HOT DRY ROCK (HDR) GEOTHERMAL ENERGY RESEARCH AND DEVELOPMENT AT FENTON HILL, NEW MEXICO

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INTRODUCTION

Conventional geothermal technology entails the production of useful energy from natural sources of steam or, much more commonly, hot water. These hydrothermal resources are found in a number of locations around the world, but they are the exception rather than the rule. In most places, the earth grows hotter with increasing depth, but mobile water is absent. The vast majority of the world's accessible geothermal energy is found in rock that is hot but essentially dry -- the so-called hot dry rock (HDR) resource.

The total amount of heat contained in HDR at accessible depths has been estimated to be on the order of 10 billion quads (a quad is the energy equivalent of about 180 million barrels of oil and 90 quads represents the total US energy consumption in 2001). This is about 800 times greater than the estimated energy content of all hydrothermal resources and 300 times greater than the fossil fuel resource base that includes all petroleum, natural gas, and coal. (Tester, et al. 1989). Like hydrothermal energy resources already being commercially extracted, HDR holds the promise for being an environmentally clean energy resource, particularly with regard to carbon dioxide emissions, which can be expected to be practically zero.

The total HDR resource base noted above was calculated by summing the thermal energy content of rock beneath the landmasses of the world at temperatures above 25°C (77°F), from the surface to a depth of 30,000 ft (9,150 m). Obviously, much of this HDR resource resides in rock that is only marginally warmer than 25°C and is thus of such low-grade that it is not practical to recover it. In addition, a large part of the resource may be located in parts of the world where its exploitation may not be economically worthwhile. Nevertheless, with such a large resource base, the potential for HDR to be a major contributor to the world's energy supply makes its development well worth pursuing, especially when considered in light of its environmental advantages.

One method of evaluating the potential for HDR development in a region is to examine its geothermal gradient -- the rate at which the earth gets hotter with depth. The geothermal gradient varies widely from place to place, being much higher in tectonically active regions and in areas of volcanic activity. Figure 1 shows a geothermal gradient map of the United States. It is apparent from this map that HDR resources at useful temperatures (above 100°C) are abundant in many parts of the west.

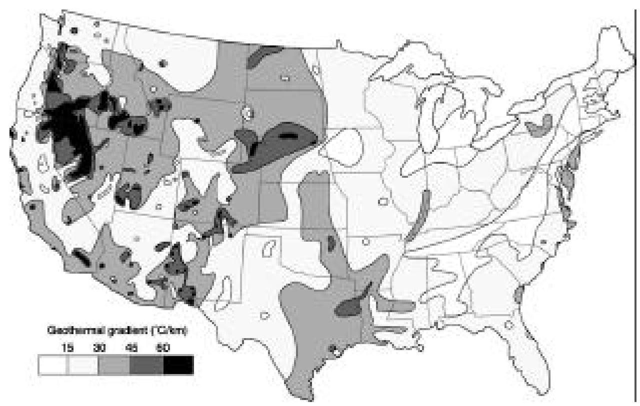

Figure 1. A geothermal gradient map of the United States. There are many high-gradient areas in the western part of the country.

THE LOS ALAMOS HDR CONCEPT

Although the fact that the earth gets hotter with depth has been known for a very long time, it wasn't until about 1970 that a team of scientists and engineers at Los Alamos National Laboratory developed a plan to access the HDR resource and bring its contained heat to the surface for practical use. As described in a patent issued in 1973 (Potter, et al. 1974), the original Los Alamos HDR development concept entailed drilling a well into hot crystalline rock, using water under pressure to create a large vertical fracture in the hot rock, and then drilling a second well to access that fracture at some distance above the first wellbore. The system would be operated by injecting pressurized cold water through the first well into the deeper part of the fracture and, after passing it across the hot surface of the fracture, returning the water to the surface as superheated fluid through the second wellbore. After extracting its useful energy, the same water would be recirculated to mine more heat. Larger systems would be developed by creating multiple fractures spaced along a single set of well bores inclined toward the horizontal at depth. As described below, this original concept was to be significantly modified as researchers learned more about the characteristics of the engineered geothermal reservoirs created during hydraulic fracturing operations.

