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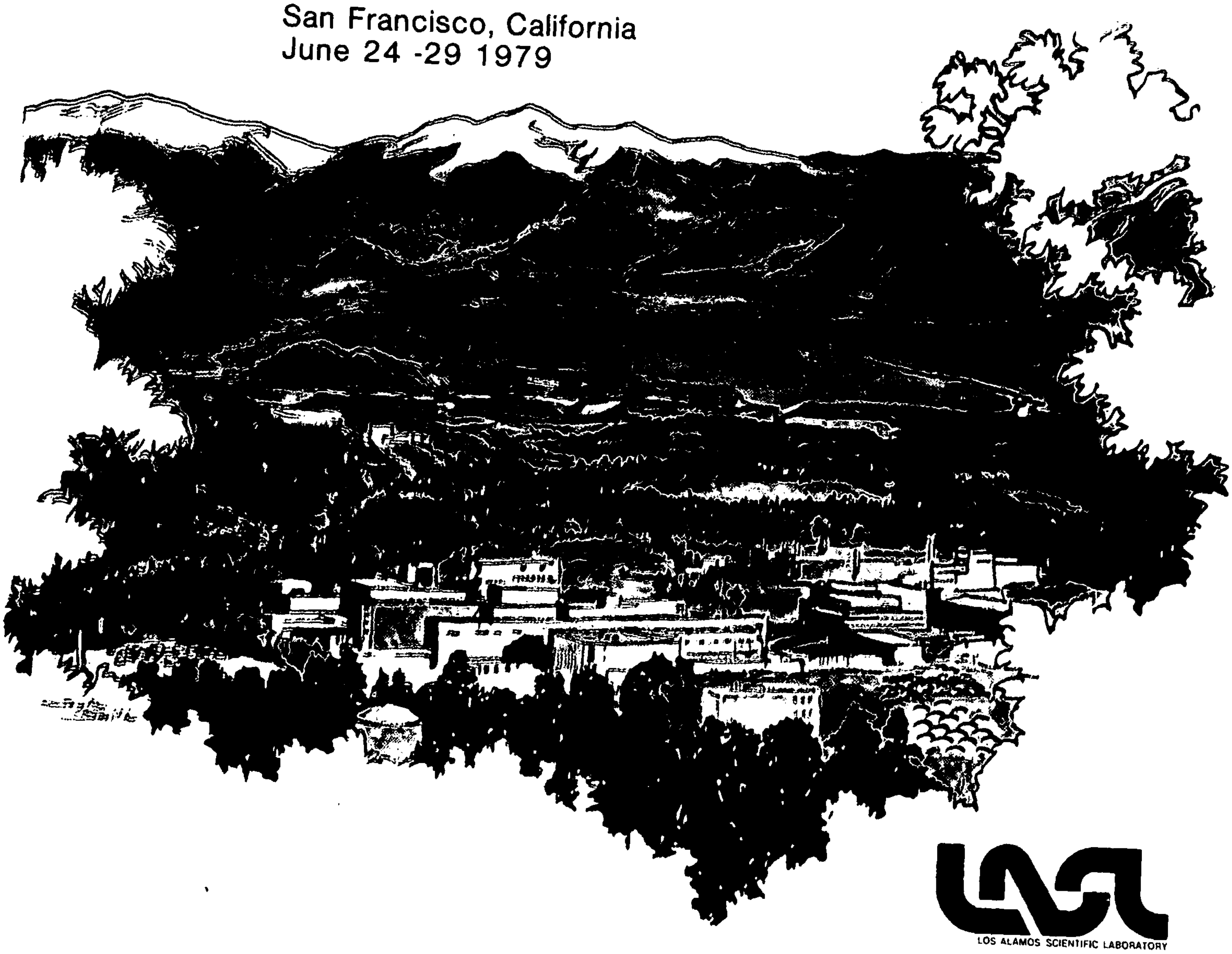

LOS ALAMOS SCIENTIFIC LABORATORY

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The Federal Hot Dry Rock Geothermal Energy Development Program: An Overview

G. J. NUNZ

INTRODUCTION

With the fossil fuel reserves of the world being rapidly exhausted, attention has turned to alternative sources that might eventually be able to satiate mankind's evergrowing energy appetite. The only such alternative which is both enormous in magnitude and potentially developable to a significant extent within this century is the inherent heat energy of Mother Earth herself--our geothermal resource base. In the United States, almost all of this energy exists as heat in "dry" rock (lithologic formations that will NOT spontaneously produce hot water or steam). In fact, it is estimated that the total energy content of the formations underlying the 50 states, to a depth of 10 km and at "commercially interesting" temperatures above 150°C, is about 13.2 million quads[2] or about 170 thousand times the present total annual consumption of energy in the US. Of this practically infinite geothermal resource base, virtually all--more than 99%--exists in hot dry rock (HDR). Of course not all of this energy can be extracted economically, but if only 2% were recoverable as was assumed in the Energy Research and Development Administration (ERDA) "Scenario I" (Ref. 1), it would be sufficient to provide the entire nontransportation energy requirement of the United States for over 2000 years at the present rate of consumption. Spurred by this enormous incentive, the Los Alamos Scientific Laboratory (LASL) has focussed its effort in geothermal energy on hot dry rock.

ENERGY EXTRACTION CONCEPT

The HDR concept proposed, shown in Fig. 1, was simplicity itself: to "mine" the heat of the earth by (a) drilling a well through the sedimentary cover into the relatively impermeable basement rock to a desired temperature level (Fig. 1a); (b) creating a large fracture system, through hydraulic or pneumatic means, near the bottom of that well (Fig. 1b); (c) drilling a second well to intersect the top of this fracture system, thus creating a large subterranean heat exchanger (Fig. 1c); and (d) forming a closed circulation loop by connecting the wells to an appropriate energy

[1]Work performed under the auspices of the US Department of Energy.

[2]1 Quad = 1 quadrillion (10^{15})Btu = 334 MW-centuries ≈ 10^{18} joules.

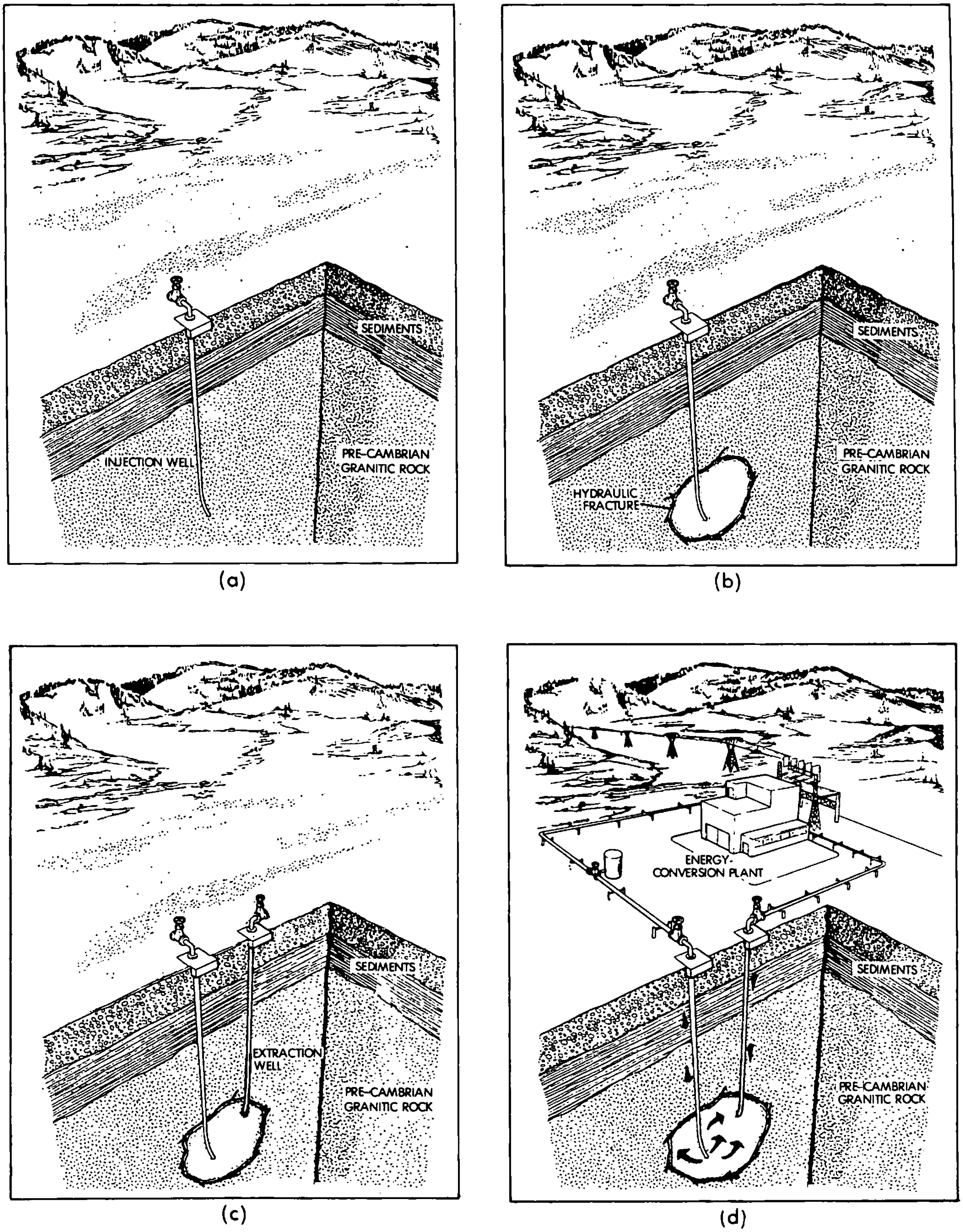

Fig. 1. Hot Dry Rock Geothermal Concept.

extraction and conversion system at the surface (Fig. 1d). Cooled water is injected through one well, heated as it flows through the fracture system, and extracted as superheated water from the second well. Sufficient pressure is maintained within the circulation loop to prevent flashing of the geofluid (recirculated water). To utilize the extracted heat energy at the surface, the geofluid is passed through one or more exchangers, as in Fig. 2, to transfer its energy to secondary fluid(s). The secondary fluid(s) may be either aqueous or organic, depending upon the application. If the temperature of the extracted geofluid is comparatively low--typically, less than 150°C--the heated secondary fluid would be used in a direct thermal application, such as for space heat or process heat. That there is a huge market for such heat is clear from Fig. 3, which illustrates that more than one-third of present US energy consumption is as heat, mostly at temperatures under 150°C. If high-temperature (>150°C) geofluid is extracted, the secondary fluid can be vaporized and used to drive a turbo-alternator with adequate efficiency for the commercial production of electricity. In the latter case, there will often be enough residual heat in the turbine discharge to provide some space or process heating as well, and the application is then termed "congeneration."

EVOLUTION OF THE PROGRAM

The Federal Hot Dry Rock Geothermal Energy Development (FHDR) Program began as a single development and demonstration project at LASL under the aegis of the Atomic Energy Commission (AEC). The idea of extracting heat energy economically from artificially-fractured, impermeable, hot rock was conceived in 1970, and thus was born the "LASL Hot Dry Rock Geothermal Energy Project." The years 1970-71 were spent in researching the state-of-the-art in the applicable technologies--deep drilling, fracturing, etc.--and in tentatively selecting an experimental site. A promising area was the western rim of the Valles Caldera, a young silicic volcano located about 55 km from Los Alamos, which had been active as recently as one million years ago. In 1972, a 785-m deep exploratory well called GT-1 was drilled there. Through 1973, the Project conducted a protracted series of pressurization and depressurization experiments on downhole hydraulically-produced fractures to measure rock surface fracture energies, compressive stresses, and permeabilities. These results were encouraging with regard to the existence of a suitable hot dry rock resource, the probability of successful drilling and hydraulic fracturing operations, and the probability of subsequently establishing a suitable pressurized-water circulation loop without excessive loss of the geofluid. It was deemed necessary, however, to confirm these observations at another location and to make similar measurements at greater depths and under conditions of higher temperature and pressure.

In late 1974, drilling began on a second borehole, at a location called Fenton Hill about 2.4 km south of the exploratory hole GT-1. Borehole GT-2 was completed during the first half of 1975 to a total depth of 2829 m. The temperature at the bottom of the hole was measured to be 197°C. Tests made before completion of the drilling determined that the permeability of the granitic basement rock was extremely low. Hydraulic fractures were produced, the largest of which had a calculated radius of about 215 m. When this fracture was inflated with water and then deflated, almost 90% of the injected water was returned, confirming the competence of the basement rock. Further encouragement, derived from a series of reservoir engineering tests, led to the decision to proceed with the drilling of a second operational borehole and the subsequent establishment of a circulation system connecting GT-2 and this new borehole.

Late in 1975 with Project sponsorship transferred to ERDA, Division of Geothermal Energy (DGE), drilling of the third borehole EE-1 began. Hydraulic fractures were created near the bottom of GT-2, and borehole EE-1 was directionally drilled in an attempt to intersect a GT-2 target fracture. EE-1 was completed in the first part of 1976. A subterranean flow connection between the two holes was indeed established in the 2.75- to 3.05-km-depth range. However, the impedance of fluid flow through this system was found to be far too great to permit a sustained water circulation rate high enough for a convincing energy extraction demonstration.

Almost all of 1977 was devoted to intensive investigation of the character of the downhole system and to the concomitant development of the necessary

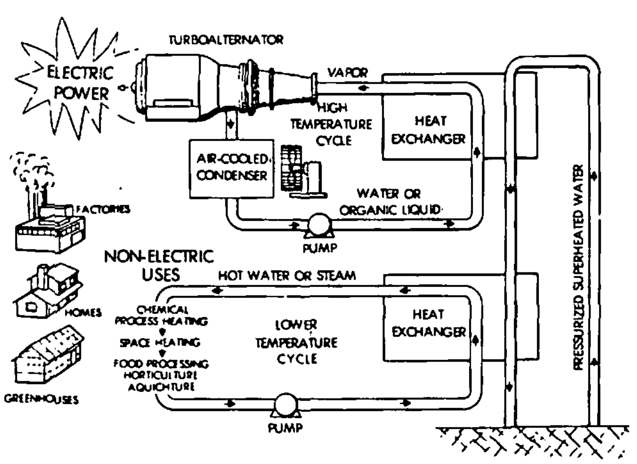

Fig. 2. HDR Surface Energy Conversion Concept.

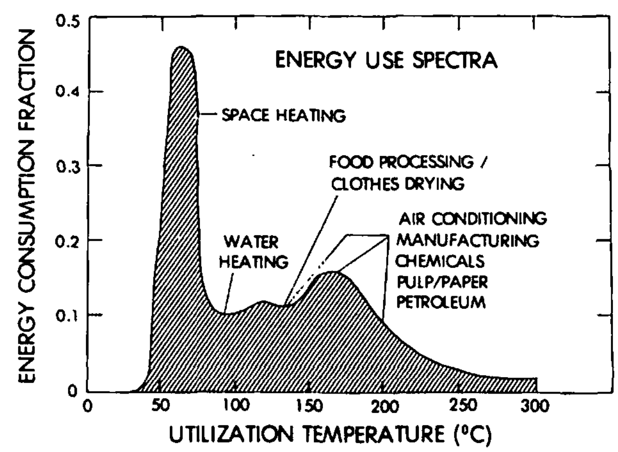

Fig. 3. National Utilization of Thermal Energy Below 30°C.

tools and techniques for understanding and improving it. It was recognized that the major part of the problem lay in the lack of understanding of the downhole geometry--both that of the wellbores and of the fractures hydraulically produced therefrom in the contiguous rock. A directed attack was therefore mounted on the reservoir geometry problem, the components of which were

(a) to study, by a variety of approaches, the reservoir geometry;

(b) given the attainment of an adequate understanding from the results of (a), to take necessary remedial steps to improve the connection; and

(c) assuming reasonable success in (b), to complete the installation of surface equipment and proceed with the activation of an energy extraction loop.

Attention was turned first to the wellbore geometry. Statistical analysis of wellbore survey errors, which used the nominal stepwise accuracies, predicted that such surveys should have overall accuracies of a few meters at 3 km depths. In these cased holes, where only gyrocompass-type survey instruments can be used, the temperatures at depth exceeded the capability of the instrumentation then commercially available and resulted in much larger errors. A redundant approach was planned to maximize the probability of accurately defining the wellbore positions in a timely manner: (1) contracts to industry to perform more accurate surveys by upgrading the temperature capability of their existing instruments and (2) LASL internal development of acoustic- and magnetic-ranging techniques. It was also recognized that the tools being developed for acoustic ranging were potentially adaptable to fracture mapping, based upon the shear-wave attenuation property of a liquid-filled fracture. Hence, such "shear-shadowing" experiments were also planned and conducted.

Success achieved in these endeavors permitted progression to remedial work. The first approach to reducing the interwellbore impedance was chemical attack on the silica content of the intervening rock. A leaching experiment was conducted but was unsuccessful. As the reservoir geometry became better understood through a series of experiments, the need for redrilling became apparent. A comprehensive, but funding-limited, workover redrilling program was executed resulting in a usable, albeit nonoptimal, downhole connection.

The surface system was then installed and connected, forming the closed circulation loop. Late in 1977, first operational test of this small manmade geothermal system was successfully conducted. Also at this time, sponsorship of the Project was transferred to the newly-formed Department of Energy's Division of Geothermal Energy (DOE/DGE). All of 1978 and the first part of 1979 have been spent in evaluating this system as subsequently discussed.

Meanwhile, in the latter half of 1978, on the basis of the technical feasibility demonstrated in LASL's hot dry rock geothermal project at Fenton Hill, DOE/DGE authorized the expansion of that project to a Federal program of national scope that embraces the Fenton Hill project and will eventually include others. This program--now officially termed the "Federal Hot Dry Rock Geothermal Energy Development Program (FHDR Program)"--is managed by a team comprising LASL and the DOE Albuquerque Operations Office (ALO), under the cognizance of a Program Director at DOE/DGE. The overall objective of this FHDR Program is "...to determine the potential of hot dry rock geothermal energy as a significant, alternate energy source and to provide for its timely development, if warranted." This general objective is made substantive by the specific subobjectives: (1) SHORT-TERM (early 1980's), to determine, in concert with the US Geological Survey (USGS), the magnitude and distribution of the economically accessible hot dry rock resource throughout the United States and provide a preliminary assessment that all requisite technologies either exist or are within reach of engineering development; (2) MID-TERM (mid-1980's), to develop and demonstrate the required technologies; and (3) LONG-TERM (late 1980's and beyond), to define and conduct such program activities as are necessary to foster the growth of an HDR-energy-producing industry.

A coordinated plan has been formulated, in conjunction with the USGS, for preliminary evaluation of the HDR resource potential within the time frame specified in the FHDR Program's charter. The Program is presently contracting for a small HDR-specific geophysical exploration effort in selected regions, augmenting the USGS' field work. The USGS will integrate the resulting data and publish the composite in forms useful to the FHDR Program and other interested parties as well.

Another--presently small but growing--important ongoing effort is in institutional and industrialization support. Legal, environmental and permitting data are being acquired on a state-by-state basis. Technology transfer, both domestic and international, continues. The domestic program includes: regular interactions with the energy-producing industry; subcontracts with various companies serving that industry, as well as with universities; publication and dissemination of appropriate documentation; and a formal annual industrial HDR colloquium. The international program has included visiting scientist participants in the Fenton Hill project, detailed briefings for representatives of foreign governments, and participation in international geothermal meetings and colloquia by FHDR Program staff.

LONG-RANGE PROGRAM PLAN

The Program plan, through the middle of the next decade, is summarized in Fig. 4. The overall program is keyed to the major decision milestone in early fiscal year 1986. To make the continue-or-not decision on HDR as an energy source at that time, one electric (or cogeneration) and one direct thermal use pilot power plant must be in operation, and the final resource potential evaluation completed. Time-line analysis of the necessary precursory sequence of events pegs the other milestones as indicated.

In the time available, an electric generation pilot plant can only be accomplished at the Fenton Hill site; hence, that has become a major objective of the site assuming successful creation of the long-lived ($\leq$ 20% drawdown in 10 yr) Phase 2

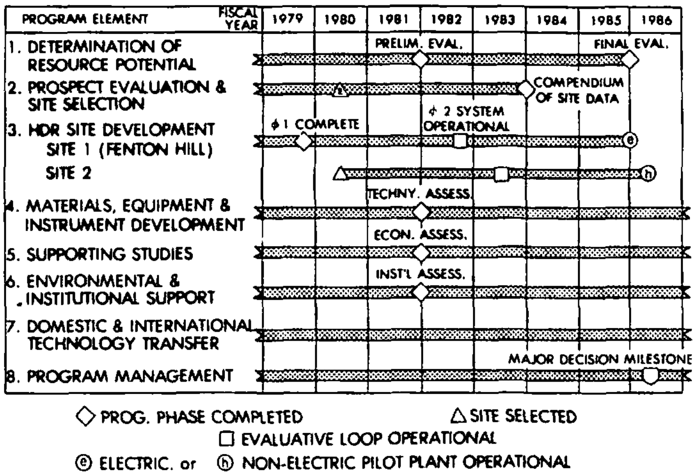

Fig. 4. Long-Range Plan, Federal Hot Dry Rock Geothermal Energy Development Program.

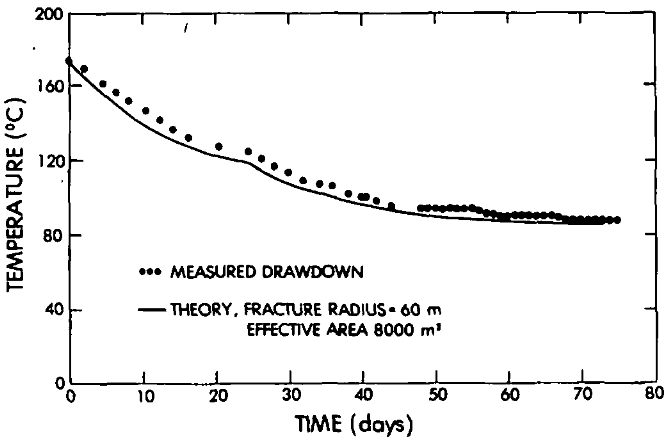

Fig. 5. Measured vs. Predicted Reservoir Drawdown Characteristic.

reservoir. The Phase 2 system must therefore be operational, ready for life-test verification, by the third quarter of fiscal year 1982.

The direct thermal-use application will be demonstrated at Site 2 and thus figures prominently in the selection criteria for that site. Again, the time constraints mandate site selection by mid-1980 and an operational loop in place by mid-1983.

ENERGY EXTRACTION EXPERIENCE AT SITE 1

To the present, the only operational HDR system is that using the Phase 1 (small, short-lived, feasibility test) reservoir at Fenton Hill. Three operational runs have been conducted to date on this loop. Run Segment I, a 100-h initial check-out and feasibility demonstration test was conducted in September 1977. Since then, operation of the Phase 1 loop has been devoted to detailed characterization of the HDR-type reservoir. In Run Segment II--a 75-day accelerated drawdown test conducted between 29 January and 13 April 1978--preliminary answers were obtained (Ref. 2), on an accelerated time scale, to questions concerning what would have been long-term effects in a commercial-size reservoir. Those preliminary answers were both enlightening and very encouraging:

- DRAWDOWN PREDICTABILITY -The somewhat simplified model of the downhole fracture system used in LASL's computations is mathematically adequate to represent drawdown. Specifically, the Fenton Hill Phase 1 system behaves like a simply-fractured reservoir with an effective heat-transfer area of about 8000 m^2 as shown in Fig. 5. Whereas the numbers are particular to this system, the results indicate that the modeling methodology should be applicable to both the next (Phase 2) system at Fenton Hill and to other sites.

