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TITLE: UNIQUE ASPECTS OF DRILLING AND COMPLETING HOT-DRY-ROCK
GEOTHERMAL WELLS

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UNIQUE ASPECTS OF DRILLING AND COMPLETING HOT DRY ROCK GEOTHERMAL WELLS

IADC/SPE

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ABSTRACT

The drilling and completion of wells in hot, non-porous crystalline basement rock has challenged conventional rotary and directional drilling tools, procedures, and instruments used for oil and gas drilling. Drilling operations at the Fenton Hill Hot Dry Rock (HDR) Geothermal Test Site have led to numerous developments needed to solve the problems caused by a very harsh downhole environment.

A pair of deep wells were drilled to approximately 15,000 ft (4.6 km); formation temperatures were in excess of 600°F (300°C). The wells were directionally drilled, inclined at 35 degrees, one above the other, in a direction orthogonal to the least principal stress field. The well site is near the flank of a young silicic composite volcano in the Jemez Mountains of northern New Mexico.

The completion of this pair of wells is unique in reservoir development. The lower well was planned as a cold water injector which will be cooled by the introduced water from the static geothermal gradient to about 80°F (25°C). The upper well will be heated during production to over 500°F (250°C). The well pair is designed to perform as a closed loop heat-extraction system connected by hydraulic fractures with a vertical spacing of 1200 ft between the wells. These conditions strongly constrain the drilling technique, casing design, cement formulation, and cementing operations.

The completion of these two wells by hydraulic fracturing is proving to be very difficult, due to the large water volumes required, problems with zone isolation, logging, and extreme temperatures. New and upgraded technologies have been developed to resolve these difficulties.

INTRODUCTION

In natural, or hydrothermal, geothermal reservoirs, surface waters penetrate deep enough to contact hot rock. The fluids are heated by the rock, but are trapped in a porous fractured system. In places a large circulating convection system has been established, with high heat flow noted at the surface. Although these natural systems are rather

rare, they are excellent sources of energy. World-wide development of high-grade hydrothermal reservoirs has reached a power production capacity of about 2500 MW(e) produced from 2500 wells drilled into 146 hydrothermal reservoirs located in 32 countries.

The ratio of dry holes to production wells in hydrothermal exploration is highly variable but averages about 3 to 1. Many of these dry holes are hot, having penetrated into a volume of hot rock that lacks fluid and natural permeability. Thus, development drilling often produces dry but hot wells, excellent candidates for artificial stimulation, or for the HDR energy extraction concept.

Project Description

The production of heat energy from hot, dry rock entails creating fracture permeability at depth by hydraulic fracturing to permit circulation of water from the surface through wells drilled into the reservoir rock. A preliminary project (see Location, Figure 1) to develop this concept was initiated by the Los Alamos National Laboratory in 1972 and in 1977-1980 succeeded in producing the first two reservoirs in a hot, crystalline formation at 10,000 feet (3 km) where temperatures are 400°F (200°C). Long-term pumping and temperature drawdown tests and reservoir simulations examined the technical feasibility of the concept for the commercial development of a larger and hotter HDR geothermal reservoir.

The results achieved in these single fracture reservoirs led to the decision to drill a second pair of deep, 35° inclined wells, so that the development of a multiple, parallel fracture reservoir could be attempted. This paper reviews the unique aspects of drilling these two deep wells into Precambrian crystalline rock and the initial phases of the completion and hydraulic fracturing efforts. Many of the problems encountered and their solutions in this project have led to improvements and innovations that are needed for ultra deep, hot formation drilling and completion methods for both the geothermal and petroleum industries.

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The drilling of the deeper well pair started with the spudding of Energy Extraction Well No. 2 (EE-2) on April 3, 1979. This injection well was drilled and cased in 409 days. The well was directionally drilled with the open hole, 8-3/4-in. (22.2 cm) section inclined at 35° and deviated in a NNE direction (Fig. 2), which is orthogonal to the inferred least principle stress. EE-2 was drilled to a measured depth of 15,298 ft (4.7 km) and the BHST was recorded as 608°F (320°C). The production well, EE-3 was directionally drilled so that the wellbore trajectory was spaced 1200 ft ±50 ft (370 m ±15 m) directly above the injection well. Well EE-3 was spudded May 22, 1980 and was finished 461 days later. Well EE-3 reached a measured depth of 14,933 ft (4.25 km) and a temperature of 580°F (280°C) BHST. The EE-3 borehole trajectory was maintained vertically above EE-2 to an azimuth tolerance of ±100 ft (±30 m). This precision was required to maximize the chances for fracture connections during completion operations.

Completion operations began in November 1981, when a small workover rig was mobilized over EE-2 to clean the wellbore. The fracturing and completion operations were initiated April 4, 1982 when a large workover rig (Brinkerhoff Signal Rig No. 78) was mobilized on EE-2. These operations are still in progress (December 1982) and the initial phases of these fracturing and completion operations are reported below.

Geology and Downhole Temperature

The geologic section at Fenton Hill (Fig. 3) consists of approximately 500 ft (152 m) of welded volcanic tuff overlying 800 ft (244 m) of Permian-age red-beds (shales and sandstones), and 1100 ft (335 m) of Pennsylvanian-age clays, shales, and limestones. Precambrian-age rocks of extremely low permeability make up the crystalline basement below 2400 ft (732 m). The temperature at the top of the Precambrian is 212°F (100°C), and the geothermal gradient in this crystalline rock (age of 1.3 to 1.7 Byr) increases from 30°F/1000 ft (55°C/km) to 49°F/1000 ft (89°C/km) at 15,000 ft (4.7 km). The temperature at the bottom of the hole is 608°F (320°C).

A 6 x 4 mile (8 x 6 km) block contains the area under development as a HDR resource at the Fenton Hill Site, with volcanic tuff and sedimentary rock overlying and insulating the crystalline reservoir rocks. The conductive heat flow of 250 mW/m² is about five times the worldwide average and results in the static temperature profile shown in Fig. 3.

A cavernous limestone zone, just above the crystalline basement rock at 2400 ft caused many difficult drilling problems related to severe lost circulation. The basement rock has compressive strengths of over 40,000 psi, is impermeable and very abrasive. Much of it is gneissic in nature, with no discernible large-scale layering. Several large bodies of granodiorite were encountered within the gneiss, and a number of narrow "altered" zones that contained chlorite, pyrite, and considerable amounts of calcite are present.

A great deal of chemical alteration has occurred in these zones. They evidently are shear zones or locally shattered zones caused by the forceful later injection of volatiles and intrusive magmatic material into the host rock. Variations in drilling performance and unexpected directional problems

further indicated the presence of faults or altered zones in the wellbores. The lithology represented in Fig. 3 was established by a few cores and cuttings without the benefit of geophysical logging.

DRILLING

It required 870 days of drilling to complete the two wells (EE-2 and EE-3) shown in Fig. 2. The drilling and casing objectives were to produce 4000 ft (1.2 km) of potential reservoir above 400°F (200°C). Circulation rates of the heat extracting fluid in this system were anticipated to be 1500 to 2000 gpm to produce 20 MW of electricity. These rates dictate large diameter wellbores to minimize parasitic pressure loss during production.

Drilling through the volcanic rock was initiated with a 26-in. (66.0 cm) drill bit and cased with a 20-in. (50.8-cm) diameter surface string set at the top of the first severe lost circulation zone. The wells were then drilled with 17-1/2-in. (44.5-cm) diameter bits to a depth of about 150 to 200 ft into the basement, and the intermediate 13-3/8-in. (34.0-cm) casing strings were cemented in two stages. The major part of the crystalline granitic basement was drilled with 12-1/4-in. (31.1-cm) bits. When the angle build points (ABP) were attained, short, hole-reduction bit runs (11 in. and 9-5/8-in. for EE-2 and a single 9-5/8-in. run for EE-3) were completed. The injection well EE-2 was then drilled with hold and slight-build assemblies to TD at 8-3/4-in. diam. Well EE-3 was required to follow or track EE-2, so after the ABP was achieved, several directional runs were made to correct the azimuthal direction, but similar angle hold and mild-build assemblies were used. Many severe twist-offs occurred in EE-3 and extremely high torque and drag problems were encountered. Thus, the EE-3 drilling was terminated about 600 ft (200 m) short of the target TD.

