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The Department of Energy has supported work on Hot Dry Rock (HDR) research since 1976 and has spent some £30 million so far. In March 1988 the Department announced funding of £8.15 million for a further three years of HDR research to be carried out by the Camborne School of Mines. I am pleased that this work at Rosemanowes Quarry has now started, and I hope that the conceptual design study of a deep prototype, involving industrial organisations will start soon.

The understanding of the technology has advanced considerably over the past decade and I am pleased that the UK work by the Camborne School of Mines team has greatly contributed to this process. HDR is a promising technology with a large potential resource in the UK and elsewhere. Teams around the world face an exciting challenge in demonstrating that HDR can be a technically and commercially viable renewable option for the future.

This international conference comes at an appropriate time therefore and presents an excellent opportunity for all concerned to exchange views and pool their knowledge. I welcome the initiative of the Camborne School of Mines in hosting this conference and wish the conference every success.
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**CAMBORNE SCHOOL OF MINES INTERNATIONAL HOT DRY ROCK CONFERENCE**

held at

Camborne School of Mines
Redruth, Cornwall, UK.
27-30 June 1989

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## FOREWORD

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International Hot Dry Rock Geothermal Energy Conference
J Rae.

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Hot Dry Rock and Its Relationship to Existing Geothermal Systems
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Following the oil crisis in 1974 it became clear that alternative sources of energy production and conservation of existing energy usage was necessary, particularly by the industrialised countries who used a significant proportion of the world energy resource. In addition, the awareness of the pollution caused by energy production and usage has caused industrialised nations to seek alternative ways of energy production and thus reduce the burning of fossil fuel.

One of the alternative sources is geothermal energy. For a system to be used as a geothermal energy resource requires the presence of three key conditions:

a. A mass of hot rocks.

b. A large permeable zone, to transfer heat from rock to fluid.

c. Large enough flow to be able to extract sufficient heat for power generation at the surface.

The extraction of energy from the geothermal resource can be broadly divided into two categories i.e. hydrothermal/aquifer and hot dry rock.

In a hydrothermal system energy is recovered from naturally occurring hot fluids contained in underground reservoirs. Most hydrothermal systems are formed in areas where rising magma brings the heat source near to the surface. These zones will always be tectonic regions associated with vulcanism and earthquakes. Hydrothermal energy is already being used worldwide to generate over 5000 MW of electric power and there is also a substantial use of direct thermal power.

However hydrothermal systems provide a very limited energy extraction from what is potentially a large resource. Conditions b and c are absent at the majority of potential sites but condition (a) is most certainly present at all sites and can be accessed by drilling deeper. The potential exploitable resource of hotter rocks at depth which require the permeability to be enhanced and the provision of
sufficient fluid to extract the heat has become known as Hot Dry Rock (HDR) geothermal energy.

In essence, the concept of developing HDR systems is elegantly simple. An injection and a production well have to be drilled in a body of hot rocks and linked together to create an artificial reservoir which has suitable hydraulic and thermal characteristics that will allow the economic extraction of the heat. In reality the creation of such a system is far from simple.

Early research carried out in mid 1970's (Figure 1) in the UK, USA, France and Federal Republic of Germany adapted techniques from oil well stimulation and idealised the reservoir as a 'penny-shaped' fracture formed in a rock mass which behaves as an isotropic continuum within a uniform stress field. The implications of creating a reservoir in such a medium was that the most likely effect of water injection under high pressures would be to 'jack' the natural joints open and form the heat exchange surface within it. Early research at various sites, in several countries, confirmed that hydraulic fracturing was not the dominant process but that the shearing of natural joints favourably aligned with the principal stress was a more important mechanism. The joints failed by shear mechanism because the fluid injection reduces the normal stress on the joints but only marginally affects the magnitude of the shear stress. The shearing mechanism allows frictional slippage to occur with some dilation due to the natural roughness of the joints. In fact, shear slippage can occur before jacking and therefore there will be a component of shearing ahead of any 'jacked' zone.

Most of the research has found shearing to be the main mechanism of reservoir growth and this change in thinking has led to the development of the HDR concept which has moved away from the conventional oil field technology towards the development of new technology relating to uniqueness of the roughly orthogonally jointed rockmass with anisotropic stresses.

Considerable progress has been made in the last five years in the understanding, modelling, creation and characterisation of a hot dry rock reservoir. Only the reservoir at the Rosemanowes site of the
Camborne School of Mines has been circulated long enough to progress from what is basically the creation of a reservoir. Although it is true to say that the creation of a commercial size HDR reservoir has still not been achieved, significant progress has been made in other important fields such as the characterisation of the reservoir and applying remedial treatment to improve existing reservoirs.

A commercial HDR reservoir will most certainly have to be considerably bigger than any circulating HDR reservoir created to date and the proposition at present is that a number of segments will have to be created instead of a single large reservoir envisaged during the late seventies and early eighties. It is becoming clear that an HDR reservoir of this size will have to be managed throughout its life and remedial treatment will have to be carried out to extend its life. Some of the remedial treatment can broadly be grouped as

i) To improve the hydraulic performance of the HDR reservoirs during their operational lifetime

ii) To seal preferential hydraulic flow paths (short circuits) which may reduce the life of reservoirs.

A reservoir has to be characterised prior to the application of a remedial treatment. The characterisation of a reservoir can include techniques such as tracers, active and passive seismics, hydraulic well tests, geochemistry, thermal modelling and other numerical modelling. A reservoir circulating over a long period is essential for evaluating these techniques.

It can be seen from the above outline that although the idea of accessing hot rock at depth to obtain heat has not changed, the understanding of the technology required to make this a reality has changed significantly. HDR research is being carried out by a number of countries (See Figure 1) and it was felt that as the technology associated with HDR has changed significantly from the early days in mid 1970, an international conference would be an ideal venue to review this technology, share experiences and exchange information.
FIGURE 1 BAR CHART SHOWING HDR PROJECTS
The International Conference on Hot Dry Rock (HDR) geothermal energy was organised by CSM Associates Ltd with support from the Energy Technology Support Unit at Harwell, the UK Department of Energy and the Camborne School of Mines. The main co-organisers of the conference were Mr R Baria, Mr H Scholes and Mr A W Brooks. The International Conference was held on 27-30 June 1989 at the Camborne School of Mines, Pool, Cornwall, UK, and was attended by 97 participants from Canada, the Federal Republic of Germany, France, Italy, Japan, the Netherlands, Sweden, Switzerland, the United Kingdom, and the United States of America, and 47 papers were given over four days.

The welcome address was given by Dr P Hackett (the Principal of the School of Mines) followed by the opening address given by Dr J Rae (Chief Scientist at the UK Department of Energy). Dr A S Batchelor (GeoScience Ltd) gave an initial keynote lecture. The closing address was given by Dr J E Rannels, Manager, Hot Dry Rock Programme from the US Department of Energy.

HDR research covers a large number of disciplines and the papers submitted to the conference show a remarkable diversity and difficult to classify. However, they were organised in five sessions as follows:

Session 1  THE HDR ENVIRONMENT
Session 2  CURRENT STATUS FOR HDR TECHNOLOGY
Session 3  HDR RESOURCE/ECONOMICS
Session 4  RESERVOIR CREATION
Session 5A  RESERVOIR DEVELOPMENT (Parallel Session with 5B)
Session 5B  RESERVOIR DEVELOPMENT (Parallel Session with 5A)
Session 5C  RESERVOIR DEVELOPMENT

The Organising Committee would like to thank all the participants and in particular the Camborne School of Mines, the Energy Technology Support Unit and the United Kingdom Department of Energy for their support.
OPENING ADDRESS

INTERNATIONAL HOT DRY ROCK GEOTHERMAL ENERGY CONFERENCE

DR JOHN RAE

CHIEF SCIENTIST, DEPARTMENT OF ENERGY

In the United Kingdom, we are fortunate to enjoy a considerable range of energy sources, with substantial reserves of coal, oil and gas, and long experience of nuclear power.

In an uncertain world with occasional energy "crises", we need to make use of all available sources of energy to provide diversity of supply. The approach by the UK Government is to provide a framework in which all economic sources of energy can be produced, supplied and used as efficiently as possible - at the lowest practicable cost - whilst at the same time meeting acceptable safety and environmental criteria.

The Department of Energy's programme of Research and Development on Renewable Energy is being undertaken as part of this overall strategy. Many other countries have also recognised the important role that renewable energy may play in the future, and have research programmes in this area. Where appropriate the UK is participating in a number of collaborative research programmes notably within the framework of the International Energy Agency and the European Commission. We are also working closely with the US Department of Energy under a bilateral agreement.
Continued collaboration forms an important part of our long-term strategy for renewable energy technologies.

The UK has pursued a programme of research, development and demonstration since 1974 in order to:

stimulate the full economic exploitation of alternative energy resources in the UK;

establish options for the future;

encourage UK industry to develop capabilities for the domestic and export markets.

The programme of work aims to:

identify and assess appropriate technologies;

develop in collaboration with industry, those technologies with commercial prospects;

demonstrate those technologies, transfer the technical knowledge to manufacturing industry and potential users and, where appropriate, transfer the responsibility for their further development.
The present phase of the UK's renewables programme has two main objectives. They are:

to encourage and promote the commercialisation of those technologies which are economically attractive. For example, simple passive solar design of buildings, and landfill gas extraction;

to reduce the uncertainty in the economics and potential contribution of those technologies currently classed as promising but uncertain so that, where possible, they become economic, and confidence is created in them. Examples of this category are wind, tidal and geothermal hot dry rocks.

Over £140 million (over £190 million at 1988 prices) has already been invested in developing the renewable technologies and a further £50 million is likely to be spent over the next three years. The Department funding provision for 1989/90 is £17.9 million.

Over 250 projects are underway or planned in the Department's programmes covering wind, tidal, low head hydro, inshore wave, geothermal hot dry rock, passive solar design of buildings and biofuels.
Further encouragement to Renewable Energy has recently been announced by Government. The non-fossil fuel obligation in the Electricity Bill for the privatisation of the electricity supply system will guarantee a level of diversity for electricity generation. In recognition of the potential of renewable sources, tranches of electricity generation up to 600MW by 2000 will be reserved exclusively for the renewable projects.

I have already mentioned the important role of international collaboration in the UK's renewable energy R&D strategy. Hot dry rock geothermal research is well suited to international collaboration and many such arrangements have been completed or are in being.

The US Hot Dry Rock geothermal energy programme near Fenton Hill started in 1974 with West Germany and Japan participation. Dr Rannels from Los Alamos National Laboratory will be talking about the Los Alamos HDR project tomorrow.

A single well has so far been drilled near Soultz, in France. This project is funded by the EEC, West Germany and France. We will be hearing about its progress from Dr Kappelmeyer and Dr Gerard tomorrow.

In Japan there is an active HDR programme and progress at the two test sites at Hijiori and Yakedake will be discussed by several
authors in the next few days.

The conference will also hear about the scheme in Sweden, and possible sites for HDR in Italy. The HDR scene is indeed an international one and it is pleasing to note the large number of visitors from abroad attending this conference.

In the UK, work on HDR started in Cornwall in 1976 and since then, the Department of Energy has spent more than £30 million on the HDR concept.

It is most appropriate that the International Conference on HDR should be hosted by the Camborne School of Mines in view of their pioneering role in the technology over the past 13 years. You will hear about progress on the research at Rosemanowes from CSM in the next few days. It is also appropriate that the keynote speaker of the conference should be Dr Tony Batchelor. Dr Batchelor was CSM's Project Director at Rosemanowes for about the first 10 years of the Department's programme and still has a very healthy interest in HDR and aquifer technology.

Before Dr Batchelor makes his contribution, I would like to spend a few minutes reviewing where we have got to in HDR research and what issues still remain to be addressed.

Most if not all commercial conventional geothermal energy is currently extracted from volcanic, seismically active regions
around the world. The hot dry rock concept is different in that it attempts to engineer geothermal systems by accessing hot granitic rocks by drilling to sufficient depths in relatively stable aseismic regions.

The HDR concept is fairly simple. In theory all one needs is a pair of wells drilled into granite terminating several hundred metres apart, and a suitable reservoir to be created by opening up pre-existing joints by some means of stimulation. Water is circulated down the injection well, through the HDR reservoir and up the production well. The heat can be used for electricity generation, combined heat and power or district heating. In the UK for example, we would need to drill to 6-7 kilometres to access temperatures sufficiently high for electricity generation.

I would like to concentrate for the moment on HDR development in the UK since I believe that many of the issues we face are common to all HDR R&D programmes wherever they are based.

HDR work at Rosemanowes in Cornwall was first carried out at 300 metres to establish the validity of the concept of reservoir stimulation. From 1980 to 1983 two holes were drilled to a depth of 2000 metres and a large reservoir was established by means of explosive and hydraulic fracturing. The resistance to flow was too high however and a third borehole drilled to a depth of 2600 metres. The main objective of the R&D up to 1988 was to determine the feasibility of creating a viable HDR reservoir.
reservoir at Rosemanowes has been circulated for about 3 years, the longest period for any HDR reservoir in the world. This experience has been invaluable.

The current programme of work which started in October 1988 includes:

- experimental work on the existing reservoir in Cornwall at 2km to help test the feasibility of techniques that would be required to create a commercial system at 6-7 kilometres.

- an initial design study for a 6km deep system in collaboration with industrial companies. This study is now underway and will be carried out by RTZ Consultants Ltd in association with the CEGB, the South West Electricity Board and Kenting Drilling Services Ltd.

- supporting technical and economic studies.

A major review of the UK HDR programme will be carried out in 1990.

The main objective of the HDR programme in the UK is to determine the technical and economic viability of HDR systems for electricity generation, combined heat and power or the direct use of heat. A successful and complete R&D programme on HDR geothermal energy would tell us three things:
a) an economical route for delivering energy to final users

b) the resource size and distribution

c) practical means for extracting heat energy.

We are not yet at this point in the UK. The R&D programme has gone a long way on a) and b) but c) still presents us with some problems. We have established that electricity generation is likely to be the most cost effective route for HDR in the UK and that we appear to have a sizeable resource mainly in South West England, although this will be reviewed in detail in 1990.

The technology of HDR amounts to drilling to depth in granite, creation and operation of a reservoir, and the installation and operation of surface plant.

There is now international experience in drilling in granite, for example the Siljan borehole in Sweden. However, despite the significant advances made in drilling technology in recent years, drilling to depths of 6 or 7 kms, as we require in the UK, will not be an easy task.

The availability and operation of suitable surface plant, should not be a major problem but the plant will need to be chosen carefully to maximise efficiency and reliability and to minimise
The main problem that we are now struggling with in the UK and elsewhere is the concept of creating a commercial HDR reservoir which will perform satisfactorily over a lifetime of 20-30 years.

Many problems remain to be solved in this area. Some of these are as follows:

- to create a reservoir that has adequate volume and surface area suitable for commercial operation. Our research has found that there is a limit to the largest volume of rock which could be stimulated in a single operation to form a reservoir. A commercial reservoir could therefore require multiple stimulation of several reservoir modules in parallel to create the target reservoir. The feasibility of this concept needs to be validated;

- to create a reservoir that will operate over a sufficiently long lifetime. Preferential flow paths or short circuits could develop. The nature of this will need to be understood and techniques to manipulate HDR reservoirs in order to correct and/or improve performance including sealing procedures at depth will need to be validated;

- problems such as possible corrosion of well linings and plant, chemical clogging of the fractures, will have life limiting
effects and will need to be understood and suitable remedies developed.

Much of this conference will concentrate on the key area of reservoir creation, maintenance and operation. Whilst delegates discuss the important scientific issues it is essential to remember that the ultimate goal is to engineer successful commercial HDR systems which can be easily replicated and operated by industrial companies. In the UK, this means accessing what may be termed "standard" granite containing reasonably well understood natural fracture systems. Unless this can be achieved, the large UK HDR potential resource will not be realised. Whilst HDR experiments in regions containing fracture systems which may be regarded as anomalous may be of some interest, the replication opportunities of such site specific projects could be severely limited, certainly in the UK.

I mentioned that the current UK HDR programme includes economic studies and a conceptual design study of a deep system. These will form important inputs to the review of HDR in 1990.

Economic cost modelling has a major role to play in the evaluation of HDR systems, as it is essential to carry out the costing of HDR in a systematic way which ensure that no major cost items are omitted.
The conceptual design study will evaluate the feasibility of creating a hot dry rock reservoir for commercial operation and will define a plan for developing a deep prototype system. The Department of Energy welcomes the important industrial input from the various companies involved in the study. Industrial participation is essential in the next stages of HDR if the technology is to progress in the UK.

Baroness Hooper, the minister responsible for Renewable Energy, in the Department of Energy said in her letter to conference that teams round the world face an exciting challenge in demonstrating that HDR can be a technically and commercially viable renewable option for the future, and that this international conference comes at an appropriate time and presents an excellent opportunity for all concerned to pool their knowledge.

May I echo my ministers' remarks and thank the Camborne School of Mines for their initiative in hosting this conference, and wish the conference every success.

JUNE 1989
HOT DRY ROCK AND ITS RELATIONSHIP TO EXISTING GEOTHERMAL SYSTEMS

A S Batchelor, GeoScience Limited

KEYNOTE LECTURE

ABSTRACT

The commercial utilisation of geothermal energy forms the basis of the largest renewable energy industry in the world. More than 5000 MW of electrical power are currently in production from approximately 210 plants and 10 000 MW thermal are used in direct use processes. The majority of these systems are located in the well defined geothermal 'belts' generally associated with crustal plate boundaries or hot spots. The essential requirements of high subsurface temperatures with huge volumes of exploitable fluids, coupled to environmental and market factors, limit the choice of suitable sites significantly. The Hot Dry Rock (HDR) concept at any depth originally offered a dream of unlimited expansion for the geothermal industry by relaxing the location constraints by drilling deep enough to reach adequate temperatures.

Now, after 20 years intensive work by international teams and expenditures of more than $250 million, it is vital to review the position of HDR in relation to the established geothermal industry. The HDR resource is merely a body of rock at elevated temperatures with insufficient fluids in place to enable the heat to be extracted without the need for injection wells. All of the major field experiments in HDR have shown that the natural fracture systems form the heat transfer surfaces and that it is these fractures that must be manipulated to provide viable reservoirs. The techniques developed for geothermal systems producing from naturally fractured formations provide a basis for directing the forthcoming programmes in HDR away from the procedures of massive hydraulic fracturing but, equally, they require accepting significant location constraints on HDR for the time being.

This paper presents a model HDR system designed for commercial operations in the UK and uses production data from hydrothermal systems in Japan and the USA to demonstrate the reservoir performance requirements for viable operations. It is shown that these characteristics are not likely to be achieved in host rocks without significant jointing given the current understanding of the stimulation processes. However, the long term goal of artificial geothermal systems developed by systematic engineering procedures at depth may still be attained if high temperature sites with extensive fracturing are developed or exploited first.

INTRODUCTION

The opportunity to present the keynote paper at this conference is an honour; in this paper I have chosen to present my personal view of developments of Hot Dry Rock (HDR) by making comparisons with existing geothermal systems already in operation. It is important to recognise
that I have not been involved in the UK HDR programme run by the Camborne School of Mines since 1986. During that three year period I have had the opportunity to reflect on various aspects of HDR development without the pressure of programme management issues.

The paper is divided into four sections:

- HDR as an integral part of all geothermal systems
- HDR as a research base for geothermal developments
- Where next for HDR?
- Conclusions

In general, the paper considers the use of HDR for power generation only and concentrates on considering HDR as part of an overall power generation system. In addition, I believe it is important to view the commercial development of HDR in a market for power that is controlled, essentially, by price. The reason for making this distinction is that the major HDR programmes in the USA, Japan, UK, France and Germany were developed in response to the first 'oil shock' of 1973. The policy targets for the UK programme were related to what was known as 'insurance technologies' and the programme goals were related to the development of energy production systems without strict regard for the immediate economics of the process. The general prevailing attitude was one of impending energy shortage and high prices; it was this assumption of a 'supply limited' commodity that formed the basis of policy development. The programmes at Los Alamos and Rosemanowes were spawned in this era; however, now, in the apparent calm of a transient period of stable oil prices and an extraordinary abundance of natural gas for the immediately foreseeable future, the target is a competitive energy production technology based on the price of the end product. The target now must be based on a 'least cost' scenario because the selling price of the energy is fixed by Government regulation in one form or another. The rest of this paper is concerned with the necessary steps that I believe are required to enable such developments to take place and quantify the contribution that HDR may be able to make in the future.

THE DREAM

The originators of the modern work in HDR, Smith (1973), together with some of the early advocates of artificial geothermal systems, Gardner (1885) and Parsons (1904), worked with a very simple and powerful concept:

- At any location drill several holes deep enough to reach high temperatures.
- Apply engineering techniques to link the boreholes with a heat transfer surface.
- Circulate water between the wells to extract the heat.
- Produce power and reinject the water.
The essential arguments were that suitable temperatures could be reached at any location by drilling deep enough and that the circulation loop was essentially closed. The challenge was to develop repeatable engineering techniques to interlink the wells on a sufficient scale to provide adequate lifetime. The working models were based on 'penny-shaped' fractures, Harlow and Pracht (1972), and much of this early work is still very useful in setting the scope and range of basic parameters. Clearly, in the long term, it is this concept of HDR that remains the ultimate target. The result of such a process would be:

- 'An infinite source of energy'
- No 'greenhouse' gases
- No 'waste discharge'
- Local facilities using established surface technology

Institutional issues such as the freedom from interference on the basic fuel supply and a lack of environmental discharges have a significant appeal but, as yet, cannot be translated into a financial return. Calculations show that the land area of Europe with geothermal gradients greater than 40°C per kilometre is such that the thermal reserves may be estimated to be 37 000 million tons of coal equivalent lying at depths less than 6 km if 5% of the heat could be extracted. Analyses of this type, coupled to the fact that this technology is the only renewable resource with continuous availability that can form secure baseload generation, shows why HDR has a major political attraction if it can be developed successfully.

The early papers and subsequent justifications for HDR development treated the subject as a separate class of geothermal resource; as I will explain later in the paper, I believe it is more helpful to consider a much wider definition of HDR to enable the HDR programmes to focus their efforts in slightly different directions. Consider the following definition of HDR:

- An HDR system is any system where reinjection is necessary to extract the heat at a commercial rate for a prolonged period.

The breadth of this definition encompasses porous formations where reinjection is used to provide pressure support at great distances without, necessarily, breakthrough of the reinjected water, high enthalpy vapour dominated systems where river water is used to augment the steam condensate reinjection and the classical version of HDR systems based on artificial fractures.

The importance of this definition is that it allows the inclusion of existing geothermal systems where the heat is being mined by the reinjection process rather than relying simply on the enthalpy of the in-place natural fluids. By using this definition, and allowing the scope of HDR to expand, it is possible to look towards both porous and fractured systems that have adequate in-situ hydraulic characteristics, without any form of recharge or existing water circulation, that could be used for geothermal power production if the boreholes can be positioned in an adequate manner. It means that by comparing
the behaviour of successful natural systems it is possible to seek engineering solutions that could be applied for energy extraction in HDR. This is very similar in concept to the 'forced geo-heat' systems discussed by Bodvarsson and Reistad (1975).

If the definition given above for HDR is acceptable then it follows that:

- All natural geothermal systems are special forms of HDR with adequate permeability coupled with large volumes of hot fluids inplace.

In this way, it is possible to consider that the existing geothermal industry is tackling the easiest, highest value geothermal resources at the moment and, by increments, is beginning to tackle more complicated situations. The underlying theme running through this paper is that the huge step from existing natural systems to totally artificial systems was probably too great, with hindsight, because the influence of vital constraints in the geological environment was not recognised and tackled systematically. I contend that HDR systems can be developed by backing away from the current 'blue skies' goal and working in a simpler environment. The understanding that would be gained during this process will lay the foundation for the long term work.

NATURAL GEOTHERMAL SYSTEMS

In April 1989, it was estimated that 5275 MW of geothermal generating capacity was installed worldwide. If all this plant was operating to full capacity, it would be the equivalent oil production of 245 000 barrels per day, worth approximately US$ 1.6 billion per annum, or 1% of the revenues of the global oil industry. Source (DiPippo, 1988, plus extrapolation!). Figure 1 is taken from DiPippo and shows the growth of geothermal power plants throughout the world. The delayed influence of the oil price instability is clear in this illustration. Table 1, also derived from DiPippo, shows the breakdown between steam and liquid dominated geothermal systems. This table highlights the development of geothermal energy. Notice that more than 50% of the installed capacity is in five countries with vapour dominated resources. The table is completely overshadowed by the very significant developments in the USA, primarily in The Geysers. Liquid dominated resources, on the other hand, are much more widespread and it is likely that approximately twenty countries will have power plants of this type in operation by the early 1990's. This highlights that the very best resources, the vapour dominated ones, have been developed followed by the more complex hydrothermal systems. Flashing power plants have been developed that can work with geothermal fluids with temperatures as low as 170°C. Work with various organic binary cycles has shown that it is technically possible to generate power at temperatures of the order of 100°C although the economics of such developments are uncertain. HDR would take the development one stage further towards systems without the substantial inplace fluids and that step alone would provide a significant expansion of the industry in the right geological circumstances.
FIGURE 1  INSTALLED GENERATING CAPACITY (AFTER DIPIppo, 1988)
### TABLE 1  GEOTHERMAL POWER PLANTS, 1988

<table>
<thead>
<tr>
<th>Country</th>
<th>Steam (MWe)</th>
<th>Liquid (MWe)</th>
<th>Power (MWe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA</td>
<td>1981</td>
<td>293</td>
<td>2211</td>
</tr>
<tr>
<td>Phillipines</td>
<td>0</td>
<td>894</td>
<td>894</td>
</tr>
<tr>
<td>Mexico</td>
<td>10</td>
<td>645</td>
<td>655</td>
</tr>
<tr>
<td>Italy</td>
<td>500</td>
<td>4</td>
<td>504</td>
</tr>
<tr>
<td>Japan</td>
<td>22</td>
<td>193</td>
<td>215</td>
</tr>
<tr>
<td>New Zealand</td>
<td>0</td>
<td>167</td>
<td>167</td>
</tr>
<tr>
<td>El Salvador</td>
<td>0</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>Indonesia</td>
<td>85</td>
<td>2</td>
<td>87</td>
</tr>
<tr>
<td>Kenya</td>
<td>0</td>
<td>45</td>
<td>45</td>
</tr>
<tr>
<td>Iceland</td>
<td>0</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>Nicaragua</td>
<td>0</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>Turkey</td>
<td>0</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>China</td>
<td>0</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>USSR</td>
<td>0</td>
<td>11 (? + 50)</td>
<td>11</td>
</tr>
<tr>
<td>Guadeloupe</td>
<td>0</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Azores</td>
<td>0</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Taiwan</td>
<td>0</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Greece</td>
<td>0</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Australia</td>
<td>0</td>
<td>(4) ?</td>
<td>(4)</td>
</tr>
</tbody>
</table>

Figure 2, based on data from DiPippo, shows the distribution of turbine sizes in the natural geothermal fields in operation. It can be seen that the vast number of these units are small, of the order of 10 MW, with another peak at 55 MW. The latter peaks tend to be the preponderance of dry steam systems while the others are flash and binary units of various types. DiPippo (1985) has reported that there is little evidence of economies of scale in the sizing of geothermal
FIGURE 2  ACTUAL TURBINE SIZES (SOURCE DIPIppo, 1985)
turbines and the size of the units is based on the minimisation of manufacturing costs and the reduction of operation and maintenance costs. Tucker (1989) has suggested that an optimum individual turbine size for a double flash unit is approximately 20-25 MW and that larger units should be composed of multiples of this size. This distribution of turbine sizes points towards a constraint on the development of artificial geothermal systems. Individual turbines will be sized on a similar basis, so plants will be multiple turbine units of the order of 25 MW each in size. This, to some degree, sets a limit on the market for these units in a developed power system because they will need to compete at baseload conditions with the large multiple sets of 500-900 MW per unit. For the UK, this points to areas with significant demands at considerable distances from the nearest baseload plant. Cornwall happens to be geographically suitable because the nearest power station is 200 km away at Hinkley Point.

