conducted at the Fenton Hill site. Results of these tests proved that using the downhole microprocessor to control data acquisition, processing, and data transmission would provide excellent image and resolution at logging rates of at least 7.6 m/min (25 ft/min) and allow preliminary surveys of open-hole and casing inspections at rates exceeding 15 m/min (50 ft/min).

During FY87 work started on developing a BAT Data Processing Workstation. Activities included design and development of algorithms to support elementary data manipulation and display.

Initial discussions were held with researchers at Stanford University and Mobil Oil, who are currently working with televiewer data. A preliminary design was established, incorporating ideas discussed at these meetings. Data management concepts were developed to organize the collected data.

Once the basic design was in place, several processing steps were identified. These included transferring the data from the data tapes generated in the field, separating the data into logical disk files, and displaying the data. To read the field tapes, a utility program was purchased from the tape-drive vendor. The first algorithm developed was designed to separate the general collection parameters from the data obtained for each revolution of the tool's sensor. This separation step was included to provide rapid access to the revolution data during subsequent processing. The second algorithm was developed to display the data for user interpretation.

To provide a user-friendly interface, display commands are selected from a menu. A wide range of options was provided for selecting data to be displayed.

7.4. Diagnostic Logging

Wellbore surveys were performed in the geothermal wells at Fenton Hill in preparation for the initial attempt to repair the damaged casing in EE-2. When it became apparent that this was not economically feasible, additional surveys were performed in EE-2 to prepare for redrilling operations. Downhole-instrument tests were also run in GT-2 to check out the operation of several new tools. The successful testing of the new high-temperature BAT was a major milestone in the instrument-development work at Los Alamos. Table V is a summary of the wellbore-diagnostic surveys.

8. PLANS FOR FY88

During FY87 the production well of the Phase II system was repaired and prepared for redrilling. During FY88 it will be sidetracked, redrilled, and completed by cementing in a 178-mm (7-in.) liner. It will then be cleaned out and logged, and a short injection test will be run to evaluate the condition of the uncased production zone below the liner.

Limited flow tests will be conducted. Well-logging, geochemical, and microseismic data will be collected and analyzed to determine the condition and increase our understanding of the fractured reservoir to be tested in the LTFT.

Procurement, installation, and testing of surface-system components needed for the LTFT will continue, although funding limitations require that acquisition of expensive components (such as the high-pressure injection pumps) be postponed to FY89 and FY90.

Arrangements will be made for the acquisition, storage, treatment, and management of water required for the LTFT and other Fenton Hill activities.

Downhole instruments will be upgraded and, where necessary, modified to meet the special conditions of the LTFT.

Development of reactive chemical tracers for monitoring depletion of the thermal reservoir will continue, together with improvement

TABLE V
SUMMARY OF DOWNHOLE TESTS AND MEASUREMENTS

<u>Survey</u>	<u>Well</u>	<u>Purpose</u>
Temperature/CCL	EE-2	Determine location at which to set casing packer for flow test.
Temperature survey	EE-2	Establish background temperature before flow test.
Temperature survey	EE-2	Run flowing-temperature log during pressurization and flow test to determine flow characteristics.
Temperature survey	EE-2	Repeat previous test with EE-2 shut in.
Temperature survey	EE-2	Inspect casing for possible flow leaks.
BAT	GT-2	Field test pressure-balance system.
BAT	GT-2	Field test acoustic assembly and downhole electronics.
STP	GT-2	Field test new STP tool.
Temperature/CCL/rabbit	GT-2	Obtain temperature log and check open-hole conditions.
Fluid sampler	GT-2	Obtain bottom-hole fluid sample.
Temperature/CCL	GT-2	Field test new tool.
STP	GT-2	Field test new STP tool; develop software.
STP	GT-2	Perform final field test of new STP tool.
Three-arm caliper	GT-2	Field test tool following modification to arm assemblies.
Three-arm caliper	GT-2	Check arm calibration and operation.
Temperature/CCL/rabbit	EE-2	Check background temperature and clearance gauge in preparation for redrill.
Three-arm caliper	EE-2	Perform caliper survey in preparation for setting whipstock.
Three-arm caliper	EE-2	Repeat survey to set whipstock.
Temperature/CCL	EE-2	Correlate drill pipe versus logging depth.

of the analytical methods needed to measure low concentrations of such tracers in the heat-extraction fluid.

Microseismic data from previous experiments will be reanalyzed with increased precision and accuracy, and microseismic data collection and analysis will be further improved.

The reservoir-analysis effort needed to model the reservoir thermally and fluid mechanically will continue.

Technology exchange and transfer to industry, other organizations, and complementary programs in other countries will be emphasized, with special attention to the Bechtel/Chevron HDR feasibility study.

Environmental surveillance, maintenance of physical plant and instrumentation, and other support and management activities will, of course, also continue.

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076-100	A05	226-250	A11	376-400	A17	526-550	A23
101-125	A06	251-275	A12	401-425	A18	551-575	A24
126-150	A07	276-300	A13	426-450	A19	576-600	A25
						601-up*	A99

*Contact NTIS for a price quote.

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