THE LOS ALAMOS HDR DEVELOPMENT PROGRAM

With sponsorship by the U.S. Atomic Energy Commission, fieldwork to demonstrate the feasibility of extracting useful energy from HDR began at Los Alamos in the early 1970s. After a number of preliminary drilling and fracturing experiments, a site at Fenton Hill, NM, about 40 miles west of Los Alamos was chosen for the establishment of the world's first HDR circulation system. The Fenton Hill site is located in the Jemez Mountains of north-central New Mexico, on the western flank of the Valles Caldera just outside the ring fault structure, where the local geothermal gradient is on the order of 65ºC/km (3.6ºF/100 ft) . It is just off a paved state highway that facilitates the transport of personnel, supplies, and equipment. At the time of its selection, the land, which is owned by the US Forest Service, had recently been burned over and was available for scientific work on a permit basis.

THE PHASE I SYSTEM

The first HDR reservoir at Fenton Hill was created, tested, and enlarged in stages, with work beginning in 1974 and continuing through 1979. The ultimate configuration of the Phase I reservoir, as tested during the 9-1/2-month continuous flow test in 1980, is shown in Figure 2 (Brown 1995). The first deep borehole (GT-2) was drilled in 1974, to a final depth of 9619 ft (2932 m) in a host rock of jointed granodiorite, with a bottom-hole temperature of 180ºC (356ºF). After creating a hydraulic fracture from the bottom of GT-2, a second borehole (EE-1) was directionally drilled directly beneath the bottom of GT-2 to intersect this hydraulic fracture, but only a seepage flow connection was obtained. In an attempt to connect the two boreholes with another

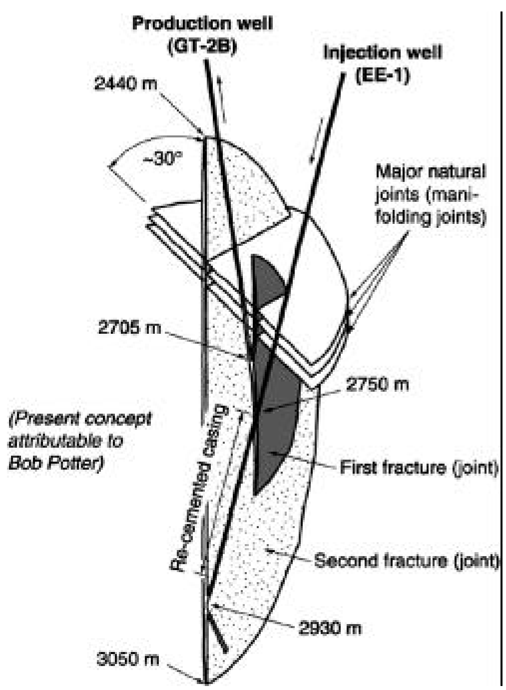

Figure 2. Conceptual view of the Phase I HDR reservoir at Fenton Hill, NM.

hydraulic fracture, a larger fracture was created in what was thought to be the short open-hole interval below the casing in EE-1, with the expectation that this fracture would grow *upward* and intersect GT-2 (since the first fracture created from the bottom of GT-2 had apparently not grown downward). But again, only a very modest flow connection was obtained (less than 1 gpm). (Actually, this fracture was initiated at a depth of about 9000 ft (2750 m), up and behind the casing in EE-1, since the cement had been over displaced during cementing operations, leaving the bottom 600 ft of the casing without cement.)

Following additional injections into EE-1, temperature logging and micro-seismic surveys, GT-2 was redrilled twice--in a direction roughly across the micro-seismically determined north-south strike of the target hydraulic fracture created from EE-1. The second redrilling in mid-1997 (GT-2B, as denoted in Figure 2) finally succeeded in producing a satisfactory flow connection to EE-1, resulting in the first-ever fracture connection between two boreholes in deep crystalline rock and ultimately, the world's first HDR reservoir.