By examining the developments of geothermal power plants, it is possible to set criteria for wells that will form economic geothermal systems. Typically, these are:

- Depths of 1000-2500 m
- >50 tons per hour (dry steam)
- >350 tons per hour (liquid dominated)
- Maximum production, approximately 225 tons per hour (dry steam)
- 650 tons per hour (liquid dominated)
- >200°C reservoir temperature

Kruger and Otte (1973) have stated that any geothermal system that is not obviously economic without the use of computer models and major economic appraisals is definitely not economic. The overall level of risks in the business are such that 'obviously good' systems have sufficient margin to cover the unexpected difficulties of long term production, eg scaling and corrosion which can be quantified during start-up.

These general observations of an obvious economic well point towards the incremental step for HDR to be in the non-productive areas of regions where the depths and temperatures remain similar to those already in use. The Japanese project, Hijiori, is a perfect example of this step, although even that project has gone into a region that may not have sufficient natural fractures to provide significant wellbore interlinking. In Europe, conditions of this type are only found in Italy and Greece; Kappelmeyer (1986) has long been an advocate of developing HDR technology in association with the work in Italy.

Coupled to the 'obvious' economic well are perhaps some sweeping generalisations associated with reservoirs. Successful reservoirs have three key characteristics:

- Most are comprised of vertical fractures.
These fractures are open below a certain depth.

A significant number of fields have in-situ recharge from aquifers.

The second feature highlighted above concerning the depth of open fractures has been proven repeatedly by drilling programmes encountering 'lost circulation' or 'top of steam' below certain depths in areas of moderate uniform geology. A more recent development of systematic microseismic monitoring of geothermal fields, Ziaogos and Combs (1988), has shown that the seismicity has a distinct top in these systems. The techniques for analysing these microseismic events have been developed from the very successful programmes at Rosemanowes and Los Alamos and this topic highlights a key area of cross fertilisation which will develop rapidly as the use of microseismic monitoring grows.

One of the challenges facing the development of natural geothermal systems can be summarised as follows:

- Assess fracture azimuth, fracture dip, fracture length
- Estimate aperture variations
- Determine fracture frequency
- Predict fracture interconnection
- Predict flowpaths
- Estimate production from the interlinked system

To date, natural systems have exploited those reservoirs that are so highly productive that they do not require further investigation. It should now be possible to use the constraints understood in those systems to identify the key characteristics of reservoirs that are more difficult to bring on-line. For people that have been active in HDR, the list of challenges identified above is very similar to those associated with the development of an entirely artificial reservoir.

COMMERCIAL ASPECTS

Natural geothermal systems that have been used for power generation have developed various contracts to safeguard both the resource owner and the power generating utility. The more successful of these contracts point to five key elements that can maximise the income of such a unit. By understanding the implications of these elements, it is possible to set limits on the overall system design. The key features of such a Power Sales Agreement could be:

- A base capacity credit, greater than 75% availability
- A premium capacity credit, greater than 85% availability
- A super premium capacity at peak times on notice
- An energy price per kilowatt with a 'floor price'
A value for reactive power

The key feature of such a contract is to ensure that the majority of income to the steam field system is generated from the capacity credit rather than the energy sales. This is because the large capital requirements and proportionally small operating costs need to be serviced in a different manner to those associated with a relatively cheap fossil fuel system whose costs are totally dominated by the fuel element during operation. The constraint established in a sales contract of this type is that the longevity of the reservoir needs to be proven at an early stage to ensure that the project can be financed. The existence of the power plant, say two thirds of the capital cost of the project, can only be justified if the hot fluid production system can be demonstrated to be able to provide the heat source for an adequate life. The crucial commercial challenge facing HDR development is not simply the technology to generate interlinked holes but, even more important, the techniques to demonstrate unambiguously that the reservoir is of sufficient size to provide an adequate life. Until these techniques are developed, all HDR geothermal developments are going to be subject to an 'act of faith' at the time when the project is developed and this will be a major obstacle to be overcome. Focusing attention on techniques like microseismic and other geophysical investigations does not enable this proof of reservoir size to be given. It is only the geochemistry and the tracer test developments that will identify the flowing reservoir structures and their sizes immediately after reservoir creation that will be acceptable in the longer term.

HOT DRY ROCK RESEARCH

Batchelor et al (1989) estimated the international expenditure on HDR as follows:

<table>
<thead>
<tr>
<th>Country</th>
<th>US$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA, primarily Fenton Hill (Murphy, priv comm)</td>
<td>132</td>
</tr>
<tr>
<td>UK, primarily Rosemanowes (£27 million)</td>
<td>47</td>
</tr>
<tr>
<td>Japan, NEDO, Tohoku, CRIEPI and NRIPR (Kobayashi, priv comm) (Yen 3484 million)</td>
<td>27</td>
</tr>
<tr>
<td>France</td>
<td>8</td>
</tr>
<tr>
<td>Germany, Falkenberg, Urach, Fenton Hill</td>
<td>33</td>
</tr>
</tbody>
</table>

$ 247 m

This apparently sizable research effort should be set in context as a total expenditure of only one sixth of annual revenues from the geothermal business, yet, even in the short term, holds the prospect of allowing that business to expand several fold. However, much of
this effort has been spent in fundamental developments of geophysics and earth science techniques which are highly valuable but not necessarily applicable immediately for use in the development of viable HDR systems. The various international programmes in HDR appear to suffer from several common problems:

- A lack of immediate objectives
- Undertaking 'what can be done'
- Lack of customer or industrial participation/interest
- Research teams 'seen to be busy'
- Generic studies of various types

These problems are compounded because the funding is generally provided by state institutions to research centres or university research teams. The objectives are set by the political policies of the funding agency and these, by definition, change more rapidly than the ability of the operational programmes to produce sustained goals under any one policy. The classic problem is the difference between developing 'insurance technologies' and designing systems to work to a price. The risk of developing substantial new technologies in an area where the market is pre-defined cannot be borne by industry; this is a fundamental problem that needs acceptance as a 'fact of life'. The research teams undertaking the work can only tackle problems or develop prospects within the constraints of their own expertise. The nature of the work in the UK and France, for example, was dominated by an interest in the rock mechanics aspects of the reservoir development because of the background of the senior staff involved. Intermediate goals, such as the successful development of a particular geophysics tool, provide motivation for individual groups but it is important that the significant and intractable problems are tackled and this requires venturing into less well understood areas.

A significant factor of the international programmes has been the complete lack of interest on any significant scale by utilities or their collective long term research agencies. This has ensured that there is no industrial base or market enthusiast within the industry to support the development stage when some of the research results became available. A counter argument from the utilities has always been that their duty is to provide for the power needs in the near and foreseeable future and that the price available is set by their other operations. Therefore, they would be interested in HDR if the price could be seen to reflect a commercial venture. However, once it was recognised that the development of 'insurance' technologies was not an adequate policy, the absence of utility support has severely undermined the credibility of the various programmes.

The problem of 'seen to be busy' is endemic in the overall operational structure in which these programmes work. University and research laboratory teams are brought together for the purposes for the individual project. This means that they develop an inertia of their own and the ability to stand back from the technology and review what may well be mistakes made in the heat and pressure of the moment is taken away at a crucial time. There is no obvious solution to this
problem because collective expertise can be dissipated by stop/go policies yet the overhead of review periods cannot support the essential operational staff. This can lead to the final problem of the generic study which is continuously working in a vacuum and is criticised for its lack of consideration of site specific issues. At this stage of the development of the technology such generic studies can be highly dangerous either as being too optimistic, eg a CEGB report once suggested that 15% of UK power supplies could come from HDR, or overly pessimistic.

A MODEL HDR SYSTEM

Figure 3 shows an HDR system consisting of three reservoir modules each with one injector and three producers working on a double flash cycle to produce 82 MW gross. This HDR concept has been developed to take advantage of a major estuary for the supply of cooling water thus eliminating cooling towers. The double flash plant is used to ensure that the production wells flash at a depth greater than 500 m to provide 'suction' on the production side of the reservoir. The circulation pressure has been set at 95% of the in-situ effective earth stress and this model has been used to set limits on the reservoir size and engineering development for the long term heat extraction. Studies of overall systems have shown that:

- Drilling - satisfactory to 5000 m, struggle to 6000 m.
- Completion - cementing and casing design needs considerable work.
- In-situ measurements in deep wells may be suspect and misinterpreted.
- Stimulation fluid rheology, composition and proppant needs considerable work.
- Assessment of natural fracture systems that could possibly provide an adequate reservoir has barely begun.

The reservoir development to provide an adequate size of heat exchange system can be controlled only by the interwell distance if it is the natural geological structure that provides the farfield interlinking and connectivity. The only parameter under the control of the engineering development is the position of the borehole in relationship to the natural joint structure. Papers later in this conference, Randall et al (1989), are providing significant insight into the interlinking of natural systems and these will be exploited by the positioning of the wells. The model above implies interwell separations of the order of a 1000 m to provide an adequate life. None of the research programmes have got close to figures of this size so, clearly, if natural joint systems are to provide the basis of the next generation of HDR reservoirs they must be within significant permeable structures that can be utilised over distances of 1000-2000 m. The scheme presented in Figure 3 has a capital cost of US$ 253 million and a potential revenue based on the most optimistic interpretation of the local Cornish utilities prices of US$ 31 million. To make this project commercially attractive there is a need to halve the cost or
FIGURE 3  A CONCEPTUAL 63MWe NET DOUBLE FLASH PLANT WITH AN HDR SYSTEM IN CORNWALL
double the revenue but, more importantly, eliminate the risk of a failed reservoir model early in the development of the process.

Setting these targets by the examination of the site specific system has enabled further conclusions to be developed. For example, if an exploration well to 6000 m in an area thought to be heavily fractured finds that the in-situ structure is either extremely tight or non-existent, the whole concept of HDR systems within natural fractures at great depth becomes improbable. This shows one of the dangers of attempting to undertake a programme that is too adventurous too soon. However, if HDR is to continue in the UK, it is crucial that a well is drilled to the full commercial depth as soon as possible to ensure that adequate in-situ data is used for the site specific evaluation of the viability of a project. It seems likely that this will only be funded as the byproduct of another programme, say a rig testing programme, or as a fundamental development supported by Government.

GENERALISED CONCLUSIONS

The key site issues for HDR are:

- Temperature
- In-situ fluid pressure
- In-situ stresses
- Joint distribution
- Aperture variations within the joints
- Farfield interconnections between the joints

The development of the physical and analytic tools to assess whether a natural jointed system can support a viable HDR system have not yet been completed to a sufficient degree and this is a major weakness and omission from HDR developments internationally.

I draw general conclusions from the work to date:

- Jointed formations are essential.
- Stimulation activity is limited to curing near wellbore problems and not the creation of interlinked significant reservoirs.
- Maximum possible heat transfer area is predetermined by the in-situ joint geometry.
- The accessible area is controlled by aperture, fluid rheology during stimulation and the in-situ stresses.
- The minimum in-situ rock temperature should be over 200°C.
- Depth shallower than 6000 m.
* Significant in-situ structures to provide the possibility of the large interwell distances required for developing huge reservoirs.

* Non-critical shear stress anisotropy to avoid long term shearing during reservoir operations at high pressure.

The implications of these conclusions applied to the UK show that:

* It is foreseeable that 300-500 MW of electricity could possibly be developed in Cornwall over twenty to thirty years, but it is unlikely that systems will be developed elsewhere in the UK in the medium term future (Note this is 10% of the world's installed geothermal capacity at the moment and would represent a huge step forward in technology).

* To be commercially successful in the UK, the income from power sales must be at least double today's value in real terms, or the cost of the systems must halve.

A 'real' HDR system may have the following characteristics:

* Individual turbines of 15-30 MW

* Two to three turbines per plant

* Twelve to fifteen wells per plant

* Twenty to forty hectare sites

* 125-175 kg/s evaporative cooling losses

* 50-75 kg/s circulation losses

* 25% parasitic power for the pumps

* Six years to construct a system

* System costs of the order of £3000 plus per kilowatt

* 95-98% availability

* Twenty to twenty five year system life

**RECOMMENDATIONS**

By integrating the above conclusions it is possible to recommend a series of short term goals prior to considering the viability of an HDR system. I would suggest the following:

* Focus on a site specific development.

* Drill to explore conditions at temperatures over 200°C.

* Measure the in-situ conditions and assess the probability of interlinked natural joints forming the basis of the reservoir.
Establish the energy sales terms to set the characteristics of the reservoir.

Set the characteristics of the reservoir and test those against the in-situ conditions and the ability to stimulate the interwellbore distance.

It would certainly be cheaper to carry out an exercise of this type if the depth to reach 200°C is shallow. It is possible that the Japanese programme offers the best opportunity for this development at 200°C, although areas in parts of Europe are distinct possibilities.

I believe firmly that HDR systems will be developed to exploit the obvious geothermal resources that are without sufficient inplace fluids to make them viable. Ultimately, the expansion of the industry requires that HDR technology is developed to allow it to expand and reach higher production targets. The next step to bring a system to reality is to take low productivity systems on the edge of natural productive systems and take advantage of the geothermal infrastructure to avoid high overheads during the early developments. I recognise that this paper is at variance with much of the original thinking that underpinned the development of the HDR programme in the UK but I consider that it reflects the 'learning' and I believe strongly that the expertise in the existing geothermal industry needs to be brought to bear on the problem as soon as possible to ensure that the understanding of natural systems goes towards making the next key moves in the development of HDR.

ACKNOWLEDGEMENTS

I acknowledge, with thanks, the honour of being invited to present this keynote address and present some ideas on HDR that are at variance with some of the current programmes. My colleagues at GeoScience and in the Geothermal Resources International Group have been very supportive in the review and criticism of material in this paper and their help is appreciated.

The Directors of GeoScience have given permission for this paper to be published; the paper contains my personal opinions and does not necessarily reflect the official view of the company.

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SESSION 1 - THE HDR ENVIRONMENT
DRILLING AND ASSOCIATED ASPECTS OF HDR SYSTEMS

A J Beswick *

ABSTRACT

The principal cost in the construction of an HDR system is the drilling and completion of the injection and production wells. To date research efforts have been directed to system emplacement in crystalline rocks. From the drilling standpoint, this requirement together with the associated high temperature and rock stress environment, introduces special conditions which differ significantly from the normal demands of the petroleum and mining industries.

Although many of the individual requirements are within the current state-of-the-art of drilling and completion technology, there are some important areas which step outside current experience, particularly related to completions for multiple stimulations of fractured rock in hot, large diameter boreholes. The combination of the conditions and specifications for the wells are therefore unusual and demanding.

In the last ten years, significant experience has been gained in drilling both vertical and directional boreholes in granites for a variety of purposes including three intermediate depth HDR wells in Cornwall. This provides a database for the planning of a deep prototype system and gives confidence that wells to 7000 m can be drilled and developed successfully.

This background experience is reviewed in the context of HDR exploitation and areas of remaining uncertainty are highlighted.

INTRODUCTION

The principal cost in the construction of an HDR system is the drilling and completion of the injection and production wells. These boreholes fulfil two main functions. Firstly they access the heat source to the temperature and hence depth required to allow the circulation through the hot dry rock 'reservoir' and, secondly, they are the facility through which all operations to construct, manage and 'repair' the reservoir must be undertaken.

The service requirements of these boreholes are varied and at times incompatible. The borehole completion system has to withstand the rigors of the drilling, the reservoir development procedure, temperature and stress cycling and the corrosion effects of the circulating fluids during long term circulation. The completion configuration must be of such a diameter so as to minimise parasitic hydraulic friction losses through the system. The borehole system must be emplaced in a relatively hostile environment of uncertain geology compounded by extreme depths, high temperatures and adverse stress environment. The combined specification is outside the normal requirements of the petroleum industry and more demanding than the service requirements of most natural high temperature geothermal wells.

* Kenting Drilling Services Limited
Geothermal drilling worldwide is small in comparison with the petroleum industry and HDR research and development is only a very small part of the geothermal effort. The petroleum and mining industry are, of necessity, the base from which the geothermal engineer must draw the technologies and equipment. Although many of the requirements fall within the present state-of-the-art of current drilling and completion technology, there are some important and critical areas which are beyond current experience. Engineering practical solutions to these problems is an important task for the future.

It is necessary to recognise three phases of the research and development of HDR geothermal energy in any discussion on these important matters:

* Research and development
* Prototype construction of a deep operational system
* Routine construction of HDR exploitation facilities

In the context of this paper, 'hot dry rock' refers to the construction of a man made heat exchanger by stimulation of a naturally occurring low permeability rock mass and in particular granite. The possibility of selective natural enhanced permeability systems connected to deep high temperature sources are not considered in this context.

At the present time, several important research and development projects have been carried out directed to the development of this technology of which the ongoing project in Cornwall, administered by the Camborne School of Mines, is one of the most comprehensive. To date, the technology has not yet advanced to the stage where a full prototype system has been constructed or the design well defined, although much has been written about the technical requirements.

In any debate about deep geoscientific endeavours of this kind, and the drilling and completion aspects of HDR engineering are no exception, there must be recognition of the general advancement of the supporting technologies in the petroleum and mining industries and care must be taken in comparing events of the 1970's and early 1980's with what is achievable today. Advancement has been made in recent years in several important areas with direct benefit to the HDR case, but some other aspects urgently require development engineering or solution if the technological goals are to be achieved. Advancement in any technology is also a function of the prosperity of the supporting industry and since about 1984, deep hole drilling has been in depression which has curtailed many of the initiatives conceived in the early 1980's.

The construction of deep, high temperature HDR systems is a great technical challenge with high attendant risks at this embryonic stage with many unknowns still to be investigated.

This paper is directed towards a summary review of the experience gained in the last ten years and a discussion on some of the main aspects of the well design and critical areas of the associated implementation process. Aspects still requiring further engineering or study are highlighted. The paper does not address costs as this is an important subject in its own right and is dealt with in part by others (Ref 1) in this conference.
PREVIOUS EXPERIENCE

Whilst deep drilling in relatively large diameters in crystalline rock is occasionally called for in the traditional petroleum industry, much of the experience of this special application of deep drilling comes from scientific investigations and hot dry rock research programmes. A number of recent international projects of this kind form a database which provides guidelines for well planning. These include:

* The Urach-3 hot dry rock geothermal research borehole, West Germany (1977-1978) drilled from 1602 m to 3334 m in the crystalline basement (Ref 2)

* The hot dry rock geothermal energy research programme at the Los Alamos National Laboratory site at Fenton Hill, New Mexico, USA (1974 to date) where four directional wells were drilled up to 4660 m (MD) in granite below a 730 m cover of volcanics and sedimentary rocks. Bottom hole temperatures were up to 320°C. Successful sidetracks were achieved in the two deeper wells (Refs 3 and 4)

* The hot dry rock geothermal energy research programme at the Camborne School of Mines site at Rosemanowes in Cornwall, England (1980-date) where three directional wells were drilled entirely in granite up to 2800 m (MD) to precise trajectories (Ref 5)

* The comprehensive investigation carried out for the National Cooperative for the Storage of Waste (Nagra) in Northern Switzerland (1982-1986) where six boreholes were drilled with extensive coring to depths up to 2482 m, the lowermost 1000 m being drilled in the crystalline basement. A further programme of drilling using heavy duty wireline coring is currently in progress

* The super-deep programme in the USSR including the Kola SG-3 borehole (1970-date) where depths exceeding 12 km have been achieved (Refs 6 and 7)

* The Cajon Pass scientific borehole, California, USA (1986-1987) drilled 3.5 km north east of the San Andreas fault to yield heat flow and state of stress data drilled with partial coring. In Phase 1 the borehole penetrated 500 m of sedimentary rocks over 1615 m of granitic basement and was extended in Phase 2 to a depth of 3500 m (Ref 8)

* The KTB pilot scientific borehole in Bavaria, West Germany drilled to 4000 m (1987-1989) mainly with continuous coring using a purpose built heavy duty wireline coring system for the interval below 480 m (Ref 9)

* The Gravberg-1 well drilled as part of the Swedish Deep Gas Project at a site in central Sweden (1986-date) to a depth in excess of 6950 m entirely in granite (Ref 10)
The Soultz project in France (1987-date) where one borehole has been drilled to date to a depth of 2002 m, the lowermost 582 m being drilled in the crystalline basement with a bottom hole temperature of the order of 140°C (Ref 11)

The Salton Sea geothermal research borehole, California (1986-1987) which penetrated 3220 m with temperatures up to 355°C (Ref 12)

Much of the published information from these various projects relates to scientific aspects with some limited, but useful data on drilling, especially from the Camborne, Kola, Los Alamos, Swedish and KTB projects. A note on the more relevant information from these projects is presented in Appendix A. The status of various aspects of HDR drilling in 1986 was summarised in the proceedings of a joint EEC/US HDR workshop (Ref 13). An updated version of the summary of available equipment and methods is included as Appendix B.

Recent experience and studies relating to drilling fluids and the problems associated with stress breakout in deep holes have changed some of the approaches to HDR drilling and completion design for deep applications.

In general, data relating to HDR system emplacement in crystalline rock is very limited compared with the wealth of information available for traditional exploration and development drilling and completions for oil and gas in sedimentary provinces. In addition, the various deep boreholes in crystalline rock have been drilled for very different reasons in a variety of geological environments. Comparisons of experiences, equipment, performance etc from this limited data is somewhat unsatisfactory as geology, drilling conditions, approaches, objectives, priorities, pre-drilling investment and many other factors are so different. Account must also be taken of the degree of experimentation within each project, all of which confuses any attempt to normalise data. However, these limited, but valuable data form an important background to the planning of future deep HDR wells in crystalline rock.

In the context of deep, high temperature, HDR development, few of these various experiences are directly relevant. For example, there is virtually no previous experience in the creation of an engineered reservoir in a crystalline rock mass at depth in high temperature environments. The most appropriate and recent is the experience from the Los Alamos project, and in particular the stimulation work carried out in the sidetracked hole EE-3A in 1985-1986 and in the drilling of the sidetracked hole EE-2A in 1987 (Refs 14 and 4). The comprehensive field programme so far at Camborne has been at relatively low temperatures and modest depths in comparison to the 6000-7000 m deep system currently proposed.

In addition to these various specialist programmes which have involved drilling in the granitic basement rocks, background information is also available from the petroleum industry activities and such research projects as the Salton Sea geothermal programme in California where high temperature drilling, coring and logging were attempted. In the last decade, directional drilling developments have been a feature of the petroleum industry with improvements in tools and instruments stimulated by offshore drilling and the increase in 'horizontal' or 'long reach'
drilling activity worldwide. These projects have contributed to the continuing development of steering assemblies and surveying instrumentation, although some of the barriers, such as temperature limits and high vibration environments, still pose problems in the HDR geothermal context.

PRINCIPAL WELL DESIGN CONSIDERATIONS

The design of the wells requires certain basic information relating to the proposed system. This includes:

* The geological prognosis
* Assessed mechanical properties of the rocks
* Pressure and stress regime throughout the proposed drilled depth
* Temperature prognosis and cycling range
* Whether or not the well service can be limited to either solely a 'production' well or an 'injection' well or whether it is the desire for both wells may act as injector and producer
* Depth and geometry requirements and tolerances
* Minimum completion diameter
* Length of the injection or production interval
* In situ testing and geophysical logging programme during drilling
* Stimulation requirements as it relates to the completion system including pressures, interval isolation lengths, treatment sequence etc
* Design life of the system
* Normal operating and maximum production rates
* Corrosion potential of the system chemistry including any adverse conditions resulting from make up water chemistry or surface processing
* Sequence of drilling and details of any testing or instrumentation programmes that require suspension of the drilling such as for microseismic monitoring, trial stimulations etc
* Special requirements for instrumentation or testing after drilling and completion of the wells such as for geophysical sonde deployment in open hole intervals

Well design should start at the bottom of the wells and work upwards. Reiterations may be necessary to finesse the design.
The well design must first accommodate the reservoir development and system circulation plan. It must be recognised, at this stage in the development of HDR systems, that there may be incompatibility between the desire and what can be achieved realistically.