- MAKEUP WATER REQUIREMENTS - Water loss to permeation quickly declined to less than 1-1/2% of the circulation rate (under 0.2 ℓ/s), once the initial pore field saturation was achieved. This result, although obtained specifically for the Fenton Hill formation, is tentatively extrapolable to other sites where matrix permeability is in the units-to-tens of microdarcies range and indicates that makeup water requirement will not be a major constraint in such formations.

- GEOFLUID CHEMISTRY - A near-equilibrium composition was achieved in the circulating water, which remained at less than 2000 ppm total dissolved solids. Except for a slightly high terminal fluoride concentration (∿ 9 ppm), this is virtually drinking water and scarcely deserves to be called a "brine" compared to the hydrothermal brines. No evidence of corrosion or scaling was detected in the flow loop. Although these compositional data are highly Fenton Hill specific, they lend credence to the qualitative prognosis that HDR geofluid chemistry should generally be manageable.

- OPERATIONAL CONSTRAINTS - A number of stop/start transients were imposed on the system, many of them inadvertent, because of brief power outages on the local utility. Although no major operational constraints were indicated, some minor freezing problems were encountered, which pointed to the need for careful attention to surface system design at HDR sites with similar moderate-to-severe winter climate and comparatively pure water geofluid.

- ENVIRONMENTAL EFFECTS - Perhaps most encouraging, no detrimental environmental effects were observed. In particular, under extremely careful monitoring, there was absolutely no evidence of affecting the composition of local aquifers or other hydrological effects and there was no detectable induced seismicity.

After some minor modifications to the surface plumbing to permit higher flow rates, Run Segment III was conducted during the period 5 September to 27 October 1978. In this segment, comprising about 786 operating hours, three distinct flow experiments were conducted back-to-back. The first of these was a series of transient flow-dependent impedance measurements; the second consisted of interwellbore acoustic attenuation surveys under shut-in conditions; and the third (and longest) was a continuous-flow experiment under high back pressure. This run segment was terminated prematurely because of the development of a major ($\sim$3.5 ℓ/s) leak behind the casing in the injection well. In the high-back-pressure operation it was observed that reservoir flow impedance declined significantly, from over 200 kPa-s/ℓ to about 55 kPa-s/ℓ.

To date, about 10 million kWh of energy have been extracted at power levels of 3 to 5 MW.

The leak observed at the end of Run Segment III was due to final degradation of already degenerate cement in the annular space behind the casing of the injection well. Recementing has recently been completed. Some additional downhole experiments will be conducted and the results evaluated in a fourth and final run segment in this Phase 1 system.

In parallel with evaluation of the Phase 1 system, planning of the Phase 2 system has been proceeding. Although the Phase 1 system demonstrated initial technical feasibility of the concept and provided encouraging preliminary answers to some issues of concern, the establishment of a reservoir of commercially interesting size and (even more important) longevity remains to be demonstrated in the Phase 2 system. Drilling of this system is scheduled to begin in April of this year. Over a period of about two years, a new downhole system will be developed in 250-275°C rock that will be capable of producing 20-50 MW_t for not less than 10 years.

PLANS FOR SITE 2 PROJECT

A key program activity is the selection of a second experimental HDR site geologically (and hence also geographically) disparate from Fenton Hill. Development of such a site is necessary to establish that: (a) the reservoir techniques utilized at Fenton Hill, or modifications thereof, are applicable in other types of formation; and (b) proximity to a young silicic volcano is not prerequisite to the success of the HDR concept. Survey of the existing data continued through 1978, culminating in the nomination of ten candidate prospect areas throughout the US. From this listing, the most promising target prospect areas (each $\sim$ 260 km^2) will be selected for detailed geophysical investigation in 1979. Contracts are being prepared for the conduct of this field work. The anticipated outcome is sufficient positive characterization to permit selection of a specific site early in 1980.

INSTRUMENTATION AND EQUIPMENT DEVELOPMENT

Another major area of effort within the program, which directly supports experimental operations at Fenton Hill (and will, subsequently, at Site 2), is directed toward providing the specialized instrumentation and downhole equipment needs of the FHDR program, which are commercially unavailable. Whenever possible, development is accomplished through subcontracts with industry, thereby effecting immediate technology transfer as well. In addition, these developments are coordinated with those of Sandia's Geothermal Instrument program, as well as the needs of USGS, to avoid duplication of effort.

During 1978-79, Maurer Engineering proceeded with development of the turbodrill, a high-temperature downhole drilling motor, sponsored jointly by DOE/DGE and the DOE/Division of Fossil Energy Extraction (DFEE). Its first field test will be in the Phase 2 system drilling at Fenton Hill. LASL also sponsored improvements in open-hole packer and shock subtemperature capability. These high-temperature units will be tried in the same drilling program.

Development work also continues on a high-temperature multiconductor instrument cable. Procurement is currently in progress of 1000-foot evaluation specimens from several sources.

Major LASL-internal developments are listed in Table I. With the exception of the first item listed, all of these instruments have a temperature capability of at least 275°C. Those completed in the past year included improved downhole temperature- and velocity-measuring units and a temperature hardened 3-independent-arm caliper tool for borehole gaging. Subcontracted work in progress on fracture-mapping instruments includes: feasibility studies and preliminary design for a radar-based far field mapping tool and an in situ stress measurement device; fabrication of a prototype downhole acoustic transceiver unit utilizing a magnetostrictive driver; and a phased program to develop a high-temperature downhole video system which will produce real-time monochrome images under visible and ultraviolet illumination.

SUMMARY

The FHDR Program is a multifaceted long-range program of national scope aimed at establishing an energy-producing industry. It is a combined development and demonstration program whose elements include: characterizing the resource; cataloging promising sites; developing the reservoir technology, and required tools and instruments; attacking the institutional problems; assessing the economics; and demonstrating (at the pilot plant level) both the technological and economic feasibility of the concept in several geological settings.

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1. ERDA-86:"Definition Report: Geothermal Energy Research, Development and Demonstration Program," Energy Research and Development Administration, Division of Geothermal Energy (October 1975).

2. J. W. Tester, and J. N. Albright, Eds., "Hot Dry Rock Energy Extraction Field Test: First 75 Days of Operation of a Prototype Reservoir at Fenton Hill, Phase I Segment 2," Los Alamos Scientific Laboratory (March 1979).

TABLE I

HIGH-TEMPERATURE INSTRUMENTS AND EQUIPMENT
DEVELOPED TO DATE

Item	Developer/Vendor(s)
Temp./Pressure Probe (260°C)	LASL/Bell & Howell
Wellbore Fluid Sampler	LASL/Globe
3-Axis Fluid Sampler	LASL/Mark Products
Mechanical Acoustic Source	LASL/Globe
Multidetonator Acoustic Source	LASL/Reynolds/Vacuum Barrier
Fluid Sample Downhole Injector	LASL/Globe
Self Potential Probe	LASL
Temp./Conductivity Probe (275°C)	LASL
3-Indep.-Arm Caliper/ Contour Probe	LASL/Dale Electronics
Wellbore Fluid Velocity Meter	Worthwell-LASL
Radiotracer Injector/ Monitor Tool	Worthwell

Energy Extraction Operations: Some Preliminary Results

R. H. HENDRON

ABSTRACT

An experimental project being conducted by the Los Alamos Scientific Laboratory (LASL) has extracted thermal energy from Precambrian granitic rock by injecting and circulating water through fractured zones or reservoirs. Two boreholes were drilled to depths of about 3 km (10,000 ft) in a location selected for high heat flow and an apparent lack of faulting. Bottom-hole temperature was 205°C (400°F). The holes were connected at depth by hydraulic fracturing to form a flow path and heat extraction surface. Energy has been extracted at rates exceeding 5 MW(t) in three operations totaling 2847 h. This paper summarizes these operations.

INTRODUCTION

Increases in population and technology are accompanied by increased energy consumption. However, world fossil energy sources are apparently not infinite and their availability is controlled by sometimes unsympathetic national interests. Development of alternative sources is considered technically, economically, and politically necessary. Geothermal energy has been utilized in a few areas of the world where geologic-hydrologic conditions have made extraction and utilization relatively easy and economically attractive. Expansion of such facilities as The Geysers in California, Lardarello in Italy, and Wairakei in New Zealand, and development of other areas for hydrothermal sources is a basis for a growing technology and has attracted attention to geothermal energy.

An innovative geothermal energy scheme was patented by three staff members of the Los Alamos Scientific Laboratory (LASL) (1,2). The concept is to drill two holes into a high-temperature, low-permeability formation and create a flow passage with large surface area between the dry (not water producing) boreholes. Injecting water into one hole and extracting the same water, now heated, from the second borehole provides hot pressurized water for power generation or other thermal processes.

The program objective of the Department of Energy, with this first project at LASL, is to investigate the many details and problems, technical and economic, leading towards useful application of this concept. More specifically, the salient areas of investigation are:

1 creation and lifetime of the reservoir;
2 geochemistry related to reservoir effects, system materials, and system operation;
3 water requirements;
4 heat transfer and flow characteristics of the reservoir;
5 seismic behavoir;
6 drilling technology; and
7 downhole instrumentation.

LASL has completed a hot dry rock circulating energy extraction loop with atmospheric heat rejection. The system has been operated for three periods totaling 2847 h and at energy extraction rates exceeding 5 MW(t). The first circulating operation of 96-h duration was accomplished in late September 1977. This was followed by an 1800-h run in early 1978 and an 951-h run in the fall of 1978. Descriptions of the system, the operations, and some results of the operations follow.

SYSTEM

Site. A demonstration site was tentatively selected based on geologic studies, information from a series of heat flow holes, and a test hole drilled about 150 m (500 ft) into the Precambrian basement rock (3,4). The study included an area of approximately

*Work performed for DOE under Contract #W-7405-ENG-36.

15 sq mi. The site is on the Santa Fe National Forest, just west of the Valles Caldera, Known Geothermal Resource Area (KGRA) as defined by the Geothermal Resources Act of 1970, and is known locally as Fenton Hill. The site is at an elevation of 2965 m (8700 ft) at latitude 35.4° N, as shown in Fig. 1.

Underground System. Drilling of a first deep hole, GT-2, to confirm site selection, began in February 1974. The drilling operation included many investigative procedures as drilling progressed, such as a close watch of the temperature gradient and lithology — graphically summarized in Fig. 2. Core samples were taken for geological, geochemical, and physical studies; hydraulic fracturing experiments were conducted at various depths. The total depth of GT-2 was 2990 m (9600 ft) at a temperature of 196°C. Drilling of a second hole, EE-1, was accomplished in 1975 with total depth of 3062 m (10,047 ft), and bottom-hole temperature of 205°C. Directional drilling techniques were employed to make the interception of the fracture near the bottom of GT-2. The resulting downhole fracture connection had an unacceptably high specific impedance, i.e., pressure drop/rate of flow. Redrilling in GT-2 to improve the connection, from April to July 1977, provided a drill path GT-2B and a much lower impedance. The drilling programs are reported by Pettitt (5,6,7,8,9).

Downhole measurements proved to be a problem at elevated temperatures. Hardware and operational techniques have been continuously developed and reported (10). While logging service companies have been utilized, the program has also supported a two-armed approach to development of downhole tools. Contracts to industrial firms have provided some temperature-hardened tools and the LASL has developed some tools unique to our application and use.

Figure 3 is a plan view of the lower regions of the borehole-fracture region. The relative locations of GT-2 and EE-1 were painstakingly surveyed by several methods prior to the redrilling program in GT-2. The first redrill, GT-2A, established an improved but

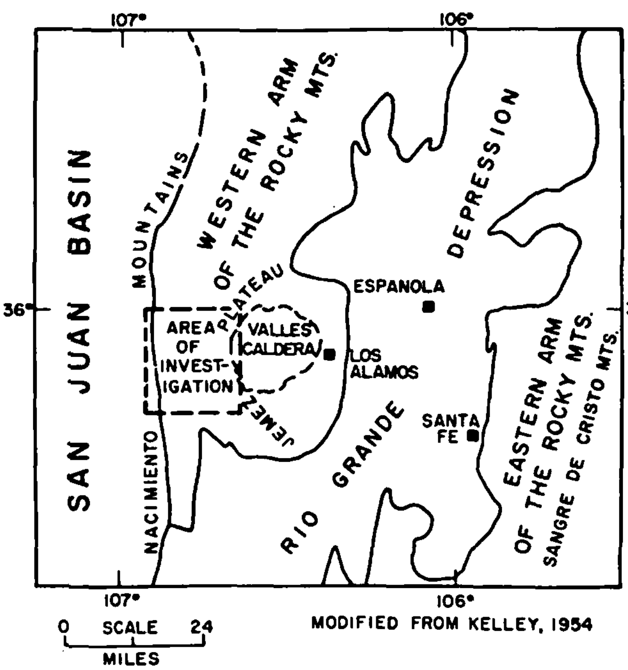

Fig.1 Major structural features and area of investigation in north-central New Mexico.

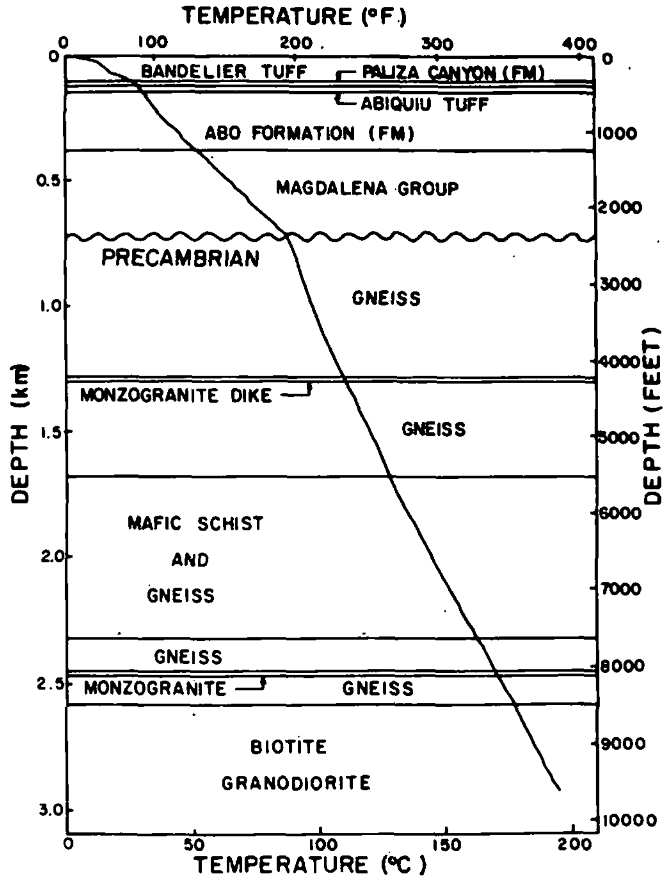

Fig.2 Temperature gradient and geologic formations penetrated in GT-2, 1974.

probably limited connection. GT-2B, a second side-tracked path, appeared very promising for circulating loop operations. The criteria were adequate fracture inlet and outlet separation for interesting heat transfer surface exposure and low impedance for reasonable flow rates.

Above-Ground System. The surface piping and equipment is shown schematically in Fig. 4. Component specifications are breifly listed below.

1 The make-up system now includes four centrifugal pumps in parallel, with individual capacity of 3.1 ℓ/s, 1.2 MPa (50 gpm, 175 psi) and a combined system test capability of 12.6 ℓ/s (200 gpm).

The pumps draw water from a 1500 m^3 (400,000 gal) reservoir, and pump through filters and flow meters to the system.

Make-up pressure (system minimum pressure) is regulated by a back pressure valve set at 1.1 MPa (160 psi).

2 The main circulating pumps are canned vertical turbines with seven stages each. Two pumps in series raise the pressure 8.65 MPa (1250 psi) at rated flow of 19 ℓ/s (300 gpm). Pumps are driven by 3500 rpm, 150 kW (200 hp) motors. A second pair provides standby capability and may be used to increase flow in future operations.

3 For the first two runs, a 2-in. manual control valve was utilized at the EE-1 wellhead. Four-inch control valves were installed at the wellheads prior to the third operation.

4 The heat exchangers are water-to-air units — vertical-forced-draft across aluminum-finned carbon-

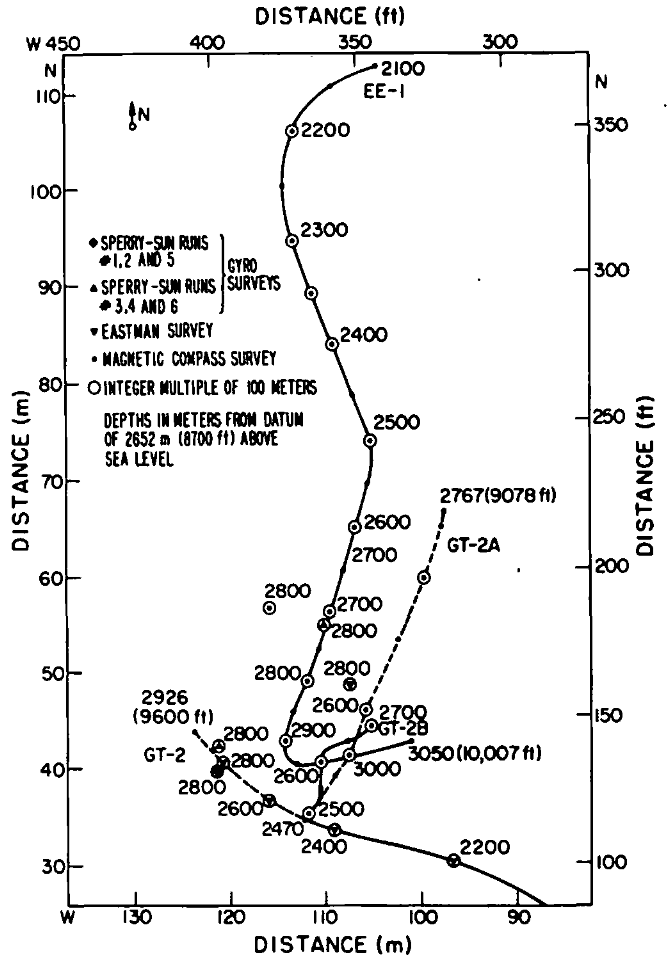

Fig.3 Plan view projections of the lower sections of the GT-2 and EE-1 wellbores.

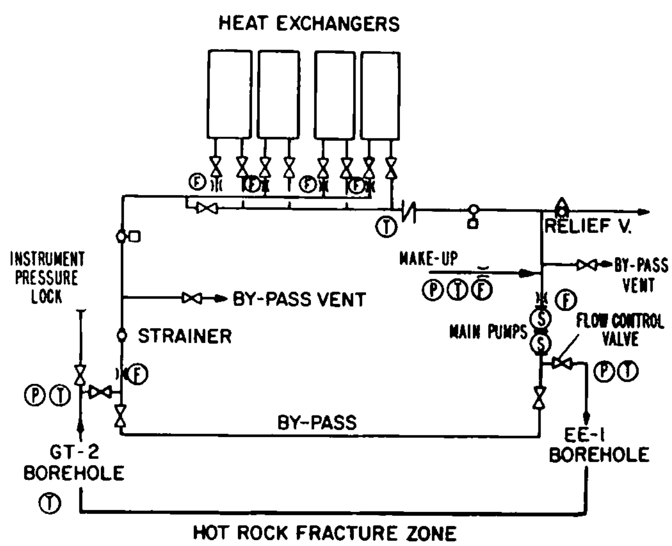

Fig.4 Schematic of the Fenton Hill Circulation System.

steel tubes. The straight tubes, in plugged headers, are arranged in six rows with twelve passes. The two bays, with two tube bundles each, allow flexible operations. Design conditions were: 17.2 MPa (2500 psi), 12.1 MW(t) per bay, water temperature 250°C in and 65°C out with 18.3 ℓ/s (290 gpm) flow, and 21°C ambient air at 2640 m (8700 ft) elevation. Four axial flow fans are gear driven from 22.5 kW (30 hp) motors. Outlet air louvers are automatically controlled from outlet water temperature.

5 The piping system design is for 17.25 MPa (2500 psi) and is generally 4-in., Schedule 160 carbon-steel pipe. The piping arrangement originally had a vent or flush line from the GT-2 wellhead piping and various system drains. Drains and vent piping have been increased for operational flexibility for planned experiments and to prevent freeze-ups during down periods for equipment or power outages. A pressure lock was added to the GT-2B wellhead for downhole measurements during the second run and another was added to the EE-1 wellhead prior to the third operation. The locks provide a 15.2-cm (6-in.) opening into the boreholes, for a 50-m (16-ft) long tool.

6 Venturi tubes with differential pressure transducers provide primary flow measurements. Turbine motors and positive displacement meters provide additional means of totalizing flow at selected locations, as well as redundancy to the calculator system. The calculator-based data system provides 80 channels for data and control functions (11). The signals are conditioned and scanned, recorded on magnetic tape, and printed at selected intervals. Signals are further monitored for significant changes which cause alarms or control sequences. Primary operator information is displayed on digital or analog displays; digital displays are updated every 15 sec. The system is backed up with a battery powered supply to avoid loss of data caused by local power outages.

A perspective sketch of the site is shown in Fig. 5. The boreholes are 76 m (252 ft) apart; heat exchangers are located away from boreholes to allow redrilling or workover operations with minimum disturbance; pumps are shown in positions used during the third operation. Support trailers are noted.

A summary of system changes related to operational segments will complete the system description.

Segment 1 employed service company piston pumps and a 2-in. manual control valve. Louvers were manually controlled. GT-2B outlet valves were 4-in. gate and globe valves.

Segment 2 utilized two of the listed pumps in series, in a temporary location near EE-1 with the same 2-in. control valve. Louvers were pneumatically controlled with manual settings changed to automatic during the run. Make-up flow, with one pump and a standby, was controlled by a back pressure valve. Pressure lock was installed on GT-2B. An ethylene glycol flush system for heat exchangers was installed during the run.

Segment 3: Four main circulating pumps were relocated near the heat exchanger. Make-up pumps: four in parallel with lower flow capability per pump to better match the low make-up requirement experienced in Segment 2, and adequate filling rate with parallel operation and standby availability during operation. A 4-in. pneumatic control valve was installed at GT-2B outlet with automatic control from flow pressure manual control. A 4-in. manual control valve and a pressure lock were installed on EE-1.

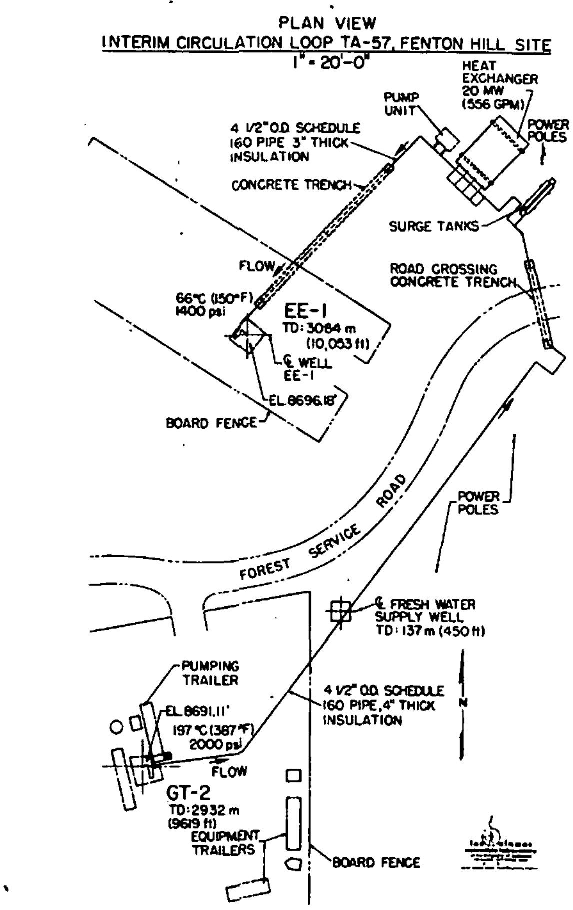

Fig.5 Plan view of circulation loop at Fenton Hill site.