The first three flow tests of the initial reservoir, the first lasting 5 days, the second lasting 75 days, and the third lasting 28 days respectively, produced a rapid cooldown of the reservoir, indicating that only a small heat transfer surface was accessible to the circulating fluid. The third flow test, operated under conditions of high back pressure, confirmed that only one vertically oriented joint was being accessed -- the small darkly shaded joint shown in Figure 2. Compared to the 75-day flow test, where the flow impedance decreased from 15 to 3 psi/gpm (1.3 kPa/L/s) as the flow path rapidly cooled, under high back pressure operation, the flow impedance varied from 2 to 0.5 psi/gpm (0.9 to 0.2 kPa/L/s) with continuing circulation (and much less cooling).

After recementing the bottom 600 ft (183 m) of the casing in EE-1, a series of additional hydraulic fracturing operations resulted in first opening the larger vertical joint shown in Figure 2--which was initiated from the bottom of the casing in EE-1 at a depth of 9600 ft (2930 m)--and then opening (at higher pressure) the inclined manifolding joints connecting the two vertical joints. These additional pressure-stimulations resulted in the final Phase I reservoir configuration in Figure 2, with the injected flow leaving EE-1 at a depth of 9600 ft, flowing up the larger vertical joint and then down the set of inclined manifolding joints, down the small vertical joint initially opened at 9000 ft (2743 m) in EE-1, and finally out the production well, GT-2B!

During the final flow test of the Phase I reservoir in 1980, the temperature of the produced fluid declined from an initial value of 156ºC to 149ºC (313 to 300ºF), at a near-constant flow rate of 90 gpm (5.7 L/s) and an injection pressure of 1200 psi (8.3 MPa). Measurements and modeling showed that the reservoir was small by commercial standards, with an estimated stimulated volume on the order of 600,000 cubic meters (21 million cu. ft). The scientific data and engineering experience acquired during testing of the Phase I research reservoir provided the basis for the development of the larger, hotter, and deeper Phase II, engineering-scale HDR system.

THE PHASE II SYSTEM

In 1979, when construction of the Phase II HDR system was begun, experience with the Phase I reservoir had provided little reason to doubt the validity of the original Los Alamos HDR concept. The Plan for the Phase II system called for the creation of multiple vertically fractured reservoirs. The deeper wellbore penetrated to about 14,400 ft (4,400 m) with the last 3300 ft (1,000 m) inclined to the east at an angle of 35^o from the vertical. The second wellbore was drilled to a total depth of about 13,100 ft (4000 m), with the last 3300 ft angled at 35^o from the vertical and positioned above the sloped portion of the deeper wellbore. Between 1982 and 1984, numerous hydraulic fracturing operations were conducted at several points along the sloped portion of the lower wellbore. All of these failed to connect the two well bores. Fortunately, advances in seismic science were making it possible to more-precisely locate the origins of microearthquakes generated during the hydraulic fracturing. This in turn, gave researchers a much better picture of where the reservoir fractures were located and how they were extending.

The most extensive hydraulic fracturing operation was conducted in the lower wellbore at a depth of about 11,700 ft (3,560 m), by the injection of 5.7 million gallons (21,500 m^3) of water at surface pressures of about 7000 psi (48 MPa). Seismic data indicated that the reservoir created during this operation was developing in a 3-dimensional manner as a 300-ft (91-m) thick ellipsoidal region with its longer axis approximately along the trajectory of the wellbore. It was apparent that no reasonable amount of additional hydraulic fracturing would lead to a connection between the two well bores. With this information in hand, the decision was made to redrill the lower portion of the upper wellbore to penetrate the reservoir region as indicated by the seismic data. When this was done, a small amount of additional hydraulic stimulation in the redrilled wellbore led to the establishment of a number of hydraulic connections between the two wells. The deeper wellbore had been damaged during the course of the multiple hydraulic fracturing experiments, so it was considered prudent to block off its lower portion and redrill it nearby through the reservoir region. With this accomplished, the Phase II reservoir was finally ready for testing. A cross section of the underground portion of the Phase II HDR system is shown in Figure 3