The principal concerns in the well design are the implications of the depth, geology and stress regime, how to achieve the required geometry of the trajectories, how to cater for the casing wear during drilling, mitigation of the corrosion of the downhole components and the thermal expansion and contraction in the casing, cementation and completion system including the wellhead.

The general concept of an HDR system is for wells to be deviated to some angle of inclination which is practical to drill while at the same time allowing the 'injection' and 'production' intervals to intersect the natural near vertical joint systems to give good communication with the potential reservoir. To date, bottom hole inclinations have been generally in the 30-35° range, although there is some debate about this feature of HDR systems. With near vertical fracture systems forming the HDR reservoir, there is a view that bottom hole inclinations should be 'near horizontal'. Despite rapid advancements in 'horizontal' and 'long reach' drilling technology and an ever growing base of field experience of this application for hydrocarbon exploitation in sedimentary rocks, the achievement of such trajectories with accuracy at the depths and temperatures required for HDR development in a granitic rock is considered unrealistic at the present time. For the future, high angle wells may be a possibility, especially for the shallower reservoirs and the use of slant drilling should not be ruled out.

Recent experience includes horizontal departures of over 1000 m. For long reach drilling, departures up to 4760 m have been achieved. A well was drilled recently in the North Sea in 93 days to a measured depth of 6017 m with an inclination of 70° and a true vertical depth of 2953 m (Ref 15). Many horizontal wells are relatively shallow up to 2000-3000 m, but in the last five years this technology has developed rapidly from the status of trials and engineering development to a relatively mature application of drilling technology.

It must be recognised that any drilling in excess of 4000-5000 m is a major undertaking and wells to these depths are still unusual in the petroleum industry. Deep boreholes to 6000-7000 m are rare. The scale of the engineering and risks involved are important factors to be taken into account in the system design.

IMPORTANT ASPECTS OF DRILLING DEEP, HOT WELLS IN GRANITE

The various experiences over the last ten years or so have given confidence that the drilling technology is available to drill deep wells in hard abrasive rock. In some respects, little has changed from the early days at Los Alamos and Camborne and contemporary reports are still relevant (Refs 5 16 and 17). The drilling mechanism itself is well understood with the best penetration results being achieved by destruction of the rock by crushing with low profile tungsten carbide insert rock bits. At high temperatures, bit seal technology becomes important.
Accurate directional drilling at great depth in hot and high vibration environments is still somewhat unproven despite the vast experience available from the oil industry. This is related to the ability to maintain hole shape to allow directional assemblies to achieve the desired response. At Los Alamos, the deeper doublet was drilled to the required trajectory in a high temperature environment, but breakout problems were not reported. At Camborne, the three intermediate depth wells were drilled accurately with no special problems. In the Gravberg-1 well in Sweden, which was intended to be vertical, directional control problems developed below about 5000 m due mainly to stress breakout giving rise to poor hole shape and a strong influence to deviate the well towards the direction of minimum principal stress. This is a warning that directional control may be a serious problem at great depth or where stress breakout cannot be controlled.

One of the principal difference between intermediate depth drilling and deep drilling to depths over 5000 m is the need to address drilling fluids more seriously, not just for hole cleaning. In recent years, experience has shown in the deeper drilling that some control of the onset of stress breakout can be achieved with good drilling fluid design. However, the dilemma is that what is necessary for the drilling may be incompatible with desire to protect the potential reservoir from invasion of drilling fines and drilling fluids. Even for drilling considerations, mud density is limited by the stress environment. The role of drilling fluids in HDR wells is discussed by Lundie (Ref 18) who includes comments on several recent projects. For the future, drilling fluids must be addressed in two stages. Firstly, up to the top of the ‘reservoir’ interval, the fluid selection can be designed to satisfy the drilling requirements alone and oil based muds may have significant advantages. Once the ‘production’ casing has been installed, the drilling fluid for penetration through the ‘reservoir’ will ideally need to be such as to minimise the damage to the ‘reservoir’, providing of course that drilling can proceed with such a fluid. Noteworthy is that pore pressures at depth are likely to be sub-hydrostatic which will promote fines invasion unless fractures can be temporarily blocked at the borehole wall.

Casing protection is a major concern. Ideally, once the main production casing has been installed to the top of the reservoir interval, there should be minimal rotation allowed in the casing. This means that penetration through the reservoir interval would have to be achieved by rotation of the bit by downhole devices. In a very deep system with a final depth of over 7000 m with a bottom hole temperature of over 200°C and a production interval approaching 2000 m, this is at the limit or even beyond the current experience of appropriate downhole motors; ‘appropriate’ in this context meaning devices that can sustain high torques to allow high weights-on-bit and slow rotational speeds to optimise bit life. Hoisting and lowering the drillstring or tools will also contribute to casing wear. Hence bit and drilling tool life is important to minimise tripping wear.

At the present time, the only relevant devices available commercially are the slow speed-high torque positive displacement motors which are limited to a circulating temperature of about 150°C. At higher temperatures, power loss or sudden failure of the device may occur. Turbines have high
rotational speeds which are inappropriate for granite drilling with rock bits. In the USSR, super-deep drilling has been achieved using downhole rotation devices, but in the higher temperature regimes, these are based on turbine technology with metal seals and reduction gearboxes which give the desired parameters at the bit. This approach introduces yet more complex equipment into a high risk borehole situation and is undesirable if it can be avoided, although current participation in the design and construction of a more robust reduction gearbox and turbine combination with a sealed gearbox and lower bearing assembly by a western company may make this option attractive in the future.

In the recent sidetrack in EE-2 at Los Alamos from 2965 m to 3768 m, it would appear that 6-3/4 in postive displacement motors with elastomeric stators were used successfully for the directional drilling. Rock temperatures were up to 250°C, although the sidetrack was effected mainly using 22 rotary assemblies with only the initial kick-off and trajectory corrections made with six downhole motor runs (Ref 4). For an HDR system designed for long term use, the use of rotary assemblies to this degree would be undesirable, although their use does overcome the temperature limit problems with motors.

The quality and maintenance of downhole tools and drillstring become increasingly important in the deeper holes. Granite is a very abrasive rock and bit gauge and reamer wear are a characteristic feature which is a very expensive element in the overall costing. In very deep holes, optimisation of the rotation time is also an important aspect and will be increasingly so in the drilling of production systems. This means that each item must be examined critically. The aim must be for long life to minimise tripping. For sedimentary rocks, the advent of the polycrystalline diamond drill bit (PDC) has resulted in much longer bits runs and hence less tripping time where these bits can be used. Unfortunately, PDC bits are unsuitable for granite drilling. Given sufficient lead time, the optimum appears to be to design oilfield bits with some of the features of mining bits including additional gauge protection such as gauge lugs and shirttail reinforcement with high quality bearings. Another feature, used for the drilling at Gravberg, for example, is to improve the quality of the gauge carbides in the cones to help maintain gauge. These modifications normally need extended lead time and this must be taken in to account in planning such drilling programmes.

One area requiring special attention is the design of reamer and stabiliser tools and cutters. Roller reamers and stabilisers are necessary in these conditions, but these are expensive tools to use and the cutter wear is high. Given sufficient lead time, some attention can be given to building special reinforced versions of these tools. Ironically, sealed bearing versions of these tools, now commonly used in the oilfield, are more susceptible to damage as the rollers tend to skid with light side faces resulting in accelerated localised wear.

Some improvement in tool wear can be achieved by a more effective drilling fluid programme. Historically, much of the early drilling was achieved with water and this resulted in poor hole cleaning and accelerated tool wear. As mentioned above, the choice of drilling fluids for the 'reservoir' interval may be directed to minimising reservoir damage, but this may prejudice the hole cleaning features necessary to optimise tool life.
Drillstring maintenance is very important in any deep drilling and particularly so in drilling HDR wells. A rigorous programme of preventative inspection and timely repair of drillpipe, heavy wall drillpipe, drill collars, reamers, rotary substitutes and other downhole tools is essential for trouble free drilling. String failures can be very costly and may result in the necessity to sidetrack a well with the consequential trajectory correction problems and increased costs. The Gravbery-1 well in Sweden has been sidetracked three times due to hole stability conditions and string failures. This feature alone necessitates a disciplined approach to the drilling operations and expenditure on inspection services and drillstring replacement, but the benefits are obvious.

Provision should be included in any drilling programme for remedial cementing to stabilise excessive breakouts during drilling. Successful plug placement requires careful design.

Coring in deep, hot deviated boreholes still remains unsatisfactory. While the results of some recent deep scientific projects have shown that coring at depth in granites can be successfully achieved, these experiences were in special circumstances. In the Cajon Pass borehole, coring was relatively successful to 2884 m. The programme included spot coring with specially designed diamond impregnated corebits rotated by downhole motor. The coring system was similar to a heavy duty mining corebarrel in a 6-1/2 in diameter hole. Continuous cores have been obtained from 480 m to almost 4000 m in the KTB super-deep pilot hole in Bavaria using a purpose designed 5-1/2 in heavy duty wireline system in a 6 in diameter hole.

These important experiences, however, are not directly relevant to spot coring at great depth in deviated boreholes. Many problems arise not least the risk of granite debris on the bottom of the hole and the insensitivity of the drilling system at that depth to effectively control the operating parameters as diamond bits require relatively precise loadings to effect penetration and avoid bit damage. The roller cone concept used in Cornwall for the 1984 drilling campaign is still an option which gave acceptable core recovery. This concept was used in the KTB project to 480 m with encouraging results, but was unsuccessful when used in the Gravberg well in Sweden.

Another option is the use of wireline deployed sidewall coring devices at elevations selected from logging. Such coring was carried out at depth in the Gravberg-1 well in Sweden in granite and will be a feature of the tool development for the KTB super-deep project. The use of these tools, however, is limited by temperature.

Deep drilling for HDR applications should include the provision of mud logging services and an associated computerised drilling parameter monitoring and recording system.

The drilling rig and associated equipment would normally be a standard unit available from contractors. The rig specification needs to address the specific features for the well programme and the contractual arrangements must be consistent with any plans to suspend operations for trial stimulations, specialist testing or the like. Rigs capable of being skidded between the wellheads may be advantageous to reduce move costs,
especially if a programme calls for moving backwards and forwards several times during the programme to meet specific well construction programme features and to workover the wells during and after the stimulation programme.

COMPLETION OF HDR WELLS

Completion includes all permanent installations such as casing, cementation and production equipment. The casing design needs to address the arrangement and sizes required in the 'injection' and 'production' intervals and the additional features required to minimise corrosion over the design life as well as any damage from in hole activity. Consideration must be given to the use of replaceable liners if hole sizes allow.

The actual completion system in the potential 'reservoir' region is a question of some debate. The development phase calls for some form of stimulation treatment. Recent developments in thinking suggest multiple stimulations are necessary requiring zone isolation. At Los Alamos, inflatable, high temperature, open hole packers have been used with some success (Ref 3), although this approach requires a stable borehole with a good 'round', gauge profile. Many of the available proprietary packer systems also limit the drilling circulation internal diameter which introduces high pressure losses.

One of the principal questions to be addressed is whether or not a deep HDR well can be drilled with a long (up to 2000 m) open hole section without some form of permanent support? Experience suggests that at great depths this introduces a serious risk which is unacceptable. This leads to the conclusion that an HDR well should be protected with a liner once logging has been completed. This affords permanent protection to the borehole and allows assured re-entry to the full depth. However, such an expedient raises the important question as to how such an arrangement can accommodate a multiple sealing system between the liner and the borehole wall in association with the necessary arrangements for thermal expansion.

The traditional oilfield system of a cemented liner with perforations across the selected 'pay' intervals cannot be seriously contemplated as the very act of cementing will severely damage the geothermal 'reservoir' by invasion of the cement into the fracture system. The idea of using multiple open hole packers at these depth is daunting and the likelihood of obtaining a 'round' gauge hole necessary for their successful deployment is small, although some systems inflated by cement are available which can accommodate some degree of hole irregularity. Degradation of any packer system with time is also likely, although this would only affect completions which require the packers to be left in place for some period.

Ideally, the completion system should permit stimulation and production. Any arrangement which caters for the stimulation programme and then has to be changed for the production phase is undesirable, especially if remedial work is necessary in the borehole or selective stimulations are required later. Such a system must also address the possible need to effect some form of flow control or selective production from specific zones.

This element of HDR well construction still requires development engineering. Any system to be deployed at great depth must be simple and effective. Complex completions are likely to fail. Stimulation programmes
require high pressures and system failure at this stage would be serious. A system allowing repeated treatment in the sealing areas and the zones accessing the reservoir, with the potential to shut off selective intervals even by using 'scab' liners, is desirable. Thermal expansion and contraction will necessitate either expansion joints or some flexibility in the seals to maintain the integrity of the system under all temperature conditions.

Once the bottom hole arrangement has been decided, the remained of the casing and cementing system is relatively straightforward but with special attention needed to casing grades, metallurgy and thicknesses to withstand the service requirements. Cementing should be simple and strong, but cement heights may be limited by pressure constraints resulting from the rock stress anisotropy. The use of exotic lightweight cements should be avoided where possible unless the consistency can be guaranteed. Wells will require pre-cooling prior to cement placement and intercooling during cement setting. Cement slurry design should be relatively straightforward using materials commonly used in high temperature natural geothermal wells.

Casing installation procedures should include prestressing to mitigate thermal effects. The wellhead itself requires special attention and should provide for thermal movement as well as the range of pressures and flow rates that may be required during the stimulation and production phases. Wherever possible, systems should be monitored for corrosion and stress during operation.

**AREAS REQUIRING FURTHER INVESTIGATION**

The principal area of uncertainty requiring further investigation and engineering is the whole question of the completion arrangement for stimulation and injection or production in the reservoir intervals. The desires of the reservoir engineers, with plans for multiple stimulations in a hostile environment and the necessity to maintain the integrity of the completion system for an extended system life, poses special problems which are as yet unresolved.

Associated with the bottom hole completion is the hole size and casing design. Wherever possible standard hole sizes should be used, although the possibility of a requirement for thick wall casing may create hole sizing problems. The use of protective casings or replaceable completion strings is also worth of further consideration.

Directional drilling equipment including rotational devices and high resolution surveying tools for use in high temperature environments needs further investigation. Trajectory positions should be known accurately not least to reduce the error on any subsequent microseismic analysis using instruments deployed at depth.

The accommodation of seismic sensors in deep wells where permanent liners are planned is also an area of uncertainty.

Drilling fluids is also a topic requiring further discussion particularly with the reservoir engineers. The possibility of using oil based muds,
even through the 'reservoir' intervals, would be advantageous, but this approach introduces further complications in potential reservoir damage. Associated with drilling fluids are the requirements for solids control equipment and surface cooling of the drilling fluid. Solids control equipment should be capable of removing the fine fraction from the mud system to prevent a build up of mud weight and to minimise the dilution and hence disposal requirements during the drilling. Surface cooling systems should be arranged where possible to minimise the potential for additional oxygen entrainment in the mud.

An area worthy of serious consideration is the potential for using air drilling methods to drill the uppermost 2000 m or so of large diameter hole. The objective must be to reduce costs. This method is widely used in other drilling applications, but the degree to which it is relevant to HDR drilling and the cost benefits has not yet been demonstrated. A deep, large diameter air drilling trial through granite would be of interest.

Further study of appropriate cementing technology is also an important area which is associated with the system adopted for completion.

CONCLUSIONS

Reference to recent international scientific projects and the wealth of data available from the petroleum and mining industries provides a useful data base for the design of HDR wells. However, some of the requirements are outside current technology and experience, notably methods for zone isolation for multiple stimulations in large diameter holes.

The successful design and implementation of deep HDR systems is dependent on the ability to engineer an appropriate system to complete the wells to assure the successful development of the reservoir and subsequent system operation.

The drilling itself is formidable, but feasible with current technology and equipment, although it must always be recognised that drilling to depths greater than 5000-6000 m is especially demanding and risky.

The design of the drilling fluids system to satisfy the drilling requirements, including the need for good hole cleaning and the control of stress breakout, together with the desire for minimal damage to the potential HDR reservoir, is a matter of concern.

There is a need for high temperature downhole rotation devices with performance parameters consistent with the requirement for slow rotational speeds and high torques for directional drilling and for drilling the lower section of the wells after the main casing has been installed. Steering and surveying systems must be capable of operation in the severe environment at depth to a high resolution.

Deep air drilling may give potential savings for the upper hole drilling and needs further investigation and a possible trial.

Cementing generally requires further investigation especially associated with the development of zone isolation systems.
Drilling and completion of deep HDR systems is a challenging endeavour, but one which is considered feasible with adequate investigation, engineering and investment.

Wherever possible, the emphasis for future deep HDR geothermal drilling should be on the innovative adaption of existing materials, equipment and methods used in the petroleum, high enthalpy geothermal and mining industries rather than inventing new approaches except where the shortfall in suitability threatens the whole concept of technology.

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NOTES ON RELEVANCE OF RECENT PROJECTS

Urach-3, West Germany (1977-78)

This was the first of the recent HDR research projects in Europe. In 1980, Urach and Los Alamos were about the only relevant data on which to base well planning for deep drilling in crystalline rock. Reference to the records from Urach (Ref 2) illustrates the advances achieved in the last 10 years in drilling equipment performance. The average daily penetration including drilling, coring, casing, cementing, logging and some testing was 14 m. This compares with an average of over 40 m/day in the three Camborne wells drilled in 1981 and 1984.

Los Alamos, USA (1974 to date)

Records and reports from Los Alamos cover all aspects of drilling and completion and are the most comprehensive of direct relevance to deep, hot HDR applications. Los Alamos addressed the temperature problems at the same time as the technology was being pioneered and the resulting experience is of great value to the geothermal community.

Camborne, United Kingdom (1980 to date)

The intermediate depth system at Camborne has provided comprehensive data on several aspects of drilling and completion of wells in granite with rock temperatures up to 100°C. The first use of slow speed-high torque downhole motors for this application demonstrated the advantages of these tools for granite drilling (Ref 20).

Nagra, Switzerland (1982-1986)

This programme provided a very comprehensive experience of continuous coring in granite using oilfield, modified mining and heavy duty wireline coring systems. This project was the catalyst for the development of high quality televiwers and the formation microscanner tool (FMS), the results of which were compared with the core, some oriented, over several boreholes. The records from this programme provide a important database for this class of work, although it is of limited direct use in HDR applications.

Super-deep programme, USSR (1970 to date)

This is without doubt the pioneering programme for very deep drilling in the crystalline basement and the records and publications as such as they are available in the western world form a valuable insight into the full range of deep drilling aspects in such conditions. Of note is the different approach to drilling in the USSR with a high proportion of the boreholes being drilled with downhole rotation devices. The reports contain various accounts of problems encountered and the design changes necessary for downhole tools in these extremely deep boreholes, many of which confirm the difficulties foreseen in constructing deep HDR systems.
Cajon Pass (1986-1987)

The data from the Cajon Pass project is relevant as it covers deep drilling in temperatures up to 200°C in a granitic rock with varying degrees of fracturing. The coring, logging and breakout experience from this project are also of interest.

KTB project, West Germany (1987-1989)

The 4000 m deep pilot hole for the super-deep project in Bavaria provides good data on a polymer mud system, the effect of the mud properties on controlling the onset of breakout and particularly on continuous coring with heavy duty wireline coring equipment with diamond bits. The developments in this important area for scientific drilling are noteworthy. The planning for the main borehole together with the many associated studies and equipment development programmes are important for future HDR drilling as the super-deep borehole is scheduled to penetrate 10-14 km where rock temperatures are anticipated to be of the order of 300°C.

Gravberg-1, Sweden (1986-date)

This pioneering project to investigate the presence of abiogenic gas in the crystalline basement has provided a rare opportunity to drill a deep borehole principally using open hole methods similar to those necessary for HDR exploitation. The records and publications from this project cover many of the aspects of deep drilling including stress breakout, bit and tool usage, drillstring performance and drilling fluids. Although the temperature conditions are different to those required for HDR development (110-120°C bottom hole rock temperature at 6.5 km), nevertheless, the data from the Gravberg well is of great value for future planning.

Soultz, France (1987 to date)

The drilling through the crystalline rock addresses many of the features of granite drilling and provides another useful experience for planning future drilling programmes.

Salton Sea, USA (1986-1987)

This project contributes important information on drilling in very hot environments with some illustrative records including turbodrilling, bit life, coring and drilling fluids.
APPENDIX B

SUMMARY OF STATUS OF VARIOUS ASPECTS OF DRILLING RELATED TO HDR

Drilling rigs

Suitable rigs exist for drilling to depths up to 10,000 m both in Europe and North America. Some rigs of this capacity are currently located elsewhere in the world. For use in Europe, rigs not originating from Europe may need extensive modifications to conform with the various environmental, mining and safety legislation, particularly noise attenuation, hazard areas and electrical equipment. The advent of the Single European Market by December 1992, or thereabouts, may result in further changes to regulations as yet unspecified. At the present time, rental rates for drilling equipment are severely depressed and the current rate levels should not be used in any forward planning as the market should recover in the next two to three years. For long programmes, the option to purchase a suitable unit and arrange a labour contract or directly employ the crew are options (as adopted for the Gravberg-1 well in Sweden), but this is only realistic if the financial outlay less residual value is sensible and the equipment is technically suitable. For long projects, rig power from mains electricity may be cost effective and has acoustic advantages.

Drilling methods

Standard rotary drilling using air, water and mud as appropriate is adequate for the vertical sections of the wells. The use of downhole rotation devices is required for deviated drilling to correct trajectory orientations and ideally to drill below the main production casing to minimise drilling induced wear.

Drilling bits

For air drilling, which is a possibility in the upper sections of the wells, current bit technology is adequate. For the remainder of the drilling, low profile tungsten insert tricone rock bits have performed well. As depths increase, bit life is an important factor and so sealed bearings and improved gauge protection are desirable features. Bit bearings have improved over the last ten years and more use of new high quality journal bearing bits as against roller bearing types is an option. For drilling at depth, high temperature seals and lubrication systems are required. Gauge wear will continue to be a problem in highly abrasive formations. The Gravberg-1 well has provided good data on bit performance using one type of bit (Ref 19). Full face diamond and polycrystalline (PDC) bits are inappropriate for drilling granitic rocks.

Coring methods

The use of low area ratio (thin kerf) diamond bits and associated core barrels for taking spot cores at depth in deviated boreholes in granite is unlikely to be successful for a variety of technical reasons. The use of roller cone type coring bits has been of limited success, but this approach may be the only realistic option at reasonable cost for attempting to obtain spot cores at great depth. Downhole motor driven coring assemblies using diamond bits will probably be effective at shallower depths, but bit costs and the risk of premature damage will be high. Coring is expensive and difficult in a granite environment at depth.
The use of sidewall coring systems to recover small cores for identification and simple tests has proven to be feasible at depth in granite, although the degree of success is not as good as could be expected with in weaker rocks. At depth the costs are high due to tool and wireline surcharges. Tool deployment is limited by temperature.

Reamers and stabilisers

Roller reamer type reamers and stabiliser tools are necessary for granite drilling with rock bits. Blade type stabilisers, even with high quality tungsten protection, are generally unsuitable and wear rates are very high. Some work is necessary to improve the body protection and the cutter design on tools. As maintenance of gauge is so important and the risk of unstable boreholes accelerating wear on tools especially at great depth, reamers and stabiliser costs can be very high and hence these tools must be a target for improvement to reduce overall costs. The use of sealed bearing tools, which at first seems attractive, may be a disadvantage as roller type cutters that do not rotate easily will probably be worn flat quickly if the applied side force is inadequate.

Other drilling tools

The selection of all downhole tools, such as jars and shock absorbers, to be used in deep granite wells should address the ruggedness and temperature suitability of the tool mechanism. High vibration and abrasion wear is a feature of granite drilling with rock bits. Faulty or failed seals will generally be unnoticed at the surface, but may result in tool failure which can be very costly. In general, the use of shock absorbers is considered undesirable for this reason and also because it introduces flexibility in the bottom hole assembly which may prejudice directional control.

Drillstring

Existing materials and standard equipment are adequate, but measures must be taken to protect strings from abnormal wear without inducing additional problems of accelerated casing wear due to abrasive tool joint hardbanding. The general environment, exacerbated by the deviated trajectories, will be conducive to accelerated fatigue failure and a rigorous preventative inspection and replacement programme for all drillstring components should be included in any deep drilling programme. Drillstring failures are generally very expensive and at worst could result in the loss of part of a well necessitating a sidetrack and a long redrilled interval. New drillstrings will probably be necessary for the deeper drilling to give the necessary drillpipe rating. Drillstring programmes should also be suitable for drilling in potentially corrosive or hydrogen enriched environments which may limit the degree to which high strength steels are used.

Steering tools

Wireline conveyed steering tools with heat shields are available for use in high temperature environments and have proven resilient to high vibration. The use of MWD (measurement while drilling or mud pulse telemetry) systems with rock bits in high temperature and severe vibration
environments is unproven, although temperature limits for sustained use for this class of tool are generally modest of the order of 125°C. Some service companies claim operation limits as high as 150°C. It should also be borne in mind that the loss of MWD tools due to hole problems, which is a relatively high risk, would be expensive unless the main instrumentation package can be recovered through the drillstring in a similar way to a wireline conveyed steering tool.

The use of MWD type systems would be a considerable advantage if such equipment is developed that would withstand the service requirements and offered a resolution consistent with the tolerance demanded by the well programme.

Survey tools

A variety of single and multishot magnetic and gyro survey tools are currently available. Some modifications and the addition of heat shields will be necessary. Some limitations on mission time may result. Deep and hot intervals will prove more demanding on survey time and measurement precision. Where possible, redundancy of survey runs will be necessary to develop well trajectory profiles with an acceptable level of resolution to satisfy any geophysical instrumentation deployment where accurate location is required. The use of suitable survey instruments with associated data storage to avoid long interruptions to drilling for surveys at depth using conventional tools would be desirable if prototype tools now available are shown to be rugged enough for this application. Associated circulating temperature data from the bottom of the hole can also be acquired with this type of tool and would be of value in assessing the likely performance of downhole motors.