OPERATIONS

Segment 1. Operation Segment 1 was conducted starting September 18, 1977, soon after the redrilling of GT-2B established a workable downhole fracture connection. The operation was planned to obtain preliminary information of the loop's operating characteristics before the final installation of pumping, control, and instrumentation facilities and to provide a functional checkout of the complete closed-loop system (except for use of service company pumping equipment). The experiment also provided preliminary information of extracted power, make-up water requirements, and geochemistry, in addition to final checkout of instrumentation, controls, and on-line computation algorithms. The experimental operating parameters included a steady-state injection flow rate of about 9.5 ℓ/s (150 gpm) with the injection pressure to be maintained below 9.7 MPa (1400 psi), corresponding to a system impedance of 1.09 MPa-s/ℓ (10 psi/gpm). Extensive fluid sampling was basic to the geochemistry studies.

The first 35 h of the flow test were run with the GT-2 effluent diverted to a catch pond bypassing the heat exchangers. The total throughput of about 1.1×10^6 ℓ (300,000 gal) during this period was intended to flush the wellbores and reservoir, and to provide baseline water chemistry data. The outlet temperature increased from the static surface ambient to above boiling, producing a steam plume. The loop was then closed, to run through the heat exchangers for non-flashing circulating operation during the remainder of the test. Flow stabilized at about 9.5 ℓ/s (150 gpm); impedance was about 1.3 MPa-s/ℓ (12 psi/gpm). The maximum thermal power was measured at 3.2 MW(t) at a temperature of 132°C at the wellhead. The injection pressure was nominally 6.9 MPa (1000 psi) for the first 50 h and was maintained at 9.1 MPa (1325 psi) for the following 46 h.

Several shutdowns and restarts were accomplished during the run. A sodium-fluorescein dye injection experiment was performed to detect any dramatic changes in fluid residence time in the fracture system caused by the redrilling operation. Some minor problems occurred when pulsations from the rented piston-driven pumps caused a drain valve in the loop plumbing to vibrate open. On one occasion a vibration cutout switch on one heat exchanger fan tripped the fan off (caused by a misalignment of motor and gear reducer). There was also some discrepancy in the total fluid inventory among system flow meters, indicating the need for in situ calibration of all flow metering instrumentation.

The numerical results of the experiment were consistent with predictions, and the test was extremely useful in wringing out the various subsystems under operating conditions.

Segment 2. Operation Segment 2 started on January 27, 1978 and continued to April 13, 1978, a total of 1800 h. The experiment was designed to examine the thermal drawdown, flow characteristics, water losses, and fluid geochemistry of the system in detail. The area was closely monitored for induced seismic activity.

System start-up began with an approximate 150,000 ℓ (48,000 gal) vent to the lower pond, bypassing the heat exchangers, to flush the stagnant water from the system. When the total dissolved solids decreased from 3300 ppm to less than 400 ppm, the flow was diverted through the heat exchangers and the main pumps for closed loop operation. Under circulating conditions, the flow and pressures increased toward the selected limits and the make-up flow decreased. As the EE-1 injection pressure approached the "red line", 9 MPa (1300 psi), the flow was throttled at the control valve. The system stablized at approximately 7.9 ℓ/s (125 gpm) throughput and 9 MPa (1300 psi). GT-2B outlet pressure, limited by fracture impedance, was compatible with make-up pressure.

After three weeks the impedance of the fracture system started to decrease, resulting in a higher injection flow rate to maintain the wellhead pressure at 9 MPa (1300 psi). Finally, with the control valve wide open, the flow reached 17 ℓ/s (270 gpm) with the injection pressure still decreasing. Due to the concern for inordinately high fluid velocities in the temporary 2-in. valve and piping at EE-1, a compromise was made in selected operation: the loop would be controlled at a flow rate of 14.5 ℓ/s (230 gpm) and accept whatever pressure could be maintained. Throttling the GT-2B outlet became necessary to allow minimum make-up flow. The system was operated under this mode until "shut in" on April 13. The system was held shut in for 10 days and then vented.

The operation of the system for 75 days was without major problems with only a total of 2% downtime. Some of the longer downtimes or recurring problems were as follows.

1 The main pump seals failed. The mechanical seals were cleaned and repaired by manufacturer's representative and continued through the test without further problem.

2 Difficulty with seals and flexible couplings on the make-up pump toward the end of the test was countered by utilizing the standby pump.

3 Performance of a turbine meter in the main flow line was erratic (the meter has since performed well)

probably due to dirt in the line, or wiring problems.

4 The control head on the pressure lock, which allowed continuous monitoring of GT-2B downhole temperatures, leaked excessively (10 gpm) after 65-days operation with almost daily temperature logs (requiring movement of the cable through the control head under pressure) performed during that period. The temperature probe had to be pulled and the control head refitted.

5 Two power outages occurred which were in excess of 12 h. As these occurred during winter storms special efforts were needed to prevent freezing in exposed piping.

6 System perturbations, such as rapid flow changes resulting from impedance changes, caused temporary operating problems. The fracture system can be represented as a large 400 m³ (10^5 gal) accumulator where the output flows through a restriction or impedance. When the impedance was rapidly reduced, the exit flow increased rapidly. The increased flow at higher temperature resulted in higher heat exchanger outlet temperature causing automatic pump shutdown when seal limits were exceeded. Not having anticipated such rapid perturbations, several manual adjustments were necessary to restart and stablize the system. Two such instances contributed to the downtime.

7 A very disturbing freezing and rupturing of heat exchanger tubes had occurred between Segments 1 and 2. The tubes were presumably drained, but 12 of 684 tubes had to be plugged during the initial days of Segment 2. Fortunately at least one bundle was operable at all times. The location of ruptured tubes was random.

8 During the run a small flow from the annulus around the EE-1 casing was observed and monitored at the wellhead. This was the first evidence of casing cement deterioration which ultimately required workover operations.

Segment 3. A series of experiments and three operating modes were planned to further characterize reservoir behavior. Basic studies would be continued and the geochemical investigations were particularly enhanced as an on-site laboratory was being furnished and staffed. Planned operational modes were as follows.

1 Flush vent as before to stable chemical content.

2 Closed loop circulation at high back pressure on GT-2B and the reservoir, with pressures at the GT-2B wellhead at 9-9.6 MPa (1300-1400 psi). This experiment was to determine the effect on impedance and heat transfer surface of high pressure over entire fracture zone.

3 Reduce back pressure to repeat Segment 2 pressure conditions and continue reservoir drawdown with the higher flow rate now attainable.

4 Cyclic operation ("huff-puff") of reservoir defined as: (a) high pressure, 13.8 MPa (2000 psi), injection of a specified volume into EE-1 with GT-2B closed in at wellhead; (b) shut in both wells for soaking period; (c) vent from GT-2B through heat exchangers; and (d) repeat, based on 24-h cycles. Rented piston pumps would be necessary for the high pressure and volume charging phase.

Downhole temperature measurements at the casing bottom in both holes would simplify reservoir heat transfer analysis and further confirm models of borehole heat transfer and would be obtained for all modes.

The operation started as planned with background temperature and spinner (flow) surveys in early September 1978. Closed-loop operation started on September 18th with desired operating pressures being reached the following day. Make-up flow did not decrease as previously experienced. A leak around the cable packoff (control head) and flow from the EE-1 annulus accounted for some of the required makeup.

A power outage and broken valve resulted in 21 h without pumping. On October 16, the high-back-pressure mode was terminated with the following conditions:

EE-1 Injection	GT-2B Production
12.5 ℓ/s (198 gpm)	9 ℓ/s (142 gpm)
22°C Surface	103°C Surface
58°C Downhole	100.6°C Downhole
9.2 MPa (1330 psi)	9.7 MPa (1402 psi)

Venting continued until October 23 when the second mode was initiated. System conditions soon reached 8.9 MPa (1300 psi) and 20 ℓ/s (320 gpm) injection, 1.5-1.8 MPa (215-260 psi) and 15.8 ℓ/s (250 gpm) production; EE-1 annulus leakage increased to 1.3 ℓ/s (20 gpm). Following a third sodium-fluorescein "diagnostic" measurement, Segment 3 operation was terminated October 26 due to the high make-up and EE-1 annulus flows. The prevailing conclusion was that the casing cement had deteriorated further, allowing significant flow up the annulus, only part of which reached the surface, and the rest going into a thief zone in the overlying sedimentary beds. Mode 3 was thus much shortened and Mode 4 was not attempted.

RESULTS

In general the results, characteristics, and data reported below are from Segment 2, with differences obtained from Segment 3 noted. The data analyses are more thoroughly reported by Tester and Albright (12). The small active reservoir heat transfer surface area (<10,000 m²) enable the examination of reservoir performance in a compressed time scale with the hope that the accelerated thermal drawdown would hasten the development of thermal stress cracks. The difference between observed and calculated thermal drawdown could be used to identify changes in reservoir size and the occurrence of stress cracking. Information about changes in fluid chemistry, water losses, residence time, flow impedance, and production zones will improve reservoir design modeling and concepts to insure that sufficient in situ surface area can be achieved for future systems. Studies of buoyant flow effects for increasing the effective heat transfer area and reducing pumping requirements were also attempted.

Heat Extraction

Temperature Measurements Downhole. Temperature measurements in GT-2B have been used as the basic data for thermal drawdown interpretations. The tool used to obtain this data is a thermistor device with resolution of 0.05°C and is capable of being used in surveying or stationary modes. Fifty-eight surveys of the lower portion of the borehole were taken during the 75-day run (Segment 2). Between surveys the tool was stationed at 2.6 km (8600 ft), just above all the known producing zones, to obtain a continuous mean temperature of the mixed fluid flows into GT-2B. A typical set of temperature surveys is presented in Fig. 6. Only the downhole region where the produced fluid enters the well is shown. These surveys indicate a complex reservoir-to-well connection pattern. The major temperature changes at the arrows indicate major flow connections. Earlier tests had shown that 20% and 80% of the flow entered at Points 1 and 2. The more detailed data shown, in which measurements were obtained every 0.15 m, suggest these major connections seem to have fine structure that changes with time. At Connection 2 a colder flow entered at the bottom while 2 m further up water at least 5°C hotter entered. The second survey,

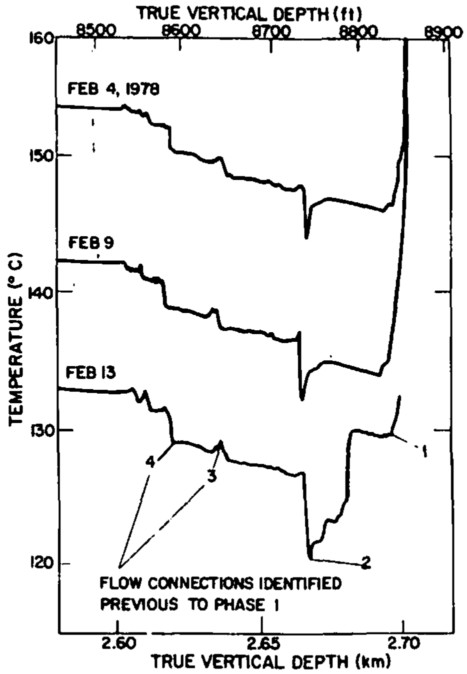

Fig.6 Three temperature surveys taken in the bottom section of GT-2B during Segment 2.

and even more the third survey, shows the development of new flow connections between the previously established major Connections 1 and 2. This information is utilized in reservoir analyses along with flowing spinner surveys and radioactive tracer logs to characterize the production and injection zones.

Thermal Drawdown. Thermal drawdown, Fig. 7, presents the variation of temperature with time at the 2.6-km depth showing the overall thermal drawdown of the reservoir and comparing measured and calculated drawdown. The anamoly at 22 days is associated with a change in production flow rate and impedance. The model assumed a circular fracture (not a necessary assumption) to provide an estimate of the fracture area effective for heat transfer. It was further assumed that fluid was confined to the fracture and that heat from the rock was transported to the fluid in the fracture only by means of thermal conduction in the rock. The possibility of thermal stress cracking is not considered in this model. Fluid loss was assumed to occur uniformly over the fracture area so the permeation effect can be approximated by assuming that on the average heat was removed from the reservoir by all of the produced water flow. Other conditions of the calculation were: the fracture was 0.2 mm thick; impedance was 0.3 MPa-s/ℓ (3 psi/gpm); fracture injection entry temperature was calculated from EE-1 wellhead temperature to account for radial conduction by computer code WELBOR (13). Time variation of injection flow, initial rock equilibrium temperatures and measured GT-2B downhole temperatures were input data. Repeated calculations resulted in the plotted curves and a 60-m (200-ft) fracture radius which agrees reasonably with the distance between EE-1 exit at 2760 m (9050 ft) and GT-2B entry at 2690-2660 m (8850-8730 ft). This does not represent the total fracture area but the effective area (i.e., area exposed to flow) limited by the above entry and exit.

Thermal Power. The thermal power produced is shown by Fig. 8. Declining production temperatures were more than offset by the increasing flow rate during the first half of the run to maintain a good power extraction rate. Peak power was 5 MW(t) during Segment 2 and 6 MW(t) during Segment 3.

Flow Characteristics

Impedance. The reservoir flow impedance is the pressure drop through the fracture system connecting two wellbores divided by the flow rate. With no downhole pressure data measured, the pressure drop through the fracture system was obtained from the measured surface pressure difference between EE-1 and GT-2, corrected for the difference in fluid density between wells. The buoyancy correction remained almost constant during the last six weeks of operations. A possible 20% error in buoyancy is reflected as less than 5% error in impedance since such correction was a small portion of the measured surface pressure difference. Figure 9 shows the variation of impedance day-by-day through the 75-day run starting at a value slightly higher that that obtained at the end of Segment 1 in September, then decreasing to the end. The low-side spike at Day 21 is noteworthy because of a rapid decrease in impedance which caused an upset and

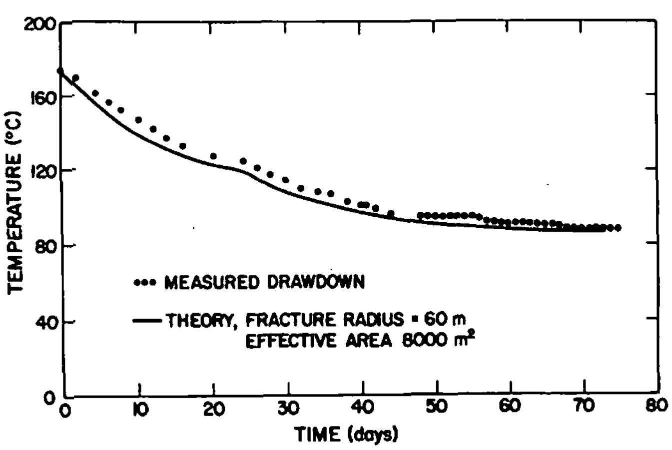

Fig.7 Thermal drawdown of produced fluid measured at a 2.6-km (8500-ft) depth in GT-2B.

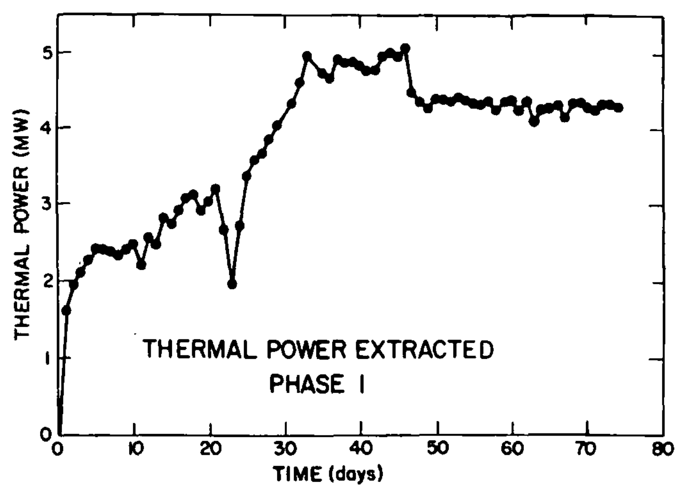

Fig.8 Net thermal power extracted during Segment 2.

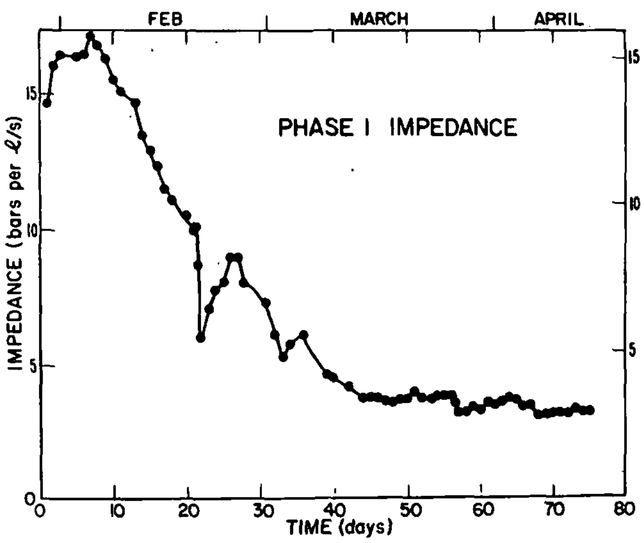

Fig.9 Net flow impedance between the GT-2B production and EE-1 injection wells with buoyancy correction included.

shutdown of the entire system. The high-back-pressure sequence of Segment 3 demonstated impedance decreasing with time and values lower than recorded in Segment 2 from 214-52 KPa-s/ℓ (2-0.5 psi/gpm). The final mode of Segment 3 showed impedances comparable to the later stages of Segment 2.

Fracture System Size. Dye tracer techniques developed previously (10) were used to characterize the fracture system volume from fluid residence-time-distribution within the reservoir during circulation. In four experiments run during the 75-day test, a 200-ppm, 400-ℓ (100-gal) pulse of sodium-fluorescein dye was injected into the EE-1 wellhead, pumped down EE-1 and through the fractured region and up the GT-2 wellbore. Dye concentration in the produced fluid was monitored spectrophotometrically at the surface as a function of time and volume throughput. From these experiments, it is concluded that flow in the fracture system can be described as well mixed with no major short circuits. The degree of mixing cannot be adequately accounted for by dispersion of flow in a single hydraulic fracture. Because of this fact, and of the known existence of multiple flow paths between EE-1 and GT-2B, the observed shape of the residence-time-distribution is caused by dispersion within individual flow paths as well as superposition from mixing of various production flows in the wellbore. The median volume probably represents the flow through the major production paths in GT-2B. Several general comments can be made.

1 The fracture flow system had grown considerably in size during the 75-day test; the integrated mean fracture system volume was 56,000 ℓ (14,900 gal), up from 37,500 ℓ (9900 gal); and the median volume was larger, 48,500 ℓ (12,800 gal) versus 28,800 ℓ (7600 gal).

2 There is evidence for the development of additional flow paths; that is, the tendency toward earlier and later arrival of dye with smaller and larger residence time (volume) causing an increase in the spread of the distribution.

3 The apparent degree of mixing or dispersion is virtually unchanged between experiments.

Fluid Losses. The water loss, or the difference between the EE-1 injected flow and the GT-2B produced flow, is determined by the fracture geometry and an appropriate average permeability and pore (or reservoir) compressibility associated with all types of porosity accessible to the flow. The fracture area involved is not necessarily the same as the heat transfer area determined by the GT-2B temperature drawdown. There are other fractures intersecting the EE-1 wellbore; fractures connected to the GT-2 and GT-2A wellbore could also contribute to the water storage and loss to permeation. Any fractures directly connected to the GT-2B wellbore did not contribute significantly to the water loss since they were maintained at close to hydrostatic pressure during the operation. The observed permeability is an average over the large scale permeability opened by previous pressurizations, plus any welded joints, and the microporosity. Similarly, the reservoir compressibility, or the ability of the reservoir to store water, includes the compressibility of the main fractures as well as the microporosity. Conservation of fluid mass and Darcy-type flow in all forms of porosity are assumed.

Because multidimensional-permeation flow was anticipated for long pumping times; two-dimensional axially-symmetric models were used. However, it is likely that only one-dimensional flow was observed for the entire 75-day pumping period. The one-dimensional portion of the flow can be characterized by the magnitude of the diffusion parameter $a = A\sqrt{k\beta}$ at hydrostatic pressure (k = permeability, β = compressibility, A = effective diffusion area). If multidimensional flow develops, a time constant is needed. Figure 10 shows the fluid loss data as recorded from the make-up flow venturi-tube meter. The dashed line is the result of the AYER (14) one-dimensional calculation. The data have been corrected for the EE-1 annulus leak occurring after the 35th day. The recorded data reflect system operational transients from all causes as well as reservoir phenomena.

Fluid Chemistry. During the 75-day period of Segment 2, a gradual rise in the concentration of dissolved species was observed to approach steady state levels corresponding to the concentrations observed for water which remains in contact with the reservoir for an extended period. The effects of mixing between

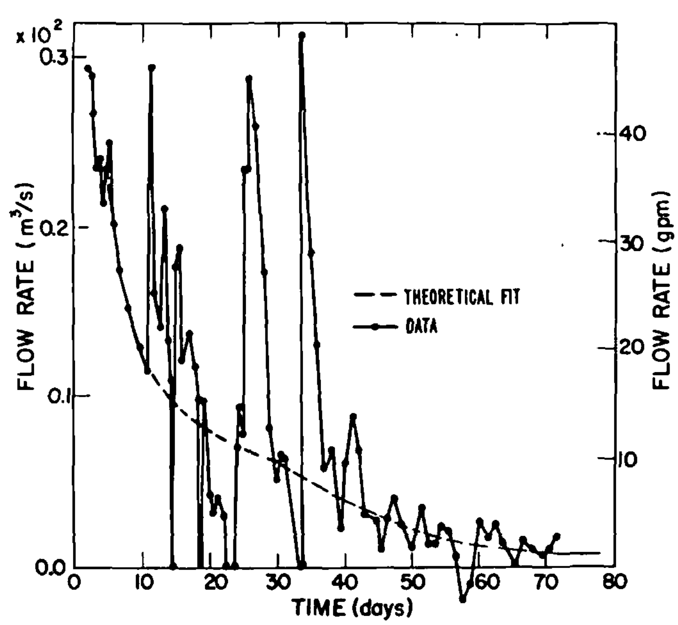

Fig.10 Make-up water loss rate as recorded on the make-up venturi flow meter.

various flow paths and mass transfer were very evident in the observed concentration change of dissolved species with time.

Samples were collected at the GT-2B producing wellhead through a cooling coil and throttling valve. Through the first month of operation, the sample flow was continuous to prevent freezing in the tube. This flow caused deposition of calcite which eventually plugged the tube. Samples of the injected fluid were taken between the main circulating pumps. Make-up water samples were collected downstream from the 100-micron filters and pumps of that subsystem.