Drill Bits

The following criteria have been established for identifying lengths of bit runs that are considered to be characteristic of very good performance in the Precambrian crystalline basement:

- Rotary drilling; above 11,000 ft (3350 m), inclination <30°: 300 ft (91 m).
- Rotary drilling; below 11,000 ft (3350 m), inclination 35°: 200 ft (61 m).
- Motor drilling: 100 ft (30 m).

Bit runs that exceed this performance were picked out of the drilling record and are presented in Tables 1 and 2.

For rotary drilling the 12-1/4-in. hole at depths of less than 11,000 ft (3350 m), Hughes J-55 bits gave excellent performance. During motor drilling operations, the Smith Q9JL and Security H8J bits gave superior performance in the 12-1/4-in. hole.

A special geothermal three-cone rock bit was used to great advantage almost exclusively to drill the 8-3/4-in. hole. This bit, manufactured by Smith Tool Company, is identified by the code type 7GA (see Fig. 4), and is a nonsealed, air circulation, TCI bit. Several special features that account for its superior performance are:

- harder carbide buttons on the gauge row of the cones,
- hard facing for extra wear resistance on the leg shirt-tails,
- wear pad build-up and carbide inserts on the shanks of the legs,
- use of nonsealed bearings, and
- additional clearance in the bearings to allow for more circulation.

These improvements increased downhole bit life (and reduced the number of trips from the deeper portions of the hole) to more than offset the 10% additional cost of the bits.

Three cone, TCI bit performance while drilling with a downhole motor was predictable, although disappointing. Severe gauge wear at the higher rotational speeds (350 to 500 rpm) greatly restricted the useful life of motor-driven assemblies. For comparison, minimum-cost-per-foot rotary drilling was obtained by operating IADC Code 635 bits at high-energy levels. Typical operating parameters of 5500 to 6500 lbs of bit load per inch of bit diameter, 65 to 75 rpm rotary speed and 4.5 to 5.5 hydraulic horsepower per square inch of bit area resulted in penetration rates of 22 to 24 ft/h and maximum bit life of 30 to 40 h.

The drilling of approximately 24,000 ft of hot crystalline Precambrian formations has led to the following conclusions:

- (1) Drilling rates in basement rock are uniform with depth.
- (2) Drilling rate is primarily dependent upon tooth configuration and weight on bit.
- (3) Gauge wear is the primary bit problem.
- (4) Sealed bearings are temperature limited; open bearing bits are required above about 400°F (200°C).
- (5) Bit bearing life decreases with increasing temperature (i.e. depth).
- (6) Only tungsten carbide cutting structures were found effective for granite drilling.

In addition to the above, the severe drilling conditions readily destroyed poor quality bits. Even minor manufacturing defects lead to rapid bit failures which might not have occurred in less severe drilling conditions. Each new bit was required to ream due to gauge reduction of previous bit runs. Weak leg bits readily "pinched," and lost teeth and cone tips, and torqued-up quickly. Blast hole type bits proved superior for reaming granites.

Coring

Obtaining sufficient amounts of core from HDR boreholes is essential in determining a number of reservoir parameters. The need for this information is not as acute in either oil or gas wells or in conventional geothermal systems. Some of the more obvious items of information to be derived from core samples are:

- existence and orientation of natural fractures;
- nature of fracture filling minerals, if any;

- rock structure and foliation as it might affect hydraulic fracturing;
- rock type and age;
- rock porosity and permeability;
- core orientation by paleomagnetism;
- acoustic and velocity values;
- rock-water interactions;
- circulating fluid chemistry, as it might affect scaling or fouling of heat exchanger tubing;
- calibration of geophysical logging tools; and
- future bit design.

Previous intermittent coring operations at Fenton Hill, using modified JOIDES bits, resulted in fair core recovery and bit life at moderate depths. Diamond core bits were also used, but the extremely short bit life (<1 ft) was an ineffective means of coring.

Use of Hybrid Stratapax Bits⁶

During the drilling of EE-2, cores were planned to be obtained at approximately 600 ft (180 m) intervals, below 11,000 ft (3350 m). To accomplish this, six hybrid roller cone Stratapax bits with Polycrystalline Diamond Cutters (PDC) were purchased from Smith Tool Company (Fig. 4). The bits are 7-7/8-in. (20-cm) o.d. by 3-in. (7.6-cm) i.d. and consist of four cones with TCI buttons and four PDC pads (cutters) mounted on tungsten carbide studs between the cones.

A total of 29 ft (9 m) of core was obtained in EE-2; coring was not performed in EE-3. Table 3 is a summary of the coring runs made in EE-2. Rotational speed varied from 35 to 50 rpm with 10,000 to 20,000 lbs weight. Every bit was pulled when the penetration rate slowed to about half. Two oriented coring operations were unsuccessful because of the temperature and mechanical difficulties.

After the EE-2 coring runs had been completed, Smith Tool conducted an evaluation on 5 of the hybrid core bits. Based on this analysis, it was concluded that major problem areas existed with the Stratapax studs breaking and higher-than-expected seal temperatures. However, the hybrid core bits performed well and improved versions are the first choice for future coring operations in crystalline, abrasive rock.

Drillstring and BHA

Both the EE-2 and EE-3 wells were plagued with severe drill string wear and twist-off problems. The strings for the two wells were different, but very high drag and torque existed in both wells, caused by the lack of filter cake and the clear water circulating fluid system. The EE-2 string design was a 5-in. O.D., 19.50 lb/ft and 25.60 lb/ft, Grade E; and 19.50 lb/ft, Grade G, with NC50 tool joints. Drilling of EE-3 was initiated with this same string of 5-in. pipe.

A 4-1/2-in. drill string was selected to replace the 5-in. string at 10,528 ft, after a complex fishing job. The 4-1/2-in. string consisted of 7000 ft of 16.60 lb/ft, S Grade pipe on top and 9000 ft of 16.60 lb/ft E Grade on the bottom, with XH connections. The drill string failures for the two wells are summarized in Table 4. The final phases of drilling EE-3 required the use of two 4-1/2-in. drill strings, with inspections performed every 30 days or

500 hours of rotating time. The two-string approach allowed the one string to be laid down, inspected and hardfaced while the other string (previously inspected) was run in and drilling continued during the inspection.

The less frequent drill-string failure rate for EE-2 than for EE-3 was due in part to the decreased dog-leg severity (DLS) as shown in Fig. 5 than for EE-3 and to the more fatigue resistant 5-in. drill string. A strict DLS minimization effort and comprehensive inspection program is mandatory for such wells.

Drilling Fluids⁷

In the drilling of the overburden, the 2400 ft (730 m) of volcanics and sediments, were costly problems in lost circulation and hole stability were encountered. These rocks were drilled with a bentonite based fluid. Because of the large hole diameters 26-in. and 17-1/2, an inverted rheology was provided by polymeric flocculants to assure adequate hole cleaning. The lost circulation problems at the base of the limestone were never solved. This area was penetrated by drilling rapidly without returns. The 20-in. surface casing was run to just above the first lost zone at about 1800 ft (600 m), then drilled out with a 17-1/2-in. bit and packed hole assembly. Nonrotating four-bladed rubber stabilizers were used to avoid digging into the wall of these soft rocks, while allowing high bit weight and ROP. The intermediate 13-3/8-in. intermediate casing was then set 150 to 200 ft into the granite. This strategy sealed off the lost circulation zones and high flows of saline aquifers for the remainder of the drilling.

