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THE COMMERCIAL REQUIREMENTS FOR AN HDR RESERVOIR SUPPLYING A DOUBLE FLASH POWER PLANT

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ABSTRACT

Hot Dry Rock (HDR) geothermal systems have been under investigation by research groups in several countries for the past 18 years. This work has cost in excess of $240 million and has probably utilised more than 1000 man years of effort. However, the central problem of developing an adequate heat extraction region with the correct hydraulic properties has still not been solved.

The results from the large field experiments suggest that the heat transfer areas are formed by the pre-existing natural fractures in the reservoir region and that HDR systems will be dependant upon the natural interconnections in the fractures forming flow paths to extract the heat. This means that the reservoir geometry will be predetermined by the interaction of the selected injection and production positions with the joint network, despite the fact that some form of stimulation may be necessary to reduce the resistance to flow. Work is already in hand to understand the nature of suitable joint distributions and, secondly, to determine if the results from an exploration well can be used to support continuing a project into a development phase.

In addition, measurements must be made in the reservoir that give an early indication of heat transfer area, hence, allowing longevity assessments to be made to ensure that an individual project can be funded properly.

This paper presents some results from a continuing sensitivity analysis of the performance of a HDR system based on a double flash plant for a commercial project based in the UK. It shows that it is possible that geological constraints on HDR reservoirs may restrict the commercial application of the process in the near future. However, the indications are that HDR does have a viable future under the right circumstances but the research effort on reservoir behaviour is in need of adequate direction and requires operational experience of longterm flow in fractured systems.

INTRODUCTION

The idea of using subterranean heat from formations that do not contain large and exploitable volumes of water or steam has been discussed for more than a century (Starkie-Gardner, 1885). However, modern interest in Hot Dry Rock (HDR) systems really began in the late 1960's with the pioneering work at the Los Alamos National Laboratory, New Mexico (Smith, 1973) and several countries have now supported major research programmes. Much of this work has been presented comprehensively by Armstead and Tester, 1987, in their book 'Heat Mining'.

All of the current concepts for HDR systems under field investigation have three common factors:

- Injection wells with pumps
- A heat transfer region, the HDR reservoir
- Production wells

The HDR reservoir has been the main focus of attention and considerable disagreement still exists on the nature and form of the reservoir amongst the various groups working on HDR.

The major research expenditures to date are estimated to be:

	US$ million
USA, primarily Fenton Hill (Murphy, priv comm)	132
UK, primarily Rosemanowes (£27 million)	47
Japan, NEDO, Tohoku, CRIEPI and NRIPR (Kobayashi, (priv comm) (Yen 3484 million)	27
France	8
Germany, Falkenberg, Urach, Fenton Hill	33
	$ 247 m

This includes EEC contributions to national programmes but excludes items like the OECD Mages project ($2 million ?) and expenditure in the USSR.

Internationally, the current annual spend is approximately $15 million.

The majority of this money has been spent by national government research programmes with research organisations and, generally, they have studied various aspects of generating the necessary heat transfer area within the body of hot rock.

However, despite the very considerable effort (say 1000 man years) and obvious international financial support, the original goal of finding an engineering solution for the reservoir creation phase has not been reached. At the current level of comprehension of the behaviour of fractured rocks at depth, it seems clear that a less ambitious approach may be more successful.

The one common factor that has emerged in most of the larger scale field programmes with wellbore interlinking has been that the flow paths were formed by the naturally occurring joints and fractures despite local artificial fracturing near the wellbore. The research programme in the UK was specifically planned to exploit the natural fractures, while the programmes at Los Alamos, USA, Mayet de Montagne, France and Falkenberg, West Germany were originally planned to create 'penny-shaped' artificial fractures in solid rock.

The main implication of the observation that the natural joints dominate the system behaviour is that the maximum accessible heat transfer area is predetermined by the chosen position of the injection and production well locations in the existing joint network. All the far field links in the joints will already be in place, even though the initial apertures may be too small for adequate flow behaviour.

The in situ stress field, the in situ fluid pressure and the distribution and extent of the jointing are the key factors that must be known or modelled for any given site before the reservoir geometry can be considered. This topic is discussed further in the paper by Ledingham and Lanyon (this volume) at this meeting but, in principle, HDR systems in jointed rocks are as site dependant as any other form of geothermal or mineral exploitation. The problem is to quantify the nature and extent of geologically suitable sites before considering the modification of the natural characteristics of joints themselves. This geological constraint is a possible restriction on the original concept of HDR systems that could be placed anywhere and simply drilled to a depth necessary to reach the desired temperature. At the moment there is insufficient information to know if this is an onerous restriction.