The volume of the Phase II reservoir has been estimated in a number of ways. The seismic volume includes the entire fractured region, while the fluid accessible volume encompasses all parts of the reservoir, even dead-end joints, that are reached by the injected fluid. However, perhaps the most meaningful definition of reservoir volume is the flow-accessible or heat transfer volume, which includes only those portions of the reservoir that are accessible to the circulating fluid. From a practical standpoint, it is only this part of the reservoir that can provide energy to the circulating water and, ultimately, to the energy production facility at the surface. A number of different techniques involving seismic, pressure, and tracer measurements have been employed to determine the

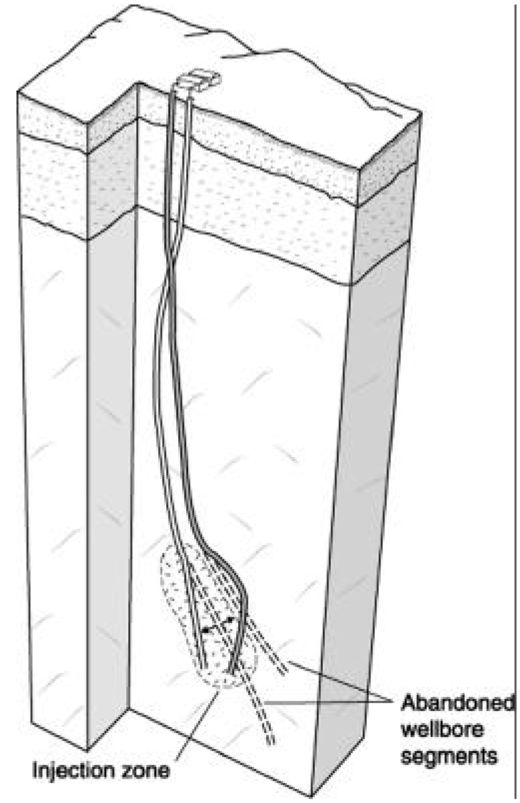

Figure 3. ***Conceptual view of the Phase II HDR reservoir at Fenton Hill, NM.***

volume of the Phase II reservoir. These indicate a fluid accessible volume of 15-20 million cubic meters and a heat-transfer (flow accessible) volume of about 6-8 million cubic meters (1.6 to 2.1 billion gallons) (Brown, et al 1999). Much of the fluid-accessible but flow-inaccessible part of the Phase II reservoir lies in the fractured region that is on the opposite side of the injection well from the production wellbore. Obviously, another production well placed in this region would greatly increase the productive capacity of the Fenton Hill Phase II HDR system. In any event, the Phase II reservoir is many times larger than the Phase I system in which cooling was observed.

REASSESSMENT OF THE HDR RESERVOIR CREATION PROCESS

The difficulties encountered in creating the Phase II HDR reservoir led to a significant revision in the concept of the effects of hydraulic fracturing, at least in deep, essentially closed systems like the Phase II reservoir region at Fenton Hill. The idea that hydraulic pressure causes competent rock to rupture and create a disc-shaped fracture was refuted by the seismic evidence. Instead, it came to be understood that hydraulic stimulation leads to the opening of existing natural joints that have been sealed by secondary mineralization. Over the years additional evidence has been generated to show that the joints oriented roughly orthogonal to the direction of the least principle stress open first, but that as the hydraulic pressure is increased, additional joints open.

The deep earth stresses at Fenton Hill were difficult to determine because of the temperatures involved and the fact that conventional hydraulic fracturing stress measurement techniques were unreliable in a multiply jointed crystalline rock mass, where the tensile strength of the unflawed rock was of the order of 5000 psi (34 MPa) (Brown, 1989). Since the Fenton Hill HDR site is situated near the west-bounding fault structure for the extensional Rio Grande Rift, it was not surprising to confirm, through fracturing and other stress determination techniques, that the least principal effective earth stress was oriented east-west (orthogonal to the direction of the rift structure), with a modest value of about 10 MPa at 3500 m (1450 psi at 11,500 ft). In contrast, other measurements determined that the maximum effective earth stress was vertical and equal to the overburden stress (59 MPa [3,500 psi] at 3500 m). The intermediate effective earth stress was oriented north-south, with a value determined by joint opening and closing stress measurements, to be on the order of 30 MPa.