The Precambrian section, both 12-1/4-in and 8-3/4-in. holes was drilled with a clear water fluid system. The crystalline rocks are essential chemically insensitive to the fluid. Because the matrix permeability is extremely low ($K = 10^{-9}$ darcy), no filter cake forms. Fifty barrel, high-viscosity pill sweeps of bentonite were used to aid with cuttings removal. Lubricity was enhanced by 50 barrel pill sweeps with slugs of a triglyceride, plus alcohol additive. Corrosion control was necessary; a sulfite system was employed with continuous additions of an oxygen scavenger and caustic to maintain pH = 9.5 and keep the drill string corrosion within acceptable limits. The sulfide system gave some problems when the 15,000 bbl circulating waste pit started producing H_2S by bacterial action in the bottom slime.

The dry rock would accept about 50 bbls of water per 300 ft (100 m) drilled in the 8-3/4-in. hole. This amount is believed to be the displacement of the pore fluids; porosity <1%. A small amount of CO_2 and H_2S was possibly released in this process and may account for some of the cementing problems encountered during sidetracking. The lubricity agent degraded rapidly at the higher temperatures and was replenished when high drag conditions were evidenced. The degradation products formed a black gunk that coated and clogged logging tools.

DIRECTIONAL DRILLING

The deeper EE-2 injection well was drilled first with a kick off point (KOP) at 7000 ft (2100 m). Downhole motor runs alternated with rotary hold or build assemblies until the azimuth of $N60^\circ E$ and 35° inclination were established. Below the angle build point (ABP) at 11,600 ft (3540 m), the 8-3/4-in.

diameter wellbore was rotary drilled with hold or build assemblies to maintain the 35° inclination, but no azimuth corrections were attempted and about 20° of right hand walk was experienced.

The reservoir design requirements dictated that the production well EE-3 be placed precisely vertically parallel to EE-2. The 8-3/4-in. diameter wellbore targets were:

- 1200 $\pm$ 50 ft (370 m $\pm$ 15 m) vertically above EE-2.
- $\pm$ 100 ft ($\pm$ 30 m) lateral tolerance.
- A TVD of 13,230 ft (4030 m) which is 1200 ft vertically above EE-2.

The KOP for EE-3 was at 6500 ft (2000 m) and the ABP was finally achieved at 10,800 ft (3300 m) where an inclination of 34° and a direction of $N55^\circ E$ were established. Hold and angle-build rotary assemblies were used to drill the 8-3/4-in.-diam borehole. Eight turbodrill (five successful) corrections were necessary to maintain alignment with EE-2.

Downhole Motors

A summary of motor assembly runs is presented in Table 5. A total of 79 downhole directional motor runs was attempted (excluding sidetracking operations) and 62 (78%) were successful.

The major results from these downhole motor runs for directional corrections are:

- (1) Thorough hole cleaning and reaming are required.
- (2) Float valves are necessary to avoid plugging when a connection is made.
- (3) Positive displacement motors (PDM) can operate satisfactorily at formation temperatures less than $400^\circ F$ ($200^\circ C$).
- (4) A PDM with lower RPM and higher torque is preferred when TCI bits are used in crystalline rock.
- (5) Above $400^\circ F$ ($200^\circ C$), all-metal turbodrills are required.
- (6) A steering tool is required to monitor and adjust motor correction progress.
- (7) Most steering tools are heat-damaged above $400^\circ F$ ($200^\circ C$) and rough drilling conditions with TCI bits often damage the tools.
- (8) Downhole motor bearings (and steering tools) can be protected and their life extended by use of high-temperature-rated shock absorbers.

A high temperature turbodrill with high torque and low RPM operating characteristics compatible with TCI bits and crystalline rock was developed. Two each 7-3/4-in. and 5-3/8-in. diameter tools were fabricated and used for the directional corrections at temperatures greater than $400^\circ F$ ($200^\circ C$) with 12-1/4-in. and 8-3/4-in. bits respectively.

A prototype turbine tachometer (rpm indicator) was developed to provide a surface indication of downhole motor speed. Its operation was based upon a pressure pulse produced during each revolution of the turbine shaft by a perturbation in the blading of the motor. The pulse was transmitted through the fluid column in the drill string to the surface where it was detected and processed. Nitrogen-operated, pressure-pulse dampers were assembled and placed in series in the mudline at the outlet of the triplex rig pumps. These dampers were required to improve the signal resolution of the turbodrill tachometer.

Also, to dampen vibration and shock transmitted from the bit to the motor, high-temperature-rated shock absorber tools were used.

Usually a 60 to 90 ft (20 to 30 m) run was sufficient to obtain the desired change in azimuth. The major reasons for short motor directional runs or aborts (in order of frequency) were: (1) steering tool failure; (2) bit dulled rapidly, usually undergauge; (3) float valve leaked (plugging motor); or (4) the motor failed. A few runs were pulled due to tight hole conditions and the motor failing to rotate. These occasions were caused by insufficient reaming or a severe dogleg. Operationally these conditions could be alleviated by reaming down with the motor; or starting the motor drilling, then adjusting to the required orientation by small angle changes and short drilling increments.

One very important operational aspect of directional drilling in crystalline rock that must be strongly emphasized is the need for close monitoring with a steering tool and frequently spaced 60 ft (20 m) single shot surveys. A misdirected motor run or a too-sharp angle change is nearly impossible to correct. Multiple reaming runs with two, near-bit, 6-point roller reamers had little effect.

Rotary Hold and Build BHA

Experience in the application of BHA design for build and hold assemblies was similar in both wells. Blade stabilizers were not usable, they wore too rapidly, so roller reamers and roller stabilizers were required. Blade stabilizers with TCI wear protection wore so rapidly in these abrasive conditions that the desired point of tangency was lost. Blade stabilizers also added significantly to the torque. A 3-point near-bit roller reamer was run in essentially all of the 8-3/4-in. hole drilling.

The strategy for the drilling of the straight-hole reservoir section of the wells was to drill ahead with very stiff, packed-hole holding assemblies, maintaining 35° inclination, until the single-shot data indicated that corrective measures were required. Variations in formation effects did require corrections in both azimuth and inclination in EE-3 in order to maintain the required trajectory tolerances. Azimuth correction runs used the high-temperature-rated turbodrill because the formation temperature was 450°F (210°C) at the ABP. The most effective rotary hold assemblies consisted of: 8-3/4-in. bit, 3-pt or 6-pt roller reamer, 6-3/4-in. short drill collar, 3-pt roller reamer, drill collar (Monel), 3-pt roller stabilizer or reamer, five 6-3/4-in. drill collars, 15 joints of HeviWate drill pipe, drilling jars, and 22 joints of HeviWate drill pipe.

Jars

Hydraulic drilling jars (HYDRA-JAR) were modified by Houston Engineering to operate successfully at temperatures to 550°F (290°C). For fishing operations, Bowen Tool Type J and Dailey L. I. mechanical jars were used.

Keyseating

It is often assumed that it is not possible to keyseat in a crystalline rock formation. However, in the 12-1/4-in. section of EE-3 an s-shaped dogleg was introduced just below the KOP in the 6500 to 7200 ft

(1980 to 2195 m) depth interval. The dogleg severity (DLS) averaged 3.6 degrees/100 ft and peaked at a DLS of 5.6 degrees/100 ft (Fig. 5). The many trips and rotating hours spent drilling the 12-1/4-in. hole below this depth wore a deep groove (greater than 20-in. deep) with a diameter of the 6-1/4-in. hard-banded tool joints. Tripping out with the first 8-3/4-in. BHA jammed the top 6-3/4-in. drill collar in the keyseat. Another BHA jammed in the keyseat before sufficient reaming with 8-3/4-in. string roller reamers wiped out keyseat.