We decided to constrain the specification of the reservoir by matching a potential power sales contract to the ideal system behaviour before attempting further hypothetical modelling of reservoir behaviour. The key issue was to tie a specific plant behaviour to HDR systems with various features and determine the required performance characteristics of the system to achieve financial viability.

POWER SALES CONTRACT

The UK electricity utilities are currently state owned but, in 1990/91, the government have planned stock floations to make them private companies. Retail sales of electricity will be handled by local distribution companies who will purchase the power from any of the generator companies provided that 20% of that power is from 'non fossil sources'; in reality, this is protection for the nuclear power plants rather than any attempt to support large scale HDR developments! The distribution companies will also be able to generate power and participate in generation projects.

Looking at the market potential for HDR in the UK's privatised system, there are two major points which have to be noted:

i The privatised generating companies will contain the old base load fossil-fuelled and nuclear generating capacity. These will still be the rolling giants which work on very long payback periods, although changes are being made in order to attract investment.

ii The emphasis for new generating capacity in the UK is aimed at the load between base and peak demand. It follows that tariff negotiations for power purchases are going to be far more lucrative in this sector and small payback periods may well be achievable, effectively creating the real competition in the supply industry.

This means that the provision of small base load generating capacity by HDR, or in fact any other source, will not be supported nationally. Arguments based on specific local demands will still hold for Cornish HDR in such a system, but any consideration of widespread development in the UK must be highly unlikely unless the large generating utilities take responsibility for the development at some stage.

We have considered an HDR system based in Cornwall which is more than 200 miles from the nearest major power plant and has the best prospects for a deep HDR system in the UK (Batchelor, 1987).

The purchase tariffs in the UK for the energy and capacity payments have a premium scale based on time and duration related to both national and local demand profiles. Typically the variation can be from 1.7 p (3 c) to 17.1 p (31 c) per kWh. However, in levelised terms including capacity, for a station running at constant output, the price is likely to be 2.7 p/kWh (4.8 c). This may not be the best method for operating an HDR plant.

The desirable contract has the following elements:

- Basic capacity payment for proven performance.
- Bonus capacity payment for proven extra performance at set times.