Figure 11 shows the concentration-time history of dissolved solids as totalled from the individual analyses. Samples were analyzed for: bicarbonate; fluoride ion; silicon dioxide; chloride ion; sulfate as SO_4; calcium; sodium; potassium; silicon; and lithium, and pH and conductivity. Several features were common in all species and are reflected in Fig. 11. At first, samples had high concentrations of dissolved species which decreased rapidly during the initial purge with relatively pure make-up water before changing to closed loop circulation. As make-up flow rates dropped during circulating operation, the make-up dilution effect was lessoned and the concentrations of dissolved material began to rise toward steady-state values.

A detailed summary of analyses listed above is given in Ref. 12, as is the argument for identifying different flow paths through the reservoir. The low silica and bicarbonate concentrations have allowed operation for this relatively short period with no scaling problems in surface equipment. Special studies of the fluid also reported in Ref. 12 are:

1 Tabulated results of analyses for trace elements.

2 A study of the $^{87}Sr/^{86}Sr$ ratio as a hydrologic tracer to identify sources of mineral bearing waters in a mixed sample.

3 Radon content and measurements to study reservoir structural and final flow properties. This study was done in cooperation with Stanford University.

Seismic Monitoring. During operation of the energy extraction loop, monitoring was done to detect local seismic sources and to discriminate among several possible source types – manmade disturbances, earthquakes, and rock failure induced by the pressurized fluid injection into the hot dry rock reservoir.

The monitoring array consisted of seven surface stations at distances up to 750 m from the wellheads, two shallow borehole stations (125 m deep) at about 1 and 3 km, and stations of the LASL regional seismic network – the nearest of these is about 10 km away (10).

Local earthquakes identified during the Segment 2 operation were located by the regional array near a fault 15 km west of the Fenton Hill site. There were many blasts and earthquakes observed with more distant epicenters and many sonic booms – some of the smaller of these acoustic signals required the seismograms of the regional network for positive identification.

Although the stress alterations to the reservoir during the 75-day operation were significant but not overwhelming, the absence of detectable surface seismic activity is an encouraging observation. The seismic monitoring will continue with an improved network during future flow experiments.

SUMMARY

The hot dry rock experiment at Fenton Hill has been operated successfully in energy extraction modes thus demonstrating the concept. Characteristics studied include heat transfer, water make-up requirements, water geochemistry, reservoir, and seismic response.

The loop has been operated for about 2800 h at energy withdrawal rates up to 6 MW(t) for a total production of 250 MW(t) days. Calculated thermal drawdown agrees with that measured for a reservoir of approximately 8000 m^2 surface. Water requirements were acceptably low at 0.2 ℓ/s (3 gpm) or 1.3% of injected flow. Reservoir studies indicate multipath flow with no short circuits and an impedance as low as 320 KPa-s/ℓ (3 psi/gpm). Water chemistry presented no insurmountable problems and induced seismic activity was not detected. Results to date encourage expansion to a larger reservoir at higher temperatures to further

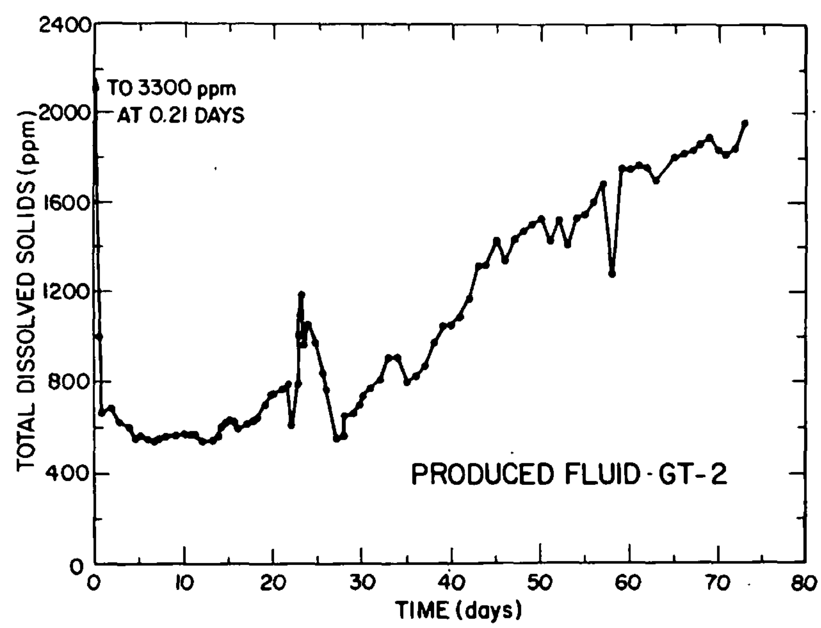

Fig.11 Water quality for the Swgment 2 energy extraction experiment.

establish the technology of hot dry rock geothermal energy.

ACKNOWLEDGEMENTS

This paper is a summary report of a project conducted by many people. The combined and individual efforts and contributions are hereby acknowledged without specific credits. Where practical, specific credits are traceable through references to detailed reports of specialized topics.

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Hydraulically Actuated Treating Packers for Dry Rock Geothermal Applications

T. E. UPTON **D. M. SPRIGGS**

ABSTRACT

A downhole well packer has been developed by Guiberson Division of Dresser Industries, Inc. for use in boreholes where elevated temperatures would prevent the use of standard oil well packers. The most recent development of this equipment has been prompted by the requirements of the Hot Dry Rock Geothermal Project being pursued by Los Alamos Scientific Laboratory. This paper is a case history which includes data on the equipment specifications, testing performed, and the proposed end use.

The tools were designed to utilize a special set of packing elements backed up to multiple steel plates. System tests have been performed at elevated temperatures and differential pressures to 570 F (299 C) and 5000 psi (3.44×10^7 Pa) with no leakage or deterioration of parts.

GEOTHERMAL ENERGY

Due to the increasing value of all energy sources, the traditional role of technology in energy production has changed. The worldwide energy picture has created rapid growth in the need for new products and services for the efficient production and utilization of available energy resources. In addition to trying to supply our nation's continuing energy needs with petroleum products, we are faced with the eventual prospect of having to rely, at least to some extent on alternate energy forms. One such form is geothermal energy.

The interior of our planet has long been recognized as an enormous reservoir of high temperature heat energy. Due to extremely poor accessibility, except at a very few places on the surface of the earth, this vase cache of energy has seen only nominal use throughout the energy using history of mankind.

When this energy has been tapped, it has always been where a portion of it has been stored in hot water or steam. The water or steam has been produced and served as a working fluid from which the energy could be extracted. Much of the inaccessibility of geothermal energy, however, is due to the fact that a very small portion of the energy exists stored in a naturally occurring working fluid.

LOS ALAMOS PROGRAM

A concept of extracting heat energy from a dry geothermal reservoir is currently being demonstrated at Los Alamos Scientific Laboratory. This concept, as shown in Figure 1, involves duplicating the natural process in hydrothermal systems by introducing water into the reservoir and producing it back after it has absorbed the available heat energy. At least two holes are drilled into the reservoir to facilitate the introduction and production of the fluids in the system.

Since the rocks present in the dry geothermal reservoirs are normally not permeable, the holes are connected at depth by cracks which are produced by hydraulic fracturing. Even though hydraulic fracturing is a well developed technology in today's oilfield, one very large problem appears when the wellbores to be treated have been drilled into a geothermal reservoir where temperatures exceed 400 F (204 C). That problem is one of containing the high pressure treating fluids in a controlled interval downhole, where temperatures are too high for standard oil well packer equipment to be used.

SOLUTION TO EQUIPMENT REQUIREMENT

Previous attempts to solve this problem having limited success involved inflatable type formation packers utilizing Viton bladders, or sealing elements which degraded rather quickly at the 400 F (204 C) plus temperatures encountered.

Guiberson's existing high temperature packer technology consists of either an old style hydraulic formation packer design incorporating a spiral wrapped asbestos sealing element, or standard casing packer designs with formed rope asbestos seal elements and valves. Both designs could handle the specified temperature, but were limited to about 1500 psi (1.034×10^7 Pa).

Our approach for meeting this recent challenge was to develop the tool around the old style spiral formation packer, utilizing a new seal element system developed in conjunction with a supplier (Johns-Manville), and to demonstrate the capabilities of the system and test it under true downhole conditions at our test facility in Dallas, Texas.

DETAILS

The Los Alamos specifications called for a test tool consisting of the top half of a straddle packer system to be built to their specifications and tested at 500 to 600 F (260 - 316 C) with 5000 psi differential (3.44×10^7 Pa). The tool was to be set hydraulically, have a maximum O.D. of 7-1/2" (19.05 cm), minimum I.D. of 3" (7.62 cm), and seal in an 8-3/4" 22.22 cm) I.D. hole, which required sealing a radial gap of 5/8" (1.58 cm). Since the end use was as a straddle packer with 5000 psi (3.44×10^7 Pa) between the two tools, a tensile strength capability of 300,660 pounds was required for the entire system (Figure 2).

These design requirements presented several problems which had to be overcome before the design could be finalized. O-rings to seal the setting chamber had to be able to withstand a dynamic setting pressure of 3000 psi (2.07×10^7 Pa) at 300 to 600 F (149 - 316 C) after soaking at that temperature for as much as several days. A sealing element had to be developed which could withstand the high temperatures and pressures and yet bridge a 5/8" (1.58 cm) gap.

Our approach to solving the O-ring problem was threefold

1) Control all clearances and tolerances so that, at worst case, the maximum gap would be .004" (.101 mm) per side.

2) Use backup rings on all stroking O-rings to provide "zero" gap clearances. The backup rings were machined from International Polymer Corporation's Ryton 5307 tubing, which has a continuous use temperature rating of 500 F (260 C).

3) An ethylene-propylene compound was chosen for the O-rings because of prior Dresser experience with logging tools in geothermal wells. This compound will withstand the temperatures expected in steam or hot water, but will degrade in oils.

The sealing element problem was solved using some old Guiberson technology in conjunction with a special high temperature packing element. The element consists of a 1200 F (649 C) plastic core of asbestos fiber treated with various fillers, including graphite suspended in gylcerin and formed in a die by compressing approximately 50 percent. The formed core is then wrapped with a biased asbestos cloth to retain and protect it. The old Guiberson technology came into play because the plastic core would extrude through the asbestos wrap at high temperatures under pressure. It actually became liquid enough during tests to flow through a 1/4 inch needle valve. Sets of ten special 16 gauge steel expanding plates were added to each end of the seal element system, which created a retaining bridge between the packer and the hole I.D. and kept the plastic filler confined. The sealing system is illustrated in Figures 3 and 4.

Guiberson Division's engineering test lab in Dallas, Texas has the capability to test packers at temperatures up to 600 F (316 C) and pressures of 10,000 psi (6.89×10^7 Pa) differential. This is accomplished by setting the tool in a bullplugged section of casing with a wellhead in which a differential pressure can be applied, and immersing in a recirculating heated oil batch which can be controlled from ambient to 600 F (316 C). (Figures 5 and 6.)

The test packer was run in the test pot with a 4000 psi (2.76×10^7 Pa) expendable ball and seat below it for setting purposes. The temperature was brought up to 300 F (149 C) and the tool allowed to soak for four hours to soften the seal elements prior to setting. The setting procedure was to pump 3000 psi (2.07×10^7 Pa) inside the setting chamber and hold it for thirty minutes, then advance to 4000 psi (2.76×10^7 Pa) and blow the ball and seat out. After setting, 5000 psi (3.44×10^7 Pa) was applied below the tool and held while the temperature was steadily increased to 575 F (301 C). The tool was held at 575 F (301 C) and 5000 psi (3.44×10^7 Pa) for eight hours with no leaks whatsoever.

Upon completion of the test, the tool and test pot were allowed to cool overnight, then the tool was pulled for inspection. All petal plates had expanded to the bore wall perfectly, the elements had compressed about 40 percent, and all O-rings were reusable, but the Ryton backup rings required replacement.

RESULTS

All persons involved with the test, both from Los Alamos Scientific Laboratory and from Guiberson, were very satisfied with the test results. Plans are underway to build two complete straddle packer assemblies with a high temperature, shiftable ported collar between them to test in actual field conditions fracturing the new deeper Los Alamos Lab's test wells sometime in 1979.

FUTURE POSSIBILITIES

If the Hot Dry Rock Geothermal concept being demonstrated by Los Alamos Scientific Laboratory proves to be an economically workable concept for energy mining, the use of the equipment and techniques brought together in this project could be greatly expanded to other efforts of a similar nature. There are a great multitude of potential sites where this type of energy mining might be feasible.

An obvious benefit of the project, however, is the experience gained by those applying the technology in hostile operating conditions. This experience gained can serve to increase expertise and reliability in all applications of downhole well equipment and procedures wherever that becomes necessary in our quest for efficient source development.

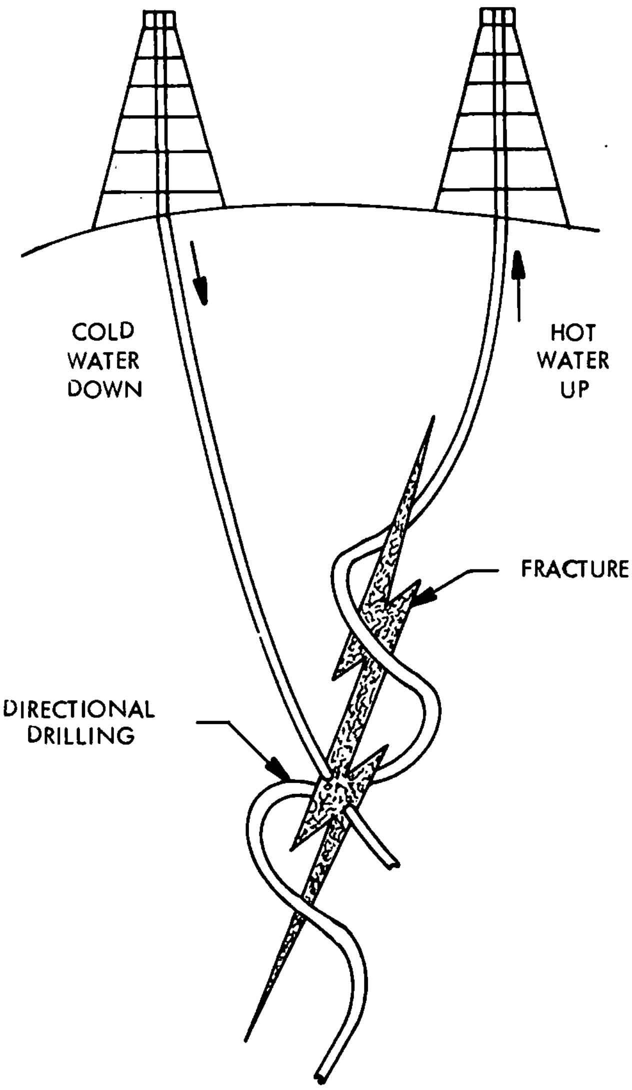

Fig. 1

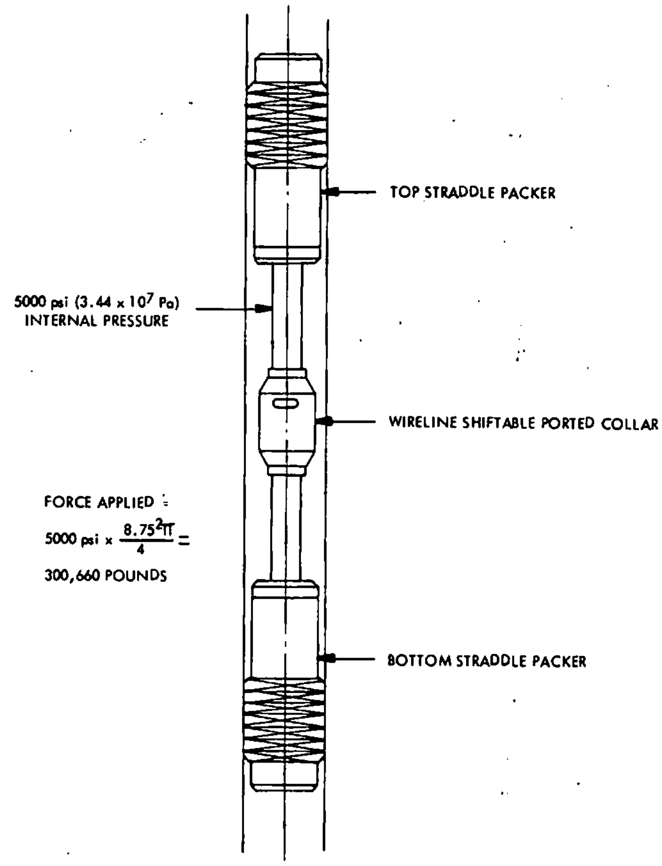

Fig. 2

Fig. 3

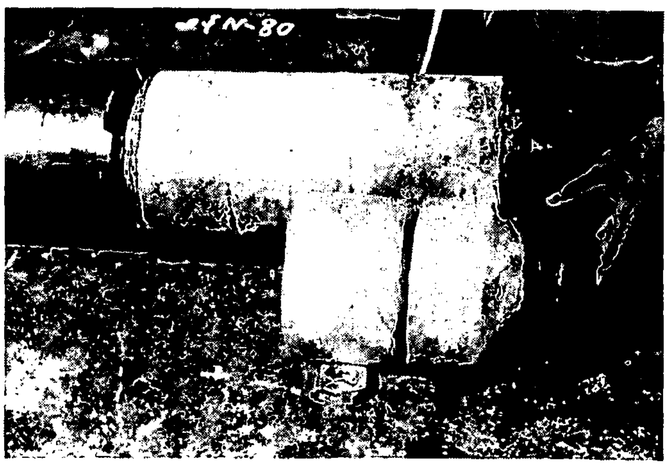

Fig. 4

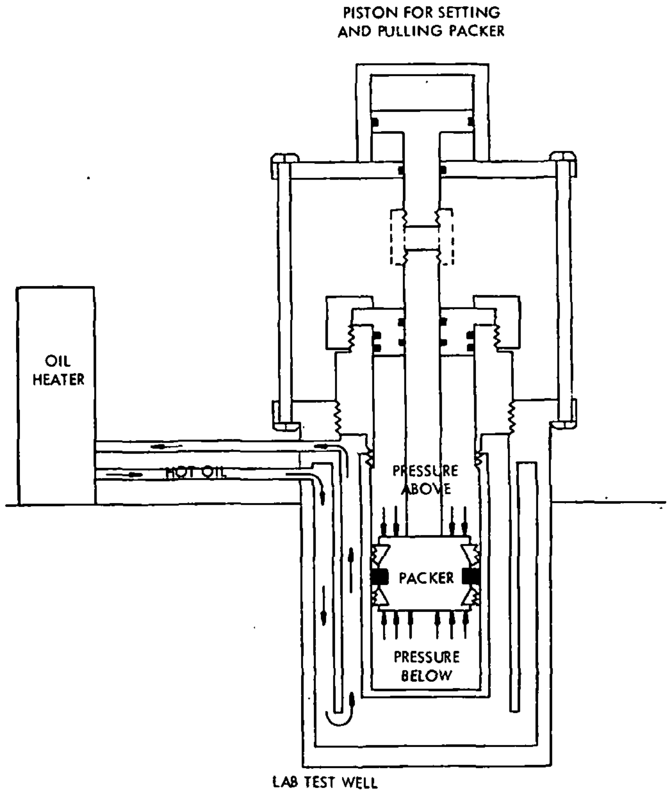

Fig. 5

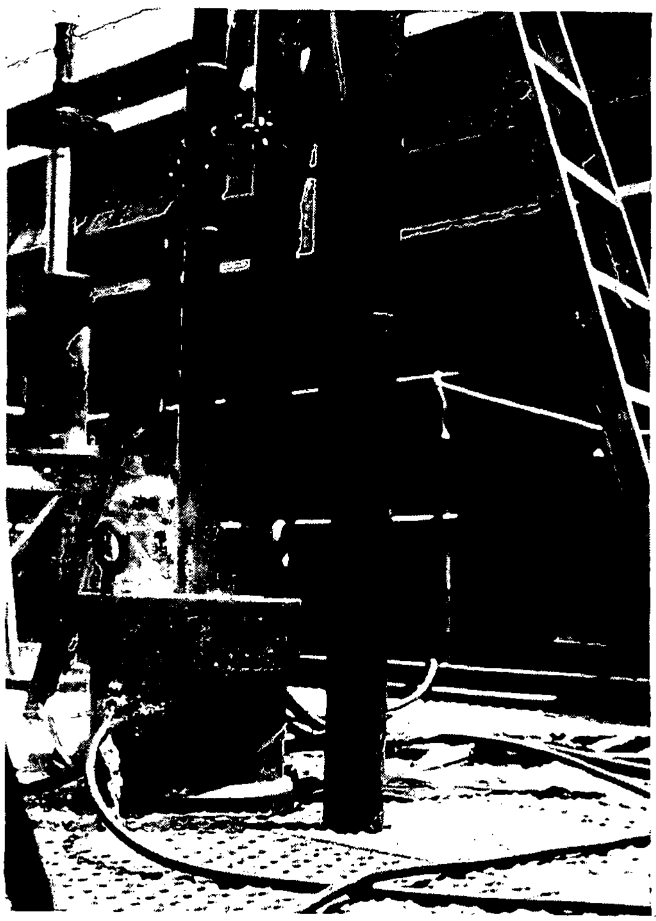

Fig. 6

UTILIZATION OF HOT DRY ROCK GEOTHERMAL ENERGY: POWER PLANT DESIGN CONSIDERATIONS

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ABSTRACT

Electric power cycle selection considerations will be discussed from the standpoint of utilizing geothermal fluids produced by hot dry rock (HDR) reservoirs. HDR resource parameters will include: fluid quality, potential wellhead temperature range (100-300°C), reservoir drawdown rate and heat rejection conditions with sub- and super-critical Rankine cycles employing non-aqueous working fluids and direct steam flashing cycles considered. Special attention will be given to the effect of plant size from 60 kW(e) to 50 MW(e) on component selection. Parasitic power losses associated with heat rejection and pressure losses in the working fluid and geothermal fluid loops will be discussed. In particular the relationship of dry cooling tower size and parasitic losses to net plant output will be included.

1. INTRODUCTION

The conversion of geothermal energy derived from hot dry rock (HDR) to electrical energy is the primary topic covered. Other forms of HDR utilization such as process or space heating and co-generation are discussed in references [1] and [2] respectively. A simplified model of an HDR reservoir which considers temperature drawdown, fluid composition and circulating water loss rates is presented. Since drilling-related costs can represent 60% or more of the total capital investment of an HDR power plant, designing and operating the conversion system near its thermodynamic optimum is warranted.

This paper attempts to outline many of the factors that are important considerations in order to achieve this goal. Besides the need for high component efficiencies which is somewhat obvious, the parasitic power consumed by the heat rejection system should be selected to maximize the net output of the plant. This is particularly important when using dry cooling towers. Dry cooling towers may be the only choice for some sites because of limited water availability. Under many climatic conditions, dry cooling towers may result in lower condensing temperatures than wet towers. The relationship between dry cooling tower size, parasitic losses, and net plant output are presented for a 60 kW(e) scale model plant designed for conditions found at the Fenton Hill HDR test site in the Jemez Mountains of Northern New Mexico [2].