The principal difference between the Phase I and Phase II HDR reservoirs was the change in the orientation of the main fluid-conducting joints. Between these two regions of Precambrian plutonic and metamorphic rock, there exists a significant brecciated shear zone on the order of several tens of meters thick. Above this interface, as shown in Fig. 2, the continuous joints were essentially vertical and interconnected by inclined "manifolding" joints. In the Phase II reservoir region below this shear zone, there was apparently a more-or-less continuous joint set, striking N29W and dipping 76º to the east, and with an opening stress level of about 31 MPa (4,500 psi). That joint set appeared to control the overall flow impedance of the reservoir.

The flow impedance and fracture-extension pressures of the multiply-connected Phase I reservoir (Fig. 2) were controlled by the set of inclined manifolding joints that exhibited an opening stress of about 15 MPa (2,200 psi). This difference in opening stress levels for the "manifolding" joints between the two reservoirs -- 15 MPa vs. 31 MPa -- explains the principal difference between both their fracturing and circulating pressures.

This new understanding mandates modifications in the conceptual design of HDR systems. Perhaps most important, because reservoirs are three dimensional, but typically elongate, as determined by a combination of the earth stresses and the joint structure, a three-well system with an injection well located approximately in the center of the reservoir and production wells at each end will allow the highest production rates by holding open a number of the previously high-impedance interconnecting joints without inducing reservoir growth at the boundaries. In this design, the production wells act as pressure relief points, thereby permitting the use of injection pressures so high that they would lead to additional hydraulic fracturing if these pressure sinks were not in place. Additional evidence has shown that the majority of the resistance to flow (flow impedance) is concentrated in the region of the production wellbore(s) (Brown, 1996). The best way to obtain a reservoir with a long lifetime, therefore, is to separate the well bores by as great a distance as is feasible. These two important lessons were learned at Fenton Hill, but budget considerations precluded drilling any additional well bores. The system as tested and reported below therefore represented far less than what we now know to be the optimal design of an HDR system.

CONSTRUCTION OF THE PHASE II SURFACE PLANT

With the Phase II reservoir and well bores finally in place, work between 1987 and 1991 concentrated on the design and construction of a surface plant that would allow the reservoir to be flow-tested in a manner simulating the operation of a commercial HDR facility (Ponden, 1991). The layout of the main closed-loop portion of the completed surface plant is shown in Figure 4.

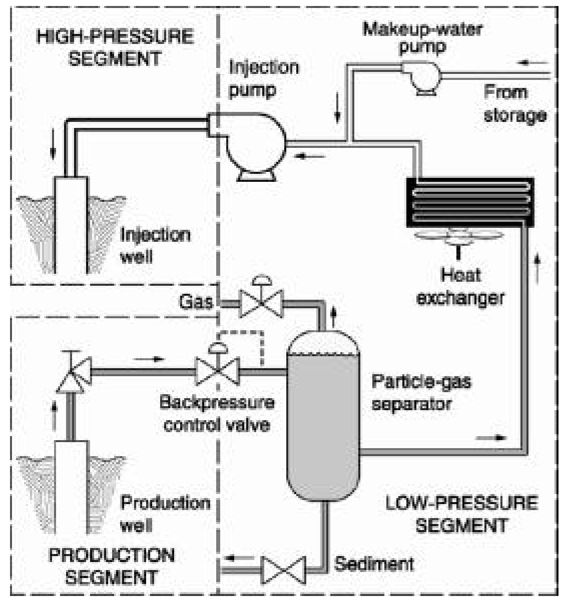

Figure 4. Layout of the closed-loop portion of the Phase II HDR surface plant.