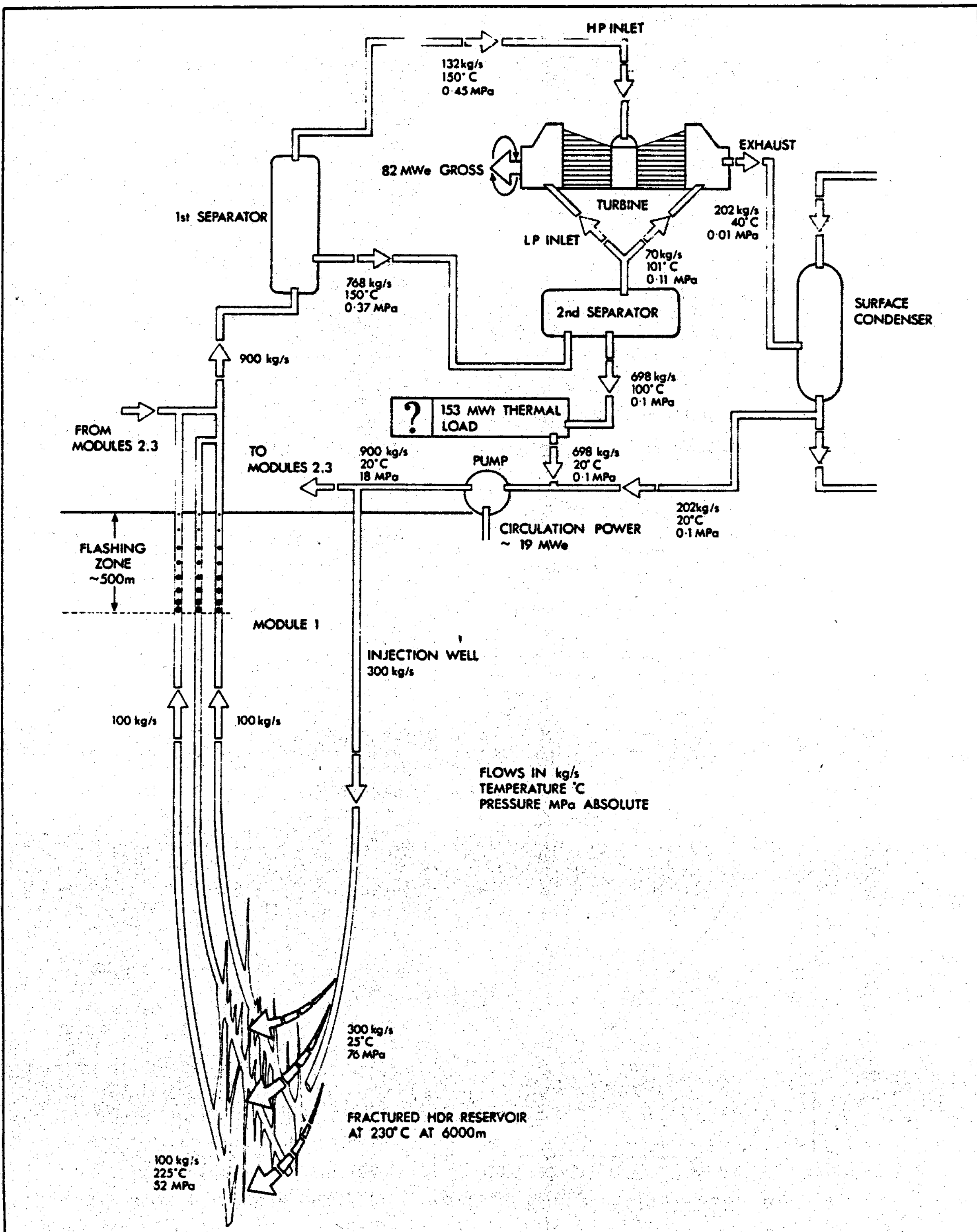

FIGURE 1 A CONCEPTUAL 63 MWe NET DOUBLE FLASH PLANT WITH AN HDR SYSTEM IN CORNWALL

- Energy payments based on set demand patterns.
- Bonus payments for energy delivered at peak times on notice from the utility.

The typical diurnal variations in energy payment are between approximately 1.7 p (3 c) and 7.9 p (14 c) between night and day during the high demand periods of November to February.

The tariffs are designed to attract generation systems that can follow demand without major capital investment in excess capacity. To maximise revenue from such a tariff, an HDR system needs the capability to vary its output significantly.

THE DOUBLE FLASH HDR SYSTEM

Figure 1 shows a conceptual double flash system for UK conditions coupled to an HDR system using twelve wells in three modules of four wells. The gross power from the plant in this example is 82 MWe with a parasitic power of 19 MWe for the circulation pumps.

Sensitivity to temperature, hence depth

Part of the sensitivity analysis was based on varying the production temperatures from 150 to 250°C to identify the influence of the depth and temperature on performance. Figure 2 shows the specific brine requirements for power generation under local conditions and it can been seen that moving to 4500 m at 150°C

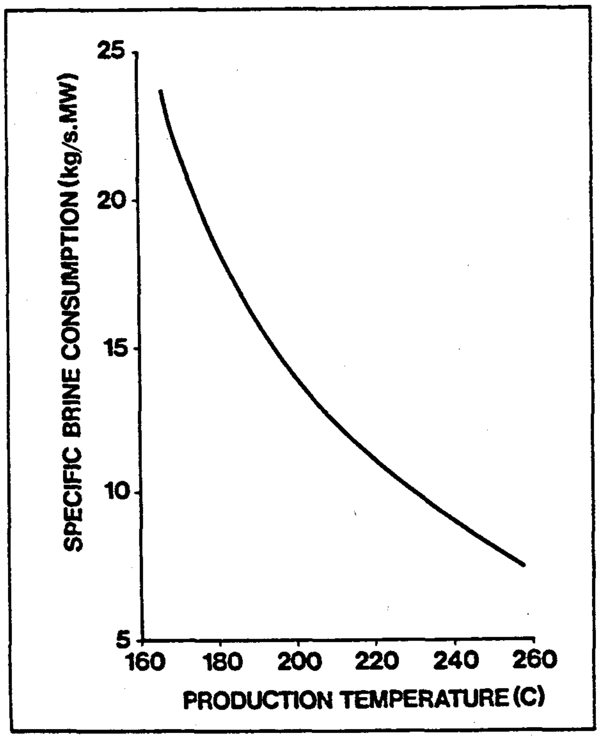

FIGURE 2 SPECIFIC BRINE CONSUMPTION AS A FUNCTION OF RESERVOIR TEMPERATURE FOR A DOUBLE FLASH PLANT IN CORNWALL

would reduce the gross power by a factor of three because the specific brine consumption increases from 11 kg/sMW to 33 kg/sMW. However, the parasitic power remains similar so the net power varies from 63 MWe to 8 MWe or nearly an eight fold reduction in saleable power.