2. HDR RESERVOIR CHARACTERISTICS

The reservoir concept being investigated for low permeability, hot dry rock (HDR) formations involves using a fractured rock system to provide sufficient heat transfer surface. Artificial stimulation using hydraulic fracturing techniques is being used to provide the necessary in situ permeability with a contained flow path of pressurized water over the surfaces of the fracture as shown in Fig. 1. One injection and one production well are required for each fractured reservoir with large enough separation distances to avoid flow short-circuiting. Under ideal conditions with homogeneous stress and rock physical properties, circular fractures with small elliptical apertures should be formed.

Because the inherently low thermal conductivity of the rock quickly limits the rate of heat transfer to the circulating fluid, large fracture surface areas are required to minimize thermal drawdown. This may be achieved in practice by a number of techniques: (1) single large fractures with radii greater than 500 m, (2) multiple parallel fractures, and (3) thermal stress cracking to increase the effective heat transfer area of the system. [1] In addition, remedial restimulation might be possible. For example with a parallel, inclined arrangement of boreholes, additional fracturing could be used to provide new surface area in a hot region of rock.

The efficiency of electric power production over the 20- to 40-year lifetime of an HDR power plant will depend on the temperature and composition of the geothermal fluid produced. Thus, knowledge of the anticipated thermal drawdown and fluid chemical composition will be crucial in developing optimal plant designs and reservoir management strategies. For a fractured reservoir with low formation permeability, the thermal drawdown rate will depend on:

1) accessible fracture surface area, $A = \pi R^2$
2) mass flow rate of circulating fluid, $\dot{m}$
3) distribution of fluid across the fractured surface
4) thermal properties of the rock

A simplified approach to estimating this rate assumes that a certain fraction η of the recoverable power, corresponding to uniform flow across the face of an ideal plane fracture, is extracted. The thermal power P(t) at any time t can then be expressed by solving the one-dimensional, transient heat conduction problem through the rock to the fracture surface and results in

$$P(t) = \eta\dot{m}\, C_w(T_i - T_{min})\ \mathrm{erf}\left[K\left[\frac{R^2}{\dot{m}\sqrt{t}}\right] \right] \tag{1}$$

where R is the effective fracture radius, C_w is the heat capacity of the geofluid, T_i is the initial average rock temperature, T_{min} is the reinjection temperature, and K a constant that depends on the thermal conductivity and density of the rock and the heat capacity of the rock and geofluid. [1] The term η describes the uniformity of flow across the fracture $(0<\eta\leq 1)$.

A generalized drawdown curve is shown in Fig. 2 which provides estimates of reservoir lifetime for specified ideal fracture sizes and production rates.

Fluid chemical composition is another matter. Because the circulated water is not indigeneous to the natural environment, rock-water reactions will occur which may produce substantial changes in composition. Deeper, hotter reservoirs should also have higher solubilities and reaction rates. Although these effects are necessarily site specific, large amounts of non-condensable gases are not anticipated but silica and/or carbonate scaling may be a problem particularly as rock-water temperatures rise. However, field experiments at the Fenton Hill site have not shown any tendency for scaling in process equipment including heat exchangers and only minute amounts of dissolved gases. [3]

Water loss by permeation into the formation surrounding the hydraulic fracture system can be important for economic reasons. For example at Fenton Hill, water availability is poor and make-up usage becomes an important practical as well as economic consideration. Early field tests of the reservoir have indicated that acceptable loss rates of less than 40 ℓ/m (10 gpm) may be possible during extended pressurization of the fractured system. Consequently, the need for downhole pumping to reduce fluid pressures and thus lower permeation rates may not be necessary.

3. POWER CYCLE OPTIONS

Rankine cycles have been used for power production with water as the working fluid, particularly when natural steam is available. For water-circulated hot dry rock reservoirs, steam vapor could be created by flashing the geothermal fluid. Then, the produced saturated steam would be used to drive a turbogenerator with the unflashed liquid fraction being added to the condensate for reinjection into the HDR reservoir. Binary-fluid cycles employing non-aqueous working fluids are alternatives to single or multiple flash systems. A binary-fluid cycle involves a primary heat exchange step where heat from the geothermal fluid is transferred to another fluid, which is then expanded through a turbogenerator, followed by a condenser/desuperheater for heat rejection to the environment. The cycle is completed by pumping this condensate up to the maximum operating cycle pressure and returning it to the primary heat exchanger. A dual-flash steam cycle and a binary-fluid cycle employing a tube and shell primary heat exchanger are shown schematically in Fig. 3. Non-aqueous working fluids with high vapor densities require smaller turbines and condenser flow areas than do the low-pressure steam turbines employed in flashing systems of the same power output. This is particularly true where heat rejection temperatures of 30°C or less exist. Flashing cycles are, of course, simpler in that they do not require a primary heat exchanger.

Detailed calculations of binary-fluid Rankine cycle performance have been performed by Milora and Tester [4] and are compared to flashed steam cycles. For low-temperature resources (below 200°C) binary cycles provide higher utilization factors than a flashed steam plant. The utilization factor (η_u) is a measure of a system's ability to convert the available thermal energy of the geothermal fluid to electrical energy. For a 200°C resource temperature a properly designed binary plant has a η_u of 70.6% while a dual-stage flash has 59.8%. These values are for a condensing temperature of 26.7°C. If the condensing temperature for the steam is raised to 37.8°C (a more realistic value for steam) its performance drops to 52%. The binary cycle has a similar advantage over flashed steam at 150°C resource temperatures. The main reason that steam requires a higher condensing temperature is because of the practical limit on the exhaust end area of the turbine. This is illustrated by Table 1 where a figure of merit, proportional to exhaust end area is shown for several working fluids. The exhaust end size for water is several times higher than that for higher density non-aqueous fluids. It should be pointed out that it is very difficult and costly to attempt to achieve the 26.7°C condensing condition with water. When higher condensing temperatures are used this reduces the total cycle temperature difference and performance. Consequently, for these conditions, binary-fluid cycles have a potential performance advantage over steam cycles.

A 60 kW(e) scale model power system was designed to operate with fluid produced by the LASL HDR reservoir at Fenton Hill. At this site, the ambient air temperatures vary from -20°C to +27°C with an average annual value of about 3°C. This is a relatively low heat sink temperature and even with dry cooling should provide the potential for achieving lower condensing temperatures and higher efficiencies than are practical for steam flashing systems.

4. WORKING FLUID CHOICE

A large number of hydrocarbons, fluorocarbons, and other organic working fluids have been examined for the potential use in low-temperature power conversion cycles as a replacement for water. For example, Milora and Tester [4] selected refrigerants, R-22 ($CHClF_2$), R-600a (isobutane, $i\text{-}C_4H_{10}$), R-32 (CH_2F_2), R-717 (ammonia, NH_3), RC-318 (C_4F_8), R-114 ($C_2Cl_2F_4$) and R-115 (C_2ClF_5) in their studies to provide a range of properties including critical temperature and pressure, and molecular weight. In addition, Shepherd [5] compared the performance of R-21 ($CHCl_2F$), R-600a (isobutane) and Fluorinol (tri-fluoroethanol) and Eskesen [6] considered a number of hydrocarbons including propane (R-290), propylene (R-1270), isobutane, n-butane (R-600), isopentane, and n-pentane as well as R-115, R-22, R-32, and R-717. All of these compounds have relatively high vapor densities at heat rejection temperatures as low as 20°C and would result in very compact turbines in comparison to steam turbines of similar capacity.

In selecting non-aqueous working fluids for power cycle applications, turbine sizes must be small to reduce costs because of the economic trade-off between the additional heat exchange surface area required for binary-fluid cycles with the much larger and more costly turbines required in steam flashing systems.

Furthermore, it is important to operate turbines at high efficiency. A similarity analysis of performance shows that turbine efficiency is essentially controlled by two dimensionless numbers involving four parameters: (1) blade pitch diameter; (2) rotational speed; (3) stage enthalpy drop; and (4) volumetric gas flow rate (Baljé [7], Eskesen [6], Shepherd [5]). This assumes that Mach and Reynolds number effects can be neglected. For operation at maximum turbine efficiency the relationship among these parameters is specified; therefore, turbine sizes and operating conditions and consequently costs can be estimated. For fluid screening purposes. a generalized figure of merit ξ which scales directly with turbine size was developed by Milora and Tester [4]. ξ is expressed as an explicit function of the fluid's molecular weight M, critical pressure P_c, and reduced vapor energy density $h_{fg})_r/v_g)_r^{sat}$ where $h_{fg})_r = h_{fg}/RT_c$ is the reduced latent heat and $v_g)_r = v_g/v_c$ is the reduced saturated gas specific volume evaluated at the condensing temperature T_{cond}. Table 1 presents values of ξ for water and a number of hydrocarbon and fluorocarbon working fluids.

The organic fluids described in Table 1 obviously offer a significant reduction in turbine size. For example, a 100 MW(e) capacity plant designed for a 150°C liquid-dominated resource would require numerous, large turbine exhaust ends with steam flashing whereas a single exhaust end would be possible in an ammonia binary cycle. It should again be emphasized that organic turbines have not been manufactured with capacities larger than about 1 MW(e) while low-pressure steam turbines for geothermal operations with 50 MW(e) capacity have been commercially produced for a number of years. In fact, only one organic binary cycle using geothermal water at 80°C has been in commercial operation (Moskvicheva [8] and Vymorkov [9]). Several small systems ($\sim$ 100 kW(e) have been built by Barber-Nichols for geothermal demonstrations, including an isobutane binary, a direct-contact isobutane binary, and a R-114 binary. A number of others have been constructed for solar Rankine cooling and waste heat recovery systems using hydrocarbon and fluorocarbon working fluids. Nevertheless, Holt and Ghormley [10] and Eskesen [6] suggest that axial and radial flow turbines designed for capacities up to 50 MW(e) with non-aqueous fluid service will require only modest engineering developments. For example, careful design to keep inlet and exhaust pressure losses at a minimum as well as the development of adequate seals will be necessary.

In comparing the performance of low-pressure steam turbines to organic units of similar capacity the large differences in fluid densities at exhaust conditions, moisture content during expansion, and stage enthalpy drops or isentropic expansion work cause significant differences in design. For example, in low-pressure, condensing steam turbines it is necessary to increase exhaust end flow capacity, at the expense of efficiency, by allowing the ratio of blade height to pitch diameter (h/D_p) to exceed its optimum performance value of $\sim$0.1. In large capacity units, blade lengths approximately one-third as long as the last stage pitch diameter are commonly found (see Eskesen [6]). Another factor, wet expansions in geothermal flashing systems can lead to severe turbine bucket erosion by liquid droplet impingement. In addition, these wet expansions also cause a decrease in efficiency requiring the use of moisture separators at each stage to improve performance. This can be completely avoided in organic binary systems by proper selection of working fluids and operating conditions.

Other factors besides desirable thermodynamic properties frequently determine practical working fluid choices. These include, fluid thermal and chemical stability, flammability, toxicity, materials compatibility (corrosion), and cost. Unquestionably, the one major disadvantage of hydrocarbons such as propane, pentane, and isobutane is their flammability and thus requirements of costly explosion-proof equipment and ventilating systems. Below 300°C, the rate of dissociation of ammonia to hydrogen and nitrogen is relatively slow and should not limit its use in power cycle applications. The situation with fluorocarbons is much more confused. Eskesen [6] cautions those who may consider using fluorocarbons for temperatures much above 125°C because of potential unstable behavior especially in the presence of oil, steel, or copper which may catalyze chemical decomposition. However, extensive evaluation of a number of fluorocarbons for geothermal, solar, waste heat recovery, and automotive applications by Allied Chemical (Murphy [11]) and Monsanto (Miller, Null, and Thompson [12]) suggest that acceptable operation may be possible at temperatures well above 200°C.

Thermal stability studies of fluorocarbons have been largely directed at their applications in hermetically-sealed, domestic and industrial refrigeration systems which are expected to operate with little or no maintenance for

20-year periods. Thus these applications have imposed very stringent requirements and it is improper to evaluate fluorocarbon working fluids for power cycle applications on the same basis as for refrigeration systems. Hydrocarbon molecules nearly saturated with fluorine tend to be the most stable. For example RC-318 (C_4F_8) and R-115 (C_2ClF_5) have been tested for extended periods at 200°C in the presence of iron, steel, and copper with no observable decomposition. Very stable behavior is also observed when chlorine atoms are not present, for example R-32 (CH_2F_2). However, even R-113 ($C_2Cl_3F_3$) has been shown to be stable at 200°C for 10,000 h when exposed to carbon steel. Another factor to consider is the important effect oil seems to have on thermal stability. In most refrigeration systems, oil exposure occurs but in geothermal power cycles fluorocarbon pressures will always be above 1 atmosphere, so any leakage that occurs around seals, etc. will be out-leakage. Furthermore, as has been common practice in fossil-fired steam cycles, boiler feed makeup is used to replace lost or contaminated steam. Although costs associated with fluorocarbons are higher, some level of makeup should be economically feasible.

6. 60 KW SYSTEM DESIGN

The design specification for the 60 kW(e) plant called for a system utilizing current technology. The source temperature for design was 140°C with a 3°C dry bulk sink temperature. Source temperature limits were 110 to 180°C. The sink at this site is ambient air as cooling water was not available. One other constraint required that the power unit package would be incorporated on a skid and the entire plant would be easily transportable from one location to another.

To establish a system configuration that best met the requirements listed, several binary-fluid cycles were studied. The cycles evaluated a number of potential working fluids. Initially the cycles were screened using assumed component performance efficiencies and as the one or two best fluids emerged more precise component efficiencies were established to clarify the final selection. For any system the primary element in obtaining optimum performance is the working fluid selected. The selection of the fluid is influenced by the source and sink temperatures, system size and related component performance and constraints such as "current technology."

In the evaluation of working fluids the relation of the enthalpy-temperature profile during preheating and boiling of the fluid to that of the geothermal fluid is of paramount importance in obtaining a high utilization efficiency. This relationship can result in the choice of a fluid whose actual cycle efficiency is lower than others because the combined effect of a good preheating/boiling match with power cycle efficiency determines the best utilization efficiency. The ideal fluid would have a profile that paralleled the geothermal fluid temperature-enthalpy curve, and would allow the geothermal fluid to be cooled to a temperature just above the condensing temperature. This fluid of course would have a cycle efficiency equal to or better than any other fluid. The fluids available are not perfect; however, some of the available fluids if used in a supercritical cycle can approach this match with the geothermal fluid (water). Milora and Tester [4] show the relationships of cycle efficiency and temperature-enthalpy match and the resulting utilization efficiencies for numerous fluids.

The evaluation of fluids for the 60 kW(e) system started with two organic hydrocarbon refrigerants R-32 and R-115, both of which can operate supercritical with the available source temperature. A problem immediately emerged, caused by the required boiling pressure level. The optimum pressure for R-115 was

7.9 x 10^6 Pa (1150 psia) and for the R-32,10.3 x 10^6 Pa (1500 psia). These pressure levels and the head rise required to achieve them would require the development of special pumps. Working pressure level was arbitrarily dropped in half and cycle performance again evaluated. At the reduced pressure level, there was still a problem. Although pumps were available to meet the lower pressure and flow requirements, pump efficiencies of greater than 50% were needed. Suitable pumps that have low flow rates with high head and low NPSH capability were not available. With expected pump efficiencies of less than 50% and high pump work duties, the R-32 and R-115 cycle performance can be matched by an R-114 cycle operating subcritically with lower pump work requirements. In a supercritical fluid cycle, the pump work contribution is large and thus cycle efficiency is very sensitive to pump efficiency.

R-114 turns out to be an excellent fluid for a Rankine cycle power plant of this size and requirements, and was selected for detailed calculations. The fluid is thermally stable at the peak temperatures and there is considerable industrial experience with it. At the required operating levels components with excellent operating efficiencies can be obtained. The final cycle selected is shown on Fig. 4. The bottom line for the system is a predicted cycle efficiency of 5.7%, a source utilization efficiency of 24.7% and a source production factor of 5.5 watt hours per kg. This performance is lower than predicted for similar cycle conditions for refrigerant R-114 by other investigators. A major factor in the lower number is the horsepower required for the air-cooled condenser. These numbers reflect all of the system parasitics. The effect of condenser performance and other components on overall performance are discussed more in the subsequent paragraphs on system component selection. Other significant factors include the lower turbine efficiency of 70% and feed pump efficiency of 62%. Much higher values would be possible in larger capacity units as discussed in Section 6.

The physical configuration of the R-114 system is shown schematically in Fig. 5. The major components include a feedpump, preheater, boiler, turbine, condenser, hot well and generator. To achieve a low system cost and permit a short fabrication cycle, off-the-shelf or catalog type items were selected wherever practical. The following paragraphs describe the hardware and discuss some of the alternatives considered in their selection.

The condenser was the one off-the-shelf component subjected to an in-depth design performance review. The air condenser proposed was a Halstead-Mitchell 200-A. Two of these units could be packaged on a 40-foot skid above the rest of the components. These off-the-shelf units did not provide good performance as they required 18.6 KW of power and would produce a condensing temperature 22°C above ambient.

The lowest parasitic power solution is to provide enough transfer area for natural convection cooling. This solution was not acceptable as a self-contained portable package was required and the cost would be prohibitive. The only practical solution for this system was to evaluate various condenser configurations and try to optimize the condensing temperature versus fan power relationship. Figure 6 shows system power output as a function of condensing temperature and fan power required for different condenser areas. At a 21°C condensing temperature, for example, the required fan power can be reduced from 18 KW to 2.5 by doubling the area. By combining the power output curve of the generation with the required fan power as a function of the matching condensing temperature, a net power curve is produced which readily shows the optimum fan power for a given condenser. For packaging reasons, a 320A unit was chosen which has twice as many tube rows. This provided twice the area although not as efficiently as using four 200A's. These bigger units optimize to give an approach temperature of 16.7°C at a power level of 10 KW or less.

There is one aspect of this off-the-shelf condenser that was not optimized for the working fluid and that is a manifolding configuration that would give a lower pressure drop.

The preheater selection was straightforward. The unit is a counterflow finned tube within a tube configuration fabricated by Thermal Fintube International. The unit has a very low pressure drop, is easily fabricated for high pressure levels and is cleanable.

Boiler selection was based on past experience. Two configurations were considered, one being a pool boiler and the second a single pass counterflow exchanger. Both configurations are capable of low pressure drop and low pinch temperature differentials. With the wide range of operating inlet temperature conditions specified, a pool boiler was chosen because its performance is much better at off-design point conditions. The requirement to handle geothermal fluid pressures up to 1500 psig prevented the utilization of various off-the-shelf refrigeration water chillers but Precision Heat Exchanger Co. promised to fabricate the required unit in an acceptable time period.

A positive displacement pump would have provided the system good pumping efficiency but these pumps require a boost in inlet pressure in order to prevent cavitation and insure proper operation. The use of two pumps and their associated mechanical drives is not warranted over one primary centrifugal pump. The pump selected is a Gould 3935 series which has an NPSH capability of less than 5 ft. and can deliver the required work at an efficiency of 62%.

The selected working fluid led to a choice of turbine types. Specific speed and diameter calculations for the turbine showed that either a radial in-flow wheel or a partial admission axial flow wheel could be used with good efficiency. A radial wheel would turn about 16,000 rpm and produce an efficiency of around 75%. The partial admission axial wheel would produce a 70% efficiency with a shaft speed of 3600 rpm. The 16,000 rpm radial wheel would need a gear box and lube system which results in an output shaft efficiency around 71% which is not significantly better than the 70% axial which can drive a two-pole generator directly. Additionally the direct drive 3600 rpm turbine does not require a high speed shaft seal to prevent leakage of the R-114 fluid, thereby increasing reliability and life. The choice of the axial configuration was quickly made. Barber-Nichols is designing and fabricating the turbine/drive shaft assembly. The wheel has a pitch diameter of 42 cm, 110 blades and a blade height of 2.86 cm. The turbine and direct drive output shaft are supported on grease-packed antifriction bearings.

Control of the Rankine cycle power plant is very simple. A hot well, collecting fluid from the condensers, is monitored for fluid level. By controlling this fluid level through throttling, the pump flow rate and the working fluid inventory is maintained in balance throughout the system. This is the only control required for the working fluid. In this particular application generator speed is controlled by a governor that controls the amount of power fed to the load. Additionally the system will have safety type controls that will cause shutdown when selected parameters exceed preset limits.

6. EFFECTS OF PLANT SIZE

In scaling-up a 60 kW(e) unit to a 50 MW(e) or larger plant, several important engineering design considerations appear. Some economy of scale would be anticipated up to 50 MW(e). But for larger capacities, the need for redundant, parallel heat exchanger, condenser, feed pump, and turbine units, as well as a complex wellhead-to-plant fluid distribution system, will reduce any further economy.

Feed pump and turbine performance is also dependent on capacity. Table 2 gives approximate optimum efficiencies expected in practice for units varying from 100 kW to 10 MW or greater. Furthermore, as unit capacities increase, working fluid choice needs to be more carefully made. As seen in Table 1, turbine exhaust end size can vary by more than an order of magnitude for the hydrocarbons and fluorocarbons listed. Because exhaust end area will strongly influence costs, an economic incentive exists to minimize turbine size while maintaining cycle performance. For example, R-114, although very suitable for a 60 kW(e) system might not be the best economic choice for a 50 MW(e) plant.

7. CONCLUSIONS

Engineering design criteria relevant to power conversion using hot dry rock reservoirs were presented to illustrate the options available. In particular, the choice between a multistage steam flashing system and a binary-fluid Rankine cycle employing a non-aqueous organic working fluid rests largely on the interaction of a number of reservoir and site conditions, including geothermal fluid temperature, composition, and anticipated drawdown, ambient temperatures for heat rejection, and water availability. For the conditions at the Fenton Hill HDR site, a dry-cooling, R-114 binary system has a relatively high performance for a unit with a nominal installed capacity of 60 KW(e). At higher capacities, other organics with smaller turbine exhaust end sizes might be preferred to reduce turbine costs. Furthermore, at these higher capacities, pump and turbine performance improves considerably such that higher pressure supercritical operation may be warranted. Optimization of a dry-cooling system for the R-114 cycle quantitatively illustrated the performance tradeoff between lower condensing temperatures and higher cooling fan parasitic power losses.