EE-3 SIDETRACKING ACTIVITIES

A twist-off occurred in EE-3 while drilling the 12-1/4-in. hole at a depth of 10,500 ft (3200 m). Sidetracking was initiated to bypass the stuck bottom-hole assembly. The hole was underreamed to a 16-in. diameter from 9760 to 9774 ft (2975 to 2975 m) and from 9885 to 9900 ft (3013 to 3016 m). Six cement plugs were set before the directional drilling consultant was satisfied with the hardness of the cement. The penetration rate on the first five plugs was about 1 ft/min at 5000 lbs load; the sixth plug drilled at 0.3 ft/min at 10,000 lbs load.

Two Dyna-Drill runs with a Smith 9-7/8-in. Q9J6 button bit and 2 in. bent sub were made in plug number 6 to 9780 ft (2981 m), at a penetration rate of 7 ft/h and load of 2000 lbs, without any indication of weight increase or sidetracking action. Two more cement plugs were set, and sidetracking was attempted with 7GA and diamond bits, without success.

A 10-1/2-in. (27-cm) o.d. whipstock with a 10 ft (3 m) slide designed to accommodate a 12-1/4-in. bit was run with 30 ft (10 m) of tailpipe. It was oriented to deflect the bit 40° to the right of the high side of the hole; and cemented with the ninth cement plug. The assembly used to drill off of the whipstock consisted of a Smith 12-1/4-in. Q9JL button bit, 6-1/4-in. drill collar, jars, and HeviWate drillpipe. The bit drilled 17 ft (5 m) in 15.5 hours with 5000 to 15,000 pound load. As the amount of gneissic chips in the cuttings was increasing steadily, an angle-building assembly was made up and 97 ft (30 m) of new hole was drilled, which definitely established the successful sidetrack after three months of attempts.

Cementing

Cement plugs for sidetracking consisted of Class G or H cement, ranging from 0 to 40% silica flour, retarded for 1 to 8 hours of thickening time. The eighth plug contained Class J cement with 20% silica flour. In spite of careful measurements to obtain bottomhole circulating temperatures after the second plug, the cement usually drilled at a rate of 1 ft/min with no load. Causes of this behavior were attributed to over-retardation, contamination from a triglyceride base lubricating agent used during drilling and lack of bond to the borehole wall, with no definite cause being pinpointed. Cores taken in the plugs proved that the cement set up almost as hard downhole as it did in laboratory tests but for some reason it drilled easily. General consensus among directional drillers is that if a cement can be drilled at 1.5 to 2 min/ft with 10,000 lbs load, it is hard enough for sidetracking. However, granitic and gneissic rocks are much harder than even the hardest cement, so that the bit tends to follow the old hole.

Sidetracking Bits

The life of diamond bits in cutting abrasive crystalline rock is very short; the maximum run in EE-3 was 8 ft (2.5 m) in 15 hours and the maximum penetration rate was 1 ft/h at 15,000 lbs load. Diamond bits are the only available tool with significant side-cutting capability, but this advantage is largely canceled by the gauge diamonds being worn off while traveling downhole on the bent sub Dyna-Drill assembly.

Smith Q9JL bits were used to sidetrack off the whipstock. Inspection of the cutting structure of a button bit usually tells if it has started to sidetrack. When cutting on the sidewall first begins, the outside buttons are worn down, with the wear pattern gradually extending toward the center of the bit as more sidewall is cut.

Conclusions

Three successful sidetracking operations⁹ in Precambrian crystalline rock have been conducted at Fenton Hill (the first two in previous operations):

- o Using diamond bits with a Dyna-Drill -- 2-1/2 weeks.
- o Using button bits with a Dyna-Drill -- 2-1/2 days.
- o Using button bits with a whipstock -- 1 day. (Three months were consumed in unsuccessful attempts using cement plugs and bits before setting the whipstock).

Sidetracking in hard crystalline rock requires:

1. Adequate geologic knowledge.
2. A ledge or underreamed section of the hole, or whipstock.
3. Carbide insert button bits.
4. Good cement plugs, which will drill at not less than 1.5 min/ft at 10,000 lbs load with a mill toothed bit.
5. A dedicated directional driller who believes in himself, will spend long hours on the rig floor, with hands on the rig controls.
6. Good orientation equipment.
7. Unlimited patience.

PRODUCTION CASING

The production casing for the HDR wells was designed for unique conditions.¹⁰ The design of the production casing and subsequent completion operations in these wells indicated that thermal cycling, anticipated operating pressures, and wear during downhole operations are major considerations for both casing specifications and installation procedures.

The production casing in EE-3 is anticipated to undergo a large increase in temperature during future energy production. The injection well casing string also will undergo a large decrease in temperature during injection. The order of magnitude of these changes has been estimated, and for design purposes the maximum extremes were used.

The original design concept for cementing of the 9-5/8-in. production casing in EE-2 called for running the casing to approximately 11,600 ft and then cementing to the surface in four stages. The requirement for cementing to the surface was largely

determined by the necessity to reduce the severe axial stresses in the casing string, for an injection water temperature of 104°F (40°C) during circulation of the underground loop. Also, because of this cool operation mode, it was planned to cool the hole before cementing, and to maintain a temperature of 250°F (129°C) in the casing for 48 h after cementing, to allow the cement to set around a cooled and contracted casing string.

However, the procedure was revised to cement only the bottom 1000 ft. The criteria that influenced this change in cementing design were as follows:

- Necessity to install the casing in the least amount of time, while pumping without returns.
- Probable failure of the F0 stage collars to function above temperature of 325°F (163°C) as experienced in the Cerro Prieto geothermal field in Mexico.¹¹
- Intervals of high dogleg severity below 9000 ft which might cause nonuniform circumferential loading of casing and result in buckling.

The precementing cool-down of the hole took four days. Running of the 9-5/8 in. production casing was completed to the design depth of 11,578 ft. Shortly afterwards, the cool-down flow through the casing was started. Three days later, the bottom 1000 ft of the production casing was cemented with 75 bbls of cement consisting of Class H with 80% silica flour. Following the cementing operation, circulation was maintained in the casing through open-ended drill pipe to produce a slow cure of the cement.

The following production casing plan for well EE-3 was developed to alleviate or minimize axial movement,¹² axial stress and any potential collapse problems. Efforts were made to obtain 47 lb/ft and 43.5 lb/ft S-95 casing, but only 47 lb/ft P-110 grade with Vallorrec VAM connections was available. The top two joints were 53.5 lb/ft L-80.

The 8-3/4-in. reservoir section of EE-3 was drilled to measured depth of 13,933 ft (13,048 ft TVD). The hole was then plugged back with cement from 10,900 ft to 10,400 ft, and casing tensioning jacks were installed around the wellhead.

The string was cemented from 10,374 ft to 7300 ft, tensioned and then cemented from 7300 ft to 3000 ft, all without cooling (Fig. 2). The first stage of cementing was accomplished without major problems. The stage collar opened and excess cement above the stage collar in the annulus was circulated out. Approximately 72 h after finishing the first stage cementing, the casing tensioning and second stage cementing began. The tensioning jacks were cycled up and down four times to stretch the casing and work tension down the casing. These cycles resulted in the following casing stretch (see Fig. 6):

1. stretched casing 2.3 ft w/7000 psi (529,000 lbs)
2. stretched casing 1.9 ft w/6475 psi (498,600 lbs)
3. stretched casing 4.1 ft w/8350 psi (643,000 lbs)
4. stretched casing 4.1 ft w/8300 psi (639,100 lbs)

Upon completion of cycling, tension resulting from the jack cycling had been worked down to approximately 6440 ft and 3.0 ft of casing stretch was retained. The casing head slips were then set. Next

the casing was cemented from 7280 ft (DV collar) to 3000 ft and the DV collar closed.