Drilling costs as function of depth

We chose to cost each well on an AFE basis rather than use a drilling cost algorithm of uncertain accuracy. This exercise required great patience from the suppliers once the engineering studies had established the limitations to the well designs. The majority of this work was undertaken by Southern International and was based on actual experience gained during the drilling of the Gravberg #1 well at Siljan in Sweden.

An example of the variations on the basic drilling costs is given in Table 1. The values include all casing and completion hardware and assume that the rig was purchased and amortised over four wells.

TABLE 1 AN EXAMPLE OF VARIATIONS IN WELL COST WITH DEPTH (based on 8.5 in completion)

Depth (m)	Injection wells	Production wells
5000	M$4.467	M$4.533
5500	M$5.12	M$4.88
6000	M$5.8	M$5.6

The absolute values in Table 1 may be in error by 20% but the relative values are much more reliable. Overall, the variation in drilling related costs from 5000 m to 6000 m of 25% is not outweighed by the doubling of the saleable power output if the risks of HDR at 5000 m are similar to those at 6000 m.

This study also concluded that drilling and completing wells below 6000 m at the necessary diameters was beyond current technology.

A commercial HDR plant in the UK

The overall study to maximise return and minimise risk, but assuming success at each stage, gave the following general specification for an HDR plant in the UK.

- Individual turbines 15-30 MWe
- Two to three turbines per plant
- 12-15 wells per plant
- 20-40 Ha sites
- 125-175 kg/s evaporative cooling losses
- 25-75 kg/s circulation losses

° 20-25% parasitic power for pumps

° Six years to build a system

° System costs £2200 ($4000) to £3000 ($5400) plus per kW

° 95-98% availability

OVERALL MODEL

Figure 3 shows an overall model of the system where the gross power from the plant is a linear function of mass flow rate at a given temperature but the parasitic power is a power function of the mass flow rate. Typically, the value of the index is between 1.5 and 2.5 for the systems studied.

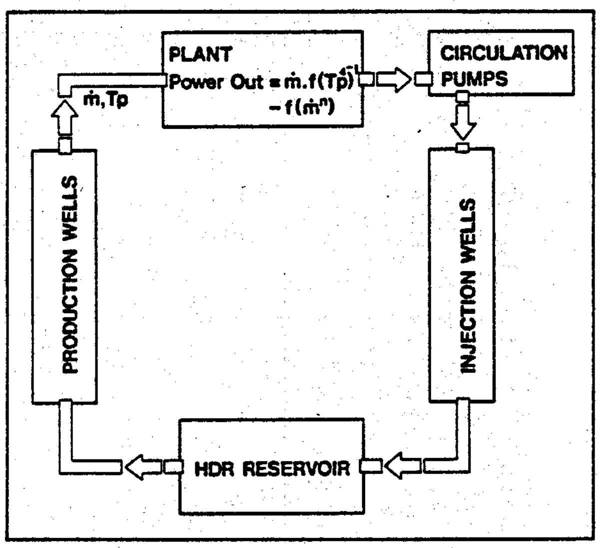

FIGURE 3 MODEL ELEMENTS OF AN HDR SYSTEM

Injection well behaviour

The field work shows that injection pressures can be raised to the point where the losses increase rapidly or the onset of sustained microseismicity indicates joint motions in the reservoir region. Typically, this limit has been set in Cornwall by the prevailing least principal stress and the in situ fluid pressure. The relationship between pressure and flow rate has been found to be linear over the range of pressures and flow rates that are useful for HDR systems, hence the hydraulic power requirements are related to the square of the flow rate in simple terms. Therefore it seems likely that the injection side would run at a maximum flow rate limited by the operational pressure limit. This value can be estimated from experimental data available from Los Alamos and Rosemanowes.