The heart of the plant was the injection pump. This unit provided the pumping power to force the water down the injection wellbore, across the reservoir, up the production wellbore, and back to its own inlet. Both wellheads were equipped with a variety of valves to allow bypass flow and to provide protection against over pressure as well as to control normal circulation.

Beyond the production wellhead a series of pressure-letdown valves allowed control of the production well back pressure. Strainers and a particle/gas separator assured that any contaminants picked up by the circulating fluid in its passage through the reservoir would be removed before the water was returned to the injection pump for reinjection (in practice, only dissolved gases and almost no suspended solids were found in the produced fluid). The surface piping then delivered the water to a heat exchanger, which cooled it to ambient temperature. From the heat exchanger, the surface line entered the makeup-water building where water was added to replace the small amount lost in circulation through the reservoir. From this point, the fluid was returned directly to the inlet of the injection pump. The production piping string was designed to allow for thermal expansion in those parts of the loop where hot fluid would be present.

The entire loop was highly automated. Important operating parameters such as temperature, pressure, flow-rate, etc., were automatically measured and recorded at frequent intervals. Numerous safety measures were in place to assure that the plant would shut itself down in the event that any of a number of parameters moved out of a selectable control range. It was found entirely feasible to operate the plant for extended periods of time with no on-site personnel; a fact that has important economic implications for the ultimate commercialization of HDR technology.

Two reciprocating pumps, powered by diesel engines and capable of producing pressures of up to 5,000 psi (34.5 MPa), were originally installed at Fenton Hill to provide the needed inject-ion pressure. The plan was to operate the pumps on alternating cycles of 10 days each, with pump maintenance, such as changing the oil in the diesel drivers, being performed during each pump's idle period. Both these pumps failed due to a materials problem associated with their construction about 2 months after long-term flow testing began. They were eventually replaced with a centrifugal pump that proved to be both reliable and efficient. Aside from this single, but very significant, problem, the operation of the surface plant was practically trouble-free over the entire term of the flow testing program.

FLOW TESTING OF THE PHASE II HDR SYSTEM

A number of short flow tests of the Phase II reservoir were conducted during 1986-1987, prior to the construction of the permanent surface plant. These tests established the viability of the system for longer-term circulation experiments and provided guidelines for the establishment of reasonable operating parameters, particularly the maximum injection pressure that could be maintained without inducing reservoir growth as evidenced by seismic activity and excessive water consumption.

In March 1992, after the completion of the surface plant and a few short preliminary circulation tests, a long-term flow test (LTFT) of the Phase II HDR reservoir was initiated. Although this test was originally scheduled to encompass a year of continuous circulation, the pump failure described above resulted in an interruption of circulation on July 31, 1992, after 112 days of operation. This interruption combined with subsequent budget shortfalls resulted in a LTFT program that spanned more than three years and involved three steady-state segments as well as several shorter circulation periods, with the total circulation time amounting to somewhat over 11 months. Table 1 summarizes operating data from the steady-state segments of the LTFT.

The results reported in Table 1 do not reflect the significant amount of work conducted during the periods between the steady-state test segments. When steady-state operations were not possible, shorter experiments were conducted to investigate specific characteristics of the Phase II reservoir and evaluate techniques to improve the productivity of the system.

As shown in Table 1, the 1995 steady-state operating segment was broken into four stages. In the first stage, the conditions of the first two steady-state segments were reestablished. The latter three stages involved manipulations of the production schedule to confirm the advantages of operating scenarios that had been briefly explored during the interim periods. In the second stage, the back pressure was raised to a higher level to reduce the net pressure drop across the reservoir. In the third stage, one-half-hour daily shut-ins of the production well were employed to repeatedly jack open the fluid-carrying joints, which experience had shown tended to slowly close with time under steady-state circulation.