Drilling fluids

Developments in the status of this important topic are discussed elsewhere in this paper and by Lundie (Ref 18). The main change in approach for very deep wells following recent field experience is the necessity to design drilling fluid systems to reduce the effects of stress breakout. Drilling requirements and the desirability to minimise invasion into the natural fracture system of the potential HDR reservoir may be incompatible.

Downhole motors

The current limit on circulating temperatures for effective use of downhole positive displacement motors using elastomeric stators is about 150°C. Turbines are of limited use due to their high speed and relatively low torque characteristics, although turbine technology has more potential in hot wells. In the USSR, turbine driven devices with speed reduction gearboxes are used for deep, hot boreholes in crystalline rock, but this application has not been developed so far to any extent in the western world. For rock temperatures up to 200-220°C, circulating temperatures will be at or above the known limit of positive displacement motors and at these high temperatures some power loss and reduction in motor life may be experienced.
Casing

Casing design is critical for HDR systems. Temperature and pressure cycling combined with corrosion provision and drilling induced wear will dictate casing grades and thicknesses. Casing design would be simplified if each well could be defined as an injector or a producer. The use of protection casings and replaceable production liners has merit if these can be accommodated.

Casing connections should be suitable for high temperature operations and avoidance of the potential for trapped fluids is important to minimise failures due to expansion as temperatures rise.

Cementing

Many problems arise in cementing from high temperatures, loss of cement in fractures, exacerbated in the case of strong crystalline rock by adverse stress profiles and contamination of cement by drilling fluid further complicated by hole inclinations. Many high enthalpy wells are completed at much higher temperatures than are currently being considered for HDR. The integrity of cement over long periods at high temperatures is uncertain, particularly with cyclic loading from variable wellbore pressures and thermal movements. The cement annulus is likely to fail. Cementing programmes should be simple and strong, but cementation will probably be limited to the lower part of the main casing string due to limits imposed by shear stress profiles in the rock.

Packers

There is some evidence that packer materials and design has advanced to a stage where packers can be considered for some type of completions. However, poor shape holes at depth and hydraulic limitations together with the general concern about the suitability of packers for long term use, probably limits their potential for deep systems.
ABSTRACT

The properties and formulation of drilling fluids can significantly influence the prospect of obtaining the declared objectives of a hot dry rock reservoir. This paper examines those objectives and the required properties of the drilling fluid. The experience base from comparable projects will be reviewed and recent technical advances in drilling fluid technology will be described. Details of fluid systems that may be considered will be given.

INTRODUCTION

The functions of drilling fluids or "mud" and the required properties are well established from experience in drilling for oil and gas. The two essential functions and corresponding properties are to transport the cuttings from the bit to the surface by adjustment of both flow rate and viscosity and to control downhole pressures by adjustment of the density of the fluid.

Drilling wells to exploit hot dry rock (HDR) reservoirs introduces special problems of both protecting the "reservoir" and the problem of the high temperature.

This paper will examine the special requirements for drilling fluids for HDR reservoir and will review the world wide experience gained at drilling deep, hot holes including holes in granite. Finally a suggested drilling fluid programme will be presented.

FLUID PROPERTIES FOR HDR DRILLING

Density. The drilling fluid exerts a pressure on the formation that is directly proportional to the true depth of the well and the density of the fluid. This mud pressure is used to control both the pressure of fluids in pores in the rocks and to reduce the radial stresses around the hole generated by drilling a hole in stressed rock. The minimum density normally accepted is that of the pore pressure although this pressure is often exceeded to provide mechanical support for the stressed formation and a safety factor for pressure control.

The radial forces tending to collapse the stressed rock are proportional to the matrix stress of the undisturbed rock. The pressure exerted by the mud is designed to reduce the stresses to a level where the rock will not fail. There is
an upper limit, where, if the pressure is too great, the rock will "fracture" and fluid will be lost to the formation. The drilling rate also is lower if the density is higher than that required for a stable hole.

If there is a high degree of "anisotropy" or unequal distribution of horizontal stresses within the rock, failure may occur more in one direction than another so that the hole cross section becomes elongated. This problem is widespread but can be pronounced in granite where the mechanical failure is referred to as "breakout". An increase in mud density to correct this problem may fracture the rock if the pressure required to control breakout exceeds the minimum earth stress. The situation will be further complicated if a permeable fault zone or joint is intersected as there will be severe mud losses. The out of gauge hole caused by the mechanical failure of the rock can make control of direction of drilling very difficult.

The density may be controlled by either forming a suspension of finely ground dense minerals (such as barite or hematite) or by the addition of salt to form a solids free brine which can be formulated to have specific gravities (SG) over 2. Sodium and calcium chloride systems easily and reasonably cheaply cover the density range up to an SG of 1.4. A combination of solids and brine may also be used. An advantage of a brine system is that it contains no solids and so has the potential to minimise damage to the production zone.

Hole Cleaning. The cuttings are transported from the bit to the surface through the combination of the upward flow of the fluid in the annulus between the drill pipe and the hole and the resistance to flow or viscous properties of the fluid. The viscous properties of the fluid are an important factor in hole cleaning although subservient to the annular flow rates. The flow properties are normally engineered to be shear thinning so that the fluid's viscosity increases as annular flow rates decreases. The increase in viscosity should compensate for the lower flow rates. The fluid should also exhibit time dependent thickening or gel formation so that the cuttings are suspended when circulation is stopped.

Other factors which influence the transport is the relative density between the cuttings and the drilling fluid, the size of the cutting and also the rate of generation of solids which is the penetration rate plus the cavings.

The cuttings transport mechanism is related to the hole angle because the distance the cutting has to fall before it reaches the borehole wall decreases as the hole angle increases. Up to about 20°, the upward movement of the fluid counters the settling velocity. At angles above 30° the fluid has to keep a bed of cuttings fluidised and so the efficiency of cuttings transport is much lower. The rheological properties and flow regimes should change as the hole deviation changes.
The hole cleaning process is much less efficient if the wellbore is irregular. At the enlarged sections the annular flow rate is reduced and cuttings start to accumulate. Problems will then arise when the solids slump into the hole and then jam the pipe. This potential problem is treated by high viscosity sweeps of say 25 barrels before a trip.

The rheological properties are well characterised with a Fann viscometer. The required rheological parameters of the fluid are determined from cuttings transport efficiency calculations for a given flow rate. Note should be taken of the influence of a temperature gradient on the viscous properties of the fluid. The required viscosity properties can be obtained by the addition of clays or water soluble polymers.

Rheological data can also be used to calculate engineering parameters such as pressure losses in the circulating system and the swab and surge pressures generated by pipe movement in the hole.

Fluid Loss Control This property is the ability of the fluid to lay down a filter cake of low permeability (about 0.001 millidarcies) against a more permeable zone and so isolate the wellbore fluids from the formations being drilled.

A drilling problem called "differential sticking" is due to the differential pressure between the mud pressure and the pressure of the fluid in the formation pressing the pipe against the hole wall. A thin filter cake will minimise this problem.

For a filter cake to form solids must be present in the fluid that are at least a third the diameter of the pore throats or fracture that is to be blocked so that they can form a bridge. If these solids are not present whole mud will be lost to the formation. These bridging solids will not, by themselves, be expected to lower the permeability of the filter cake but rather initiate the filter cake formation on the surface of the wellbore. The size of the solids will therefore be related to the pore throat diameter. A maximum particle size of 150 microns will suffice for all formations except gravel beds, vugs or open channels that will require the addition of special "lost circulation" material such as blends of mica flakes, fibre and solids. Bridging particles are added at concentrations in the range of 15-45 kg/m³ (5-15 lb/bbl).

The fine capillary network required to establish a low permeability filter cake should contain colloidal particles below 5 microns. These may be supplied by the secondary bridging particles, contaminating drilled clays, purposely added clays such as montmorillonite (bentonite), colloidal solids such as lignite, lignosulfonate resin derivatives or starch. Polymers adsorbed onto colloidal solids can also contribute to the colloidal sealing process.
Polymers used for viscosity control will also decrease the filtration rate significantly. If the filter cake is well formed with solids with the right size range, then the pore throats in the filter cake will approach the size of the polymers and they will be concentrated in the filter cake.

These general concepts of fluid loss control also apply to oil based fluids but there are important additional features. One is the capillary effect that prevents oil wetting a water wet surface and so oil will not readily enter water wet capillaries. The other is the ability of the colloidal sized water droplets to block a filter cake built of oil wetted solids. The fluid control properties may be so well developed that the drilling rate declines in some formations. In this case the level of emulsifier is lowered and a "relaxed" formulation can give higher fluid losses.

The concept of fluid loss control plays an important part in the protection of the reservoir.

**Inhibition.** Water has a very high affinity for mineral surfaces such as clays and silica. Adsorption of water from the drilling fluid can generate additional stresses that may cause the rock to fail. This problem is often encountered in drilling shale formations and may be encountered in granite at greater depths and confining stresses because water will readily hydrate the mineral surfaces of silica, feldspar and mica and in so doing will increase the rock stress.

The hydration reaction can be modified by adjustment of the chemistry of the drilling fluid. The property of inhibition refers to the extent to which reaction with water is reduced. For example, fresh water has poorly developed inhibitive properties that can be improved by the addition of salts and polymers such as high molecular weight polyacrylamide to reduce the mobility of the water.

Fluid loss control also plays an integral part of borehole stability because the formation of a filter cake allows the pressure exerted by the fluid column to bear onto the formation and so give support to the rock and blind the pore throats or micro-fractures.

Oil based mud provides the most inhibitive drilling fluid almost entirely eliminating reactions with the formation. This is brought about by eliminating contact of the rocks with water through the continuous oil phase and also by adding high levels of salt to the water phase. The salt is added to counter or "balance" the adsorptive forces for water in the formation. The amount of salt required will depend on the particular formation being drilled. Oil based fluids have very developed fluid loss control characteristics and this property must contribute to the high level of hole stability obtained with oil muds.

**Reservoir Protection** The "reservoir" in a hot dry rock project in granite is the fractures or joints. In other
cases it may be a sandstone rock. The well bore pressure is likely to exceed the pressure of the water in the reservoir so solids will be forced into the potential production zones and form a very effective seal. It has been shown that a relatively weak mud filter cake, with a compressive strength of only 5 psi, in a perforation hole can withstand a 200 psi negative pressure differential and 5,000 psi positive pressure. Therefore consideration must be given to the type of filter cake and methods of removal.

Acid soluble solids can be removed by acid treatment, although this may be difficult and dangerous at the high bottom hole temperatures encountered in these wells. Another solution would be to use brines for density control and salt crystals as fluid loss control agents. Fresh water is used to dissolve the salt and so remove the seal. This approach is increasingly used with success in completion and workover operations in oil or gas wells.

There is also the possibility that the massive fracturing operation will generate new pathways well past any zones that may have been blocked by mud filter cake so there is no need for concern. However, excessive plugging could make pre-stimulation evaluation difficult.

Oil based mud will probably form a thin and effective filter cake and will make the granite surfaces oil wet. In conventional reservoir analysis this wettability change may cause damage, but in this case no problems would be anticipated. Surfactants could be used to reverse the formation wettability changes.

Corrosion Control An increase of 10° C normally doubles the rate of a chemical reaction so corrosion rates that may be tolerated at 100° C will be totally unacceptable at 200° C. The problem is essentially one of relating the corrosive characteristics of the fluids to that of the steels used in the casing and drill pipe.

Oxygen corrosion will be a major problem, particularly at high temperatures. The oxygen can be removed by oxygen scavengers such as sodium or ammonium bisulphite. The oxygen levels should be continuously measured to ensure that the correct level of scavenger is added to ensure oxygen levels are below 10 parts per billion.

Abrasition Control The factors that control the abrasive nature of a slurry are complex and varied. The important variables, in probable order of importance are hardness, size, shape, size distribution, concentration, density and fluid velocity.

Corrosive action on metals leaves the corrosion products on the surface which can protect the pipe from further corrosion, but they are often mechanically weaker than the base metal, so are easily removed by abrasion. The combined action of corrosion and abrasion can result in rapid erosion taking place.
On the Moh's Scale of hardness of minerals, quartz and feldspars which make up over 75% of granite are the hardest minerals that will be encountered in drilling. Abrasion problems, therefore, are important ones to address when drilling massive granite and are best countered by very careful attention to the correct operation of a solids control programme.

Lubricity There are two approaches to the problem of lubrication. One relies on molecules being chemically adsorbed on the bearing surfaces and the other on a "ball bearing" effect with relatively large solids.

Modified fatty triglycerides have been used in water based muds but should not be used for wells where the temperature is in excess of 150°C because they will hydrolyse to release fatty acids or soaps that give problems with foam and oil wetted barite. Muds formulated with 8-15% of polyglycols have low coefficients of friction. More expensive, but heat stable water dispersible lubricants are available for use in the deeper sections. Lubricants have to be continuously added as they tend to be removed with the drilled solids.

Oil based muds have good lubricating properties due to the high level of oil wetting surfactants in their formulation. Their coefficient of friction is about 60% less than those of water based muds. Oil based muds would be recommended if the torque was above the limits of the drill string.

Water or Oil Based Fluids Drilling fluids are either formulated with water or oil. The main differences are summarised in Table 1. The main reasons for using oil mud is the added borehole stability due to the excellent inhibition and borehole stability, excellent lubricity properties, reduced corrosion and abrasion and stability at high temperatures. These factors may be crucial at the final stages of the well. The main problem would be to assess the effects the oil based muds will have on the permeability of the fractures and joints that make up the reservoir. At the present time this factor is not known.

REVIEW OF COMPARABLE DRILLING PROJECTS

There are a number of recent drilling projects that have comparable objectives to those planned in the present exercise. This section will review these projects with particular attention being paid to the drilling fluid systems to evaluate whether the objectives were achieved and potential problems successfully solved.

Los Alamos, New Mexico Two papers (Ref. 1 and 2) describe a sepiolite clay based drilling fluid used to drill a side-tracked well from 2803-4018 m (9373-13182 ft) with bottom hole temperatures of 232°C (450°F).
TABLE 1  COMPARISON BETWEEN WATER AND OIL BASED MUDS

<table>
<thead>
<tr>
<th>PROPERTY</th>
<th>WATER MUD</th>
<th>OIL MUD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td>Moderate to high</td>
<td>High, particularly if there are losses</td>
</tr>
<tr>
<td>Temperature stability</td>
<td>Good if properly formulated</td>
<td>Excellent</td>
</tr>
<tr>
<td>Density control</td>
<td>Can use solids or brines</td>
<td>High loading of solids</td>
</tr>
<tr>
<td>Fluid Loss Control</td>
<td>Can be good if additives used</td>
<td>Excellent</td>
</tr>
<tr>
<td>Inhibition</td>
<td>Can be adjusted</td>
<td>None better</td>
</tr>
<tr>
<td>Reservoir protection</td>
<td>Good</td>
<td>Good but may need surfactant</td>
</tr>
<tr>
<td>Corrosion Control</td>
<td>Needs treatment</td>
<td>Excellent</td>
</tr>
<tr>
<td>Abrasion Control</td>
<td>Abrasive and needs solids removal</td>
<td>Less of a problem than water based but solids removal more difficult</td>
</tr>
<tr>
<td>Lubricity</td>
<td>Poor, needs additives</td>
<td>Excellent</td>
</tr>
<tr>
<td>Environmental</td>
<td>Good to poor-depends on formulation</td>
<td>Very poor if it enters ground water Special disposal</td>
</tr>
</tbody>
</table>

This mud was claimed to be an improvement on the earlier system that consisted of water with viscous sweeps. The benefits of better hole cleaning resulted in the recovery of larger cuttings. The solids were kept to a low level and the density was in the range 1.04 - 1.07 SG (8.7 - 8.9 ppg). No detail was given of the solids removal equipment.

Kola SG-3 Well, USSR. The well was drilled to 9750 m (23567 ft) with a bottom hole temperature (BHT) of over 200° C. A report (Ref 3) has summarised the "washing fluid" in fair detail. The fluid formulation was modified as the depth progressed.

The muds are essentially bentonite and CMC. The Russians have carried out a lot of research on the addition of antioxidants to improve the performance of this polymer at high temperatures. The performance of this fluid has been modified by the addition of lignite derivatives and a synthetic polymer, methacrylamide- methacrylic acid copolymer. Comparable additives have been developed in the West. No details are available on the chemical character of the lubricant, Smad-1, that apparently performed well,
although there may have been problems keeping the oil emulsified. Graphite was used in the deep section from 7959m but no comment was made as to its efficiency.

The Russian system would be an example of a simple mud type of low cost. It is not clear how successful they were at overcoming the problems of corrosion or whether graphite reduced high torque. The fluid would have been loaded with solids so nothing has been done to address the problem of potential formation damage.

Gravberg-1 Well, Sweden. This well has been drilled to 6957 m in granite with the objective of natural gas deep in the crystalline basement. More and Brittenham (Ref 4) describe the operational problems in drilling down to 6337 m TVD in granite. The well was suspended and redrilled in 1988-89 to a final depth of 6957 m. The well was drilled with three water based systems and finally used oil based muds. The oil based mud provided excellent lubricity and the hole stability was substantially improved as shown by the calliper logs (Ref 4).

The water phase salinity was adjusted with calcium chloride and the oil/water ratio and the volume additions were closely monitored in the latest drilling phase. These studies showed that water was lost to the formation when the salinity was low and that the trend could be changed by increasing the salinity. This behaviour would indicate that the granite at these depths and pressures is capable of reacting strongly with water and that the inhibitive properties of oil based mud contribute significantly to the stability of the formation.

KTB Pilot Borehole, Bavaria, West Germany This well is interesting and the progress should be closely followed. An objective of the mud system was that it should not contain any organic derivatives. Henkel, in collaboration with N L Baroid have developed an inorganic calcium magnesium silicate product that will be marketed as "Duratherm". Reports to date show that the polymer is providing adequate control of the rheology to the final depth of about 4000 m. Calcium carbonate is added to generate filter cake solids. Some problems were encountered with corrosion that have to be addressed before the mud system is used again.

Soultz Geothermal Project, Strasbourg, France. This well was drilled to 2000 m with a programme very similar to that used in Cornwall. A simple water system with Hydroxyethyl cellulose (HEC) and defoamer was used. A mud density increase from 1.02 to 1.07 was achieved by the addition of salt. This system would not be efficient above 75°C due to polymer breakdown. No details are known of how the problems of corrosion, abrasion and lubricity have been addressed.

CSM Project, Cornwall. Three wells were drilled to 2500 m with a very simple system that was essentially large volumes of water with occasional sweeps of HEC viscous plugs. There was no evidence of hole collapse at 2500 m.
OUTLINE DRILLING FLUID PROGRAMME FOR 6 KM WELL IN GRANITE

This section will put forward the best options for drilling typical wells to 6000 m as summarised in Table 2 in order to illustrate the design principles of a mud programme.

TABLE 2 SUMMARY OF DATA FOR TYPICAL WELL

<table>
<thead>
<tr>
<th>Hole section</th>
<th>Data</th>
<th>17 1/2 &quot;</th>
<th>12 1/4 &quot;</th>
<th>8 1/2 &quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth m</td>
<td>600 - 1500</td>
<td>1500 - 5000</td>
<td>5000 - 6000</td>
<td></td>
</tr>
<tr>
<td>Intermediate casing size, in</td>
<td>20</td>
<td>9 5/8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BHT, °C</td>
<td>60</td>
<td>140</td>
<td>210</td>
<td></td>
</tr>
<tr>
<td>Mud Weight, SG</td>
<td>1.0 - 1.1</td>
<td>1.1 - 1.2</td>
<td>1.2 - 1.4</td>
<td></td>
</tr>
</tbody>
</table>

17 1/2 inch Hole The "flushing agent" would probably be water with viscous sweeps of bentonite. Synthetic polyacrylate polymer could be used to control viscosity and fluid loss if required. The solids content will be kept as low as possible by the use of solids control equipment and dilution. Corrosion is not expected to be a problem in this section and will comprise pH adjustment to 8.5 - 9.5 with caustic soda.

12 1/4 inch Hole This section will require a higher mud density below about 2500 - 3000m and the viscous properties will have to be increased due to the longer hole sections to be cleaned. This increased complexity increases the number of options. The expected BHT at the bottom of this interval of 140° C will also start to impose restrictions on the components that may be used. The options are summarised in Table 3.

This is a long section and the temperature may reach 130-150 °C (266-300 °F) which is in the upper limits for some mud systems. The key factor to be decided is the means of increasing density. The simple fresh water, bentonite, polymer and barite system would offer the cheapest and most conventional system. Control of fluid properties such as viscosity and fluid loss control should be done with synthetic polymers as these will show the required temperature stability and are totally resistant to biological degradation.

Brine systems will provide an opportunity to continue with the programme to totally remove the solids to maintain a non-abrasive conditions but will be more expensive.

The corrosion control programme should be in place at this stage. Tolerable corrosion rates should be determined from consideration of the metallurgy of the casing string.
TABLE 3. SUMMARY OF OPTIONS FOR 12 1/4 HOLE

<table>
<thead>
<tr>
<th>Property</th>
<th>Option</th>
</tr>
</thead>
<tbody>
<tr>
<td>DENSITY</td>
<td>NaCl brine to 1.2 SG or CaCl₂ to 1.4 SG</td>
</tr>
<tr>
<td></td>
<td>Calcium carbonate or marble flour</td>
</tr>
<tr>
<td></td>
<td>Barite</td>
</tr>
<tr>
<td>VISCOSITY</td>
<td>Sepiolite or attapulgite in brine</td>
</tr>
<tr>
<td></td>
<td>Bentonite in fresh water</td>
</tr>
<tr>
<td></td>
<td>Calcium magnesium silicate system</td>
</tr>
<tr>
<td></td>
<td>Bentonite / CMC as in simple mud</td>
</tr>
<tr>
<td>PROPERTIES</td>
<td>AV, cps 20</td>
</tr>
<tr>
<td></td>
<td>PV, cps 15</td>
</tr>
<tr>
<td></td>
<td>YP, lb/100 sq ft 10</td>
</tr>
<tr>
<td></td>
<td>Gels, lb/100 sq ft 4/8</td>
</tr>
<tr>
<td>FLUID LOSS</td>
<td>No control with 20-40 ml API</td>
</tr>
<tr>
<td></td>
<td>Losses will require control to 8-10 mls</td>
</tr>
<tr>
<td></td>
<td>Polymer system stable to 150° C</td>
</tr>
<tr>
<td>PROPERTIES</td>
<td>API, 20-40 mls</td>
</tr>
<tr>
<td></td>
<td>HTHP, 100-150° C/500 psi, 40 - 60 mls</td>
</tr>
<tr>
<td>LUBRICITY</td>
<td>Heat stable lubricant with surfactants to be added at end of section</td>
</tr>
<tr>
<td>CORROSION</td>
<td>pH Control to 8.5 - 9.5</td>
</tr>
<tr>
<td></td>
<td>Oxygen scavenging system</td>
</tr>
<tr>
<td></td>
<td>Passivating system</td>
</tr>
</tbody>
</table>

8 1/2 inch Hole  The question of reservoir damage has to be seriously addressed in the design of the mud system in this section. The thermal degradation of the mud system and a need to cool the mud will also be new factors to consider seriously.

One option will be to continue with the bentonite / sepiolite / synthetic polymer mud and increase the density as appropriate. The advantages of this approach will be the cost and convenience of continuing with the same system. This system does not provide the criteria of a non damaging fluid with respect to the reservoir. The clays and barite solids would be difficult to remove so this system may not be acceptable as it does not meet the most important criteria.

The second option would be the one that is directed towards providing the system with the highest degree of reservoir protection. These two systems are summarised in Table 4.

A calcium chloride brine with suspended salt solids will provide the highest degree of reservoir protection. These solids would be removed by spotting unsaturated brine in the hole. The fluid loss and viscosity properties will need to
### Table 4. Summary of Drilling Fluids for 8 1/2 Hole

<table>
<thead>
<tr>
<th>Property</th>
<th>Option</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Density</strong></td>
<td>SG 1.2 - 1.4</td>
</tr>
<tr>
<td></td>
<td>Barite system in fresh water</td>
</tr>
<tr>
<td></td>
<td>Calcium chloride brine with suspended salt</td>
</tr>
<tr>
<td><strong>Viscosity</strong></td>
<td>Bentonite / sepiolite system in fresh water</td>
</tr>
<tr>
<td></td>
<td>Calcium magnesium silicate system</td>
</tr>
<tr>
<td><strong>Properties</strong></td>
<td>AV, cps 28</td>
</tr>
<tr>
<td></td>
<td>PV, cps 20</td>
</tr>
<tr>
<td></td>
<td>YP, lb/100 sq ft 15</td>
</tr>
<tr>
<td></td>
<td>Gels, lb/100 sq ft 8/12</td>
</tr>
<tr>
<td><strong>Fluid Loss</strong></td>
<td>Controlled to prevent differential sticking and to minimise formation invasion.</td>
</tr>
<tr>
<td><strong>Properties</strong></td>
<td>20-40 mls at 150° C/ 500 psi</td>
</tr>
<tr>
<td><strong>Lubricity</strong></td>
<td>To be determined. Graphite could be considered.</td>
</tr>
<tr>
<td><strong>Corrosion</strong></td>
<td>pH control to 8.5-9.5</td>
</tr>
<tr>
<td></td>
<td>Oxygen scavenging system</td>
</tr>
<tr>
<td></td>
<td>Passivating system</td>
</tr>
</tbody>
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be controlled. Products will have to be developed and evaluated for this application although the concept has been well developed for completion fluid applications.

If bore hole stability and torque problems are threatening the completion of the well then consideration may have to be given to oil based mud even though this will not meet the reservoir protection criteria.

The question of cooling the drilling fluid is a complex one. Fluids can be formulated to be stable at the maximum anticipated temperature of 210° C. Other items of downhole equipment such as mud motors, MWD tools and bearings of bits may require lower temperatures for their efficient operation.