Figure 4 shows a curve of 'losses' vs injection pressure from the Rosemanowes experiments; it can be seen that there is a sharp departure from the linear trend at approximately 10 MPa in this case.

For the conceptual design at 6000 m, the anticipated least stress is 70 MPa with an in situ fluid pressure of 56 MPa. This means that the maximum overpressure during operation at the inlet point to the reservoir is 14 MPa. The head losses in the injection well are anticipated to be 4 MPa, hence 5.4 MW of hydraulic power are needed per module and 19 MWe of prime mover power are needed for the three modules.

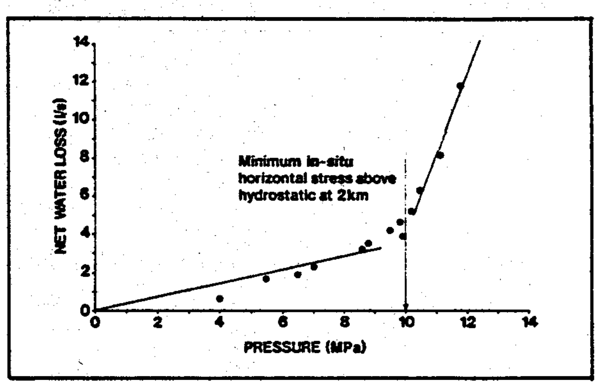

FIGURE 4 WATER LOSS RATE AS A FUNCTION OF INJECTION PRESSURE AT ROSEMANOWES

Production well performance

A flashing wellbore simulator was used to predict well behaviour setting flow rates to 100 kg/s and surface, flashed conditions to 0.5 MPa, 75 psi. The simulator is based on that from Parlaktuna, 1985.

The flowing downhole pressures can be seen in the example here to be 52 MPa or 4 MPa below the in situ formation pressure. In this way it is possible to have a degree of control over the losses that may be anticipated from the circulation loop. The validity of the simulator behaviour has been tested against published data and well tests run by GEO in wells up to 3000 m deep. Its validity in modelling the flow in a 6000 m well is unproven.

The depth of this model system helps the flow behaviour by providing a substantial bouyant pressure drive that is enhanced by the wellbore flashing. The actual pressure difference across the reservoir will be between 16 and 20 MPa with flow path resistances of 0.18 to 0.2 MPa/kg/s, values that have not yet been attained in practice.

Cyclic behaviour

The plant cannot operate over a wide range of mass flows; indeed if the production flow rate is decreased substantially then the heat losses in the wellbore will reduce the output temperatures.

The obvious way to enhance the performance is to cut the parasitic power by reduced pumping. At the moment when the pumps are cut the peak output will reach some major fraction of the gross power and this will then diminish as the production rate falls. Figure 5 shows the flow reduction following a pump rate change at Rosemanowes. It can be seen that a 60% reduction in injection resulted in only a 15% loss of production after 24 hours.

This production is coming from stored fluid that is not necessarily in the main flow channels and could be extracting heat from regions not cooled by steady circulation. The flowing 'huff-puff' mode could be enhanced by diverting more power to the circulation pumps at night during the low tariffs to maximise revenues during the day. In times of severe demand for one to two hour peaks when the maximum possible value is attached to the power (ten times the basic rate), the full power output from the plant could possibly be achieved by stopping the pumps for a short period.