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TABLE 1

TURBINE SIZE FIGURE OF MERIT AT VARIOUS CONDENSING TEMPERATURES (T_{cond})

$\xi \propto$ Turbine exhaust end area

$$\xi = \frac{\sqrt{M}}{P_c}\left[\frac{v_g)_r^{sat}}{h_{fg})_r}\right]_{T_{cond}}$$

$(g/g\ mole)^{1/2} bar^{-1}$

Compound	Formula	T_{cond} = 26.7°C(80°F)	T_{cond} = 37.8°C(100°F)
R-717	NH_3 (ammonia)	0.177	0.133
R-32	CH_2F_2	0.223	0.173
R-1270	C_3H_6 (propylene)	0.258	0.204
R-290	C_3H_8 (propane)	0.327	0.249
R-22	$CHClF_2$	0.411	0.308
R-115	C_2ClF_5	0.649	0.487
R-600a	C_4H_{10} (isobutane)	0.881	0.734
R-600	C_4H_{10} (n-butane)	1.114	0.711
RC-318	C_4F_8	1.628	1.170
R-21	$CHCl_2F$	1.962	1.413
R-114	$C_2Cl_2F_4$	2.246	1.604
Isopentane	C_5H_{12}	3.210	2.490
n-pentane	C_5H_{12}	3.770	2.639
Fluorinol	$C_2Cl_3H_2OH$	5.090	3.902
Water	H_2O	30.71	17.47

M - molecular weight

P_c - critical pressure

$v_g)_r^{sat}$ = reduced specific gas volume at saturation $= (v_g/v_c)^{sat}$

$h_{fg})_r$ = reduced enthalpy of vaporization = h_{fg}/RT_c

TABLE 2

COMPONENT EFFICIENCIES

Unit Size (kw)	Turbine (%)	Feed pump (direct drive) (%)
100	70	62
600	80	75
1500	85	80
$\geq$10000	85	80

HOT DRY ROCK GEOTHERMAL CONCEPT

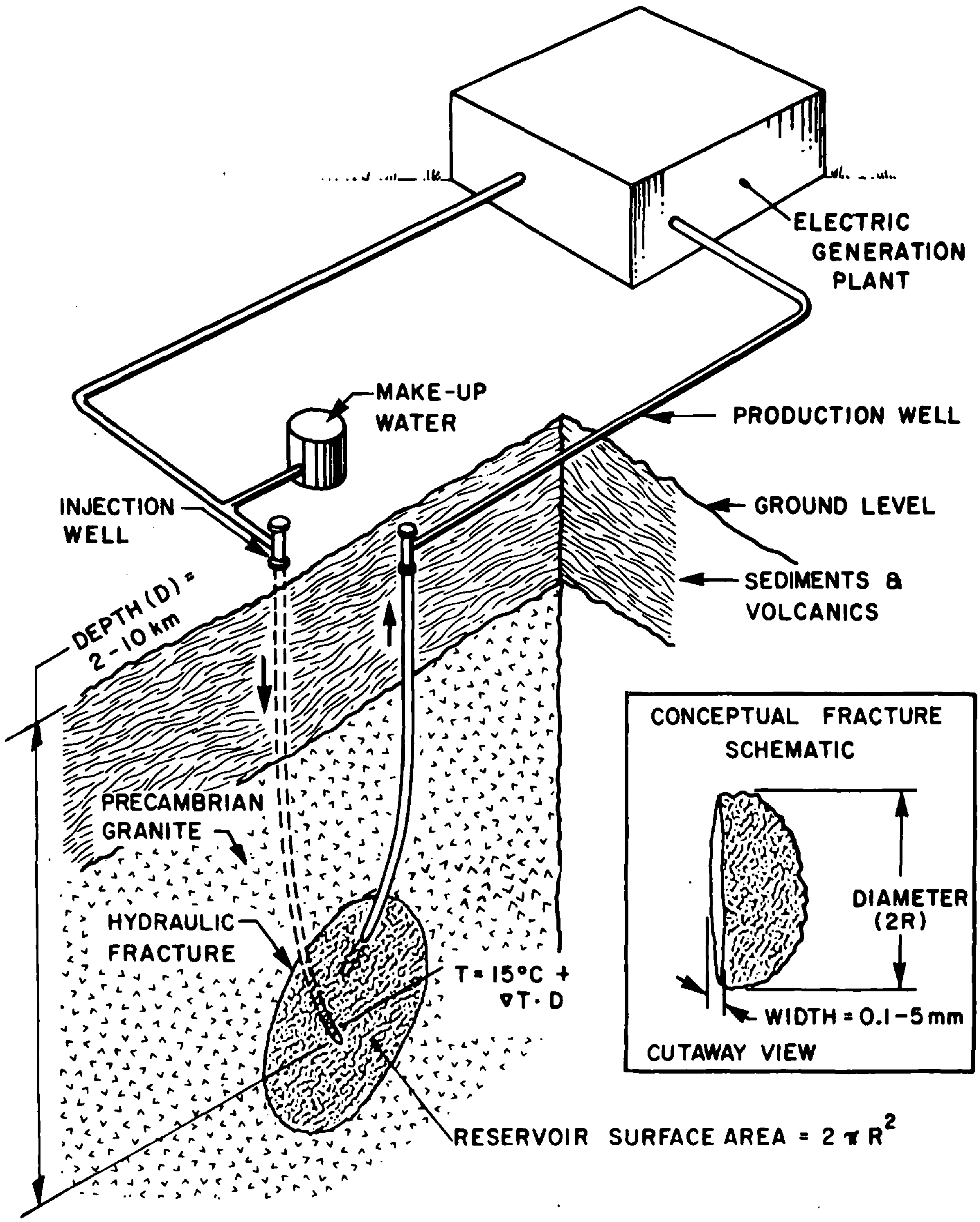


Figure 1. HDR concept for low permeability formations using hydraulic fractures.

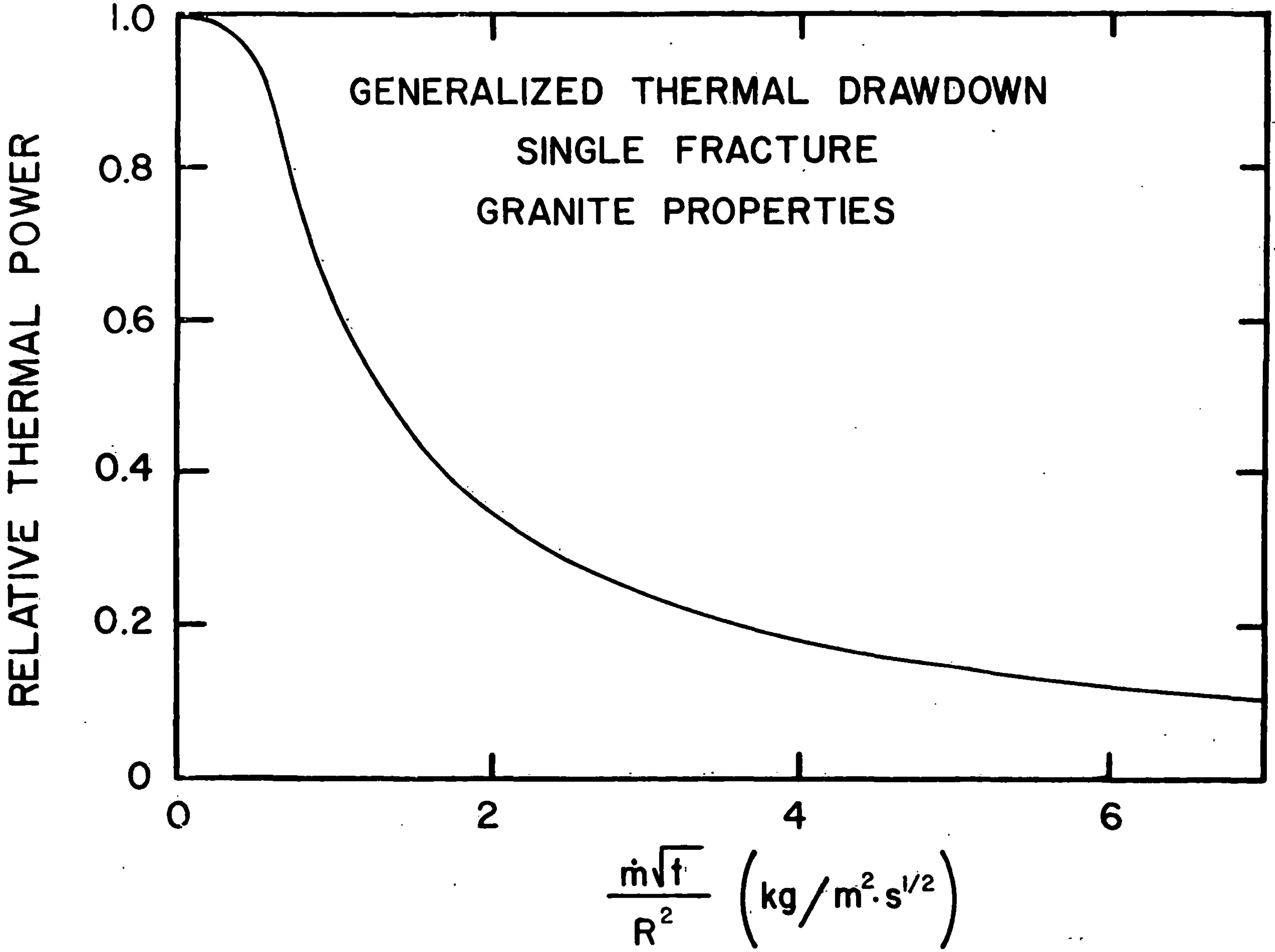
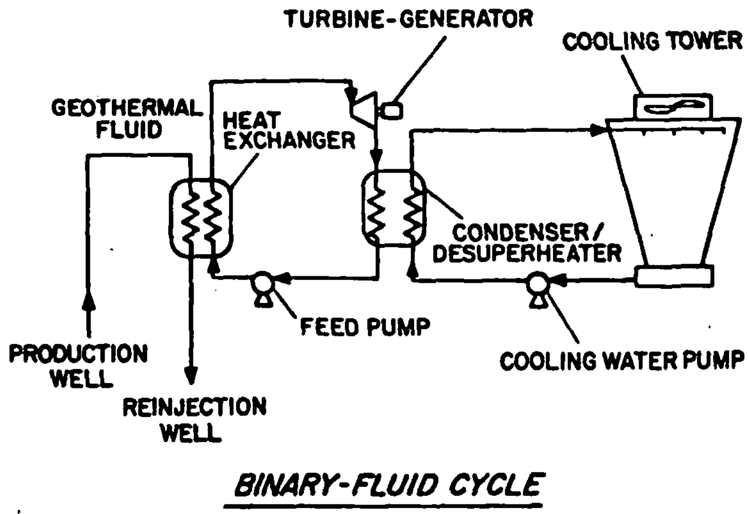


Figure 2. Thermal drawdown for a single fracture with uniform flow and thermal conduction only, no thermal stress cracking.



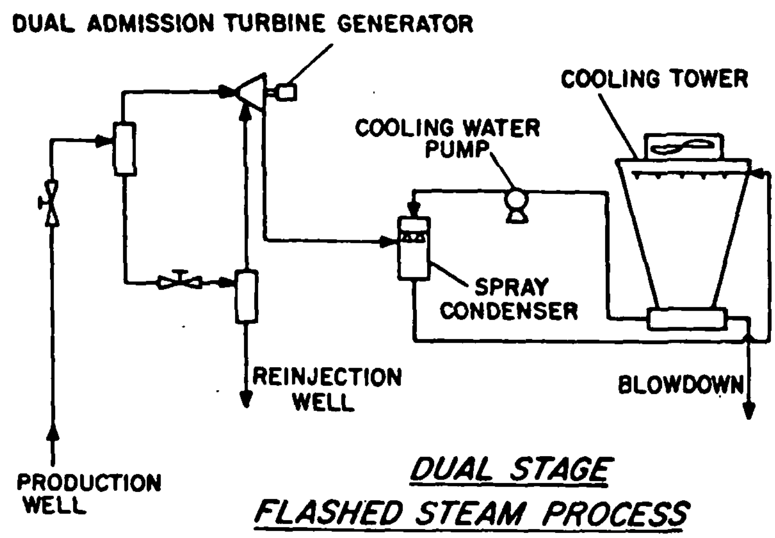


Figure 3. Power cycle concepts.

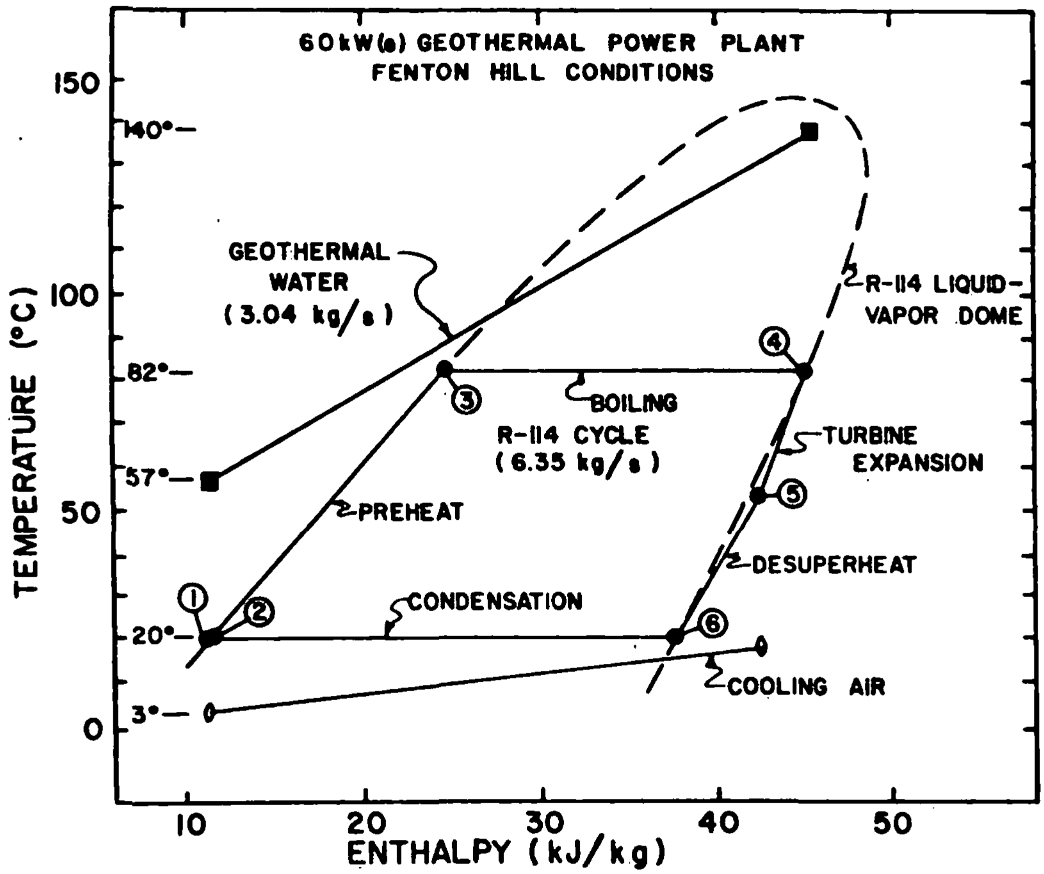


Figure 4. Temperature enthalpy diagram at design conditions. Cycle state points and assumptions listed below.

State Point	Pressure Pa x 10^{-4}	Temp °C	Enthalpy kJ/kg
1	18.7	19.4	11.34
2	120.8	19.9	16.68
3	97.1	82.2	25.22
4	95.0	82.2	45.89
5	24.1	52.8	43.07
6	24.1	19.4	38.15

Component Efficiencies	
Turbine	70%
Pump	62%
Gear Drive	99%
Pump Drive	98%
Generator	90%

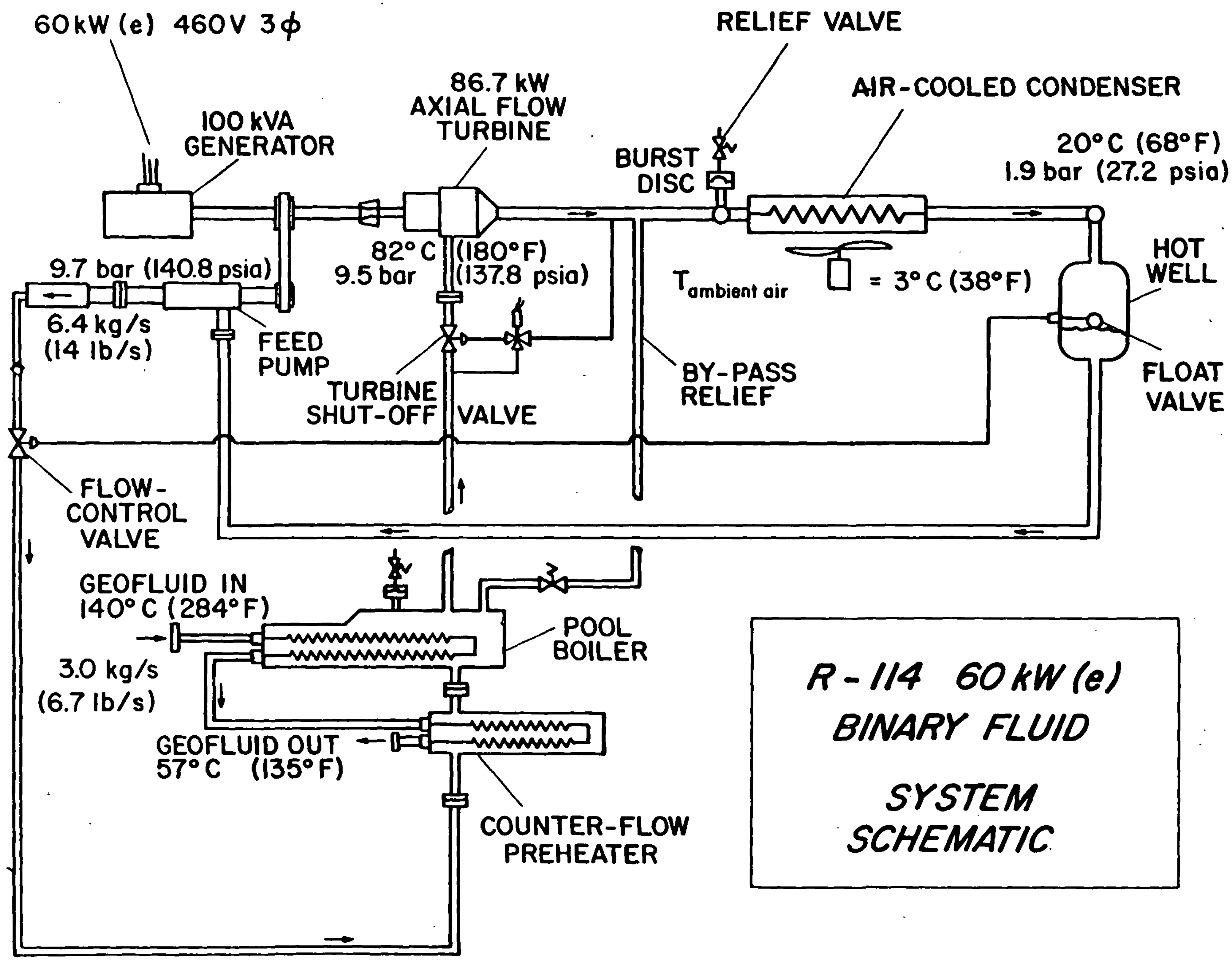


Figure 5. Schematic drawing of R-114 60 kE(e) binary-fluid power cycle.

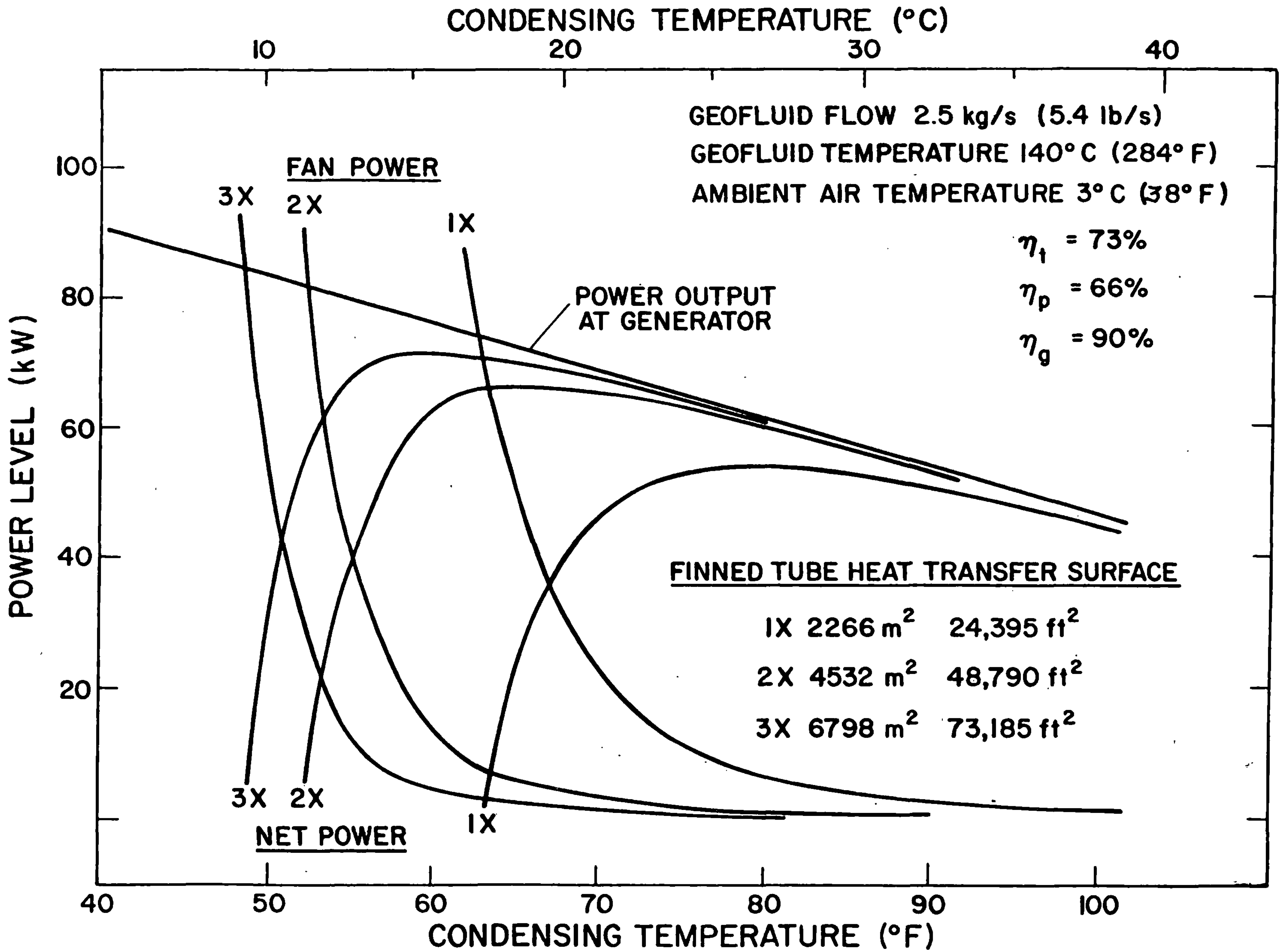


Figure 6. Condenser parameter influence on R-114 binary-fluid cycle performance.

The Future of Hot Dry Rock Geothermal Energy Systems

M. C. SMITH

I. INTRODUCTION

Where a natural ground-water circulation system does not exist to form and maintain a hydrothermal reservoir, the obvious method of extracting heat from the earth's crust is to imitate nature by creating one. This involves introducing a heat-extraction fluid into the hot rock, somehow insuring that it flows over a sufficient surface area to extract heat from the rock at a useful rate for a usefully long time, recovering the heated fluid, and finally extracting the useful heat from the fluid and either using the heat directly or converting it to some other form of energy. Many variations are possible in systems of this general type, whose individual utilities will depend jointly upon the characteristics of the local subsurface geology and of the local market for energy. However, nearly all such systems will share several common characteristics.

A. The Fluid Used. Principally because of the large volume of fluid needed to transport heat at commercially useful rates and the fact that a significant fraction of this fluid will be lost from the system into rock even of extremely low permeability, a very inexpensive heat-extraction fluid is required. The obvious choice is water, whose physical and thermodynamic properties fortunately are favorable for this use. However, the remarkable solvent power and interactive chemical nature of water make it probable that its use will also usually result in systems problems associated with mineral dissolution and alteration, scaling, and corrosion.