The temperature of the circulating fluid will not reach the bottom hole temperature because of evaporative cooling at the surface and cooler rocks near the surface. The static fluid will take about 24 hours to reach about 90% of the down hole temperature. The temperature profile can be mathematically modelled and the cooling requirements on the surface calculated. The fluid formulation should be tested at the bottom hole conditions to ensure that the system is reliable.
REFERENCES


Hydrogeothermic Studies in the Hot Dry Rock Project at Soultz sous Forêts

R. SCHELLSCHMIDT, R. SCHULZ

Abstract

Hydrogeothermic studies were carried out in the joint German-French HDR-Project at Soultz sous Forêts to determine the natural temperature field of the test site and to detect water accepting zones within the borehole GPK 1. The undisturbed temperature field was measured in the borehole GPK 1 and in three oil wells in the surroundings. The virgin rock temperature is about 140 °C at 2000 m depth. The temperature gradient decreases from 100 mK m⁻¹ to 30 mK m⁻¹ at about 1100 m depth.

The heat flow density, is more than 180 mW m⁻² in the Muschelkalk and about 70 mW m⁻² in the granitic section. This determination validates the assumption of a horizontal convective heat transfer within the aquifers.

The results of a production test show, that there is only one inflow zone in borehole GPK 1 at 1812 m depth. Three injection tests, using different injection flow rates, were conducted in borehole GPK 1. A total number of about 20 water accepting joints could be detected by temperature measurements. A second major outflow at 1728 m depth was encountered besides the one at 1812 m depth. About 47 % of the injected water was lost at 1728 m depth and about 53 % at 1812 m depth.

The high resolution temperature measurements showed definitely, which joints are water accepting (partly dependent on pressure) and which are not.

1. Introduction

Geothermal energy from hot steam and hot water reservoirs have been used industrially in many countries worldwide for several decades now. In the case of heat stored in deepseated hot basement rock the development is different. It is the exploitation of this energy potential that the Hot Dry Rock (HDR) concept has as its objective. This concept was developed in the early 70s by scientists of the Los Alamos Scientific Laboratory in the USA. Large frac-
ture surfaces are induced artificially in tight basement rock masses situated many kilometres below surface. Cold water is injected under pressure into this joint system, the water is heated by the hot rock masses, and returns to surface, either by a second production well or through the injection well. The produced heat is mainly intended for power generation. Large scale industrial use of the HDR concept is subject to the question of economic viability, in addition to the overcoming of technical problems.

Joint German-French project studies are planned to investigate the Upper Rhine Rift Valley as source of economic geothermal energy using HDR technology.

On 7 December 1987 geothermal well, GPK 1, in the Upper Rhine Rift Valley near Soultz sous Forêts (France), reached a total depth of 2000 m, with basement rock encountered at 1377 m. The well location is in the centre of the largest positive heat flow density anomaly in Central Europe. In this area the temperature gradients in sediment are at least 60 mK m\(^{-1}\), at the well location (Soultzer Horst) values are in excess of 100 mK m\(^{-1}\).

2. The Original Temperature Field in Boreholes of the Soultz Area

Fig. 1 shows the undisturbed temperature as a function of depth in borehole GPK 1 and in three recovered oil wells (4598, 4609, 4616) in the surroundings (max. 350 m). The maximal temperature is 104 °C in well 4598 (at 838 m depth), 116 °C in well 4609 (at 973 m depth), 116 °C in well 4616 (at 1383 m depth) and 140 °C in borehole GPK 1 (at 2000 m depth).

When the drilling operations were completed, in borehole GPK 1, the original temperature field around the borehole was disturbed. A stand-by time of 6 weeks was necessary for a complete recovery of the original rock temperature. The only exception is a small interval around 1812 m depth. This zone was much more cooled down than other borehole sections, because here a great amount of drilling mud was lost and entered a fault zone. The temperature at this depth was still increasing (see Fig. 1) in January 1988.

The recorded temperatures and temperature gradients of borehole GPK 1 are given in Fig. 2 as a function of depth. At about 1100 m depth a decreasing of the average temperature gradient from 100 mK m\(^{-1}\) to 30 mK m\(^{-1}\) is clearly seen. The decreasing temperature gradient can be explained.
by assuming a convective heat transfer in the Buntsandstein/Muschelkalk aquifer (947 - 1377 m).

The thermal conductivity of cores of the well GPK 1 (Muschelkalk, Buntsandstein, granite) was measured in our laboratory under original thermal conditions. The heat flow density, the product of thermal conductivity and temperature gradient, is more than 180 mW m$^{-2}$ in the Muschelkalk and about 70 mW m$^{-2}$ in the granitic section. This determination validates the assumption of a horizontal convective heat transfer within the aquifers.

3. Influx and Water Loss in the Open-Hole Section of the Bore-Hole GPK 1 Determined by Temperature Measurements

The results of a production test show, that there is only one inflow zone in borehole GPK 1 at 1812 m depth. The aim of the injection tests was to determine the positions of water carrying joints and to investigate the influence of fluid pressure on the injectivity of the borehole (ratio of injection flow rate to injection pressure). The injection experiments were followed by a production test for studying the chemical reaction (BRGM) of the injected fresh water in the basement.

The thermal measurements have been evaluated by the "Flow method" and the "Shut-in method". For these experiments it is necessary to measure the undisturbed rock temperature in the borehole before the hydraulic stimulation. In addition, two or three measurements during water injection are needed when using the "Flow method" and two or three measurements must be made during the shut-in interval. The evaluation method has been described in detail by Michel and Haenel (1984); it is based on a method by Murphy (1977). It was shown in 1984 that thermal flowmeter measurements are comparable to spinner flowmeter measurements regarding the resolving capacity (Schellschmidt and Haenel, 1987). The thermal flowmeter is advantageous if the water flow is small and the temperature is high.

Three injection tests, using injection flow rates of 0.5 l s$^{-1}$, 1.5 l s$^{-1}$ and 3.5 l s$^{-1}$, were conducted in borehole GPK 1. A well head pressure of 35 bars was built up to inject water with a flow rate of 1.5 l s$^{-1}$. A water loss of 20 % was detected at 1735 m depth; but the major amount of water (about 73 %) was lost at 1812 m depth (Fig. 3). A second major outflow was opened at 1728 m depth during the injection test with a flow rate of 3.5 l s$^{-1}$ and a well head pressure of 43 bars. The water losses were about 47 % at 1728 m depth and about 53 % at 1812 m depth (Fig. 4).
Further more the results of the temperature measurements immediately after shut-in prove that the joint at 1812 m depth is connected to a very large fault zone in contrary to the joint at 1728 m depth. This result is represented in Fig. 5 (depth interval 1700 m to 1825 m). Between 1704.4 m and 1733.8 m depth joints are observed, which are not connected to a fault zone. These joints opened at a wellhead pressure of about 35 bars and after shut-in they closed. Because the joints have no connection to a fault zone, the injected (cold) water was flowing out of these joints after shut-in, running down the borehole and entered the joint at 1812 m depth.

During water injection cold water had entered at different depth into joints of the granite. These joints were much more cooled down than the granite around the borehole. The jointed borehole zones need more time for the temperature recovery than the other borehole sections. By means of the "Shut-in method" it is possible to determine the distribution of water accepting joints; even very small water losses can be detected. The temperature during shut-in as a function of depth is given in Fig. 6 for the injection test with a flow rate of 3.5 l s⁻¹. A total number of 20 outflows have been detected, but no water accepting joint was observed below the depth of 1812 m.

A comparison of the borehole logs proved, that only the high resolution temperature logs detected definitely which joints are water accepting and which are not.

4. References


Fig. 1: Undisturbed temperature as function of depth in borehole GPK 1 and in three recovered oil wells (4598, 4609, 4616) in the surroundings
Fig. 2: Undisturbed rock temperature and temperature gradient as function of depth (temperature measurement on January 19th, 1988)
Fig. 3: The quotient $\Delta T/g$ as a function of depth (injection test on June 24th, 1988)
Fig. 4: The quotient $\Delta T / g$ as a function of depth (injection test on June 28th, 1988)
Fig. 5: Temperature measurements before and during shut-in for the depth interval 1700 m to 1825 m (injection test on June 24th, 1988).
Fig. 6: Rock temperature during shut-in (injection test on June 28th, 1988)
Determination of Instantaneous Shut-in Pressures in Hydraulic Fracturing Tectonic Stress Measurements

Kazuo HAYASHI
Institute of High Speed Mechanics, Tohoku University, Sendai 980, Japan
and
Izumi SAKURAI
Fujitsu Co Ltd., 1011 Kamiodanaka, Nakaharaku, Kawasaki 211, Japan

Abstract

A new method is presented for the determination of the instantaneous shut-in pressures in the hydraulic fracturing tectonic stress measurements. The method is developed by the analysis of the closure process of the crack induced by hydraulic fracturing, where the analysis is based on linear theory of elasticity and fracture mechanics. The method utilizes the inverse of the decrease rate of the downhole water pressure after shut-in. The plot of the inverse of the decrease rate vs the downhole pressure consists of two straight lines. The point of intersection of the two lines corresponds to the onset of crack tip closure, and the pressure at this point, i.e., the crack tip closure pressure (CTCP), is an excellent estimate to the tectonic stress component which is acting perpendicularly to the induced crack. The new method is applied to the pressure vs time records which were obtained in field experiments. It is revealed by the application to the field data that the new method can clearly determine the crack tip closure pressure (CTCP) from all of the pressure vs time records.

Introduction

The construction of the subsurface heat exchange systems of HDR geothermal heat extraction consists of two main steps, as well known. The first step is the creation of an artificial reservoir by hydraulic fracturing and the second step is the connection of production and injection wells through the artificial reservoir. The orientation of the artificial reservoir is mainly governed by the orientation of the principal axes of the tectonic stress. So far, there proposed three methods for the measurements of the tectonic stress in the deep earth's crust, i.e., the hydrofrac stress measurement[1], the differential strain analysis (DSA) [2] and the anelastic strain recovery (ASR) [3]. Among these, the hydrofrac stress measurement seems to be most powerful and promising. In DSA, the relation between the strains obtained from recovered core samples and the in-situ tectonic stress is not necessarily clear, and ASR is difficult to be applied to weakly anelastic rocks, such as crystalline rocks.

The hydrofrac stress measurements use three pressure data, generally. These are the breakdown pressure, the crack reopening pressure and the instantaneous shut-in pressure. The breakdown pres-
sure is the water pressure value at which an artificial crack is newly created, and the reopening pressure is the water pressure value at which the crack opens again in the successive pressurization cycles. The instantaneous shut-in pressure is defined as the water pressure value which balances the compressive tectonic stress component acting perpendicularly to the crack. The balance is believed to be achieved during the closure process due to leak-off of water into the rock from the crack surfaces after the pressurization circuit is completely closed (shut-in). All these three pressure data are routinely used practically. However, there remain essential problems to be solved. Firstly, the breakdown and reopening pressures are highly dependent on the pressurization rate. Secondly, the closure process after shut-in is not fully understood.

In the previous paper [4], the crack closure process after shut-in was analyzed based on linear theory of elasticity and fracture mechanics, and the methods which were so far proposed for the determination of the instantaneous shut-in pressure were applied to shut-in curves constructed by the numerical simulation for various conditions of leak-off, equipment compliance and partial crack closure. It was revealed that the method of the point of maximum curvature gave a good estimate of the compressive tectonic stress component acting perpendicularly to the crack surfaces. However, it frequently happens in many field experiments that the point of maximum curvature does not appear so clearly. In this reason, in the present paper, a new method is proposed for the determination of a pressure value that gives an excellent estimate of the compressive tectonic stress component acting perpendicularly to the crack surfaces. The basic idea of the method is to use the plot of the inverse of the decrease rate of the downhole water pressure after shut-in vs the downhole water pressure. When the method is applied to the shut-in curves which were obtained by numerical simulations in the previous paper [4], each plot consists of two straight lines. The point of intersection between the two lines gives an excellent estimate of the compressive tectonic stress component acting perpendicularly to the crack surfaces. Finally, the new method is applied to the shut-in curves which were obtained in the field experiments of the T-Project, Tohoku University [5].

Numerical Simulation of Shut-In Curves

Based on linear theory of delasticity and fracture mechanics, the crack closure process after shut-in was analyzed in the previous paper [4] for a pair of two longitudinal cracks (Fig.1) induced on a wellbore surface by hydraulic fracturing. Figure 2 shows examples of the shut-in curves obtained by the numerical simulation in the previous paper[4], where T is time after pressurization in each pressurization cycle, P is the downhole pressure, R the radius of the wellbore, \( L_0 \) the half length of the cracks, \( h_c \) the height of the cracks and \( C \) the fluid loss coefficient from the crack to the rock. The stress \( \sigma_1 \) and \( \sigma_2 \) are the tectonic stress components shown in Fig.1. Figure 3 shows schematically the crack closure process after shut-in. Before shut-in, water is flowing into each crack from the wellbore to the crack tip and there is a pressure gradient along the crack due to viscous losses. Just after shut-in the inflow in the crack stops and the pressure gradient diminishes. This makes the stress intensity factor exceed
the fracture toughness and, as a result, the crack grows up instantaneous to make the water pressure decrease to an uniform level corresponding to a stress intensity factor which is equal to the fracture toughness \[4\]. After the instantaneous crack growth, the water pressure decreases gradually due to the leak-off of water from the crack to the rock to make the aperture of the crack decrease gradually, and finally the crack tip starts to close at a certain instance. After this, the closed region propagates towards the wellbore and the opened region shrinks as the water pressure decreases due to the leak-off of water from the crack to the rock. In Fig.3, the stages A and B correspond to the instance of the finish of the instantaneous crack growth and to the onset of the crack tip closure, respectively. These two stages A and B are indicated by the points A and B, respectively, in Fig.2. The rapid decrease from the instance of shut-in down to A is due to the instantaneous crack growth. Between A and B, opening is kept all over the crack. At B, the crack closure takes place at the crack tip and, beneath B, the closed region propagates gradually from the crack tip towards the wellbore. The point A in Fig.2 corresponds to the so-called inflection point and the pressure level of this point is fairly high above the tectonic stress component \(\sigma_2\) acting perpendicularly to the crack surfaces, as shown in Fig.2. The point B appears as the point of maximum curvature on shut-in curves, as described in the previous paper [4] and as can be seen in Fig.2. It can be seen from Fig.2 that the pressure at B is very close to the tectonic stress component \(\sigma_2\) acting perpendicularly to the crack surfaces. Conversely speaking, the tectonic stress component acting perpendicularly to the crack is given by the downhole pressure value at the point of maximum curvature on a shut-in curve of hydrofrac stress measurements.

It should be noted that the point of the maximum curvature corresponds to the instance of the onset of the crack tip closure. Therefore, the pressure at the point is better to be called the crack tip closure pressure (CTCP) than the instantaneous shut-in pressure (ISIP). The definition of ISIP is phenomenological and is vague. CTCP, on the other hand, gives a sharp physical image what it means. In the next section, let us discuss how to determine CTCP from pressure vs time records of field experiments.

**Determination of Crack Tip Closure Pressure (CTCP)**

There are many techniques to determine the instantaneous shut-in pressure from shut-in curves. They can be listed as (a) the pressure at the point where the shut-in curve just starts to inflect [6], (b) the pressure at the point of intersection between tangents drawn to initial and late parts of the shut-in curve [7], (c) the pressure at the point of maximum curvature [7] and (d) the pressure where the shut-in curve ultimately levels off [7]. In addition to these methods which use the original shut-in curves, there are rather complex methods which re-draw the shut-in curves into other forms such as (f) pressure vs \(\log\) (time) [8], (g) \(\log\) (pressure) vs \(\log\) (time) [9], (h) pressure vs \(\log\) (time/(time after pressurization)) [10] and (i) \(\log\) (pressure) vs time (Muskat method) [11]. These methods generally give different values of the instantaneous shut-in pressure from a single shut-in curve, and there seems to be no deterministic method [12]. In the previous paper [4], all these methods were applied to the shut-in curves obtained by the numerical simulation.
It was revealed by the application that the four methods (c) and (f)-(h) were reliable and they gave essentially the same pressure value which is the pressure level at the point B stated in the previous section, i.e., CTCP. However, shut-in curves obtained in field experiments generally do not have clear appearance of the point of maximum curvature and, as a results, fairly large uncertainty is left.

As stated in the previous section, the point B corresponds to the instance at which the crack tip closure takes place, i.e., the stress intensity factor becomes zero. Before this instance, the crack opens all over the cracked region, but after this instance, the closure propagates gradually from the crack tip towards the wellbore. Namely, the behavior of the crack is completely different before and after the instance corresponding to the point B. Under these considerations, let us examine the the relationship between the water pressure $P$ and the inverse of the decrease rate of the water pressure $dT/dP$. The results obtained for the shut-in curves given in Fig.2 are shown in Fig.4, where the point at the right end of each plot corresponds to the point A in Fig.2. As shown in Fig.4, each plot of $dT/dP$ vs $P$ consists of two straight lines and the pressure at the point of intersection between the two straight lines gives a very good approximation of the tectonic stress component $\sigma_2$ acting perpendicularly to the crack surfaces.

Now, let us apply the method to shut-in curves obtained in field experiments. The shut-in curves used in the following are those for longitudinal cracks created during the hydrofrac stress measurements performed in the $\Gamma$-Project, Tohoku University [13,14]. The depths of these cracks are 288.2m, 325.5m, 345m, 356.4m and 359m. The rock of the field is well graded tuff. The permeability of the rock is $3.0 \times 10^{-15}$ - $6.4 \times 10^{-17}$ cm$^2$ and the fracture toughness is $0.6 - 1.0$ MPa$\sqrt{m}$. The original shut-in curves and the corresponding $dT/dP$ vs $P$ plots are shown in Figs.5-9, where $dT/dP$ was calculated by applying an usual finite difference approximation to the data picked up every 0.1 or 0.2 MPa from the original shut-in curves and the results are shown by solid circles in Figs.5-9. The plots of Fig.5,6,8 and 9 consist of three straight lines and the plot of Fig.7 can be approximated by three straight lines. There are two intersection points in each plot. The intersection point with a lower pressure of the two intersection point is on the heavily curved portion of the original shut-in curves. Therefore, this point corresponds to the intersection point appearing in the plots obtained by the numerical simulation (Fig.5). Thus, the pressure of this point is CTCP and must give a reliable estimate to the tectonic stress component acting perpendicularly to the induced crack. The intersection point with a higher pressure of the two intersection points is considered to be the inflection point, since the pressure of this point is fairly close to the pressure at the instance of shut-in.

Now, let us try to determine CTCP from the original shut-in curves given in Fig.5-9. Except for the case of Fig.8, it is fairly difficult to determine CTCP positively and ambiguity is left in the determined value of CTCP. The same thing can be said even if the methods employing logarithmic plots, such as the methods (f)-(i). Figure 10 is showing the plots of $P$ vs $\log(T/T_0)$, where Fig.10(a) and (b) correspond to Figs.5 and 8, respectively. It can be readily understood from Fig.10 that, if original shut-in curves do not have clear turning points, logarithmic plots are helpless either. On the
contrary, the method using the $dT/dP$ vs $P$ plot can always determine CTCP clearly, as already shown in Figs.5-9.

Conclusions

By analyzing the shut-in curves obtained by numerical simulation of the closure process of a pair of two longitudinal cracks after shut-in, a new method is proposed for determining a pressure value which is an excellent estimate to the tectonic stress component acting perpendicularly to the cracks. The conclusions that can be drawn from the present study are as follows:

1. The new method utilizes a plot of the inverse of the decrease rate of downhole pressure vs downhole pressure after shut-in. When the method is applied to field data, this plot consists of three straight lines and, therefore, there are two intersection points.
2. The point of intersection with a higher pressure corresponds to the inflection point in the original shut-in curve. The point of intersection with a lower pressure represents the onset of crack tip closure and the pressure at this point, i.e., the crack tip closure pressure (CTCP), is an excellent estimate to the tectonic stress component which is acting perpendicularly to the crack surfaces.
3. The new method was applied to five sets of field data. For all of the five sets, the new method gave clearly the intersection points and the crack tip closure pressure (CTCP) were determined without any ambiguity.

Acknowledgments

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Fig. 1 Longitudinal cracks on the wellbore surface
Fig. 2 Examples of shut-in curves obtained by numerical simulation

![Graph showing shut-in curves](image)

\[
\frac{P}{\sigma_2} = 1.5 \\
2L_0/R = 5 \\
h_0/R = 60 \\
R/C\sqrt{T_o} = 75, 750
\]

Fig. 3 Crack closure process

![Crack closure process](image)

shut-in  crack growth  decrease of aperture  crack tip closure (K=0)

Fig. 4 (dt/dp) vs p obtained by numerical simulations

![Graph showing (dt/dp) vs p](image)
Fig. 5 Result of application to field pressure-time record (288.2m)

Fig. 6 Result of application to field pressure-time record (325.5m)
Fig. 7 Result of application to field pressure-time record (345m)

Fig. 8 Result of application to field pressure-time record (356.4m)
Fig. 9 Result of application to field pressure-time record (359m)

Fig. 10 Pressure vs log(time) plots
(a) 288.2m
(b) 356.4m
IN SITU STRESS MEASUREMENTS IN DEEP WELLS

A S P Green, R J Pine, A Jupe

ABSTRACT

A knowledge of the in situ stresses is essential in the development of an HDR reservoir. The stresses determine the pressures required to induce reservoir growth and the orientation of growth, whether it be by tensile fracturing or shear stimulation of existing joints.

In Cornwall, the in situ stresses have been determined down to 2.5 km by hydrofracture stress measurements (HFSM) in the wells and overcoring in local mines at 790 metres. At depths down to 6-7 km, the depths at which temperatures are high enough to generate electricity in SW England, HFSM are unlikely to be practical. There are a number of other techniques that can be used. Borehole breakouts, seismic wave polarisations and microseismic fault-plane solutions may provide stress orientation but limited information on magnitude, whilst hydraulic tests and laboratory measurements of core may provide information on stress magnitudes.

These alternative methods of determining the stress tensor and their applicability to deep wells will be reviewed. It will be seen that no single method is likely to provide information on the complete stress tensor at a depth of 6 km and that it will be necessary to employ a number of different techniques.

INTRODUCTION

The exploitation of hot dry rock (HDR) geothermal energy requires the creation of a high permeability heat exchange region in a hot low permeability rock mass. The region of high permeability, the reservoir, is created by fluid injection. The direction of growth of the reservoir, whether it be by the fracturing of the rock mass or the stimulation of existing joints, is governed by the magnitude and orientation of the in situ stresses.

At the Camborne School of Mines (CSM) HDR geothermal energy Project, reservoir growth at a depth of 2 km in the Cambmenellis granite in SW England has been downwards and, in plan, in a NW/SE direction. This growth is controlled by the interaction of the in situ stresses and the natural jointing (Pine and Batchelor 1984, Pine and Nicol 1988). The in situ stresses have been measured by a combination of HFSM to a depth of 2.5 km and overcoring at 790 m in a local mine, with supporting information from other techniques (Pine et al 1983a, Pine et al 1983b, Batchelor and Pine 1986).

A commercial HDR system designed to generate electricity will have to produce fluids at temperatures in excess of 200°C. In south west England this can only be achieved by drilling to depths greater than 6 km. Attempts have been made to predict the in situ stresses at 6 km.
based upon the information available down to 2.5 km. These predictions will need to be confirmed after the drilling of the first well of a deep commercial prototype. It is already clear that hydrofracture stress measurements will become increasingly difficult to carry out at greater depths and other methods may have to be utilised.

This paper briefly reviews the different methods of determining in situ stress. These methods will be evaluated for their potential to provide reliable data at depths down to 6 km and temperatures of 200°C in the Carnmenellis granite.

HYDROFRACTURE STRESS MEASUREMENTS

Hydrofracture stress measurement (HFSM) is the most commonly used technique in deep boreholes. There are a number of variations in the approach but these can be divided broadly into three main types:

(i) "Conventional" HFSM using a straddle packer located adjacent to a "joint-free" zone (eg Pine et al 1983b).

(ii) Refracture of natural joints in different orientations identified by detailed logging (eg Cornet and Valette, 1984).

(iii) Single packer used at the bottom of a borehole, followed by coring (eg Daneshy, 1988).

In the conventional method a fracture free zone must be identified from previous logging or coring. A complete test can provide magnitudes of maximum horizontal stress, \( \sigma_H \), and minimum horizontal stress \( \sigma_H \). Post-test logging of induced fractures can give stress orientations. The conventional assumption that the vertical stress, \( \sigma_v \), is given by the overburden thickness and unit weight product is probably satisfactory at most deep locations. This was substantiated at 790 m depth in the Carnmenellis granite by overcoring measurements and conditions could be expected to be more uniform at greater depth away from topographical influences.

Conventional or refractured HFSM may be undertaken with straddle packers mounted on drillpipe or on a wireline, with inflate lines (Rummel 1988).

The estimate of the magnitude of \( \sigma_H \), which depends on the magnitude of in situ tensile strength, assumed elastic stress distributions and a variety of interpretational approaches, has low reliability. Often the best that can be achieved is to determine if \( \sigma_H \) is greater or less than \( \sigma_v \).

Post-test fracture location by logging or use of impression packers is often unsuccessful at very deep locations. This affects the confidence of the interpretation and does not allow the direction of \( \sigma_H \) to be determined.

In the refracture method the problem of in situ tensile strength determination is overcome at the expense of a more lengthy test procedure involving the setting of the straddle packer interval over individual joints. This requires very detailed pre-test logging and...
very careful depth control. These difficulties may well be too great in deep applications.

The use of a single packer at the bottom of the borehole followed by coring to determine fracture orientation was described by Daneshy (1988) at a recent international symposium on HFSM. It has not been widely practised to date but appears to have considerable merit (simplicity) for the deepest applications. The taking of oriented core for fracture direction determination is a potential problem at the greater depths.

In deep locations there are a number of problems which might affect all the HFSM methods. The main potential problems are:

(i) Highly stressed borehole walls will be affected by breakouts.
(ii) High temperatures will affect the behaviour of the packer rubber elements.
(iii) Depth control on logging/packer location.
(iv) Existence of sufficiently long suitable test intervals.
(v) Incipient hydraulic fracturing.