Table 1. LTFT Steady-State Operating Data

Steady-State Segment:	First		Second		Third	
Time Frame:	Mar-Jul,1992		Feb-Apr, 1993		May-Jul, 1995	
Duration, Days:	112		55		66	
Injection						
Pressure, psi	3960	3960	3960			
Flow Rate, gpm	106		103		120-128	
Production	A	B	C	D		
Back pressure, psi	1400	1400	1400	2200	2200	2200-500
Flow Rate, gpm	90	90	105	94	98	92-150
Temperature, ºC	183	184	184	181	183	183-189
Water Loss						
Rate, gpm	12.5	6.8	18	21	18	a
% of Net Injected Vol (b).	12	7	14	18	15	a

a. Water loss data were meaningless during segment 3D.
b. After subtracting loss due to a small leak in the injection wellbore that immediately returned a small fraction of the injected fluid to the surface.

In the fourth stage, the potential for load-following operation of the HDR system was explored (Brown 1996). During this stage, as shown in Figure 5, the fluid production rate was increased rapidly each day, maintained at a rate about 60% higher than its baseline for a period of 4 hours, and then rapidly decreased to its former level. This was accomplished by manipulating the back pressure on the production wellbore using the plant's automated control system. Injection continued at a relatively steady pace throughout this stage of the test.

The steady-state segments of the LTFT demonstrated a number of characteristics of HDR reservoirs that have great significance from the standpoint of economic energy production: Routine fluid production for long periods with no human intervention showed the potential for the operation of HDR systems with minimum manpower. The rapid attainment

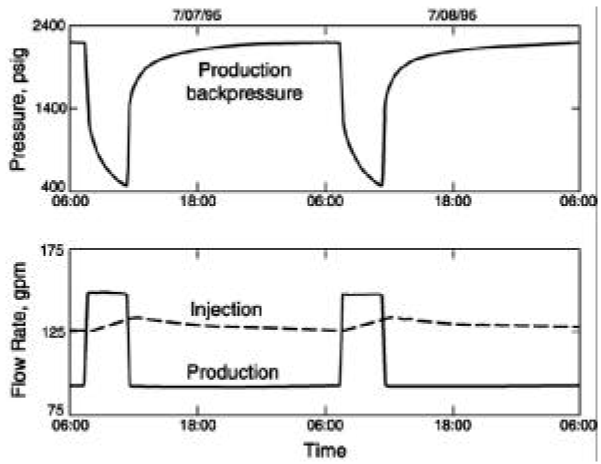

Figure 5. ***Injection and production conditions during the last two cycles of the load-following flow test of the Phase II HDR reservoir at Fenton Hill, NM.***

of repeatable operating conditions after either short or long shut-in periods indicated that HDR reservoirs have the long-term stability required for predictable energy production. The capability to rapidly and repeatedly adjust production rates, as illustrated in Figure 5, highlighted the potential for manipulating the production rate to produce more energy from HDR reservoirs at periods of peak demand when power is most valuable.

Production temperatures were stable throughout the term of the LTFT, and predictive modeling indicated that the Phase II reservoir could have operated for many years without an appreciable decline in the temperature of the produced fluid. Tracer data collected during all three of the test segments indicated that the reservoir is a dynamic entity, with cooler flow paths closing and new flow paths through the hot rock developing as circulation progressed, providing additional evidence that long thermal lifetimes can be expected for HDR reservoirs.

Experience from the LTFT, as well as earlier static pressurization tests, showed that the rate of water-loss declines with time at constant reservoir pressure. In this regard, it is important to note that the reservoir pressure was maintained at operating levels during the seven months between the first and second steady-state test segments, but allowed to decay during the 2-year period between the second and third test segments. The water-loss rates during the third segment reflect this fact.

Geochemical problems were essentially non-existent during the LTFT. Concentrations of dissolved solids rapidly reached about 3,500 ppm (about one-tenth the salinity of seawater) and then remained steady. Dissolved gases reached an equilibrium level of less than 2,000 ppm, with carbon dioxide being the preponderant species. The gases remained in solution during closed-loop circulation because even the production side of the loop was maintained at a pressure in excess of 600 psi (4 MPa).