The jacks were then cycled up and down three times resulting in the casing being stretched 5.1 more feet for a total (including 3.0 ft of pre-second stage cementing casing stretch) of 8.1 ft for a force of 885,000 lbs. The 9-5/8-in. casing head slips were then set in the casing landing spool.

During the installation, cementing and tensioning of the production casing in EE-3, the strain in the top joint of the string was measured using electrical resistance strain gages. Four axial strain measuring gages were welded onto the outside surface of the casing at equal intervals. The strain gage data (Table 6) show that the strain gage joint was stretched in tension on the 20th of August when the casing string was tensioned. A calculation using the change in length or strain from gages 1 and 3 (between the 19th and 20th of August) of approximately 550 $\mu\text{in./in.}$ gives a change in tensile stress of 16,500 psi ($E\epsilon = \sigma$, where $E = 30 \times 10^6$ psi, $\epsilon =$ strain in $\mu\text{in./in.}$ and $\sigma =$ stress in psi). Using an area of 15.5 in.^2 for the 53.5 lb/ft, 9-5/8 in. casing gives a tensile load of 256,000 lb which is only about half of the 580,000 lb load applied. This discrepancy is probably due to changes in apparent strain due to temperature changes. The gages were not compensated for temperature. A dummy gage mounted on unstrained casing material located near the strain gages (in the same temperature environment) should be used in future installations in order to compensate for temperature-induced apparent strain.

LOGGING AND EVALUATION

Obtaining realistic surveys and logs were hampered by the extremely harsh borehole conditions. Most commercial geophysical logging tools and cables do not operate at temperatures above 425°F (218°C). The inclination of the boreholes required strong tool centralization mechanisms, which were not readily available. In addition, the lower half of the EE-2 borehole was filled with a mixture of water, cuttings, and Torq-Trim residue (a triglyceride compound used to reduce drillstem drag and friction), forming a black "gunk" that coated the borehole wall and gummed-up the survey tools.

A number of downhole surveys were considered to be required for the successful development of the HDR reservoir system:

- Gyro-directional surveys; for determining the azimuth and inclination of the boreholes.
- Temperature; for use in cementing, leak detection, fracture locations, and expected life of logging tools and downhole hardware.
- Cement bond; for inspection of the 9-5/8-in. casing cementing, and the cemented-in liner PBR assemblies.
- Seismic event detection; for determining the direction of fracture propagation in real time.
- Borehole caliper; for determining packer setting locations, possible fracture initiation points, and cement slurry volumes.

A successful gyro survey of the EE-2 wellbore¹³ was made with a Sperry-Sun multishot directional tool on a Dresser-Atlas high temperature cable which

verified the single-shot surveys taken during drilling (Fig. 7).

Temperature survey tools developed by the Los Alamos Geoscience Instrumentation Group have performed exceptionally well, giving reliable continuous temperature readings under extremely adverse conditions. The Los Alamos tool is a thermistor device, with a glass temperature sensor; it has measured a maximum downhole temperature of 608°F (320°C).

Cement bond logs (CBL) of the 9-5/8-in. casing cement in both EE-2 and EE-3 were obtained by Schlumberger; both logs indicated good bond over sufficient lengths of the cemented intervals. An attempt was made to obtain a CBL of the cemented-in liner/PBR assembly, but was unsuccessful due to high temperature.

The detection of downhole seismic events in real time during fracturing operations has been very successful, giving valuable information as to the extent and direction of the fracture propagation. Previous experience at Fenton Hill (and theory) indicated that vertically-oriented hydraulic fractures were formed in the research reservoir at 10,000 ft depth. From data obtained from the seismic instrumentation, it appears that the zone of induced seismicity created at 14,000 ft extends outward and upward from the wellbore at an angle of 45° from the vertical, and that minor fracturing is distributed in an egg-shaped area which contains this zone (Fig. 9).

The Los Alamos Instrumentation Group has designed and built a high-temperature borehole caliper tool, which has produced a reliable caliper survey, after the developmental problems were overcome. A thru-tubing commercial caliper was attempted in the lower part of EE-2, but failed because of its temperature limitations.

The following geophysical logs are valuable for determining the character of the rock encountered in the borehole.

- Seismic logging.
- Gamma ray; or spectral gamma.
- Neutron; thermal, epithermal, gamma-ray neutron.
- Density; gamma-gamma.
- Sonic; delta t and full wave.

Normally, these geophysical logs could have been run during or immediately after drilling, before the downhole temperature had a chance to rebound to static values, but it was a management decision that these logs could be obtained later, if necessary. Also contributing to the lack of geophysical data was the presence of the black "gunk" in the holes. Later geophysical logging was attempted during fracturing, but the borehole roughness, high temperatures, pressures, and out gassing, prevented their successful running (except for seismic).

ZONE ISOLATION FOR HYDRAULIC FRACTURING

The first connecting fractures were planned to be created from the bottom portion of EE-2 extending upward to EE-3. Isolation of a section of the open wellbore is necessary for pressurization to achieve the fracture connections. Methods of isolating sections of the borehole for fracturing operations included the use of open-hole packers (both straddle

and single), and a cemented-in scab liner/PBR assembly.

Open Hole Packers

Development of two types of open hole packers for HDR use was initiated in 1978. These packer systems were intended to be run in a straddle configuration in a 8-3/4-in. drilled hole. The specifications called for 540°F (280°C) temperature at 5000 psi pressure differential, and a 72 hour operating life. These were conditions extrapolated from the earlier research reservoir in the 9000 to 10,000 ft (2.7 to 3 km) depth interval. Both compression-(Guiberson-Dresser)¹⁴ and inflatable-type (Lynes, Inc.) packers were developed and both exceeded the requirements in laboratory tests.

Only the inflatable packers have been run thus far. Two units were run into EE-2 in early May to a depth of 15,000 ft (4.5 km) with a formation temperature of 600°F (315°C). The packers were run in as single units on the 3-1/2-in. work string and stood off bottom with five joints of 5-in. drill pipe with a slotted joint and bull nose on bottom, and with 125,000 lb. stacked weight. A 8-5/8-in. integral blade stabilizer was run immediately below the packer to prevent damage to the packer during run-in. The packer elements set, but both failed (see Table 7). Both packers showed evidence that the internal pressurization bladder (an EPDM compound) elastomer had burst but showed no signs of deterioration.

Casing Packers

Two drillable 9-5/8-in. casing packers (Baker model FB-1) were run on 3-1/2-in. work string with long, 4-1/2-in. diam tailpipes. Hole conditions thwarted both attempts and caused premature setting. Fishing required jarring and washover operations. A third Baker permanent casing packer (model FAT) was run on a wireline with a high-temperature, detonator-actuated, pressure-setting tool. The packer was successfully set at 11,320 ft (3450 m) after some difficulty with the setting tool, which had to be fished from the hole. Subsequent attempts to install the seal bore were prevented by hardware problems and the packer was fished from the hole.

Four successful runs of a developmental (Otis Engineering) retrievable casing packer were accomplished. These were set at about 11,400 ft (3475 m) in the 9-5/8-in. casing and provided successful major pumping operations below the casing shoe. The packers were run on the 3-1/2-in. work string and set by right hand rotation. The annulus was pressurized to 1700 to 2200 psig and fracturing pressures up to 7000 psig were sustained (Table 7). This sequence of fracturing and fracture extension operation was plagued by splits in the couplings and tubes of the S-135 work string, caused by the H₂S and CO₂ content of the vent-back flows.

Improvements in the Otis casing packer for the HDR application include a circulating by-pass valve, a mechanical or pressure-actuated setting mechanism, and a redressable seal mandrel system. The basic problem of the high temperature elastomer seal elements appears to be resolved by using L'Garde Y267 EDPM technology.¹⁵ The major disadvantage of most retrievable packers is the relative low rated pressure drop limitations, i.e., 3500 psi.

High temperature casing and open hole packer technology for large diameters required for HDR applications are in need of significant upgrading for consistent and reliable fracturing operations.