The existence of breakouts is useful for stress orientation determinations. However, if pervasive, they will make the seating of packers difficult, if not impossible, and will greatly affect the logging for suitable test zones. In the Carnmenellis granite, Pine and Kwakwa (1988) have shown that this may be a major problem at 6 km and possibly as shallow as 4 km depth.

Depending on the actual in situ stresses it has been predicted that straddle differential pressures in excess of 100 MPa with adjacent rock temperatures in excess of 200°C could apply at 6 km depth in the Carnmenellis granite. Similar values would apply at other potentially commercial HDR sites in SW England. These values are beyond the limit of current packer technology and some further development would be necessary.

It will only be possible to control wireline logging depths to within a few meters at great depth. This means that for successful packer location the unjointed lengths for conventional tests would have to be at least 10 m. In the refracture tests similar lengths are necessary to ensure target joints are contained between packers. It is not evident that such suitable geological conditions will exist at any potential HDR site.

It may be possible for hydraulic fracturing to occur during the drilling of the borehole particularly where horizontal stresses are strongly anisotropic. In this case determination of \( \sigma_h \) may be possible indirectly (from mudweight calculations) but \( \sigma_h \) cannot be determined. Some information on stress orientation may be available from logging of the incipient hydraulic fracturing.

There are clearly some major limitations with HFSM applied to deep measurements and comprehensive results are unlikely. For HDR
development partial results could be satisfactory. A reasonable amount of success has been achieved so far in the Carnmenellis granite to a vertical depth of about 2.5 km (Pine et al. 1983, Pine and Kwakwa 1988).

Based on the discussion above, it appears that it would be unwise to expect much from HFSM in granites below a depth of about 4 km.

HYDRAULIC DATA

The analysis of hydraulic data during variable flow injections and stimulations can provide information on the in situ stresses.

The breakdown pressure at the start of a stimulation and the closure pressure at the end can both provide data on the minimum horizontal stress (Nolte 1979, Lee 1985). It is important to identify whether classical hydraulic fracturing or the refracturing of joints not oriented in the direction of the minimum horizontal stress has occurred. The latter situation will lead to overestimates of the minimum stress.

For lower flow rate injections it has been observed that there is a repeatable relationship between injection flow rate and injection pressure. At a particular injection pressure there is a marked increase in flow rate. This, again, is governed by the in situ stresses and providing the orientations of the flowing joints from borehole logging are known it is possible to confirm previous values obtained.

Both of the above analyses can be performed in 6 km deep wells but because they require fluid injection into the rock mass they would have to be used to confirm measurements taken previously.

MICROSEISMIC DATA

The mechanism through which seismic failure occurs on natural fractures is governed by the stress regime in which the fractures exist. It is therefore reasonable to surmise that a study of seismic focal mechanisms may provide information on the in situ stress field at the time of failure.

The vast majority of seismic mechanisms result from shear failure and may be studied using a double-couple approximation (McKenzie 1969, Madariaga 1987, Pearce and Rogers 1987). The double-couple comprises a point source consisting of a pair of orthogonal shear force couples. The seismic compressional (P) and shear (S) wave radiation patterns consist of four quadrants in which the observed first ground motions are either compressional or dilational. The P-wave quadrants are separated by two nodal planes, one of which is the failure plane, and the other an auxiliary plane which is normal to the failure plane, and has no geological significance. By plotting the observed seismic wave polarities onto a stereographic projection it is possible to constrain the seismic focal mechanism.

An example from the CSM site is shown in Figure 1, where the range of solutions shown are all compatible with the P-wave first motion data. Due to the symmetry of the double-couple it is impossible to say which
of the two nodal planes is the failure plane unless some additional information is available. In the case of induced microseismicity this is limited to the spatial distribution of associated seismicity or an a-priori knowledge of the stress field.

The convention has arisen that the centres of the compressional and dilatational quadrants, the tensional (T) and compressional (P) axes, are taken to represent the orientations of the maximum and minimum principal stresses. This is based on the assumption that failure occurs on newly created fractures in a homogeneous rock-mass. Although in certain circumstances the P and T axes may be a useful approximation to the principal stress axes (Celerier 1988), the general assumption is invalid for seismic events which occur on pre-existing fractures. Consequently the principal axes may lie anywhere in their respective quadrants (McKenzie 1969, Celerier 1988) and the P and T axes approach must therefore be treated with caution.

Perhaps the most promising development is the recent analysis of focal mechanisms using inverse techniques (Anglier 1984, Michael 1987, and Gephart and Forsyth 1984). With inversion techniques it is possible to obtain estimates of both the stress field orientation and one relative stress magnitude \((\sigma_2 - \sigma_3)/ (\sigma_1 - \sigma_3)\), where the compressive principal stresses are \(\sigma_1 > \sigma_2 > \sigma_3\). This offers the potential for obtaining a value for \(\sigma_1\). A technique of this type has been applied to CSM data and has produced encouraging and constructive results (Jupe et al 1989).

Figure 2 shows this technique applied to the fault-plane solution in Figure 1. The orientation of the principal stresses show a good agreement with the measured stresses. Similar analysis of microseismicity down to a depth of 4 km shows no change in the orientation of the principal stresses.
The calculated value of the relative stress magnitude is 0.3, which is lower than the value of 0.5 from HFSM. From experience at CSM determination of the relative stress magnitude appears to be more sensitive to errors in the fault-plane solution than the stress orientation. This may prove to be a limitation in this technique.

As with direct interpretation of hydraulic data inverting fault-plane solutions to provide in situ stress data can only be done after microseismicity has been induced. This could be either in low flow rate hydraulic tests or the first hydraulic stimulation.

BOREHOLE BREAKOUTS

The walls of many boreholes show elliptically shaped, vertically elongated zones of wall spalling. Two mechanisms have been suggested for this spalling. It has been attributed to localised wellbore collapse where drilling encounters fractured rock, in which case the breakouts are aligned with the fractures. Alternatively they may be caused by shear fracturing in the zone of stress amplification close to the borehole wall in which case the long axis of the ellipse is orientated in the direction of the minimum horizontal stress (Figure 3). A number of recent studies indicate that the latter explanation appears to be the most common and breakouts are good indicators of stress orientation (Dart and Zoback 1989, Teufel 1985).

The mechanism of borehole breakouts is not completely understood but it is believed that the shape and size is controlled by the in situ stress magnitudes, rock shear strength and pore pressure in the rock. Attempts have been made to determine the stress magnitudes as well as the orientation from the breakout shape (Haimson and Herrick 1985). However, this must be considered as speculative at this stage of our understanding of breakouts.

The normal assumptions in the analysis are that the borehole is vertical and that the vertical stress is one of the principal stresses. Mastin (1988) has looked at deviations from these assumptions, which may be applicable to boreholes deviated from the vertical. In strike-slip faulting regimes the breakout orientation is insensitive to borehole deviations, with deviations of as much as 30° from vertical giving theoretical orientations within 10° of \( \sigma_\alpha \). In normal and thrust faulting regimes there may be significant changes in breakout orientations even in boreholes that deviate by less than 10° from vertical.

Measurements of borehole breakouts are usually made with dipmeter logs, with four arm calipers, or borehole televiewers (BHTV). It is, of course, important that the logs are accurately oriented within the borehole.

There are several advantages in the use of borehole breakouts to determine the in situ stress orientation in a deep system in Cornwall. The present 2.5 km wells at Rosemanowes show little evidence of breakouts but extrapolation of the measured stress deviator suggests that they will occur at not much greater depths. It will be necessary to run BHTV logs to obtain jointing information and therefore breakout
information can be acquired without extra expense. It is unlikely that any information on stress magnitudes will be produced and high temperature BHTV's are only in an early stage of development. Nevertheless, it is expected that breakouts will be observed at a depth of 6 km in the Carnmenellis granite and will play an important part constraining the stress tensor.

LABORATORY MEASUREMENTS

When a rock core is removed from a borehole there is an instantaneous elastic strain recovery and a time dependant anelastic strain recovery. There are three techniques that use the anelastic changes that occur when a rock core is brought to the surface to determine something of the stresses acting on the core when in situ. The first, anelastic strain recovery, is a passive method which monitors the anelastic changes that occur immediately the core is removed. The other two methods involve loading the core and monitoring changes in either the core shape or the acoustic emission rate.

These methods have the ability to reveal the full stress tensor, if oriented cores are available, before any stimulations are carried out. The three methods are now briefly described.

Anelastic strain recovery

According to viscoelastic theory it is possible to calculate the magnitude of the principal horizontal stresses directly from the values of the anelastic strain recovery that occurs when the core is removed from the borehole (Teufel, 1983).

The strain recovery can be measured by means of inductive displacement transducers in the axial direction and three different radial directions at constant temperature and pressure. There are two main assumptions in this method:

a) The rock is homogeneous, isotropic and linear viscoelastic.

b) The borehole is aligned with one of the principal stresses.

Acoustic emissions have been observed during the process of strain recovery and these are caused by tensile microfracture formation. Bursts of acoustic emission are probably avalanche like microfracture interactions.

The recovery process lasts between hours and days. In order to determine the stresses by this method it is, therefore, necessary to make the measurements as soon as the core becomes available.

Differential Strain Analysis

The cores are cut into cubes and strain gauges bonded to the surfaces. The cubes are then covered in a flexible membrane and loaded hydrostatically in a pressure cell. The loading/unloading curves show non lineairities due to the closure of microcracks induced by the original coring process. It is assumed that the total strain due to reclosure of these cracks is proportional to the normal stress release. From the curves a strain ellipsoid can be determined, from
which, if the orientation of the core is known, information on the in situ stress orientation and magnitudes can be determined.

Experimental work on core from depths of between 1.3 and 2.5 km at the CSM test site gave mixed results. DSA measurements of the in situ stress magnitudes above 1.5 km show good agreement with the hydrofracture stress measurements. However, the deeper DSA measurements indicate that the maximum stress is vertical, contrary to the results of the HFSM.

The Kaiser effect of acoustic emissions

Acoustic emissions (AE) are transient elastic waves generated by the rapid release of strain energy associated with induced micro-cracking in rock specimens. It has been suggested that the monitoring of AE during rock deformation experiments may be able to provide the in situ stress levels prior to the rock sample being removed from the ground. These suggestions are based on the AE phenomenon that has come to be known as the Kaiser effect (Kaiser 1950). The Kaiser effect has been defined as the absence of detectable AE until some previously applied peak stress level has been exceeded. There have been a number of reported cases, with varying levels of success, in which the in situ stresses have been estimated using the Kaiser effect. In core samples deformed in the laboratory (Hayashi et al. 1979, Michihiro et al. 1985, Holcomb and Martin 1985) and in shallow boreholes using rock jacks (Ghasemi 1986).

All of the three laboratory techniques described above are at an early stage of development. Whilst in theory the full stress tensor can be determined, good case histories need to be developed before the reliability of these techniques can be assessed. At this stage, it is not believed that these methods can justify the high cost of oriented coring at 6 km.

SHEAR WAVE SPLITTING

In a strongly anisotropic stress field, fluid filled microcracks will tend to align normal to the minimum compressional stress by such processes as subcritical crack growth (Crampin 1987). These aligned microcracks will cause the elastic behaviour of the rock to vary with direction. The effect of this is to cause the velocity of compressional and shear waves to vary with direction and for the shear waves to split into two or more phases with fixed velocities and polarisations (Crampin 1987). This is shown in Figure 4.

The fastest shear wave will be polarised parallel to the stress aligned microcracks and the difference in velocity of the differently polarised shear waves indicates the density of the microcracks. The most that can be hoped for from this technique is the orientation of the stress field.

Shear wave splitting, as this effect has become known, has been observed in a number of different geological environments. However, it has not been verified that in all cases the orientation of the seismic anisotropy is the same as that of the in situ stresses. The effects of cleavage, jointing and complex geology need to be more carefully investigated (Siegesmund et al. 1989).
BOREHOLE GUIDED WAVES

It has already been noted that the in situ stress field is perturbed adjacent to a borehole. It has been suggested that this concentration of stress will affect the velocity of wave propagation near the borehole wall. Barton and Zoback (1985) examined whether the polarisations of borehole guided waves are affected by this stress induced velocity anisotropy. They find that the direction of polarisation seems to be controlled by the direction of the maximum horizontal stress. However, no information on the magnitudes of the stresses can be obtained. The data can be obtained from the same three-component vertical seismic profiles (VSP) used for measuring the shear wave splitting.

Very little work on the polarisation of borehole guided waves has been carried out. Preliminary indications are that the technique can be classified as promising but uncertain.

SUMMARY

The evaluation of the in situ stress is an essential part of the development of a hot dry rock geothermal reservoir. For the production of electricity from the Carnmenellis granite a reservoir will have to be created at a depth of approximately 6 km. The conventional methods of determining in situ stresses in boreholes,
such as HFSM, are likely to prove difficult, if not impossible, at a depth of 6 km. Six alternative methods have been examined. Table 1 summarises the results of this examination and their applicability to 6 km.

Assuming the HFSM methods will only achieve any success at depths less than 4.5 km the following programme is suggested for obtaining information on the in situ stresses at greater depths.

The initial surveys will determine the direction of the minimum in situ stress from borehole breakouts (BHTV). Shear wave splitting (VSP) and borehole guided waves (VSP). These have a low opportunity cost and can be carried out on the undisturbed borehole.

They will be followed by low flow rate injections. The analysis of these injections will provide information on the minimum horizontal stresses. These injections may well induce microseismicity from which stress orientations and relative magnitude can be obtained.

**TABLE 1**

<table>
<thead>
<tr>
<th>Method</th>
<th>Mag.</th>
<th>Orient.</th>
<th>State of Art</th>
<th>Opportunity cost</th>
<th>Application to 6 km</th>
</tr>
</thead>
<tbody>
<tr>
<td>HFSM</td>
<td>Y</td>
<td>Y</td>
<td>3</td>
<td>H</td>
<td>1</td>
</tr>
<tr>
<td>Hydraulic tests</td>
<td>Y</td>
<td>N</td>
<td>3</td>
<td>L</td>
<td>3</td>
</tr>
<tr>
<td>Breakouts</td>
<td>N</td>
<td>Y</td>
<td>2</td>
<td>L</td>
<td>3</td>
</tr>
<tr>
<td>Seismic</td>
<td>Y</td>
<td>Y</td>
<td>3</td>
<td>L</td>
<td>3</td>
</tr>
<tr>
<td>ASR (</td>
<td>Y</td>
<td>Y</td>
<td>1</td>
<td>H</td>
<td>1</td>
</tr>
<tr>
<td>DSA (</td>
<td>Y</td>
<td>Y</td>
<td>1</td>
<td>H</td>
<td>1</td>
</tr>
<tr>
<td>Kaiser)</td>
<td>Y</td>
<td>Y</td>
<td>1</td>
<td>H</td>
<td>1</td>
</tr>
<tr>
<td>Shear waves</td>
<td>N</td>
<td>Y</td>
<td>1</td>
<td>L</td>
<td>3</td>
</tr>
<tr>
<td>Borehole waves</td>
<td>N</td>
<td>Y</td>
<td>1</td>
<td>L</td>
<td>3</td>
</tr>
</tbody>
</table>

**State of art**

1 - not in routine use, not well understood
3 - in routine use, well understood

**Application to 6 km**

1 - unlikely to be applicable
3 - likely to be applicable

Finally, the analysis of the breakdown and shut-in pressures during hydraulic stimulations can be used to confirm the previous results and assist in the planning of further stimulations.
The present state of knowledge regarding laboratory methods such as differential strain analysis and the Kaiser effect is not considered well advanced. It is considered that these methods alone cannot justify the high cost of oriented coring.

ACKNOWLEDGEMENT

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ABSTRACT

Rock stress measurements have been conducted using different techniques as part of the Swedish Hot Dry Rock research project, carried out at Fjällbacka in the Bohus granite massif. Overcoring, hydraulic fracturing and hydraulic tests on preexisting fractures (HTPF) were used to determine the in situ stress situation.

Hydraulic injection test data gave information mainly about the vertical stress component which was found to correspond to the weight of overburden at several injection depths down to 500 m.

The stress orientations are poorly constrained, but both the overcoring and hydrofracturing method indicated a major horizontal compression striking NW-SE, which was also confirmed by inversion of fault plane solution data from induced microseismicity.

The stress situation proposed by the hydrofracturing results (horizontal stresses in excess of the weight of overburden down to 450-500 m) is in good agreement with the observed reservoir growth and behaviour and these results are considered as the most reliable as compared to the other measurements.

INTRODUCTION

A Hot Dry Rock (HDR) geothermal energy research reservoir is at present being developed in the Bohus granite on the Swedish west coast. At the research site close to the village Fjällbacka, a 500 m deep well (Fjb1) was drilled (figure 1) and high pressure hydraulic stimulation was performed at about 450 m depth (Eliasson et al., 1988 a,b). Based on the distribution of induced microseismicity the stimulated zone was located at a depth of about 450 m and a second 500 m deep well (Fjb3) was drilled inclined into the major seismic area at a lateral distance from Fjb1 of 100 m (Sundquist et al., 1988). The drilling intersected the stimulated fracture zone and a hydraulic contact between the wells was achieved. The flow connection was subsequently tested during a short-term circulation test at a low flow rate. Long-term circulation is planned to start during the spring of 1989.

As part of the research project, rock stress measurements were conducted with overcoring and hydraulic fracturing. Furthermore, information about the in situ stress situation was obtained from hydraulic injections and fault plane solutions for the microseismicity induced during these injections.

This paper reports on these stress determinations and discusses the reliability of the results.
METHODS

Overcoring stress measurements

Overcoring measurements were carried out by Swedish State Power Board (SSPB) in a 24 m deep borehole at the research site (Haag, 1983). Four stress determinations were made in the lower part of the 76 mm borehole.

This technique to measure the three-dimensional state of stress in vertical, water-filled boreholes was described by Hiltscher et al. (1979) and Hallbjörn (1986).

Hydrofracturing measurements

A series of hydrofracturing measurements were conducted in well Fjb3 (see figure 1), by the HDR research group in 1987 (Wallroth, 1989). Sections of homogeneous granite were selected with the intention of generating new, vertical fractures. To pack off the test sections, inflatable packers were used, transported in the well with a wireline rig.

The calculations of stress magnitudes were based on the classical hydraulic fracturing theory (Haimson and Fairhurst, 1967), assuming vertical fractures in the direction of the greatest horizontal compression. The pore pressure was excluded in the analysis and the hydrofracturing tensile strength was calculated as the difference between the breakdown pressure determined from the first pressurisation cycle and
the fracture reopening pressure from the third cycle.

Fracture orientations were obtained using a downhole television camera and a compass. Attempts were also made to determine the orientation of the generated fractures by use of an impression packer. However the method was unsuccessful, since the combined effect of a rough and inclined borehole resulted in destroyed impression wrap when the packer was transported in the borehole.

Hydraulic tests on preexisting fractures (HTPF)

In the first 500 m deep well Fjbl (see figure 1), stress measurements were performed by Bochum University, FRG, in 1984 (Wallroth, 1985; Baumgartner, 1986). The equipment used was a wireline hydrofracturing system with inflatable packers. Hydraulic injection tests were conducted on preexisting fractures with different dips and strikes. Fracture orientations were determined using an impression packer and an acoustic televiwer log. Because of the differently oriented (not vertical) fractures, the classical hydraulic fracturing interpretation was not applicable. Instead, another method was used based on measurements of the normal stress acting on arbitrarily oriented planes (Cornet and Valette, 1984).

The assumptions in the analysis were:

* The vertical stress component is a principal stress and equal to the weight of overburden.

* The stress field varies linearly with depth.

* The normal stress component is uniform all over the fracture surface and equal to the instantaneous shut-in pressure, ISIP.

* The fracture keeps its orientation away from the borehole.

This gave a non-linear inverse problem with five unknowns which was solved with a least squares criterion.

Injection test data

High pressure hydraulic injections were conducted at different depths in the three wells Fjb0, Fjbl and Fjb3 (see figure 1). Shallow injections between 50 and 230 m were carried out in 1985-1986 for the purpose of studying the general response of the rock mass to massive water injections. The HDR reservoir was created by the end of 1986 by large-scale injections of water and viscous gels. In March 1988, the flow connection between Fjbl and Fjb3 at 460 m depth was improved by hydraulic stimulation of Fjb3.

The pressure declines following the shut-in of the wells were analysed and gave information about the pressure at which the fractures close. In some tests, fluid was injected at varying flow rates. Each flow rate was associated with a specific injection pressure. By plotting the injection pressures versus flow rates, the pressure at which the flow rates increase significantly can be evaluated. This pressure is assumed to be a good measure of the normal stress acting across the fractures which accept fluid.
Microseismic data

During the deep hydraulic stimulation in 1986, microseismic monitoring was performed (Slunga, 1987) in order to follow the displacement of the injection fluid so as to find a suitable position for the drilling of the second well. The increased fluid pressure during hydraulic injections reduces the effective normal stress prevailing at the existing fractures. This may result in sudden shear slipping movements in fractures so oriented that large shear stresses are present. These movements release stresses in the rock mass and thereby induce microseismicity.

From the overall shape of the microseismic cloud, conclusions may be drawn about the reservoir growth and hence about the in situ stress relations.

Fault plane solutions were made by Jupe and Green (1988) on a majority of the induced events enabling the in situ stress tensor to be solved by use of an inversion technique.

RESULTS

Overcoring measurements

Four measurements were carried out between 22 and 24 m depth in a vertical borehole (Haag, 1983). One of the measurements showed a large deviation from the others and was excluded from the results.

The mean values of orientation and magnitude of the principal stresses as calculated from the three reliable measurements are given in table 1.

Table 1. Mean values of the principal stresses obtained with SSPB overcoring.

<table>
<thead>
<tr>
<th>I</th>
<th>$\sigma_i$ (MPa)</th>
<th>dip (deg.)</th>
<th>strike (deg.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>21.7</td>
<td>3.0</td>
<td>145.4</td>
</tr>
<tr>
<td>2</td>
<td>9.8</td>
<td>14.4</td>
<td>54.6</td>
</tr>
<tr>
<td>3</td>
<td>7.6</td>
<td>75.2</td>
<td>246.8</td>
</tr>
</tbody>
</table>

As can be seen, the maximum principal stress is roughly horizontal with an orientation of N35W and a magnitude of 22 MPa. The intermediate stress is also subhorizontal with a magnitude of 10 MPa, and the minimum stress (subvertical) is 8 MPa. It should be noted that the vertical stress component is equivalent to more than ten times the weight of overburden.
Hydraulic tests on preexisting fractures (HTPF)

The HTPF measurements conducted in Fjb1 (Baumgärtner, 1986) yielded data from eight different levels between 70 and 490 m depth. The calculated stress results are rather unstable due to the small data base as compared to the number of unknowns in the analysis. Furthermore, Baumgärtner (1986) interpreted two of the fracture orientations as uncertain.

The stress computations were carried out for three different data sets. The first data set was based on a minimum of five tests, while the other sets included seven tests and different orientations for one of the fractures.

All three computations gave more or less an E-W oriented maximum horizontal compression.

From the in situ data based on seven tests, a maximum horizontal principal stress of 12-13 MPa at a depth of 400 m was determined (see figure 2). The minimum horizontal compression scattered between 7-10 MPa at the same depth.

Hydrofracturing measurements

The test series in Fjb3 resulted in stress data from ten different depths between 90 and 400 m (Wallroth, 1989). The tests carried out below this depth were interrupted because of suspected packer bypass. Breakdown of the granite was not achieved in these tests despite very high injection pressures (above 30 MPa differential pressure).

In five of the tests, both the horizontal principal stresses could be calculated. These stress magnitudes are plotted versus depth in figure 2.

The hydrofracturing results from Fjb3 indicate considerably greater stresses than the stress tendency obtained with the HTPF method in Fjb1. Nevertheless, the magnitudes are much lower than proposed by the overcoring measurements.

It can be noted that the minimum horizontal stress in particular shows a fairly linear increase with depth. Linear regression lines were fitted to the data, giving the following equations:

\[ \sigma_H = 4.3 + 0.018z \text{ (MPa), } r = 0.97 \]

\[ \sigma_H = 7.1 + 0.029z \text{ (MPa), } r = 0.80 \]

where \( z \) is the depth in m, \( \sigma_H \) is the minimum horizontal stress and \( \sigma' H \) is the maximum horizontal stress.

A survey of the tested sections with a downhole television camera showed sharp fractures at two of the levels. These fractures were steep, striking N20W and N40W, indicating the direction of the major principal stress.
Injection test data

The large-scale hydraulic injections at various depths resulted mainly in horizontal flow between different wells. Preferably horizontal fractures accepted fluid even where the straddled sections contained hydraulically open fractures of varying dips. The pressure threshold at which the flow accepted by the fracture increases rapidly with a small increase in pressure should therefore be a good measure of the vertical stress. The threshold was not distinct in all tests, probably as a result of the averaging effect of several open fractures within a section.

The pressure declines following the shut-in of the wells were analysed when possible. The complex hydraulic behaviour of the HDR reservoir, as described by Sundquist et al. (1988), implied that closure effects were observed even at low pressures not corresponding to the in situ stresses. Consequently, great caution was taken when interpreting the evaluated instantaneous shut-in pressures (ISIP) and fracture closure pressures. The overall trend of the results, however, indicated that the vertical compression can be estimated as corresponding to the weight of overburden.
Microseismic data

Fault plane solutions were made by Jupe and Green (1988) on the microseismic events monitored by Slunga (1987) during the hydraulic injections carried out at about 460 m depth in Fjbl. For these solutions they used an inversion technique to estimate the in situ rock stresses. A large number of possible stress tensors, varying in both magnitude and orientation, were tested against the observed fault plane solution data.

The best fitting tensor was selected by minimising the summed misfit in the orientations of the predicted and observed slip vectors. This procedure gave the results presented in figure 3 with the largest principal stress almost horizontal and oriented in NW-SE.

![Figure 3. Estimate of the in situ stress orientations (upper hemisphere) at 450 m depth obtained from the inversion of fault plane solution data. (After Jupe and Green, 1988).](image)

DISCUSSION AND CONCLUSION

The determination of the state of stress at the Fjällbacka test site has demonstrated the difficulties of obtaining consistent data using different methods. When comparing the results obtained with different techniques, it should be remembered, however, that different scales are involved.