B. Fluid Conservation. In most places even water is expensive, and in arid regions it is often essentially unobtainable in large quantity. To conserve both water and the heat that it may already have extracted from the reservoir, it will usually be

*Work performed under the auspices of the US Department of Energy.

important that the rate of fluid loss from the heat-extraction system be minimized. At least in the upper parts of the system, this may also be necessary to avoid aquifer contamination and to conform to National Environmental Protection Agency (NEPA) and other water-quality regulations.

C. Drilling. To have remained hot through geologic time, a geothermal reservoir must in most cases have been covered by a relatively thick insulating layer of rocks or sediments. Therefore, except in areas of active or recent volcanism, the openings required to introduce and recover the heat-transport fluid must normally be deep--commonly at least a kilometer or two. To excavate them by any means other than drilling would be prohibitively expensive, and for the foreseeable future the drilling equipment and techniques will undoubtedly be generally similar to those now used to exploit petroleum, natural-gas, and hydrothermal reservoirs. Further, to accommodate the rates of fluid flow required of a commercial energy system, the drilled holes must have relatively large diameters--probably of the order of 15 - 50 cm. Finally, to conserve water and heat and to avoid dilution by and contamination of aquifers above the reservoir, these holes will in general require casing, at least in their upper sections.

D. Heat-Transfer Surface. Because rocks and sediments are poor thermal conductors, to maintain an economically high rate of heat extraction from the geothermal reservoir will require that a large surface of the hot rock be in contact with the heat-transport fluid. As is further discussed below, creation of the necessary heat-transfer surface by drilling more, larger, or deeper holes, or by locally enlarging those of normal size, is in general so expensive that it cannot be justified by the value of the increased rate of energy extraction. Therefore, provision must usually be made to circulate water outside of the borehole, through either natural or manmade flow passages, where it will contact a surface area much larger than that of the wall of the hole itself.

E. Permeability and Void Volume. To extract heat at a high rate requires not only that a large volume of water move through the rock per unit of time but that it remain in the reservoir long enough to be heated to a usefully high temperature. To provide for the required flow rates and residence times, it is necessary that--locally--the permeability of the hot rock be high and the total volume of connected voids be large.

The general image of a hot dry rock energy system that emerges is, then, one or more deep, large-diameter, drilled and cased holes, through which cool water is introduced into a natural thermal reservoir and hot water or steam is recovered from it. Around the lower, hotter section of each hole, and connecting the holes if there are more than one, is an extended permeable region with large void volume and surface area and low flow-impedance, through which water injected at one location will circulate and from which most of it can be recovered through the same or another hole or holes.

II. HEAT EXTRACTION CONCEPTS

There are many ways in which the general requirements outlined above can be met. Which of these may be appropriate to any given local situation depends upon a number of variables, one of which, of course, is the technology that is available to satisfy an existing energy need in any of a wide variety of geographic and geologic environments. In this connection it is useful to examine the concepts, designs, advantages, and limitations of some of the many underground systems that have been or can be proposed for recovery of energy from hot dry rock geothermal reservoirs of several possible types.

More than anything else, it is the magnitude and distribution of permeability in the reservoir rock that controls the design of any heat-extraction system that might be expected to operate effectively in the reservoir. Accordingly, systems concepts will be discussed here in that frame of reference.

A. Very Low Permeability. When the initial permeability of the hot reservoir rock is of the order of a millidarcy or less, the fluid circulation required to create and maintain a productive hydrothermal reservoir does not occur naturally; heat transfer is primarily by conduction; and the possibility exists of producing a relatively simple heat extraction system from which the rate of fluid loss will be low.

1. Downhole Heat Exchangers. Most of the early and many of the recent proposals for extracting energy from hot dry rock have been based upon pumped or buoyant circulation of a heat-transport fluid through a heat-exchanger inserted into a water-filled borehole(1). In fact, the value of the heat conducted into a hole through the limited surface area of its own wall is in general insufficient to amortize the cost of drilling the hole, and the situation cannot ordinarily be corrected simply by additional drilling to enlarge or extend the hole. This may not be true if thermal conduction is supplemented by the circulation of steam or hot water through the borehole wall, as evidently occurs, for example, at Klamath Falls, Oregon(2). In that special case, a simple U-tube heat exchanger works effectively and economically, at least in large part because the well casing is usually perforated at the levels of two vertically separated aquifers, so that buoyant circulation of hot water through the well is made possible. However, in a formation of very low natural permeability, this type of circulation cannot occur at a usefully high rate unless the permeability around the wellbore has been increased artificially, by some means such as those discussed below.

To correct this deficiency in surface area, it is often proposed that the wellbore be enlarged locally, preferably to a degree sufficient to permit buoyant circulation of water within the cavity so that heat is transferred rapidly from the hole wall to the heat exchanger. One suggested method is to underream the hole mechanically, which is expensive (primarily because of the drilling rig required), quite limited in the degree of hole enlargement that is possible, and introduces some danger of "junking" the hole. Another is to "spring" the hole by detonating explosives in it, which is relatively inexpensive and leaves very little junk in the hole, but again is quite limited in the degree of hole enlargement that is possible. As is discussed below, this offers the additional attractive possibility of opening fractures outside of the enlarged borehole through which the heat-transport fluid can also circulate, but with the accompanying danger that--unless the properties of the explosive are well matched to those of the rock--a compacted zone of extremely low porosity may be created around the wellbore, which can prevent fluid circulation instead of enhancing it(3).

Principally because neither underreaming nor explosive springing can enlarge a borehole by more than a few hole diameters, it seems unlikely that either will normally be useful for creating cavities which are large enough to be used economically as heat-transfer pools for a downhole heat exchanger. However, at least in some types of formations, it may be possible to create openings that are large enough, by either solution-mining or water-jet drilling. The outstanding possibility appears to be in salt domes or thick, bedded salt deposits (Fig. 1).

Because of the low permeability of salt, large cavities in natural salt deposits are now used to store petroleum products, natural gas, and compressed air. Except where an old salt mine can be tightly sealed for this purpose, the usual method of creating the cavity is by dissolving the salt in water(4). Because solid salt is a relatively good thermal conductor, convective circulation of brine should be capable of transferring heat at a relatively high rate from the wall of such a cavity to the surface of the heat exchanger. Circulation of pure water or some other liquid through the heat exchanger would then transport heat to the surface without the corrosion and salt-deposition problems that would be expected in the well casing and surface plumbing if the brine itself were circulated.

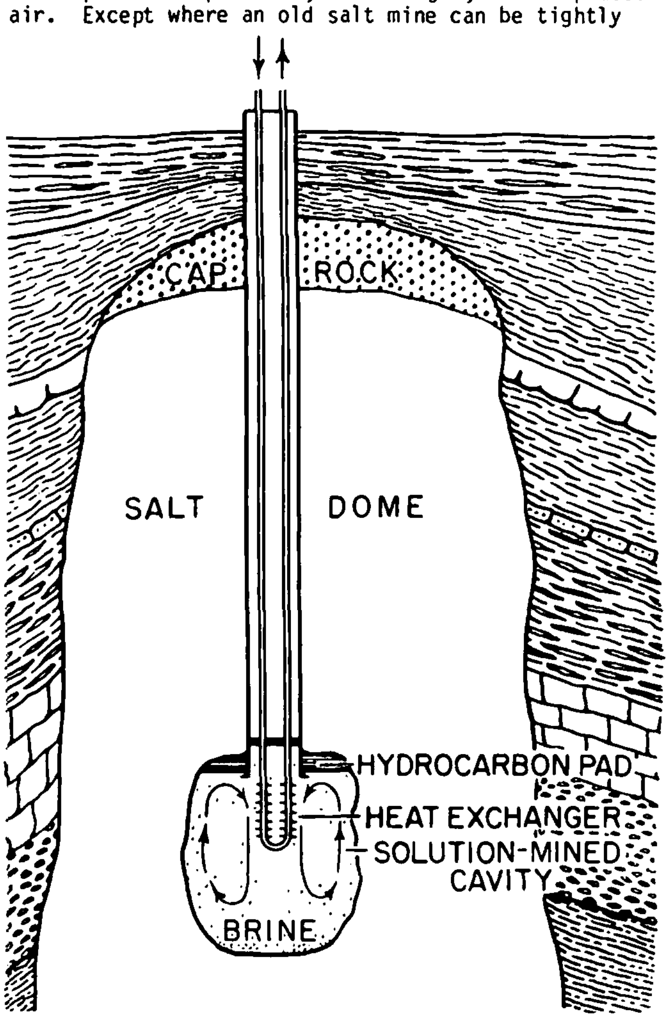


Fig. 1. Heat exchanger immersed in buoyantly circulating brine within a solution-mined cavity in a salt dome.

At least in principle, solution-mining of large cavities should be possible in other types of rock, for example in massive limestones, but--because solvents other than water would normally be required--it is unlikely that this would be economical. It is possible that a device such as the water-jet drill(5) might be used to produce a usefully large cavity by mechanically removing material from around the borehole. Again, however, it is doubtful that enlargement beyond a few hole-diameters would be practical even with water jets, except perhaps in very weakly cemented formations--where the possibility of subsequent caving may make the creation of a large cavity undesirable.

With the possible exception of solution-mined cavities in salt deposits, the insertion of downhole heat exchangers to recover energy from low-permeability formations appears unlikely to be economical.

2. <u>Creation of Local Permeability.</u> An alternative to increasing the heat-transfer area by enlarging a borehole is to create a region of high permeability around the hole, through which a heat-transport fluid can be circulated. There are a number of ways in which this might be done.

One possible method is to introduce through the borehole some chemical agent which will selectively attack one or more of the minerals present in the rock--for example, an acid to attack calcite fillings in ancient fracture systems. It is evident that, to create the connected void system required to increase permeability, the mineral that is to be removed must itself exist as a well-connected phase in the rock. In gneissic and other layered structures, and in the cases of veins, fracture fillings, and grain-boundary segregates, this may be true at relatively low overall concentrations of the reactive mineral. However, when that mineral exists as nearly equiaxed, more uniformly distributed grains, a high degree of interconnectedness cannot be expected unless its concentration is of the order of 40% or more by volume--which would represent an unreasonably large fraction of the rock to be attacked and removed chemically. The distribution as well as the composition and amount of the minerals present must, then, be taken into account when a leaching process is considered for creating permeability--although this may be less important if the object of the chemical treatment is simply to reduce flow-impedance through a pre-existing system of fine cracks or poorly connected voids.

More commonly, the methods proposed for creating permeability around a borehole involve fracturing the rock mechanically rather than attacking it chemically. Of these methods, the detonation of chemical explosives in the borehole is the most frequently suggested. This is a familiar and frequently successful technique for stimulating production from petroleum and natural-gas wells, and its use for that purpose in geothermal wells is now being investigated in both Italy and the United States. Because the explosive can be inserted and detonated on a wire line, equipment requirements and fracturing costs are relatively low, and little junk is left in the hole.

When the shape of the stress pulse from an explosion is well matched to the properties and structure of the rock, the detonation is expected to produce a set of essentially radial fractures extending outward from the borehole (Fig. 2). Because the volume of explosive that can be inserted is limited by the dimensions of the borehole, the radial extent of these fractures is also limited--and fracture density in general decreases exponentially with radial distance from the hole. In most types of rock, however, the original cracks can be subsequently extended either by repeated explosions(3) or by the use of fluid pressure(7). Unfortunately, if the pulse shape does not match the rock properties, rock close to the borehole may be crushed and compacted, actually reducing its permeability by collapsing any voids that were initially present in it(3). Further, any anisotropy or inhomogeneity in the wall rock may be reflected in pronounced asymmetry of the fracture pattern produced, and in large local variations in permeability(3). Fortunately, a wide variety of explosives and techniques for using them has been and is being developed to deal with such problems, including the use of slurries, liquids, gas mixtures, propellants, shaped charges, and gun-fired projectiles,

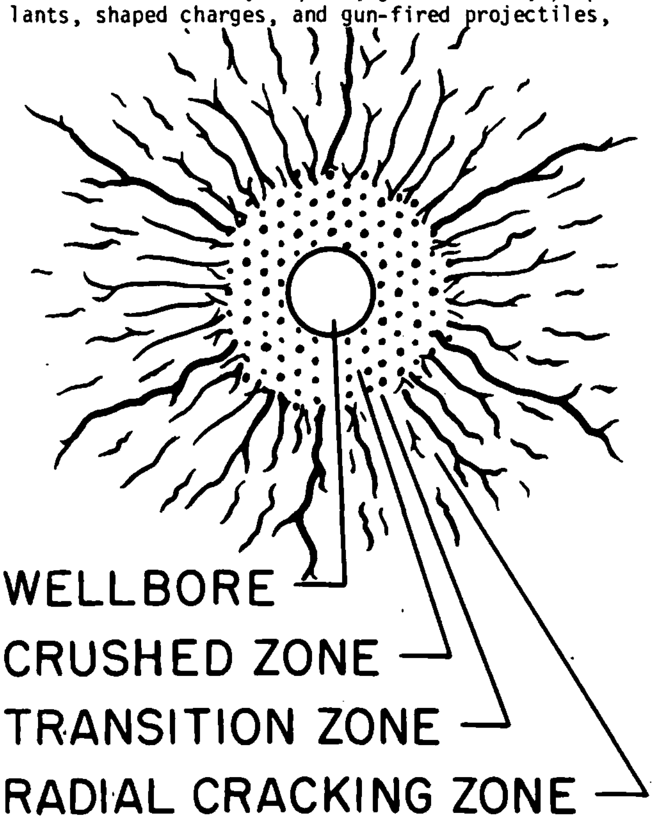


Fig. 2. Radial fracture pattern produced by detonation of a chemical explosive in a borehole (after Ref. 6).

and controlled decoupling of the explosion from the borehole wall(6). However, problems remain with regard to the stabilities of most explosives in the higher temperature geothermal environments, and to matching the properties of the explosive to the characteristics of the in situ rock--which are not often known in detail before fracturing is attempted.

The extreme in explosive fracturing is represented by the downhole use of nuclear explosives, with which there is some published U.S. experience from the Plowshare gas-stimulation program. The possible application of such explosives to the development of geothermal energy systems has been discussed by Burnham and Stewart(8), Ramey et al(9) and others. Their principal advantage is that very large amounts of explosive energy can be generated by a relatively small nuclear device, creating cavities large enough so that caving of the roof subsequently occurs to produce rubble-filled "chimneys" of considerable volume (Fig. 3). By circulating water through the rubble--or introducing water and recovering steam--extraction both of natural geothermal heat and of heat deposited by the explosion can evidently be

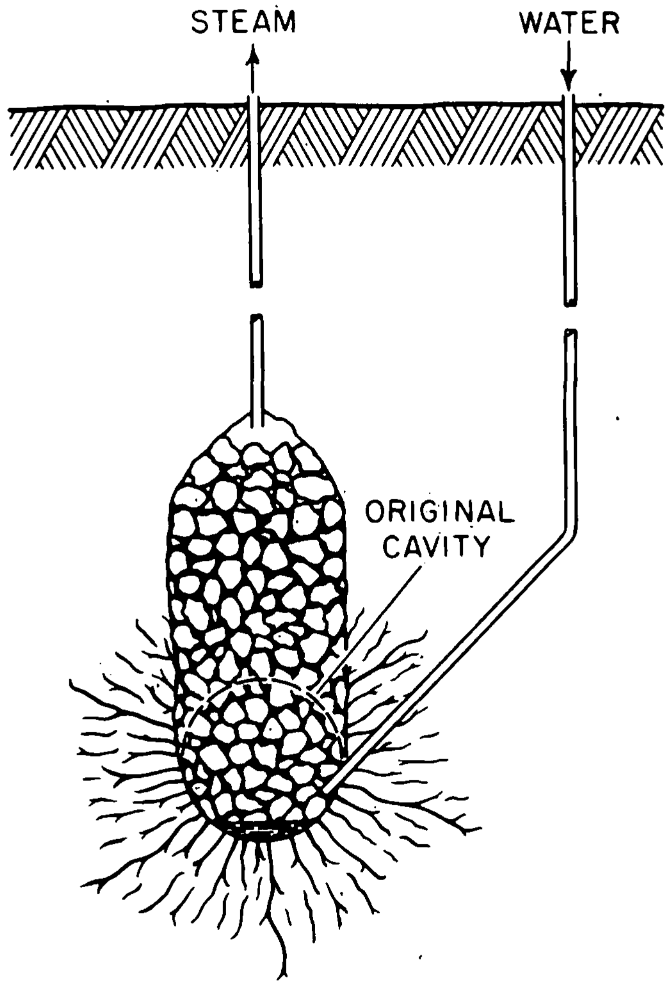


Fig. 3. Rubble-filled chimney produced by caving of the roof into a cavity produced by a nuclear explosive.

quite efficient(10). From the engineering and the economic points of view, hot dry rock systems of this type appear feasible. However, environmental concerns arising from the earth shocks produced by large explosions and from the necessity of completely containing radioactive debris(11), together with a widespread emotional reaction against use of nuclear explosives for any purpose, make it unlikely that this method of creating geothermal energy systems will be attempted in the United States in the foreseeable future. That may not always be true everywhere(12), and it is possible that it may yet be tried in other countries or somewhere under the oceans.

At least three methods have been suggested for fracturing rock around a borehole by pressure pulses produced mechanically or hydraulically rather than by an explosion. Armstead(13), has proposed use of a device resembling a pile-driver, which would strike the upper surface of a weighted piston mounted in a sleeve at the top of a water-filled well casing. This would produce a shock wave that would travel down the water column to interact with exposed rock surfaces below the bottom of the casing. By use of a high-pressure pump, water would be injected at the wellhead to raise the piston back into the striking position, and this could be repeated any number of times to form additional fractures or to extend those already present. A somewhat similar idea was at one time discussed at Los Alamos Scientific Laboratory (LASL). This involved creation of a pressure pulse by the sudden release into the wellbore of a controlled volume of pressurized water through either a quick-opening valve or a blowout diaphragm. Neither this nor Armstead's impact system has yet been tried experimentally, and questions remain as to whether a usefully large pressure pulse could be developed without damaging the wellhead, the casing, or the cement around the casing, and whether the attenuated pulse reaching the bottom of the hole could create and extend fractures. In the meantime the ENEL Geothermal Research Center in Italy[1] has proposed the less-violent technique of using ordinary pumps to produce pressure cycles in the borehole, taking advantage of the low-cycle fatigue behavior of rocks discussed by Haimson et al(14).

Other suggested methods of pressurizing the borehole wall either quasistatically or dynamically include the use of downhole mechanical or hydraulic jacks and of repeated spark discharges in the water-filled borehole.

At LASL, the use of a pumped fluid to create permeability around the borehole is being investigated(15). This technique, "hydraulic fracturing," is familiar and widely used for stimulating production of petroleum, natural-gas, and water wells. It involves isolating a section of the borehole by the use of temporary seals called "packers," then pressurizing it--usually by pumping water down a tubing string that penetrates the upper packer--until sufficient circumferential tension is developed to split the wall of the hole. The result is a thin crack, normal to the least principal earth stress (and therefore, at the depth of a geothermal system, expected to be planar, vertical, and with a specific azimuthal orientation controlled by the local tectonic stress field, as is suggested by Fig 4). Once formed, because of the stress concentration at its edges, such a crack can be extended over very large distances simply by continuing to pump fluid into it, and (in gas-stimulation experiments) there is evidence that hydraulic fractures with radii of the order of 2 or 3 km have been produced(16). This represents a very large heat-transfer surface which, however, will be useful for heat exchange only if fluid flow can be maintained through the fracture at reasonable rates and pumping pressures. Recent LASL experiments are encouraging in this regard in indicating that, in the granitic rocks being investigated there, the fractures are held open--"self-propped"--by a natural mismatch of their opposite surfaces(17). Further, probably because of thermal-contraction effects, the resistance to fluid flow through them has decreased spontaneously as heat was extracted from their surfaces. If these effects are finally insufficient to permit the required rate of fluid flow, the possibilities remain of holding the cracks open with fluid pressure, of injecting proppant particles into them, or of increasing their permeability either by chemical attack or by fragmentation with explosives. It is also possible, as has been suggested independently by R. M. Potter of LASL and by C. B. Raleigh(18) of the U.S. Geological Survey, to produce a set of parallel fractures by repeated hydraulic fracturing from a single inclined borehole and intersect several of them with a second hole. This would increase the available heat-transfer

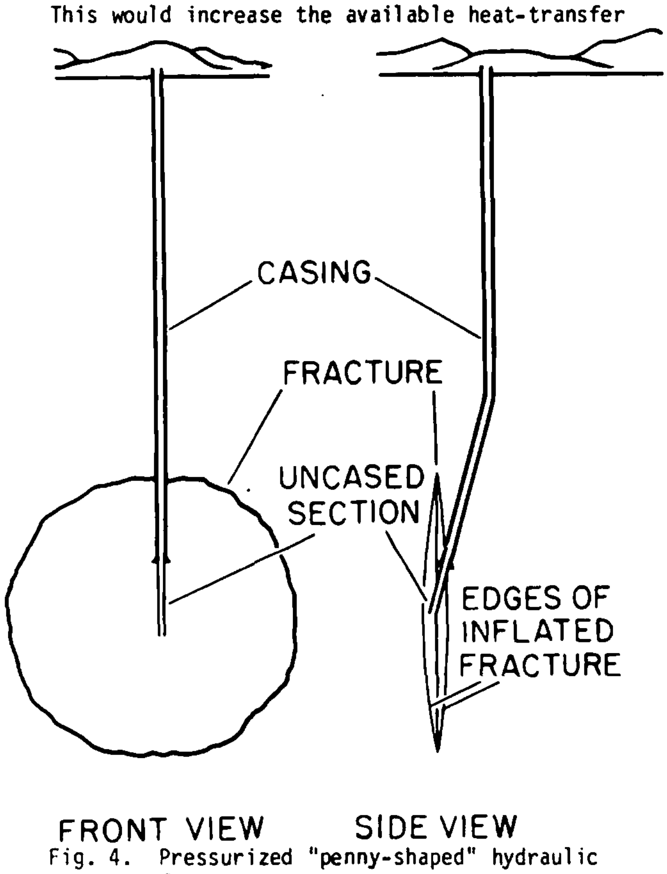


Fig. 4. Pressurized "penny-shaped" hydraulic fracture.

[1]Centro di Ricerca Geotermica, Ente Nazionale per l' Energia Elettrica.

surface and reduce the overall flow-impedance of the fracture system by distributing the total flow among a number of parallel paths.

Once fluid flow through and heat extraction from the permeable zone around a borehole have begun, thermal contraction is expected to produce additional cracks normal to the rock surfaces initially exposed to the fluid(19). With continued cooling, these may open widely enough--to widths of the order of 0.5 mm or more(20)--so that water will also circulate through them. If this occurs, the creation of new flow channels and heat-transfer surfaces should progressively reduce flow impedance, increase temperature of the recovered fluid, and extend the useful life of the system(21,22). In principle, this mechanism alone could be used to "grow" a permeable zone around a borehole. However, until a large increment of heat-transfer surface had been produced, the total rate of heat extraction would remain low, so that the initial growth of the crack system would be very slow. If it does operate beneficially, thermal-stress cracking will probably be useful primarily to extend the dimensions and prolong the useful life of fracture systems formed initially by some other method.

There is, then, a wide variety of methods for creating local permeability around a borehole drilled into hot rock of low permeability, so that water can be circulated through the rock and heat extracted from it. Of these, fracturing by the detonation of chemical explosives is being investigated intensively in the U.S.S.R.(23,24) and in the United Kingdom(7), and both hydraulic fracturing and thermal-stress cracking are being investigated in the United States (15).