Pre-testing for Liner-PBR Installation

Because suitable cement, cement placement procedures, and elastomeric materials are required to successfully cement-in and fracture below the cemented-in scab liner, an investigative program was undertaken to (a) test cement mixtures in the laboratory and (b) to test the "best" slurry and a special wiper plug under downhole conditions at the extreme temperature to be encountered.

A cement test procedure¹⁶ was designed to test the proposed slurry under downhole conditions at the depth, temperature, and pressure that the scab liner would encounter in EE-2. Concurrently, the Dowell Research Laboratory in Tulsa, Oklahoma was requested to conduct tests on three proposed slurries and downhole conditions:

A. Cement Type and Silica Content

1. Class H cement, with 40% silica
2. Class H cement, with 60% silica
3. Class J cement, with 60% silica equivalent.

B. Properties

48 hour compressive strength = >4000 psi
Slurry density = >15.0 ppg.

C. Placement Conditions:

BHCT = 275°C (525°F)
Pumping time: 4 hours
Depth: 14,500 ft
Pipe: 3-1/2-in. drill pipe, 13.3 lb/ft
Fluid in the hole: water.

D. Possible Contaminants in the Hole:

Big Cat commercial detergent: 2% solution
Friction reducer: polyacrylamide, 1/40% solution.

Extensive laboratory testing yielded the following slurry and properties for testing under downhole conditions:

Amarillo Class H cement
40% D66 (Silica flour)
5.5% Retarder/Dispersant (XE67565)*
0.2% D46 (Defoamer)
Density (ppg) - 16.6
Yield (cu ft/sk) - 1.44
Water (gal/sk) - 5.03
Thickening time - 4 hrs 10 min
Compressive strength - 4805 psi (600°F - 48 hrs)

Dowell wiper plugs (made of Y267 EPDM, formulated by L'Garde, Inc.) and Brown Oil Tool (BOT) darts were statically tested at 572°F (300°C) and 4400 psi in the Los Alamos autoclave. BOT molyglass chevron seals for the permanent scab liner/PBR assembly were also statically and dynamically tested at 572°F (300°C), withstanding 3300 psi differential pressure before failure.

The bottom-hole assembly (BHA) for the downhole cement test is shown schematically in Figure 8.

*The XE67565 is an experimental Dowell retarder/dispersant which was premixed in the mix water.

Basically, this BHA consisted of 742 ft of 2-7/8-in. tubing, containing a dart catcher sub, and a pressure and temperature (Kuster) gage holder. The assembly was run to 14,580 ft where the in-situ temperature was 580°F (305°C). The hole was cooled by circulating through the BHA for 3 hours with the rig pumps at 5.4 bbls/min. After the lower dart was released, 1.75 bbls of cement slurry were pumped downhole. The upper plug was then released, followed by 100 bbls of displacement water. Pumping pressure was 500 psi; after the lower dart bumped into the dart catcher, the pressure raised to 1500 psi. The pressure was held without leakage for 5 minutes.

The cement test assembly was started out of the hole, after having set at depth for 48 hours. The first 10 joints of 2-7/8-in. tubing contained no cement; the rest of the joints down to the dart catcher contained cement which was progressively harder with depth. There was no cement below the dart catcher, except for a small amount in the bull plug. The Kuster temperature gage apparently leaked, giving no data after 24 hours. A maximum reading thermometer, also included in the Kuster package, indicated 558°F (293°C) at 14,580 ft. Approximately 1.23 bbl of cement remained on the pipe, leaving 0.53 bbl unaccounted for. Compressive strength of the hardened cement retrieved from the tubing was 5270 psi.

The top plug, expected to be recovered at the top of the cement column, was actually found 105 ft down from the top of the cement. The condition of the darts after retrieval indicated that the bottom dart still retained some resiliency, but the top dart (when it was cut out of the tubing) was extremely brittle and decomposed.

Liner/PBR

After failure of the open-hole packers at 14,981 ft (see Table 7), and the successful laboratory and downhole cement/material testing, a short liner with a polished bore receptacle (PBR) was run in and cemented. The liner was 300 ft (91 m) long, 4-1/2-in. o.d. with the top of the liner at 14,400 ft and the re-entry guide shoe at 14,698 ft (Fig. 9).

The liner (as designed by Brown Oil Tool) was intended to create the following wellbore conditions:

- Provide 300 to 600 ft (91 to 182 m) of uncased wellbore below the liner for the first fracture attempt.
- Provide a 300 ft-long annulus seal.
- Maintain 3000 ft (915 m) of open hole above the liner and below the 9-5/8-in. casing shoe for future fracturing and completion operations.
- Provide the PBR for sealing into (and later retrieving) with the fracturing string (4-1/2-in. casing, 11.6 lb/ft, N&P grades).
- Provide a means for experimenting with perforations for fracturing in sections of the liner.
- Provide a means of controlling flow into both the open hole and the perforated sections by use of the x-nipples.

Other cemented-in casing designs were considered but the 4-1/2-in. liner/PBR had these advantages:

- Easy retrieval of the frac string.

- Placement of excess cement in the annulus around the short liner.
- Rapid cement placement at high temperatures (contrasted to the "puddling technique").
- 40-ft (12.2 m)-long polished bore, to allow frac string movement during fracturing or injection of cold water.

The liner shoe was planned to be set at 14,800 ft on a sand plug; however, during installation the liner could not be worked deeper than 14,698 ft. It was successfully cemented at a temperature of 525°F (275°C).

The liner/PBR was cemented in place with 37 bbls of cement slurry as described above. The slurry was batch mixed for two hours, and displaced with calculated volumes, as the liner wiper plug did not seat. After cement displacement, the liner setting tool was "un-jayed" and the seals picked up about 5 ft above the PBR and the excess cement reversed out.

A major problem developed when entry into the liner/PBR was attempted with the 3-3/4-in. mill. Two clean-out runs resulted in twist-offs of the 2-3/8-in. drillpipe. The reentry problem was solved by (1) use of a Baker off-set jet, flat-bottomed mill, 1000 ft of 2-3/8-in. Wilson flush joint drillpipe and 2000 ft of 2-7/8-in. American open-hole drillpipe below the 3-1/2-in. drillpipe; (2) use of a 120 ton power swivel to control torque, and (3) reducing the drag in the wellbore by "mudding-up" with a sepiolite/bentonite fluid containing Baroid Torq Trim. The surface torque was reduced with this fluid from over 10,000 ft/lbs to 4500 ft/lbs. The cleanout of the liner and washing out of sand to 15,155 ft were accomplished without problems.

There was considerable concern regarding destruction of the molyglass seals while running the seal assembly over 3000 ft of rough crystalline rock. An innovative seal cover sleeve was developed jointly by Los Alamos and Brown Oil Tool; this cover fully protected the seals during run-in.

HYDRAULIC FRACTURING

Hydraulic Fracturing Operations in EE-2

A series of experiments to test equipment, materials, and operational procedures were undertaken beginning in April 1982. These activities were oriented toward obtaining a connection between EE-2 and EE-3 for reservoir development.

The 9-5/8-in. casing in EE-2 had incurred several worn spots (from drilling in the 8-3/4-in. open hole section), so that it could not be pressurized above 2200 psi. This limitation, in conjunction with the rugosity of the wellbore and the high temperatures, had to be considered in every operation. Except for temperature surveys conducted by the Los Alamos Instrumentation Group, there was no information about the open hole wellbore conditions or formation characteristics. The first operation in April was recovering a gamma tool which was stuck at 14,200 ft. All of the seven conductor electric wireline was recovered, but the gamma tool was left in the bottom of the hole. A barite plug was placed over the tool at 15,150 ft.