The overcoring measurements were performed at shallow depth and yielded large magnitudes. These magnitudes must be considered abnormal despite the fact that the State Power Board's overcoring method as a rule has given considerably greater stresses than other methods, for instance hydrofracturing (Stephansson et al., 1987). The magnitude of the minimum stress (vertical), corresponding to more than ten times the weight of overburden, is questionable when compared with the hydraulic jacking
pressures (approx. equal to the normal stress) for horizontal flow paths at different depths in the wells. On the other hand, the ratios between the stresses seem fairly reasonable.

The two test series conducted with hydraulic fracturing (HTPF and classical) gave unequal results. In earlier comparisons between the HTPF method and classical hydrofracturing (e.g. Ljunggren and Raillard, 1986), a good correlation was found.

The HTPF measurements indicated a rather isotropic stress field (see figure 2) with the vertical stress intermediate at depths below 200-300 m. The observed horizontal reservoir growth at 460 m depth was not in accordance with this stress situation and hence, there is some doubt as to the reliability of these measurements.

An explanation for the results could be the unconvincing determination of fracture orientations. In some of the tests, fractures with different orientations within the straddled interval were observed on the televiewer log. Furthermore, the impressions were very difficult to evaluate due to the rough borehole wall. An assumption of more shallowly dipping fractures in these cases will imply greater horizontal stresses in the analyses.

The classical hydrofracturing tests are considered more reliable despite the small data base obtained and the lack of information about fracture orientations from three of the measurements. The reason for this is the good control of rock quality by both core inspection and a television camera survey of the tested sections. The very distinct breakdowns obtained during the five best tests also confirm the assumption that the fractures were initiated in the ideal way, i.e. parallel to the largest horizontal compression.

Despite the fact that no tests were carried out below 400 m depth, it is believed that the stress variation versus depth indicated in figure 2 can most likely be extrapolated to the reservoir depth (460 m) without inducing any major errors. No large fracture zones or lithological variations occur in the rock mass within this depth range.

There exists poor evidence of correct orientation of the horizontal stress field at Fjällbacka. The State Power Board tests yielded a maximum horizontal compression oriented N35W. This direction is in good agreement with earlier stress studies with overcoring in the Bohus granite massif. The two observed hydraulic fractures reported by Wallroth (1989) also confirm this stress orientation. The divergent direction (E-W) calculated by Baumgärtner (1986) could be explained as being a result of uncertain fracture orientations in combination with the small data base.

Slunga et al. (1984) found, when analysing some 200 earthquakes in southern Fennoscandia, a very consistent direction of the largest compression around NW-SE, which should represent the regional stress field. The same direction was obtained by Jupe and Green (1988) for the induced microseismicity at the Fjällbacka test site.

The fracture pattern in the bedrock at the test site is composed of two dominant vertical/subvertical fracture sets (see figure 4) and a well developed horizontal/subhorizontal set. Detailed studies of the 500 m long core from Fjb3 (Sundquist et al., 1988) have shown that the horizontal fractures often have large apertures and rough tensional
surfaces. The vertical fractures showing evidence of water seepage (hydraulically open) mainly belong to fracture set S1 (fig. 4). The S2 fractures are tighter and have smooth fracture planes. These fracture observations are in good agreement with the stress orientations shown in the figure.

Figure 4. Vertical/subvertical fractures and horizontal principal stress directions

The conclusions drawn from the stress measurements at the HDR site in Fjällbacka are:

1) The vertical stress can most likely be estimated as equivalent to the weight of the overlying rock.

2) The horizontal stresses are in excess of the vertical stress down to at least 450-500 m.

3) The largest horizontal compression strikes approx. NW-SE.

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EVALUATION OF JOINTING IN THE CARNMENELLIS GRANITE

by

M M Randall¹, G W Lanyon², J Nicholls¹ and J Willis-Richards¹

¹ Camborne School of Mines, Rosemanowes Quarry, Herniss, Penryn, Cornwall TR10 9DU
² Geoscience Ltd, Falmouth Business Park, Bickland Water Road, Falmouth, Cornwall TR11 4SZ

ABSTRACT

The circulation of the Hot Dry Rock (HDR) geothermal reservoir at Rosemanowes is dependent on the stimulation and manipulation of the natural joint system of the rock mass. Hydraulic fracturing has been used to reduce the near well bore resistance ('skin'), but otherwise is considered to have limited influence on the thermal performance of the reservoir. The aim of the manipulative techniques is to enhance and manage the natural flow network.

The assessment of these techniques can only effectively be done by computer based numerical modelling due to the complexity of the problem and the great number of possible permutations of operating conditions. A key parameter in this problem is the distribution and connectivity of the natural jointing flow network which has been studied by the use of conditional simulation to model observed joint properties.

Observational data include surface and underground mapping, remote sensing and borehole logging, whilst indirect observation of the system is achieved through the thermal behaviour of the reservoir, its response to tracers both natural and artificial, and through the pattern of microseismicity generated by stimulation and circulation.

This paper evaluates the jointing pattern seen at the surface, in underground exposures in mines and in deep boreholes down to depths of 2.5kms and presents tentative models aimed at representing the joint network.

INTRODUCTION

The extraction of geothermal energy by HDR technology entails the circulation of water between injection and production wells. The amount of heat transferred from the rock to the water is governed by the heat transfer area and by the pattern of flow. Flow along uniform evenly spaced fractures will promote good heat extraction efficiencies and high production temperatures for the maximum length of time. Thus the heat transfer area, joint connectivity and joint apertures are fundamental to the creation of an HDR reservoir.

The assessment of the potential heat transfer area in the Camborne School of Mines Phase II reservoir has been based on a number of techniques including estimates of seismic cloud volume, flow logs and
FIGURE 1  MAIN DYKES, VEINS, FAULTS AND CROSS-COURSES IN AND AROUND THE CARNMENELLIS GRANITE
cross hole tracer models, rates of radon emission and fracture logging of the boreholes. This paper deals with the structural data and presents a picture of the jointing pattern, necessarily simplified, that will aid in the development of a deep HDR system at depths of around 6 kilometers.

REMOTE SENSING

Landsat images and aerial photographs have been used (CSM, 1986a) to map lineations on both local and regional scales. The Landsat images examined the whole of the western half of Cornwall, whilst the aerial photography concentrated on the south eastern quadrant of the Carnmenellis granite.

The majority of lineations detected trended approximately NW-SE, parallel to a prominent set of clay, quartz or gouge filled fractures known from mining activity by the name of 'cross-courses'. Within the granite these fractures appear to have formed as tension gashes that have in some cases been reactivated as wrench faults. Typical fracture spacings appear to be between 0.5 and 2 kms.

Other trends are less prominent and were identified with pre-granite faults and thrusts in the country rock. Relatively few lineations in the surface topography correlated with the mineralised lode systems associated with the granite that run approximately ENE-WSW along the axis of the batholith.

Aerial photography of the area surrounding the HDR experimental site at Rosemanowes (SW735345) was used to measure the strikes of the master joints that form the boundary walls of the many local granite quarries, and to attempt an assessment of their exposed length. Most quarries were bounded by master joints, often several hundred metres in length. Some boundaries were staggered implying parallel or en echelon joint sets. Rose diagrams of 111 quarry side walls (Fig 2) show two main subvertical joint sets trending ENE-WSW ('lode parallel') and NNW-SSE ('cross-course parallel'). The HDR experimental site was selected in an area free from major surface lineations.

SURFACE MAPPING

Although only a very small proportion of the Carnmenellis granite is exposed in quarries or outcrop, the exposures are sufficient to establish the coherence of the joint sets across the pluton. The small size of the exposures, both vertically and horizontally, prevents joint continuity being determined with any confidence. Studies by Ghosh (1934), and CSM (1986a) cover the major part of the Carnmenellis granite. They reveal two major subvertical joint sets in addition to the near horizontal joints that on the basis of underground mapping die out rapidly with depth. The two steeply dipping sets strike NNW-SSE and ENE-WSW. There is considerable scatter in joint direction about these means, perhaps plus or minus 20 degrees, while the dip may be up to 30 degrees either side of vertical.
Figure 2 Circular histogram of the strike of the major joints observed in quarries.

Typical joint spacings vary from 0.5 to 2.0m for the smaller tighter joints, with noticeably more open and continuous 'master' joints every few tens of metres. Many of the longer joints intersect others of the same set, presenting a braided appearance in plan view.

UNDERGROUND MAPPING

Exploitation of the mineralised veins of Cornwall has provided numerous opportunities for the study of their orientation, filling, wall rock alteration and relative ages over the past two centuries (eg Carne 1822). For the most part the mineralised veins ('lodes') seem to occupy fractures developed from ENE-WSW striking joints. The veins developed by the relative motion of the sides of the fracture, usually as normal faults.

The mineralised veins are cut by barren 'cross-courses' which are indistinguishable in orientation from the parallel NNW-SSE striking joints. These fractures appear to be developed by the pulling apart of joint clusters, and infilling of the voids created with quartz deposited from solution, water carried kaolinite formed by the chemical disintegration of the wall rocks and collapse breccias. Many of the cross courses have been reactivated as wrench faults with offsets commonly of a few tens or even hundreds of metres, while others exhibit no relative motion of the opposite walls.

Given the apparent consanguinity of the joint and fault systems, underground mapping of joints in a mine should give results reflecting the regional patterns.
Detailed joint mapping was carried out at South Crofty Mines (SW665411) on the northern flank of the Carnmenellis outcrop to determine joint orientation, filling and dimensions. Three levels were mapped between 715 and 750m below surface using a modified form of the scanline mapping technique. This records the centroid of each trace along the walls of a drive, the trace length, infill, estimated joint aperture and sinuosity.

Figure 3 Framework for scanline survey

Based on the measurement of over 2000 joint traces from 10 separate scanlines of 50m length, a single major joint set was identified which was parallel to the local lode structure (striking ENE -WSW). Within this set there were two peaks with dip and dip directions of 75/332 and 80/145. Many other joint orientations were also seen, but did not fall into recognisable sets. The predominance of a single joint set can not be attributed to bias due to scan line orientation, since both crosscut, footwall and lode drives were examined.

Calculation of the average trace length was based on an assumed negative exponential distribution, and uses an analytical method (Priest and Hudson 1981) for determining the mean trace termination frequency ($\mu$).

$$\mu = - \log \left( \frac{(n-r)/n}{c} \right) \quad (1)$$

Where:

$n = \text{Number of traces intersecting the scanline}$
The mean trace length was then calculated from the average censored semi-trace length using various scanlines and censoring heights.

Table 1

<table>
<thead>
<tr>
<th>Scanline</th>
<th>Fractures per metre</th>
<th>No measured semi-traces</th>
<th>Mean trace length (m)</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.17</td>
<td>107</td>
<td>2.5</td>
<td>Along main cross-cut</td>
</tr>
<tr>
<td>2</td>
<td>0.44</td>
<td>67</td>
<td>4.2</td>
<td>Retaining drive</td>
</tr>
<tr>
<td>3</td>
<td>0.27</td>
<td>48</td>
<td>2.4</td>
<td>&quot;</td>
</tr>
<tr>
<td>4</td>
<td>0.75</td>
<td>28</td>
<td>4.4</td>
<td>&quot;</td>
</tr>
<tr>
<td>5</td>
<td>0.36</td>
<td>30</td>
<td>5.7</td>
<td>&quot;</td>
</tr>
<tr>
<td>6</td>
<td>0.23</td>
<td>44</td>
<td>3.7</td>
<td>&quot;</td>
</tr>
<tr>
<td>7</td>
<td>0.68</td>
<td>30</td>
<td>4.0</td>
<td>&quot;</td>
</tr>
<tr>
<td>8</td>
<td>1.10</td>
<td>23</td>
<td>6.4</td>
<td>&quot;</td>
</tr>
<tr>
<td>9</td>
<td>3.43</td>
<td>62</td>
<td>1.8</td>
<td>Lode drive</td>
</tr>
<tr>
<td>10</td>
<td>0.77</td>
<td>19</td>
<td>1.3</td>
<td>&quot;</td>
</tr>
</tbody>
</table>

The considerable variation in estimated mean trace length can be attributed to the small censoring height of between 2 and 3 metres. Exposures 4m high would have provided more reliable estimates, but are generally unavailable for study underground.

If the joints are assumed to be circular in shape, then an estimate of the average radius (R) can be formed from the mean uncensored trace length (l):

\[ R = \frac{2l}{\pi} \]

For 660 fractures drawn from the scanlines, a mean radius of 2.8 metres was estimated.

BOREHOLE LOGGING

Although the joint exposure in a borehole is limited to a small annulus (commonly 8.5 inches, 0.22m) a considerable amount of detail can be obtained. The parameters measured by or derived from wireline logging include:

1. Dip, dip direction and joint spacing using
   - resistivity (FMS, HDT) and acoustic (BHTV) logs

Joint orientations were principally obtained from the acoustic borehole televiwer (BHTV) logs run in the deep holes at Rosemanowes over the period 1984-1986. Limited success was achieved in the
interpretation of microresistivity (FMS) logs. Both the Dipmeter and FMS tools 'saw' many more fractures than the BHTV. With improved azimuthal coverage of the borehole wall these tools should eventually give better results, although both operational and processing difficulties are to be expected with tools that require contact with the borehole wall for effective operation.

Stereographic projection of the joints picked from the BHTV data from hole RH12 show about an equal number of lode parallel and crosscourse parallel joints, while the joints seen in hole RH15 were almost exclusively drawn from the crosscourse parallel set (NNW-SSE) (Figure 4). Such a bias in the RH15 data is partly to be expected from the well trajectory taken, and the high normal stresses measured on the NE-SW joints which keeps this set tightly closed at depth and so invisible to the BHTV tool.

Figure 4 Plan view of well tracks with upper hemisphere pole plots of the major joints

Repeat logging in 1984, 1986 and 1989 confirms the original fracture orientations

2 Joint aperture using

- low flow and refrac hydraulic tests
- radon production

The measurement of joint equivalent hydraulic aperture by flow tests was carried out at Carwynnen Quarry (SW650370) (Hodgkinson 1983, Heath and Durrance 1984) and on both open hole and straddle packed sections of the Rosemanowes reservoir. The equivalent hydraulic
aperture (EHA) is the width of a perfect parallel plate with the same transmissivity as the joint.

Hodgkinson reported a lognormal distribution of calculated apertures for packer tests performed every 1 metre down a 700m borehole. He also suggested that the distribution might, in fact, be bimodal due to the presence of a few very high transmissivity features resulting in interval permeabilities of between 1 and 6 Darcy, two orders of magnitude higher than the rest.

EHAs were estimated from flow tests carried out on isolated sections of hole RH15 at the Rosemanowes site. Based on that portion of the pressure/flow plot prior to joint jacking the transmissivity was calculated as follows:

\[
\frac{Q(a)}{h_o} = \frac{2 \pi T}{\ln (A/a)}
\]

Where:
- \( T \) = transmissivity
- \( A \) = distance to the zero head boundary
- \( a \) = borehole radius
- \( Q(a) \) = flow rate
- \( h_o \) = head

The transmissivity is related to the EHA by:

\[
T = \frac{(p g / 12 \mu) w^3}{EHA}
\]

Where:
- \( p \) = density of water
- \( g \) = acceleration due to gravity
- \( \mu \) = viscosity of water
- \( w \) = EHA

This analysis suggested EHAs of between 50 and 100 \( \mu m \), comparable with the majority of those determined at Carwynnen. Such values are much lower than an estimate in excess of 500 \( \mu m \) determined by Andrews (1986) from radon production data. Modelling of the results of the low flow rate hydraulic tests conducted in at Rosemanowes in 1982 required an extreme sensitivity of EHA to effective normal pressure. This may go some way to explaining the discrepancy between the radon and low flow rate EHA's.

The joint spacing along the boreholes at the Rosemanowes HDR test site was measured using the Stratigraphic Dipmeter (SHDT), BHTV and FMS. Since all joints that produced water were seen using the BHTV tool we assume that the BHTV images all joints that are capable of flow.

The spacing of the intersected joints is a function of the joint density and the relative orientation of the joints to the borehole. Rouleau and Gale (1985) state that "for a three dimensional structure formed by many planar surfaces with the same orientation the surface area per unit volume (\( S_v \)) is equal to the average number of intersections of the planar surface with perpendicular sampling
lines, per unit length (P11)". For a set of surfaces of random orientation this becomes:

$$S_v = 2P_{11}$$

If the joints are assumed to be circular and have a lognormal radius distribution (mean $\mu$ and standard deviation $\sigma$) then the joint surface ($S_j$) is given by:

$$S_j = \pi e^{(2\mu + 2\sigma^2)}$$

For RH15 the spacing conformed to a negative exponential distribution with a mean intersection frequency of 0.385 per metre and volumetric density of joint centres of 0.0003 per cubic metre with a mean joint length of 10m.

The normalised joint spacing was calculated as the length of the normal from one borehole intersection to the plane of the following fracture intersection. Plotting the results as a histogram (Figure 5) and comparing the results of South Crofty and RH12, and RH12 and RH15, it can be seen that the joint spacing can be broadly described by a negative exponential (or log normal distribution) but that there are a significant number of large spacing events that suggest clustering.

Figure 5  Histogram of normalised joint spacing for RH12 and RH15

The mean normalised spacings for the two major joint sets are given in table 2.
Table 2

<table>
<thead>
<tr>
<th>Well</th>
<th>Set</th>
<th>Strike</th>
<th>Obs.</th>
<th>Mean spacing(m)</th>
<th>Standard Deviation</th>
<th>Maximum spacing(m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RH12</td>
<td>1</td>
<td>NW-SE</td>
<td>55</td>
<td>1.5</td>
<td>2.3</td>
<td>11.6</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>NE-SM</td>
<td>61</td>
<td>3.9</td>
<td>4.2</td>
<td>18.3</td>
</tr>
<tr>
<td>RH15</td>
<td>1</td>
<td>NW-SE</td>
<td>105</td>
<td>1.9</td>
<td>2.5</td>
<td>13.9</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>NE-SM</td>
<td>19</td>
<td>6.0</td>
<td>5.3</td>
<td>35.9</td>
</tr>
</tbody>
</table>

There is clearly a large difference in the normalised spacing of the joint sets. This, with the horizontal stress anisotropy (Pine and Batchelor, 1985), will have a considerable influence on the direction of growth of an HDR reservoir in response to fluid injection. This has been demonstrated by the microseismic cloud observed during prolonged circulation in 1982 (Batchelor et al, 1983).

**FORWARD MODELLING OF THE JOINT SYSTEM**

One method of analysing natural fracture networks involves the simulation of joint patterns, from some 'generative description' of the joint system. Dershowitz (1984) discusses several models for three dimensional rock mass jointing and provides guidelines for the application of each model. The model used for the work on Rosemanowes derives from the Baecher model (Baecher, 1983) where joints are modelled as planar circular discs (see Figure 6).

The parameters in the description of each joint set are:

- Density of joint centres
- Orientation (usually specified by the pole)
- Extent or radius
- Aperture (usually specified as EHA)

Each of these parameters can be described by a probability distribution. The aim of the work to be described was to develop a description of the various sets that matched the available observations.

Measurements of joint occurrence in holes RH12 and RH15 at Rosemanowes have been used to investigate the jointing in the reservoir region. Whilst it is possible to match the observed spacing and orientation data using using a simple Poisson process for joint centres, a single description of jointing for both wells could not be found. This difference may be related to the observed geochemical changes in granite type at 2100m vertical depth (Camborne School of Mines 1986b).
Similar techniques were applied to the data from South Crofty mine. In the case of South Crofty the objective of the modelling was to match the simulated trace lengths with the data from scanline surveys of the tunnel (see Figure 3). The modelling accounted for truncation bias of the sampling procedure and considered the influence of joint density and extent.

It is of course important to take into account the very different sampling methods when analysing the borehole and exposure data. Apart from the different geometric biases, it is unclear how many of the joints visible in the exposures would be detected by BHTV logging. It may be that the FMS data might give more comparable statistics (Pearson and Batchelor 1986). These considerations are especially important when looking at the very short traces in the exposure.
Figure 6  Network generation schematic (after Dershowitz, 1984)
A satisfactory match to the observed trace length data was obtained using a lognormal radium distribution with mean radius of 2.0m and standard deviation of 0.8m, giving a joint centre density of 0.4 per m$^3$. It should however, be noted that the lognormal distribution did not match the termination statistics. This is believed to be due to many more joints terminating against other joints than would be produced by a Poisson process.

If we relate these numbers to the estimate of joint surface area derived from the borehole data we see that five times more joint surface area per m$^3$ is visible at South Crofty mine.

It is important to use great caution when considering such matches because of the large number of assumptions necessary to derive them. It is especially important to consider the uniqueness of the result, for the method cannot guarantee that many other combinations of parameters would not provide as good a fit. The following assumptions have been made to derive the current match:

1. All the sets have the same length distribution.
2. The joint radius distribution is lognormal.
3. There are no correlations between any of the joint parameters.

Recent work at Lawrence Berkley Laboratories (J Long 1989, pers comm) has shown that if no restrictions are placed on the form of the expected joint radius distribution, there is no unique way of reconstructing the 3-D parameters from the trace data.
GEOLOGICAL INTERPRETATION AND PROGNOSIS

The two subvertical joint sets seen in surface exposure extend to depths in excess of 2 kms in the deep boreholes at the Rosemanowes site. One of these sets is parallel to, and appears to be essentially coeval with, the mineralised lode system; while the other parallels a set of much later tension fractures, some of which have been reactivated as wrench faults.

Both sets of joints seem to have been formed in response to tensile deviatoric stresses. Simple arguments based on rock failure criteria suggest that such fractures are likely to exhibit increasing deviation from the vertical with depth beneath the contemporary land surface at the time of formation. Fault plane solutions for deeper induced microseismic events at Rosemanowes (about 3 - 4 kms depth) suggest inclined failure surfaces.

The lack of observed lode parallel joints towards the bottom of the deepest hole (RH15) may suggest that this set is not well developed at this depth. It is important to bear in mind that perhaps 3 kilometres of erosion may have taken place since the formation of the lode parallel joint set, and that depths of 3 kilometres beneath the present land surface may have been very close to the brittle/ductile transition for slow strain rates at the time of their formation.

The cross course parallel joint set may have formed at a time when the land surface was but little different to the present day. The possibility exists that brittle fracture may have penetrated downwards close the present day brittle/ductile transition at depths close to 6 kms.

CONCLUSIONS

The following conclusions can be drawn for the present reservoir at depths of 2.0-2.5 kms:

i There has been shown to be general agreement between surface mapping, underground mapping and borehole logging, in the identification of two main joint sets. A third set may also exist but is obscured by the wide range within the major sets.

ii The joints are generally near vertical, some dipping up to 30° from vertical, with very few flat lying features.

iii With the combination of clustering and the increased frequency of the NW-SE striking joint set at Rosemanowes and the high horizontal stress anisotropy, a high degree of anisotropic flow can be expected.

iv Conditional simulation appears to provide a suitable method of analysing complex fractured networks. A wide range of solutions must however be expected as the sensitivity of the
models is governed by the assumed distribution functions for joint orientation, shape and aperture.

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The views and judgements expressed in the paper are those of the authors and do not necessarily reflect those of ETSU or the Department of Energy.

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DETERMINATION OF PETROGRAPHIC AND TECTONIC CHARACTERISTICS AT SOULTZ BOREHOLE (Bas-Rhin, France) USING WIRE LOGGING, SABIS BOREHOLE TELEVIEWER, CUTTING AND CORE ANALYSIS

H Tenzer¹, L Mastin, B Heinemann², J P Cautru, A Genter, H Traineau³, R Jung⁴, R Schellschmidt, R Schulz⁵

Introduction

Well logging with the Acoustic High Temperature Borehole Televiewer (BHTV; SABIS-System) enables continuous recording of the natural planar discontinuities at the borehole wall and sampling data about the borehole geometry.

The orientation of strike and dip directions of the planar discontinuities is obtained by the evaluation of the televiewer logs.

The orientation of natural joint systems in the basement, which can be hydraulically activated, and their relationship to the local stress field shall be investigated by comparing the televiewer data with the results of the hydraulic tests and stress measurements.

The newly developed High Temperature SABIS-Borehole Televiewer of the Westfalische Berggewerkschaftskasse (WBK) was to be tested and prepared in the HDR-borehole Urach 3 by logging tests for the use of well logging in the exploratory well GPK-1 at Soultz in the Rhinegraben (France). The BHTV was tested down to a depth of 3364 m. The in-situ temperature at this depth is 143°C. The electronics of the televiewer worked faultlessly up to an inside temperature of the tool of 152°C without using an additional thermal shield.

Basement petrography and general structure

The petrography of the Soultz granite is based on the analysis of cores and cuttings. Porphyroid granite with K-feldspar megacrysts was observed. The primary mineralogical contents are quartz, plagioclase, K-feldspar, biotite, hornblende and accessory minerals are apatite, sphene and opaques.

The study of alteration mineralogy of the Soultz cores show the superimposition of several successive hydrothermal events. Thin sections, X-ray diffraction and electron microprobe were used to determine the composition of secondary granite phase.

1: Stadtwerke Bad Urach
2: Geophysics Institute, University of Karlsruhe (SFB 108)
3: BRGM/IMRG, Orleans
4: BGR, Hannover
5: NLfB, Hannover
Two main types of alteration occurred in the batholith. The first corresponds to a pervasive alteration which did not affect the microtexture of the rock. It shows the selective transformation of pre-existing ferromagnesian minerals (biotite and hornblende) and plagioclase into secondary clay products (corrensite, chlorite and sericite) and carbonates. Epidote, iron oxides, prehnite and smectite occur locally. This pervasive hydrothermal event is widespread in the massif and could be related to the late cooling episode of the granite body.

The second hydrothermal type (vein alteration) was caused by water-rock interaction in the natural fracturing system. Percolations in the granite developed a characteristic wall-rock effect. On core material, there is a good correlation between the density of natural joints and the intensity of vein alteration effect. The secondary phases are white mica or regular mixed layer (illite-smectite) and, in places, carbonates and iron oxides. These deposits fill fractures and their neighbouring wall-rock.