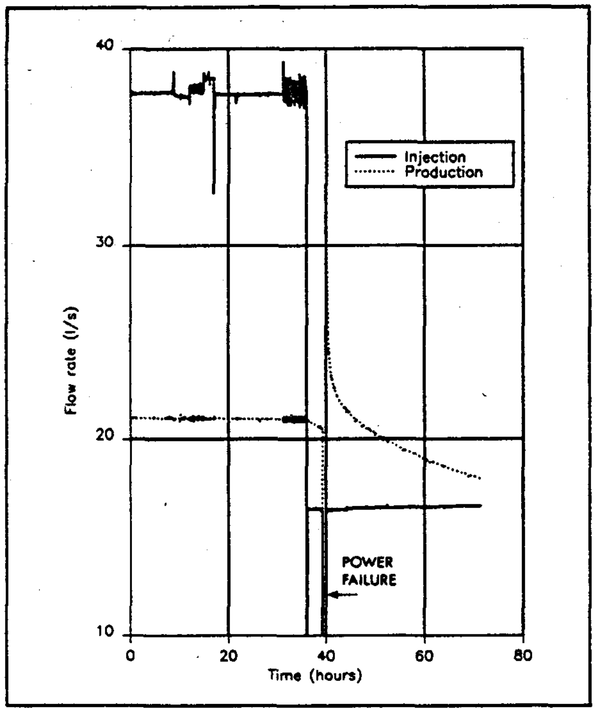

FIGURE 5 INJECTION AND PRODUCTION FLOWS BEFORE AND AFTER INJECTION RATE STEP

Various models show that the annual revenue from load following could be enhanced by 25 to 50% on the correct tariff structure to suit an HDR operation. Even so, the capital cost of the conceptual project is estimated at £145 million ($253 million or $4027/kw) and the best predicted annual gross revenues are only £18 million ($31 million). While this might represent a reasonable project in a mature industry with well understood risks, it is not a viable operation today without government development support.

SIZE OF THE RESERVOIR

The extraction of 900 kg/s at 225°C is a thermal power production of 727 MWt or 242 MWt per module. Over 25 years, cooling to 200°C, 1.43 x 10 MJ will be extracted from each module. To support such an extraction the rock volumes associated with the flowing pathways in the joint network need to be between 1500 million and 6000 million cubic metres of rock. This is much larger than some of the original calculations based on simple models. This wide variation depends on the assumptions in the various thermal modelling methods. The volume can be represented by cubes of 1100 m to 1800 m in length or slabs 300 m wide and 2200 m to 4400 m square. This implies interwellbore distances of the order of 600 m to 1000 m to avoid using too small a volume of rock.

The Ledingham and Lanyon paper (this volume) highlights the probability of forming a 'short-circuit' with interwell distances of the order of 300 m because of the low number of fractures involved. At the distances mentioned above, some 8 to 10% of the fractures could be involved and the short circuit risk is reduced.

REALITY

The various stimulations used to date have not achieved low resistance wellbore linking with adequate surface areas, even at distances of 300 m despite the fact that they were some of the largest massive stimulations ever attempted. The reality is that the sheer scale of the dilated reservoir volume , 2000 to 6000 cubic metres, plus the losses, means that the pumping requirements and job durations become unrealistically large if attempted in one operation. It is possible that cumulative, smaller stimulations, as proposed originally by LANL, may be used to reach the desired volume but it is difficult to envisage reliable completion systems.

However, if the far field natural fracture system already contains an adequate distribution of fractures and stimulation is only necessary to form a local effective access to the joints, the problem appears more tractable. Further work, as outlined by Ledingham and Lanyon, is already underway to determine the joint and fracture patterns that will support HDR operations without the need for massive stimulation operations and their associated geophysical monitoring. This will enable the basic reservoir requirements to be assessed in comparision to those available from nature.

To support this work, an exploration well to 6000 m into a region of the granite in Cornwall that is known to be heavily fractured near surface has been planned. This well is likely to be drilled as part of another R&D project but the data may be used to determine if conditions would warrant further work in the UK.

CONCLUSIONS

We believe that the grand dream of HDR is approachable in the long term if simple and less glamourous steps are taken first.

The understanding of how natural fracture systems link to form flowing reservoirs is a major goal of most geothermal operations, yet an understanding of those fracture patterns that are likely to be successful for HDR has not been achieved.

The failure of the various attempts to create commercial sized reservoirs by massive stimulation means it is worth reconsidering the idea of HDR systems that do not need such stimulations, eg the GEO-HEAT idea, Bodvarsson, 1974 and 1975. Once the conditions for possible success have been identified, it will be feasible to review the restrictions that may be placed on this class of HDR system.

HDR must be seen to deliver a success in the near term after the huge expenditures to date. It seems realistic to seek hot and fractured conditions that require no or limited stimulation for an operational project while the basic understanding of flow in fractured systems is developed. The existing base of dry geothermal wells provides an ideal opportunity to move the technology ahead at least cost and risk.

The system studies show that the power can be sold profitably if a reservoir can be generated whose performance meets or exceeds the values used in this paper.

The next steps to move HDR ahead towards such a goal are suggested to be:

Generic - Operate an HDR loop in a hot fractured formation with minimum stimulation.

Site specific - Drill a single hole to full depth to understand the in situ fracturing and fluid conditions. The decision for the work beyond those stages can then be based on reliable information.

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This version of the paper should be considered a draft and it may be amended in the final version.

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