The first fracturing attempt was made by pumping through the 9-5/8-in. casing from the surface, with the pressure limited to 2200 psig; however, the open

hole section did not break down at this pressure. In order to create a fracture initiation point (and thereby hopefully lower the required frac pressure), three operations were tried; explosive fracture initiation (EFI) using a temperature-inert high explosive developed by the Los Alamos National Laboratory, hydrojetting, and massive cooling. A dummy EFI wireline tool was run in, but hole conditions prevented the tool getting to the desired depth. (High temperature detonators had been successfully fired at the designated depth to test the circuitry of the EFI tools).

Prior to the first Lynes packer run, an attempt was made to notch the wellbore by hydrojetting at 15,128 ft (4612 m). A sepiolite mud carrier, 20/40 sand and nitrogen were pumped down 3-1/2-in. drillpipe to a jetting assembly with a tailpipe set on the barite plug. A total of 1840 bbls of mud, 22,500 lbs of sand, and 58,000 SCF of nitrogen was pumped through 1/4-in.-i.d. jet nozzles, at a calculated velocity of 37 ft/min. Although a notch was apparently cut in the bore wall, fluid acceptance into the rock was unchanged. A massive cooling attempt was made just prior to running the second Lynes packer. A circulation rate of 16.5 BPM at 7400 psig was maintained for 35 hours through open-ended drillpipe landed at 15,155 ft. Subsequent pumping at 2200 psig was also unsuccessful in creating a fracture.

Pressures and Pumping Rates

Previous fracturing and pumping tests in the shallow (10,000-ft-deep) reservoir at Fenton Hill indicated fracture gradients of approximately 0.55 psi/ft. However, fracturing operations carried out in the deeper EE-2 well required much higher pumping pressures, resulting in fracture gradients ranging from 0.8 to 0.96 psi/ft. A summary of the fracturing operations in EE-2 is presented in Table 7. During the pumping operations of October 6, 1982, instantaneous shut-in pressures of 5200 to 5900 psi were measured to give increasing fracture gradients of 0.89 to 0.96 psi/ft. The increasing gradient may have been due to several different fractures opening up in the pressurized section of the wellbore, or the fracture(s) becoming more difficult to open and extend as the distance from the wellbore increased.

Fracture Detection

High temperature downhole seismic sondes to record acoustic emissions have been developed by the Los Alamos Instrumentation Group to map hydraulic fractures in reservoir pumping experiments. Monitoring of fracture locations was accomplished with sondes placed in well EE-3 and another nearby well when fracturing operations were conducted in EE-2. Figure 10 is an example of a location plot of hypocenters of microearthquakes recorded during the deep fracturing in the zone below the liner and the zone below the 9-5/8-in. casing shoe. These events mark locations of shear failures induced by the rising fluid pressure in a small region of rock close to the main hydraulic flow path. Therefore, the foci approximately map the growth of the hydraulic ducts as progressive forceful injection of water causes a broader spread of the recorded events further away from the main flow paths.

GEOCHEMISTRY

The large areas of crystalline rock exposed during the fracturing operations released significant amounts of gases; a typical analysis is shown in Table 8. These gases were vented during the backflow of the massive fracturing attempts that did not achieve connections. The gases tended to accumulate downhole and then release as bubbles at the surface. The CO₂ and H₂S contents were sufficient to cause embrittlement and cracking of the S-135 Grade 3-1/2-in. drillpipe work string and the P-110 Grade 4-1/2-in. (buttress casing) frac string. These gases also caused rapid deterioration of the rubber seals in the blind/piperams and annulus preventer in the BOP stack during pressure shut-in conditions. Further development of elastomers for these particular gases would aid geothermal drilling and completions considerably.

CONCLUSIONS AND RECOMMENDATIONS

Many conclusions and recommendations about specific tools, materials, and operations are contained in the above text. Certain overview conclusions about deep directional drilling and completion operations in very hot crystalline rock are:

1. Drilling and completions can be accomplished with modifications of presently available equipment and materials.
2. Many improvements still need to be made for cost effective and technical efficiency of drilling, and completion hardware, especially:
 - a) Abrasive- and corrosive-resistant metals for tubulars and downhole tools.
 - b) Advanced elastomers in wider application.
 - c) Electric logging tools.
 - d) Drilling methods to reduce wellbore tortuosity.
 - e) Downhole directional survey tools and methods.
 - f) Sidetracking methodology — especially cementing.
 - g) Drilling fluids, primarily for reduction of metal/wellbore friction in hot holes.

From the fracturing operations at Fenton Hill conducted through November 1982, the following conclusions are made:

1. Massive volumes of fluid at high pressure must be pumped to connect the two wellbores.
2. Work string operations are difficult because of the high drag in the holes.
3. Extreme changes in temperature of the frac string are difficult to handle because of hole drag, depth, and pressures.
4. The unanticipated corrosive gases cause short-term equipment failure and may cause problems during long-term production.
5. Successful cementing operations can be conducted under the most adverse conditions with meticulous design, planning, and coordination.

As yet unknown are those problems which will arise under long-term production operations. However, whenever problems have arisen, there always has been help from the commercial sector. Some company has always been willing to meet the challenge of providing tools and hardware to operate in the extremely harsh HDR environment. Because of that, the entire geothermal and petroleum industries will be better equipped.

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Reference to a specific company, product name, or service does not imply approval or recommendations of the product by the University of California or the U.S. Department of Energy to the exclusion of others that may be suitable.

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TABLE 1
EE-2 ROTARY DRILLING BIT PERFORMANCE

<u>Bit No.</u>	<u>Size</u>	<u>Make</u>	<u>Type</u>	<u>Depth Out</u>	<u>Footage</u>	<u>Hours</u>	<u>Inclination</u>
17	12-1/4	Sec	H-100	2,999	358	48.75	1/2°
RR28	12-1/4	STC	F-9	4,855	493	53.25	6°
34	12-1/4	Sec	H-100	5,892	345	24.00	7-3/4°
35	12-1/4	HTC	J-55	6,492	600	22.75	5-1/2°
45	12-1/4	HTC	J-55	7,689	505	21.75	6°
47	12-1/4	HTC	J-55	8,204	461	23.75	15°
55	12-1/4	STC	F-5	8,975	308	23.75	-
104	8-3/4	STC	7GA	12,521	214	13.50	35°
105	8-3/4	STC	7GA	12,728	207	13.50	34°
117	8-3/4	STC	7GA	13,955	298	22.00	35°
138	8-3/4	STC	7GA	14,189	233	23.00	34-1/2°
137	8-3/4	STC	7GA	14,501	312	33.50	35°
140	8-3/4	STC	7GA	14,962	462	42.00	35°
142	8-3/4	STC	7GA	15,273	307	22.50	35°

EE-3 ROTARY DRILLING BIT PERFORMANCE

<u>Bit No.</u>	<u>Size</u>	<u>Make</u>	<u>Type</u>	<u>Depth Out</u>	<u>Footage</u>	<u>Hours</u>	<u>Inclination</u>
13	12-1/4	STC	F-5	4,062	313	38.50	-
16	12-1/4	STC	Q9JL	4,856	306	37.00	-
17	12-1/4	STC	F-5	5,203	347	35.25	-
18	12-1/4	HTC	J-55	5,538	335	27.75	-
31	12-1/4	STC	F-5	7,845	303	25.75	-
39	12-1/4	STC	F-5	8,727	462	43.00	17-1/4°
43	12-1/4	STC	F-4	9,142	315	36.00	20°
106	8-3/4	STC	7GA	11,120	309	33.00	34°
107	8-3/4	STC	7GA	11,454	334	26.50	33°
109	8-3/4	STC	7GA	11,926	331	30.00	35°
118	8-3/4	STC	7GA	12,895	319	37.00	37°
121	8-3/4	STC	7GA	13,365	404	40.00	36°
125	8-3/4	STC	7GA	13,933	439	34.50	36°