The LTFT led to several observations important to the design and operation of HDR systems. Evaluation of pressure changes at the injection and production wellheads when system shutdowns took place indicated that the resistance to flow through an HDR reservoir is concentrated near the production wellbore where the rate of pressure change is greatest (Brown, 1996). This implies that increasing the distance between the well bores by a large amount to create a larger reservoir would lead to only minor increases in the pumping pressure required to circulate a given amount of fluid. During one short experiment, the production well was closed in for a number of hours on a daily basis while injection continued at the normal rate. On the third day of the experiment, an anomalously large flow was noted shortly after the production well was re-opened. This event occurred at the end of second steady-state flow segment and remains unexplained. The effect did not appear to persist through the beginning of the third steady-state test segment two years later. The sudden flow increase did, however, provided further evidence that pressure manipulations can have a profound effect on HDR reservoir productivity.

The LTFT was of small scale. Only 4 to 6 MW of thermal power was produced and, at the temperatures of the produced fluid, less than 0.5 MW of electricity could have been generated if it had been possible to convert that thermal energy to electric power. The LTFT was also of limited duration. Practical HDR plants would have to operate for several tens-of-years to repay the substantial up-front investment required for drilling and reservoir creation. The data generated did show, however, that the Fenton Hill system could have generated significant excess energy beyond that required to operate the plant, and modeling indicated a long reservoir lifetime. Thus, in spite of its limitations, the LTFT provided results that greatly enhanced our understanding of HDR systems and moved HDR technology significantly closer to the demonstration of commercial viability.

OUTGROWTHS OF THE FENTON HILL PROGRAM

The pioneering HDR work at Fenton Hill demonstrated that energy from HDR could be routinely extracted for practical use. It stimulated worldwide interest in HDR technology (Duchane, 1998). Germany and Japan both participated with funds and personnel in the work at Fenton Hill during the 1980s. HDR programs were subsequently founded around the world, first in Europe, then in Japan. In the late 1980s, the European Community initiated a large field program at Soultz-sous-Forets in France, and two field programs were begun in Japan. Most recently field operations have gotten underway in Australia. Today there is a large community of experts in HDR. New innovations have sprung up as well. In Japan, 3-well systems have been evaluated and in Europe downhole pumping from a low-productivity hydrothermal system (a "hot-wet rock" or HWR reservoir) has been implemented.

Related applications of HDR technology and advanced exploitation techniques have also been considered (Duchane, 1993). Perhaps the most promising concept entails the cogeneration of clean water and energy. Treated sewage could be used as a source of feed water for an HDR system. Under the high-temperatures and pressures of the reservoir, the water would be sterilized. Purified water as well as thermal energy could then be recovered at the surface. Under the proper conditions a variety of organic wastes from industries such as food processing, paper, lumber milling, and the like could be treated via an HDR reservoir. Seawater could even be desalinated, provided proper measures were put in place to handle the large volume of salts that would be returned to the surface along with the superheated water. Cogeneration of these two most precious commodities--energy and clean water--via HDR could provide an answer to two critical problems facing the world of tomorrow.

STATUS OF HDR TECHNOLOGY TODAY

Three major issues must be resolved for HDR to become a significant contributor to the commercial energy market. The first of these is productivity. Reservoirs must be created that produce an economic rate of return in relation to the investment. The second issue is longevity. We must show that reservoir lifetimes are sufficient to warrant the large up-front investment required to establish an HDR system. The third issue is universality. It must be shown that reservoirs such as Fenton Hill can be the rule rather than the exception.

Research and development work to date, both here in the U.S. and in other parts of the world, has made a significant start toward resolving these issues, and routes to assuring positive answers to all the remaining questions have been proposed. Implementation is now essential. In fact, what is most needed today is an HDR facility that produces energy for market in order to build the track record that will make this technology an attractive investment to power producers around the world. Programs underway in both Europe and Australia show promise of developing the first commercially viable HDR system. Once this becomes a reality, HDR may rapidly move toward becoming a major clean energy resource of the twenty-first century.

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