3. Heat Extraction. When a region with adequate permeability and heat-transfer surface has been developed around a borehole, it is necessary to provide for fluid circulation within that region to extract heat from it, and then either to bring the heated fluid to the surface at a usefully high temperature or somehow to use the heat from it beneficially in a second underground system. Again, a number of engineering possibilities exist both for creating fluid circulation and for recovering thermal energy from the heated fluid.

Among other possibilities, Aladiev et al.(23) suggest the use of a downhole heat exchanger somehow inserted into the circulation path of the hot water, with which heat would be transferred to a relatively benign second fluid and only the latter would be brought to the surface. As was discussed above, even a simple U-tube heat exchanger can sometimes be used very economically for this purpose if conductive heat transfer through the borehole wall is supplemented by the buoyant circulation of geothermal water through the hole. Creation of a large region of high permeability might permit convective cells to form around the wellbore, allowing heat to be extracted from dry hot rock with a system much like that now in use in some hydrothermal reservoirs. When a large cavity can be created, as in the case of a salt deposit (Fig. 1), free buoyant circulation could certainly occur within it, increasing the probability that a usefully high rate of heat extraction could be maintained with an underground heat exchanger.

However, most current heat-extraction concepts envision bringing the primary fluid to the surface for energy recovery there rather than in a downhole heat exchanger. For example, Smith et al.(25) describe a concentric-pipe system in which cool water flowing down the central pipe would be forced by the presence of a packer to flow out into the permeable region around the borehole, would return to the hole at a higher level (above the packer) and would then flow back to the surface through the annulus between the two pipes. With this arrangement, if buoyant forces were insufficient to maintain the desired flow rate, then the fluid could be pumped mechanically. Here the obvious problem is that the long concentric pipes themselves represent an excellent heat exchanger. Unless the surface of the central pipe was very well insulated, most of the heat extracted from the rock would be transferred from the ascending hot water in the annulus to the descending cool water in the central pipe, and would simply recirculate downhole instead of being brought to the surface. Insulation capable of controlling this in a low-temperature geothermal environment is apparently available, and the West Germans plan to experiment with such a system(26). Insulating materials which would probably have economically long lives at higher temperatures in the presence of a high-velocity flow of impure water are also available, but at present they appear to be too expensive to be considered for this use. The use of a double-walled central pipe with an insulating material between its walls, as suggested by Smith et al(25), would also be expensive, but would permit readily available insulation to be used.

An alternative, originally proposed by Robert W. Rex, is a "push-pull" (or "huff-puff") mode of operation through a single cased borehole. Water would be pumped down the hole until sufficient pressure was developed in the permeable zone to inflate its void spaces elastically (Fig. 4). It would be stored there until it was sufficiently heated and then, by reducing pressure at the wellhead, permitted to flow back to the surface through the same hole, driven by the elastic restoring forces in the rock and in the compressed fluid itself. If necessary, its return could be assisted by a downhole pump. By using two or more such systems in different phases of the injection-heating-recovery cycle, a continuous supply of hot water could be produced at the surface. Here again the principal problem is one of heat exchange, in this case between the ascending hot water and the well casing and the cement and rock around it. Having been cooled by water injected during the first phase of the cycle, these would extract a large fraction of the heat from the ascending water during the recovery phase. The results of LASL analyses and field experiments suggest that a more advantageous application of the "push-pull" concept may be to increase the residence time of fluid in a permeable zone between two wellbores, as is discussed below.

To avoid the heat-exchange and heat-storage problems inherent in injecting and recovering fluid through the same hole, most proposed systems for extracting energy from hot dry rock involve the use of separate injection and recovery wells, connected at depth through a region of enhanced permeability. Thus, Diadkin and Pariisky(24) propose drilling two holes of approximately equal depth, connecting them through the hot rock by means of overlapping fracture systems produced by detonating explosives in both holes, and flowing water horizontally from one hole to the other through those fractures (Fig. 5). To the degree that the fracturing itself has been effective, this should in time effectively sweep nearly all of the useful heat out of the fractured volume. This general method should, of course, be equally useful if the permeable zone were natural or had been created by some other means such as chemical leaching or thermal-stress cracking. If the permeable region were very large, an array of holes rather than a single pair might be used to advantage.

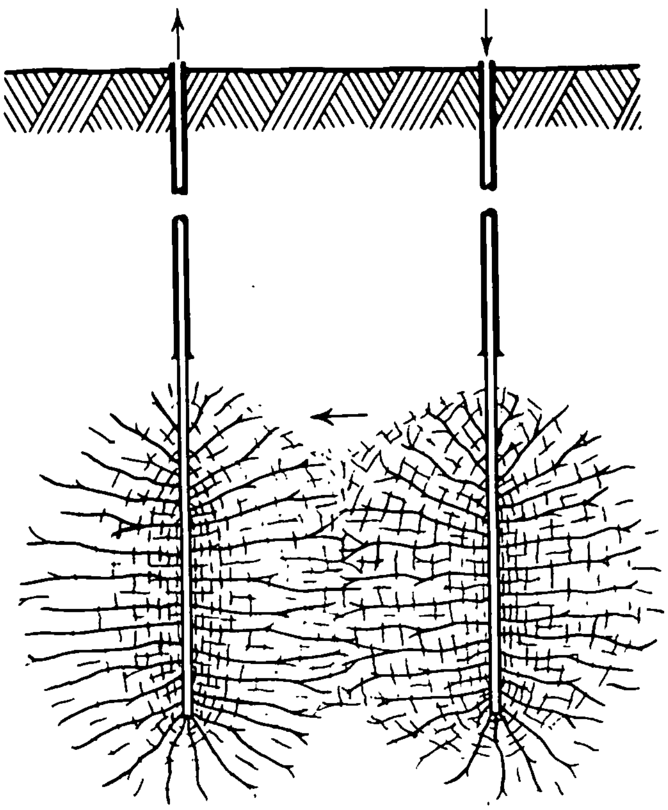


Fig. 5. Injection and recovery wells connected through fractures produced by detonating explosives in both boreholes.

In the hot dry rock system being investigated at LASL (Fig. 6), fluid circulation again is through a permeable zone connecting two boreholes, but at least initially the flow is primarily vertical and through a single, substantially planar crack rather than a three-dimensional array of cracks. (However, as has been discussed, it is anticipated that thermal stress cracking will eventually cause this to develop into a three-dimensional fracture system.) In this case, it is expected that buoyant forces will assist both in distributing the fluid over the exposed rock surfaces and in transporting it from the point of entry into the fracture to an exit at a higher level (22).

While drilling two holes is likely to be more expensive than drilling just one at a larger size, there are important advantages in using separate injection and recovery wells--particularly when the

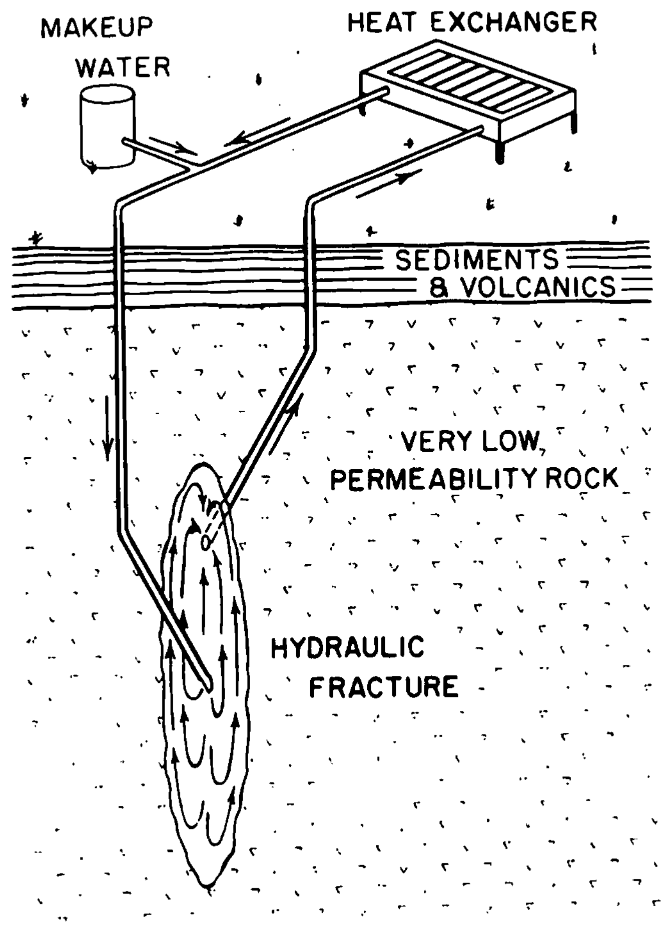


Fig. 6. Injection and recovery wells connected through a large hydraulic fracture.

highest possible temperature in the effluent fluid is required. On the other hand, a one-hole system avoids the difficult problem of insuring that an underground connection with low flow-impedance and high effective heat-transfer area is made through the hot reservoir rock between two separated holes.

4. Operating Mode. Except in one-hole "push-pull" systems, it has so far been implicitly assumed that heat extraction would be accomplished by continuous recirculation of water around a closed loop. However, other modes of fluid circulation are evidently possible.

For example, if water is plentiful locally and does not dissolve so much mineral matter from the reservoir that it presents a disposal problem, a "once-through" system might be used, in which hot water from the recovery well is simply delivered to the customer and not returned to the well field for reinjection. This could greatly increase the distances over which relatively low-temperature heat could be distributed economically.

With a connected two-hole heat-extraction system, there is the obvious possibility of direct short-circuiting of much of the fluid from one well to the other through one or a few major flow channels. If this occurs or if there is simply not enough heat-transfer surface in the permeable region to maintain the required effluent temperature at the required flow rate, then a type of "push-pull" operation may be useful. With the recovery well shut in, water would be pumped into the injection well to pressurize and elastically inflate the permeable region, stored there until it had been sufficiently heated, and then recovered through the other well. By increasing the mean residence time of fluid in the manmade reservoir, this would result in a higher, more nearly uniform temperature in water entering the recovery well. By avoiding the alternate heating and cooling involved in a "push-pull" operation in a single wellbore, this would also greatly reduce both the temperature loss in the ascending column of hot water and the danger that the well casing and the cement around it would be damaged by large-amplitude temperature cycles.

Finally, it is often suggested that the heat be brought to the surface in steam rather than hot water. The obvious advantage is that this would minimize the mass transport of dissolved solids, reducing corrosion and scaling problems in the well casing and surface plant and the danger of plugging the reinjection well and the formation around it. Against this must be weighed the following disadvantages. (a) Most of the solids dissolved by the water as it was heated within the reservoir would be redeposited in the zone in which boiling occurred, whether in the formation or in the wellbore, possibly plugging the system there. (b) In addition, unlike water, steam becomes more viscous as it is heated. Boiling within the formation would therefore result in an increasing tendency of steam to short-circuit along the coolest available path to the recovery well whereas water (with a negative temperature coefficient of viscosity) will tend to distribute itself among the hottest paths. (c) With the same pressure drop and flow-channel or wellbore diameter, the mass-flow rate of steam is much less than that of liquid water, so that--at the same reservoir temperature--less heat per unit time would be delivered to the surface by steam than by hot water(25). (d) Finally, when boiling occurs in the ascending water column, the heat of vaporization is absorbed from the water itself, and its temperature decreases accordingly. If the water is to be flashed to steam at the surface anyhow, this makes no particular difference. However, if it is to be passed through a heat exchanger and its useful heat transferred to a second fluid, the higher temperature maintained by avoiding boiling may considerably increase the efficiency with which that heat can ultimately be used. At LASL, it has so far been considered that the net advantage is in favor of continuous circulation of pressurized water, but this may not always be true. It is quite possible that in other circumstances the disadvantages noted may be outweighed by decreased corrosion and other scaling problems or by the reduced initial cost and maintenance problems of using a steam lift instead of a mechanical pump to bring the hot fluid to the surface.

Undoubtedly there are other possibilities for developing and operating heat-extraction systems in hot dry rock of very low initial permeability. However, those already discussed represent a sufficient variety to indicate the desirability of experimenting with several field systems in the varied subsurface environments that nature actually provides.

B. Low But Significant Matrix Permeability. Even in the complete absence of large-scale fracture systems, it is not unusual to encounter geologic formations in which the permeability of the rock matrix is insufficient to permit the buoyant circulation that forms and maintains a hydrothermal system, but still is too great to contain the circulating fluid in a manmade heat-extraction loop of the types discussed above. This is most likely to occur in "tight" sedimentary rocks such as well-cemented sandstones and greywackes, but it may also occur in porous volcanics and in finely fractured rocks of any kind. When it does occur, there are several possible ways in which useful heat-extraction systems might be developed.

1. Stimulation. When natural steam or hot water can be produced from a geothermal well but, because of inadequate permeability around the borehole, the production rate is too low to be economically attractive, then a "stimulation" treatment may be all that is needed--as is often the case in petroleum, natural-gas, and water wells. Such treatments are usually based on one of the methods described above for increasing permeability around a borehole: hydraulic or explosive fracturing, or selective chemical attack. If this approach is unsuccessful, it may still be possible to achieve a useful heat- production rate by any of several other methods, all of which are designed to minimize fluid loss to the formations around the reservoir volume being exploited.

2. Pressure Reduction in the Wellbore. For a geothermal fluid to flow into a well, it is evidently necessary that fluid pressure in the well be less than that at the same level in the formation around the well. In some hydrothermal fields the local hydrology is such that the pore pressure in the geothermal reservoir is above normal hydrostatic pressure at the same depth, so that an artesian flow of hot water from the well will occur naturally. In others the pore-pressure field is at or only slightly below normal hydrostatic pressure, so that the density decrease in the water as it is heated is sufficient to cause artesian flow to continue once an upward flow of hot water in the well has somehow been initiated (which may be done, for example, by releasing nitrogen or carbon dioxide in the well below the level to which it fills naturally with water). The further reduction in mean fluid density that results from permitting part of the hot water to flash to steam in the well accelerates this flow, and creates the "steam lift" that is now usually used to produce fluids from hot-water reservoirs. It also reduces fluid pressure in the bottom of the well, steepening the pressure gradient around it and increasing the rate at which water from the reservoir flows into it.

A similar reduction in pressure in the lower part of the hole can be produced by using a downhole pump, which adds cost and maintenance problems to the system, but has several advantages. If the reservoir temperature is too low to permit boiling in the recovery well, such a pump may be essential simply to lift fluid out of the well. However, even in very high-temperature systems, a pump is useful in keeping downhole pressure in the well below that of the reservoir, thus preventing fluid loss, while also keeping the upper part of the well sufficiently pressurized to prevent boiling there. This is likely to reduce scaling and corrosion problems, and will certainly increase mass flow rate at the surface, avoid the temperature reduction that accompanies boiling, and increase the rate of energy production from the well.

Whether a well has been stimulated or not, a reduction in fluid pressure downhole--by whatever means--increases the pressure gradient around the borehole and the rate at which water flows into it from the reservoir. However, in low-permeability formations, this may not be sufficient to make the well economically productive. If it is not, several possibilities remain for creating pressurized flow systems in which precautions are taken to minimize fluid loss to the reservoir rock around the system.

3. Flow Between Parallel Fractures. Total flow rate through a low-permeability formation can be increased by increasing either the pressure gradient in the formation (e.g., by reducing pressure in the recovery well) or by increasing the cross-sectional area through which flow occurs (for example, by a stimulation treatment). A possible method of doing both while also minimizing fluid loss has been suggested by R. M. Potter of LASL. His proposal is to drill a row of three boreholes to approximately the same depth, and from them to produce three parallel hydraulic fractures of roughly the same size. Pressurized water injected through the central borehole would flow horizontally outward from the central fracture, be collected in the other two fractures, and return to the surface through the two outer holes. Fluid loss could be minimized by keeping downhole pressure in the two recovery wells at or below the natural pore pressure in the reservoir rock. Unless considerable short-circuiting occurred through natural or induced large cracks in the rock between the hydraulic fractures, the heat from that rock should be swept out very effectively by the slow advance of the injected water, and the temperature of water entering the recovery wells should remain essentially constant until the front of cool water finally broke through to them. (This would greatly simplify the problem of efficiently using heat from the system.)

4. Reduced Permeability. Another general approach to reducing fluid loss by permeation of formations around the borehole is simply to reduce the permeabilities of those formations. Except where there is or has recently been active faulting or major seismic activity, the permeability of any given formation can be expected to decrease as it is penetrated more deeply. An obvious possibility, therefore, is to continue to deepen the hole until permeability is low enough to satisfactorily contain a pressurized hot dry rock system. This will also progressively increase the reservoir temperature which, within limits imposed by possible equipment, materials, and geochemical problems, is generally desirable--but must of course be balanced against what may be a large increment of drilling cost. An alternative to deeper drilling is to reduce the permeability of the rock that surrounds the active circulation system. Suggested methods include filtering out on the rock surfaces of fine particles, for example of bentonite; chemical additions which will accelerate certain mineral alterations that result in a volume increase, such as the production of clays from feldspars; and the injection of materials that will gel or polymerize or react with each other in the void spaces of the formation outside the circulation loop.

There are then, again, an interesting variety of possibilities for extracting geothermal energy from hot formations whose initial permeabilities are significant but not sufficient to yield natural steam or hot water at commercially useful rates. Several of them appear to deserve investigation in field experiments, and some may merit development of pilot- or demonstration-scale heat-extraction facilities.

C. Thin Permeable Layers. There are several geologic situations in which a relatively thin, essentially two-dimensional, permeable zone may occur naturally within a formation whose initial permeability is very low, or along the contact between two such formations. Physically, this is not unlike a hydraulic fracture within a rock of low permeability except that the heat-exchange surfaces are unbounded at their edges, so that some special arrangement is required to recover any fluid that is injected into the permeable layer.

For this system geometry, when indigenous fluids are insufficient to maintain a productive hydrothermal reservoir, Bodvarsson and Reistad(27) propose a "forced geoheat extraction" method of fluid circulation in which water is introduced into the permeable region through one or more injection wells and heated as it flows toward an array of appropriately located recovery wells. If the permeable zone dips steeply, as it may in a brecciated fault zone or along an intruded dike, the tendency of the heated water to rise buoyantly may permit it to be collected quite effectively with a relatively simple hole array, as is suggested in Fig 7. If the permeable zone is more nearly horizontal, for example along the interface between successive layers of a flood basalt, a more elaborate hole array will probably be required to avoid excessive fluid loss from the periphery of the active system. This will probably resemble one of the hole arrays developed for water-flooding systems in oil fields, which are described below. In either situation, downhole pumps will probably be required to keep pressure in the collecting sections of the recovery wells low enough so that the heated fluid will tend to flow toward them instead of escaping from the system.

D. Widely-Spaced Large Fractures. With the exception of a few very large reservoirs in sedimentary basins, nearly all of the major hydrothermal areas so far investigated occur as relatively small, elongate regions along fault systems(28). The principal flow paths for geothermal fluids are evidently open fractures associated with those faults, and successful completion of a productive steam or hot-water well is in general contingent upon drilling through one or more such fractures. Because the population density of fractures normally decreases with increasing distance from the major fault zone, so does the probability that a drilled hole will encounter at least one of them. However, until the fracture density drops essentially to zero, a stimulation treatment--which may be as straightforward as directionally redrilling the lower part of the hole--is likely to be successful.

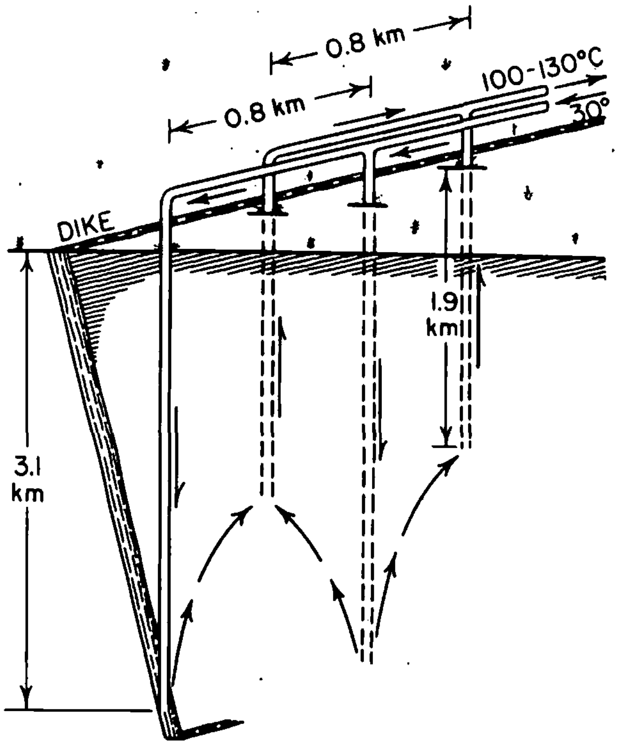


Fig. 7. Upflow system of forced geoheat extraction using an open dike in a region where the geothermal gradient is 50°C/km (after Ref. 29).

It is, then, primarily at the peripheries of fault-associated hydrothermal systems that low-permeability rocks containing relatively large but widely separated fractures are commonly found. In this circumstance, the obvious approach to achieving commercial energy production is first to attempt to stimulate dry or relatively unproductive holes by one of the methods described above and then, if that fails, to undertake development of some type of hot dry rock system such as those already discussed.

E. Thick Permeable Formations. When a relatively thick, unproductive, permeable zone is encountered rather than a thin permeable layer, a somewhat different heat-exchange mechanism and fluid-circulation pattern may be used to advantage. Instead of, in effect, flowing over a hot surface, the fluid permeates a three-dimensional porous body. Because of its higher viscosity, the cool fluid entering the formation tends to maintain a definite "cold front" that sweeps the less-viscous hot water ahead of it into the recovery well. To use the full thickness of the permeable zone to advantage, it is desirable in both the injection and the recovery wells that most of that zone communicate directly with the wellbore --usually through a slotted liner or a series of casing perforations, unless the formation is sufficiently competent to remain intact without casing.

This is, of course, very similar to the water-drive systems used to increase recovery of petroleum, and like them it will normally require that an array of holes rather than a single pair be drilled--to control fluid loss into the surrounding formation. As was discussed in connection with flow between parallel fractures, it has the advantages that a relatively large volume of rock is swept by the heat-transport fluid, so that a very large amount of heat can ultimately be extracted, and that the temperature of the fluid entering the recovery well should remain nearly constant until the "cold front" of the injected fluid finally breaks through into the well.

III. CONCLUSIONS

There are a wide variety of system geometries, construction methods, and operating modes that may be commercially useful for extracting geothermal energy from hot dry rock in the varied geological environments in which it naturally occurs. In the present state of knowledge, it is impossible to model most of them accurately enough so that their performances and economics can be predicted with confidence. At this time, therefore, their potential advantages, problems, and commercial usefulness can only be investigated semi-empirically--by actually creating and operating large experimental systems in the field. Several of the systems described above appear to have sufficient promise so that they merit this type of investigation.

Fortunately, a large number of areas of immediate geothermal interest have already been identified, representing a wide variety of geologic environments and geographic locations. A judicious selection among them will permit experimental development of hot dry rock energy systems of several kinds in local situations representative of very large geothermal energy resources of several important types. While the economics, reliabilities, and useful lives of such systems cannot be predicted with confidence until several of them have been constructed and operated for extended periods, their relative engineering simplicity makes it appear probable that one or more of them will indeed prove to be commercially viable within the next few years. The advantages of the hot dry rock geothermal resource with regard to widespread distribution, accessibility, and security and continuity of supply, will then make it essentially inevitable that this vast energy source will be exploited beneficially in many parts of the world.

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