TABLE 2
EE-2 MOTOR DRILLING BIT PERFORMANCE

<u>Bit No.</u>	<u>Size</u>	<u>Make</u>	<u>Type</u>	<u>Depth Out</u>	<u>Footage*</u>	<u>Hours</u>	<u>Inclination</u>
41	12-1/4	Sec	H-100	6,818	100	12.25	4-3/4°
52	12-1/4	STC	Q9JL	8,545	131	3.00	13-3/4°
59	12-1/4	STC	Q9JL	9,188	106	3.00	-
60	12-1/4	STC	Q9JL	9,311	123	3.00	13-1/2°
74	12-1/4	STC	Q9JL	10,035	118	5.50	-

EE-3 MOTOR DRILLING BIT PERFORMANCE

<u>Bit No.</u>	<u>Size</u>	<u>Make</u>	<u>Type</u>	<u>Depth Out</u>	<u>Footage*</u>	<u>Hours</u>	<u>Inclination</u>
22	12-1/4	SEC	H8J	6,649	129	7.50	-
24	12-1/4	SEC	H8J	7,114	270	15.00	-
36	12-1/4	STC	Q9JL	8,052	112	4.50	-

*Motor runs were often terminated at lengths of less than 100 ft (see Table 5).

TABLE 3
SUMMARY OF CORING OPERATIONS IN EE-2
(All bits were Smith Tool Hybrid Roller Cone/PDC)

Run No.	Date	Depth ft (m)	Cored Interval ft	Recovery (%)	Penetration Rate (min/ft)	Bit Condition				Remarks Recommendations	Rock Type
						Cone Teeth	Cone Bearings	Gage Wear	PDC Pads		
1	11/11/79	11,737-11,743 (7577-7579)	6	79	12	2	4	None	8	Rebuild and replace PDC studs; use again.	Biotite granodiorite gneiss; fracture oriented at 3° from vertical.
2	11/20/79	12,266-12,275 (3739-3741)	9	0	6	4	5	1/16-in.	2	Bit could be rerun as is.	No recovery; drilled through fractured/alterd zone.
3	11/26/79	12,848-12,856 (3916-3918)	8	91	18	1	3	none	3	Rebuild and replace PDC studs; use again.	Metavolcanic (dacite) intruded by granodioritic material.
4	12/8/79	13,454-13,464 (4101-4104)	10	41	18	3	8	1/16-in.	8	Scrap pile.	Biotite granodiorite.
5	12/21/79	13,955-13,962 (4253-4256)	7.5	100	15	1	4	none	3	Bit could be rerun as is.	Biotite-amphibole-feldspar gneiss intruded by biotite granodiorite.
6	5/2/80	14,501-14,504 (4420-4421)	3.3	100	6	4	6	1/16-in.	8	Scrap pile.	Biotite-amphibole-feldspar gneiss, similar to Core Run No. 5.
7 Rerun No. 2 Bit	5/6/80	14,962-14,966 (4560-4562)	4	40	8	4	6	1/8-in.	8	Scrap pile.	Biotite granodiorite gneiss, similar to Core Run No. 1.

Note: Cone teeth and bearings, and PDC pads are rated on a scale of 1 (like new) to 8 (completely ruined).

TABLE 4
COMPARISON OF EE-2 AND EE-3 DRILL-PIPE AND BHA FAILURES

Type Failure	EE-2	Remarks	EE-3	Remarks
Washout without fishing operation	4	2 in BHA 2 in drill-pipe tube	11	10 in BHA 1 in drill-pipe tube
Washout with fishing operation	1	Pipe-tube washout while drilling (fell apart on trip out)	4'	All in BHA
Twist-off	0	-	5	2 in 5-in. tube 3 in 4-1/2-in. pin
Parted string	1	Crossover sub fell apart while tripping in the hole (pin end)	3	1 in 5-in. tube 1 in 4-1/2-in. pin 1 in accelerator
Total	6		23	

TABLE 5

SUMMARY OF DOWNHOLE DIRECTIONAL DRILLING ASSEMBLY PERFORMANCE
(Excludes sidetracking runs and turbodrill tests)

Motor ^a Type	Diam in.	Total No. of Runs Attempted (Successful)		Average Length ^b Drilled, ft		Average Hours Per Run, h		Average ROP Ft/h	
		EE-2	EE-3	EE-2	EE-3	EE-2	EE-3	EE-2	EE-3
MEIT 7 ^c	7-3/4	21 (17)	17 (14)	59.8	43.3	2.8	3.4	21.6	12.7
MEIT 5 ^c	5-3/8	-	8 (5)	-	59.3	-	2.1	-	8.6
NPDM ^d	8	-	10 (9)	-	62.2	-	4.0	-	14.8
DDPDM ^d	7-3/4	6 (5)	8 (8)	54.7	59.6	4.5	5.5	12.3	10.8
BPDM ^d	6-3/4	4 (4)	5 (4)	48.8	98.5	7.8	14.0	6.2	7.0

^a Assembly performance includes bit, motor, steering tool, bent and orienting subs and float valve.

^b Note that most directional runs were set up with 60 ft (20 m), two joints, of drill pipe in the derrick.

^c High temperature turbodrills.

^d NPDM = Navidrill (Christensen Tool Co.); DDPDM = Dyna-Drill (Smith International, Inc.); BPDM = Baker Motor (Baker Service Tools).

TABLE 6

EE-3 9-5/8 in., L-80 STRAIN GAGE DATA, $\mu\text{in./in.}$

<u>Gage No.</u>	<u>19 Aug 81</u>	<u>20 Aug 81</u>	<u>22 Aug 81</u>	<u>22 Sept 81</u>	<u>19 Jan 82</u>
1	550	1090	800	840	475
2	-770	open	-	-	-
3	300	857	490	790	962
4	500	375	-	-	-

TABLE 7

SUMMARY OF EE-2 FRACTURING OPERATIONS

Date	Zone Isolation Method	Vert. Depth (ft)	Injection Data				Frac. Gradient (psi/ft)
			Vol. (bbls)	Max. Pressure (psig)	Max Rate (BPM)	Max ISIP* (psig)	
5-2-82	Lynes Paker (open hole)	14,180	3	2200	-	(Packer failure)	
5-6-82	Lynes Packer (open hole)	14,160	12	4400	3	4100(?)	0.7 (Packer failure)
6-4-82	Cemented Liner/PBR	13,950	20,000	6600	30	5400	0.7
6-19-82	Cemented Liner/PBR	13,950	31,000	6750	40	5200	0.8
7-19-82	Otis Packer (9-5/8-in. Casing)	11,200	5,700	7000	14	3900	0.8 (Pipe failure)
7-24-82	"	11,200	247	5800	5	(Pipe failure)	
10-2-82	"	11,200	167	3100	4	(Pipe failure)	
10-6-82	"	11,200	20,000	7000	34	5900	0.96

*Instantaneous shut-in pressure.

TABLE 8

TYPICAL^a EE-2 FRACTURE VENT-BACK GAS ANALYSES, VOL.%

Sample Date	CO ₂	O ₂	N ₂	CH ₄	H ₂ S ^b	H ₂	H ₂ O
31 May 1982	78.1	3.8	17.9	0.2	-0-	-0-	-0-
7 June 1982	90.0	0.47	7.4	0.17	0.08	0.55	-0-
12 Oct 1982	45.3	10.7	41.6	-0-	-0-	-0-	1.3

^a During a back-vent flow or kick, approximately 1:1 ratio of liquid to gas volume at STP is collected.

^b H₂S is detected in about 1/5 of the samples.

UNIQUE ASPECTS OF DRILLING AND COMPLETING HOT DRY
ROCK GEOTHERMAL WELLS

LIST OF ILLUSTRATIONS

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0 km 40
0 MILES 24

MODIFIED FROM KELLEY, 1954

Schematic of Fenton Hill HDR Wells

EE-2 Wellbore Configuration for Fracturing