Conventional wireline loggings (porosity, density, electrical and sonic logs, thorium content) were performed and analysed to describe the main petrographical facies of the crystalline medium before performing stimulation tests. A synthesis lithological log was drawn in terms of facies variation, hydrothermally altered zones and fracture zones (Plate A1). Calibrations were done using 43 m of cores, and the cuttings which were sampled every meter.

For the selective alteration type (macroscopically unaltered granite) the well logging responses are (Plate A2):

- Density around 2.63 g/cm³.
- Low porosity (< 3%).
- Electrical measurements always up to 1000 ohm.m.
- Uranium and thorium contents reaching 8 and 36 ppm respectively.

For vein alteration type, controlled by the joint network, these responses are different because the physical properties of granite are affected by the paleohydrothermal fluid percolations. In this case, decrease in density (2.46 g/cm³) and resistivity (< 10 ohm.m) measurements can be observed.

The analysis of cuttings showed some sections with no biotite and clay minerals. The porosity appears to be low and the density is 2.60 g/cm³. This zone is interpreted in terms of magmatic facies variation. When core and cutting samples are completely transformed into white mica, the density value is low and neutron porosity data increases up to 20%. This type of section was identified as being altered and cataclastic zones (Plate A2).

The Formation Microscanner (FMS 4 pads) imagery were analysed on a Schlumberger workstation in order to estimate the fracturing system distribution. The main families of natural fractures have been identified. The main directional family is oriented N170°E and dips 70°W or 80°E (Plate A3). This result is in good agreement with BHTV Sabis interpretation and the E-W extensional regime of the Rhingraben area during the Oligocene. Some core sections (105 cm) have been oriented by comparison with the FMS imagery.
Results of well logging with the SABIS Borehole-Televiewer

For the logging programme within the granite of GPK-1 (1377-2000 m, Bottom Hole Temperature 140°C, the Televiewer was equipped with an additional thermal shield. Altogether 1880 planare discontinuities were measured on the Televiewer logs and evaluated with the help of the GELI-NEU computer program.

The orientation of planare discontinuities was determined as well as their frequency, apparent width, and the predominant orientation of the different apparent widths.

The televiewer allow the determination of planare discontinuities and different lithological units. Especially the sound and cataclastic granite and hydrothermally altered granite can well be distinguished by the different amplitude of reflections and distinct image pattern of sonic signals on BHTV logs.

Orientation of planare discontinuities in the granite

The orientation of three main type of discontinuities were measured on BHTV log (Fig. 1.1):
- Natural, coherent discontinuities.
- Discontinuities with a segmental appearance.
- Vertical structures.

The main direction of strike of the natural discontinuities in the granite is N170°E with dips to the east and west. Most of the planare discontinuities show subvertical and steep dips with main strike directions of N10°-20°E, N50°-60°E, N130°-150°E, N160°-175°E and average dips to east, northeast and west (Figs. 1.2 & 1.3).

During the Oligocene, the subsidence of the graben took place in a E-W extensional regime. The N170°E structures correspond to this major brittle tectonic period.

Varying orientations of the natural joint system versus depth were distinguished. In particular a submaximum of joints with a NE-strike and a SE-dipping is recognizable from the top of the granite (1377 m) down to 1550 m depth (Fig. 1.2). The number of discontinuities striking SW is clearly higher in the lower borehole interval from 1805 to 1950 m than in the upper interval (Fig. 1.3).

The correlation of the BHTV log with the Density and Porosity logs enables distinguishing different rock units. There is also a good agreement between the BHTV log and the Resistivity log and the Formation Microscanner measurements.

In contrast to the Formation MicroScanner data, the Televiewer made possible the determination of more subvertical and especially vertical discontinuities. Both, BHTV and FMS tools should be used suplementarily.
Vertical discontinuities measured on BHTV log

Vertical discontinuities striking N160°-175°E are noticeable over large borehole intervals (ca. 135 m). These structures, which can be called "drilling induced hydraulic fractures" might be caused by the linkage of subvertical structures.

There is a close agreement between the orientation of subvertical and vertical discontinuities. This indicates a close relationship of these two similar structures during their origin (Fig. 1.1).

The frequent occurrence of vertical features on the BHTV logs can only be observed on a few number of samples of cores. On the FMS logs vertical structures can only seldomly be detected within one of the four pad traces.

Hydraulic tests with temperature measurements have shown that especially borehole sections with vertical structures are capable of absorbing water (Fig. 2). Among the 1880 planare discontinuities measured on the BHTV log there are about 800 natural joints.

Only about twenty joints and fractures are hydraulically significant. Most of them are almost N-S striking vertical or subvertical fractures. The dominant feature is at a depth of 1812 m where a long vertical almost N-S striking fracture intersects an altered zone.

Injection tests show that fractures start to open already at a wellhead pressure of about 40 bars. According to the results of the temperature logs run during the injection experiments these fractures are located at around 1728 m, in a borehole section where a great number of almost N-S striking steeply dipping fissures were encountered on the Televiewer log.

Furthermore the results of temperature measurements immediately after shut-in prove that the joint at 1812 m depth is connected to a very large fault zone in contrary to the joint at 1728 m depth. Between 1704.4 and 1733.8 m depth joints are observed, which are not connected to a fault zone. These joints opened at a wellhead pressure of about 35 bars and after shut-in they closed.

The identification of the important subvertical and vertical structures is only possible by means of the Borehole-Televiewer.

Width of planare discontinuities

Logging with BHTV enables the determination of the apparent width of the discontinuities. Structures of clearly less than 1 mm of size can be detected by the Borehole-Televiewer. Nevertheless the processing of 128 sonic signals per rotation (500 mm borehole circumference) does not able depiction of two points closer than 4 mm to each other on the log. The apparent maximum value per meter of depth was therefore used for the determination of the joint widths. Wide joints were especially identified in the borehole sections with sound granite.
Wide joints were identified in the borehole sections from 1 500-1 515 and 1 700-1 725 m, at 1 745 and 1 820 m, and from 1 875-1 846 m (Figs. 1.2 & 1.3).

The different joint widths do not show favourable orientations that differ from the total orientation of all joints. Joints of slight width dipping at low angles are much more abundant than gently dipping joints of wider widths.

Borehole geometry and breakouts and their implication for the regional stress field

The borehole geometry and its implication for the regional stress orientation were determined by L. Mastin and B. Heinemann of the cooperating geophysics group at the University of Karlsruhe (SFB 108). The stresses in the Earth’s crust produce a compressive stress concentration on the wall of a vertical borehole which is greatest at the azimuth parallel to the least compressive regional horizontal stress ($S_h$). Zones of failure and spalling at the azimuth of $S_h$ may cause to enlarge the borehole diameter. At the azimuth of $S_h$ (perpendicular to $S_p$) fluid pressure in the borehole may cause vertical hydraulic fractures (Fig. 4).

Caliper logs between 1 400 and 2 000 m depth were examined for breakouts intervals. No intervals were identified which revealing all the breakout criteria. Televiewer logs of WBK showed several places in which the borehole shape was slightly oval, but not spalled, suggesting that the ovalization was caused by tool gouge rather than by stress induced failure.

On the Televiewer log between 1 420 and 2 000 m depth, at least 135 m contain vertical fractures which bisect the borehole and follow the borehole axis up to a few tens of meters (Fig. 3). These vertical fractures are generally not present in the core close to the corresponding depth intervals, suggesting that they are induced by fluid pressure in the hole and the influence of thermal stress during drilling. They are therefore inferred to have formed parallel to $S_p$. The orientations of these features have an average of N169°S and a standard deviation of 11°. This is slightly more north-south than the orientation of $S_H$ determined from other stress indicators in this region (Fig. 4).

It is possible that a more north-south orientation of the most compressive stress in the Soultz area is due to its location near the west side of the Rhinegraben. An east-west tension associated with the down-wrapping of the down-dropped block within the Rhinegraben could, when superimposed on a NE-SW regional orientation of $S_H$, rotate the local $S_N$ to a more north-south direction.

The obtained results will lead to new realizations in the further development of the Hot Dry Rock-technology. Natural planar discontinuities will be included into the development of multiple frac systems and artificial heat exchange systems within the crystalline basement.
Plate A - Partial synthesis log ($A_1$), electrofacies ($A_2$) and FMS data ($A_3$) of GPK1 borehole.
Fig. 1.1 The three main types of planar discontinuities

1. Natural, coherent discontinuities
2. Discontinuities with segment appearance
3. Vertical structures
HOT DRY ROCK PROJECT AT SOULTZ
PLANARE DISCONTINUITIES measured by SABIS-BOREHOLE-TELEVIEWER
in the granite of well GPK 1
Evaluation by Stadtwerke Bad Urach

Fig. 1.2

| Frequency | Width | Orientation | Ross and Pole Diagrams | Density | Permeability
|-----------|-------|-------------|------------------------|---------|---------------
| Number per meter | 4 + 12 | 4 + 20 | 90° | 270° | 0 | 90 | 1255-1401 | 1420-1474 | 1476-1494 | 1496-1549 | 1550-1579 | 1580-1637 | 1638-1699 |
Planar discontinuities measured by SABIS-BOREHOLE-TELEVIEWER in the granite of well GPK 1.

Evaluation by Stadwerke Bod Tuchs.
**Fig. 2**

**Temperature °C**

- **Well GPK-1**

**Depth**

- 1400 m
- 1500 m
- 1600 m
- 1700 m
- 1800 m
- 1900 m

- **Casing shoe**

**Vertical structures on BHTV log**

"drilling induced hydraulic fractures"

(measured by NLFB)
Fig. 3
azimuth
(degrees from magnetic north)

azimuth of borehole deviation

azimuth of borehole elongation

azimuth of hydrofracture

D (dogleg) = abrupt change in borehole direction
INTRODUCTION

During the past 3 years French and German teams have been conducting research regarding the suitability for H.D.R. energy production of a site close to Soultz-sous-Forêts in Alsace (France). So far, a single borehole, called GPK1, of depth 2000m has been completed. The thickness of the granite is 600m, covered by several sedimentary layers. Numerous permeable joints have been recognized during drilling and hydraulic tests (Kappelmayer and Gerard, 1989). A main fracture was encountered at 1820 m, producing a highly saline fluid at 137°C. Further tests have indicated that this permeable zone is connected to a major reservoir (Jung in Kappelmeyer and Gerard, 1989). Detailed geochemical investigations have been carried out to improve the knowledge of this possible HDR site: origin and chemistry of the brine, chemical processes such as mixing and water-rock interactions affecting the injected make-up water, use of inert and reactive tracers during injection-backflow tests, experimental work.

We present here the characteristics of the formation fluid and show that the occurrence of the brine in the granite allow to quantify the extent of mixing and then dissolution of the granitic rocks when a freshwater is injected. The second part of this paper is devoted to the results and problems concerning the use of chemical tracers in a crystalline environment and at such temperature (140°C), with special emphasize on a thermally reactive ester, as proposed by Robinson et al. (1985).

CHEMISTRY OF THE FORMATION BRINE

Gas and water have been collected at the wellhead and at depth during the artesian discharge of the well at 0.57 m³/h (May-June 1988). The determination of pH, SiO₂, Cl, Ca and alkalinity was carried out each day on the site in order to monitor the evacuation of a number of additives injected during and after the foration. 500m³ of fluid were discharged before the measured parameters could reach steady state values. Despite the presence of tritium (4.1 TU) in the final sample (KS228), which suggest some contamination by surface water, this last sample is regarded as the best available, with TDS content close to 100 g/l. Na and Cl are the dominant ions and large amounts of gas (25% in volume) are released (see table 1).

Such mineralized fluids have been previously described in crystalline rocks contexts (Fritz and Frape, 1987). Here, there is some evidence that the triassic aquifers may contribute significantly to the mineralization: a fluid of very similar isotopic and chemical composition to KS228 was sampled in a nearby well tapping the triassic
horizons. The presence of acetate ions (40 mg/l) also suggests an additional origin of the fluid than a long time interaction between surface waters and the granite. The chemical and isotopic geothermometers are consistent to indicate temperatures above 200°C (Criaud et al., in Kappelmeyer and Gérard, 1989). This also tends to prove that the fluid can circulate through faults at deeper levels. This assumption is possible because of the structure of the Rhine graben. Our more complete interpretations on the geochemistry of the brine will be presented in a later paper.

A good knowledge of the initial chemical composition of the formation fluid is of interest to interpret the injection-backflow tests, where freshwater is injected. The large differences in chemistry between the former and the latter allow to define a number of natural tracers such as Cl, SiO₂, Na, Ca... which will help in quantifying the processes.

<table>
<thead>
<tr>
<th>pH</th>
<th>alk</th>
<th>Na</th>
<th>K</th>
<th>Ca</th>
<th>Mg</th>
<th>Ba</th>
<th>Li</th>
<th>Cl</th>
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<tr>
<td>KS228</td>
<td>9.71</td>
<td>10.6</td>
<td>28200</td>
<td>3320</td>
<td>6730</td>
<td>150</td>
<td>123</td>
<td>123</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>SiO₂</th>
<th>F</th>
<th>B</th>
<th>Br</th>
<th>SO₄</th>
<th>GLR</th>
<th>CO₂</th>
<th>N₂</th>
<th>CH₄</th>
</tr>
</thead>
<tbody>
<tr>
<td>KS228</td>
<td>97</td>
<td>3.9</td>
<td>34</td>
<td>299</td>
<td>215</td>
<td>25</td>
<td>46.8</td>
<td>27.3</td>
</tr>
</tbody>
</table>

Table 1: Chemical analysis of the formation brine
GLR: Gas liquid ratio, alk: total alkalinity
Data are given in mg/l, except for alkalinity exposed in meq.

INJECTION-BACKFLOW TESTS

Field operations:
In 1988, 2 kinds of short-time injection tests were carried out. In June, 250 m³ of freshwater was injected in the whole granite thickness. No chemical tracer was added, the original water composition playing the role of natural tracer. Then 118 m³ was allowed to backflow without any shut-in time.
In December, packer tests involving small volumes of water were performed. One of these was combined with the injection of a mixture (0.89 m³) of several tracers (iodide, fluorescein and ethyl propionate). At the depths of 1969 to 2000 m, 3.4 m³ of water were injected. After 10 minutes of shut-in time, 28 m³ was evacuated during backflow, then the operation was stopped. In both tests, samples were collected at the wellhead during the 41 and 16 hours respectively of production.

Choice of the tracers:
Several processes can affect the concentration of tracers in the recovered fluids. These include ion-exchange, adsorption or thermal instability, which may occur at high temperature in geothermal systems. Such processes can alter the breakthrough curve and compromise the interpretation. In order to study these processes, two conservative tracers (iodide and fluorescein) and a reactive tracer (ethyl propionate) were compared. The use of a reactive tracer with
decays with time and temperature should bring more information to the knowledge of the reservoir.

Iodide and fluorescein are known to behave conservatively in many geological environments. Experimental work on Soultz granite chips has confirmed that this dye does not decompose at temperatures up to 150°C, while the rhodamine WT was readily degraded.

For several reasons, the ethyl propionate (degrading in ethanol and propionic acid) was chosen instead of some other esters like ethyl acetate, largely studied (see for example: Tester et al., 1987): (1) its hydrolysis kinetic at the expected temperature; (2) the analytical facilities are available to determine the concentrations of the ester, and the corresponding alcool and acid; (3) acetate was found in relevant concentration in the formation fluid, so that ethyl acetate could not be used.

Injection of the tracers:
A mixture of 300g fluorescein, 5Kg NaI and 1.78Kg ethyl propionate was prepared in a 1 m$^3$ plastic container. 24.2 m$^3$ and 7.2 m$^3$ of freshwater were injected respectively before and after the injection of 0.887 m$^3$ of the tracer mixture. Because the mixture has been prepared 6 hours before its injection, a sample was collected at the moment of the test for analysis. The table 2 compares respectively the expected and analyzed concentrations:

<table>
<thead>
<tr>
<th></th>
<th>Iodide</th>
<th>fluorescein</th>
<th>Ethyl propionate</th>
</tr>
</thead>
<tbody>
<tr>
<td>expected</td>
<td>4230</td>
<td>300</td>
<td>1780</td>
</tr>
<tr>
<td>concentration</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>measured</td>
<td>4500</td>
<td>318</td>
<td>880</td>
</tr>
<tr>
<td>concentration</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 2: Concentrations (in mg/l) of the chemicals tracers in the mixture ready for injection.

For iodide and fluorescein, the results are in relatively good agreement with the expected values, then the slight discrepancies may be due to insufficient homogeneity within the reservoir. The decrease of ethyl propionate concentration cannot be related to the hydrolysis reaction, whose kinetic is very slow at ambient temperature and because no hydrolysis byproducts (ethanol and propionic acid) were detected. It seems that adsorption of ethyl propionate on plastic container occurs. Moreover such an adsorption has been observed on polyethylene vessels.

Analytical procedures:
For both tests, some parameters were monitored on-site (pH, Cl, SiO$_2$...). The samples were fully analyzed for their complete composition back in the laboratory. The determination of the added chemical tracers (unreactive and reactive) was carried out on-site, on unfiltered samples collected in brown glass bottles. A few drops of a solution of HgCl$_2$ was added to prevent any bacterial reduction. Iodide concentrations were measured with a specific electrode, the dye content was determined by absorption spectrophotometry. The ethyl propionate and its hydrolysis
byproducts (ethanol and propionic acid) were determined by gas chromatography at 130°C. According to the favourable relative concentrations, the three concentrations could be obtained in 35 mn.

RESULTS AND INTERPRETATION

The chemical composition of the water recovered at the wellhead depends, except for temperature and pressure, on two parameters:
- interaction between the make up water and reservoir rocks;
- mixing between the formation brine and the injected water.

MIXING PROCESS

The results for June and December tests illustrated on figures 1 to 4 show that the mineralization of the fluids increases rapidly versus time (or volume of discharged water). The concentration ratios of most of the species (Cl/Li, Cl/Ca.) are similar to those of KS228, thus giving evidence for mixing. On figure 1, the sharp peak between 30 and 50 m³ is due to some remaining completion brine. It does not affect the elements such as silica or Li, which are typical of the formation brine. All the data relative to the June test have been corrected for this effect.

Fig. 1: Concentration of chloride in the fluid produced during the test of June

Some elements have high concentrations in groundwater with respect to their content in the rock. Then, the mineral dissolution cannot be observed from their concentration, which can be related only to the mixing of freshwater with the brine. Boron or chloride are such tracers of mixing. Ca, Mg, Na, K..., which are more concentrated in minerals, present a profile similar to chloride one (Fig. 3). Thus, not other process than mixing can be detected from these compounds. The data of the December test show a bump in the Na, Mg, B and K concentration profiles at about 20 m³ of recovered water (Fig. 4 for Mg profile). It suggests, because of the presence of several fractures, the mixing with a more mineralized fluid.

Fig. 2: Concentration of chloride in the fluid produced during the test of December
The percentage of mixing for both June and December tests was calculated using chloride concentrations and presented versus the recovered volume/injected volume ratio (or time) (Fig. 5). The more rapid increase of mixing in the first test indicates a higher mixing rate in agreement with an injection within the principal fracture of the system, which is located at 1820 m.

We calculated the chemical composition which should have each recovered sample, if the mixing was the only process occurring in the system. The parameters used for such a calculation are the chloride content of the considered sample and the chemical composition of both injected water and KS228.

Some elements display higher measured concentration than would result of the mixing. These are silica for both injection tests (June and September 1988), fluorides, barium and total dissolved CO₂. Consequently the excess of silica (Fig. 6) is calculated from the
area located between the measured concentration curve and the mixing curve and is equal to 3.8Kg and 1.07Kg for the first and the second test respectively. Fluoride and barium excesses are in the range of 38g and 28g. These anomalies can be explained only by the dissolution of minerals in the reservoir and give some informations on the nature of the dissolving minerals.

The only carbonate mineral found is calcite. At 1900 m, veins of calcite are present (Genter and Martin, 1988), therefore, the leaching of these veins should be considered.

<table>
<thead>
<tr>
<th>Mineral</th>
<th>F</th>
<th>Ba</th>
<th>SiO₂</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biotite</td>
<td>7.94 ppm</td>
<td>1.21 ppm</td>
<td>38.6%</td>
</tr>
<tr>
<td>K-Feldspar</td>
<td>0</td>
<td>2.72 ppm</td>
<td>64.9%</td>
</tr>
</tbody>
</table>

Table 3: F, Ba and SiO₂ contents of two minerals.

Chemical analysis of granite-forming minerals indicates that fluoride is related to biotite, barium is in K-feldspar and biotite like potassium and silica is associated with all important solid phases (biotites, K-feldspar, plagioclases and quartz) (Tab.3). Then dissolution of biotites must be considered because of anomalous fluoride content and also because it represents one of the most soluble aluminosilicate (Parneix, 1987). A fluoride excess of 38g leads us to conclude that about 4.8Kg of biotite was dissolved during the water-rock interaction, in other words about 68Kg of granite is affected by the leaching. Barium and silica could be provided from biotite too. Assuming the stoichiometric dissolution of the mineral, the excess of barium and silica during the second test will be 5g and 1.78Kg respectively, instead of 28g and 1.07Kg obtained above. Therefore, the stoichiometric dissolution of the biotite cannot be the only process occuring in the system.

The leaching of aluminosilicates has been studied for a long time (see for example in Aagaard and Helgeson, 1982) and dissolution of micas is controversial. While Beusen (1987) observes a stoichiometric dissolution of Ba with respect to silica, Lin and Clemency (1980) established that the dissolution of ions is a function of their location in the lattice; First the ions from the interlayer regions are released, secondly from the octahedral sheets, then from tetrahedral sheets. In our study, the order of release should be firstly Ba, secondly F and finally SiO₂. Using chloride concentrations, both barium and fluoride were corrected of the mixing. As shown on figure 7, at the end of the test, the Ba/F ratio of the solutions are effectively higher than in biotites. A more rapid
release of Ba than F should be observed from the beginning of the experiment. But because Ba excess is delayed compared to the fluoride one, a contribution of the other Ba bearing phase: namely the alkali feldspar is expected.

Ignoring the possibility of non stoechiometric dissolution of each chemical element from the biotite, the silica excess can be related to the dissolution of this mineral. However, it is interesting to point out that during the first test, the concentration increases rapidly to reach a value close to the equilibrium with respect to quartz. It may be explained by the precipitation of a new mineral phase. Although it seems surprising, such a rapid kinetic for silica equilibration has already been observed during experimental water-feldspar interaction, at the same temperature (Pauwels, 1988).

**CHEMICAL TRACERS BEHAVIOR**

The tracer response curves are shown in Figures 8 and 9. They give the same breakthrough time for all the tracers. The peak between 6 and 16 m³ indicates the presence of at least one important fracture and the increase at the end of the experiment could suggest the occurrence of a second important fracture. However the dispersion of chemical data indicates the presence in the system of a large number of fissures. The last increase means that the experiment has not been completed and a certain amount of the injected tracers is still in the formation.

However, the percent recovery of each tracer can be compared. Cl concentration in samples indicate that 69% of the injected water was recovered and in ideal conditions the tracer recovery should be at least equal to this value. With 63% recovery, the fluorescein appears to be the least reactive tracer. The expected degradation (Gudmundsson et al., 1983) due to the temperature seems to occur, but at a small rate. Iodide (44%), one of the most commonly tracer used in groundwater, was lost during the test certainly because of adsorption on rocks (Breitenbach and Horne, 1982). The reactive tracer recovery may be calculated by adding either ester and ethanol concentrations,

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![Fig.8](image8.png)  
**Fig.8:** Concentration of conservative tracers/concentration in initial mixture ratio versus volume produced fluid

![Fig.9](image9.png)  
**Fig.9:** Concentration of reactive tracers/concentration in initial mixture ratio versus volume of of produced fluid
or ester and acid concentrations. The recovery is equal to 45% for ester and ethanol and 37% for ester and acid. These percentages are lower than those for fluorescein, but between 6 m³ and 16 m³ of recovered water, the restitution peaks are different. The rise of the ester is smoother, whereas the two curves are the same in the decreasing part. Whatever the reason of these discrepancies may be, an inhomogeneity in ester concentration during injection should be responsible for this effect. The ester less dense than water could have remained at the top of the container, where a sample was collected for analysis. If so, the recovery of the ethyl propionate should exceed 45%. The lower recovery calculated from propionic acid may be due to reactivity with the solid phase, but, it could also result from analytical errors too.

Temperature calculations
The rates of hydrolysis of most ester are dependant on the pH of the solutions (Robinson, 1985). Our calculations on reservoir temperature from ester and hydrolysis byproducts concentrations indicate that with pH variations between 7.13 and 5.75, the results are different if the pH of the solutions is considered or not. Thus, the reaction rate is proportional to both the concentration of the ester and \([OH^-]\) to the first power:

\[
\frac{dC}{dt} = -k_2 [OH^-]C \quad (1)
\]

where \(k_2\) is the second order rate constant and \(C\) is the concentration of ethyl propionate and \([OH^-]\) the concentration of hydroxyl ion. For ethyl propionate, \(k_2\) can be derived from an equation given by Robinson (1985):

\[
\log \left( \frac{1}{k_2[OH^-] \times 3600} \right) - \frac{5 \times 10^3}{T} = 11.25 \quad (2)
\]

Temperatures were calculated incorporating equation (2) in the integral of the equation (1). The initial ester concentration on each point can be considered as being the sum of either ester and alcohol or ester and acid concentrations of each recovered sample. The reaction time is taken as the time during which the sample was injected, corrected from the time of transfer between the reservoir and the wellhead.

If we consider that \(k_2[OH^-]\) is a first order rate constant (e.g., the kinetic of the reaction does not depend on the pH), the calculated temperatures decrease from about 155°C for the shorter interaction times to about 130°C for the longer ones. Because equation (2) was established by Robinson for a pH value at 25°C (pH=6.0), the pH values measured at the wellhead, with sampling temperature only slightly different from 25°C, have been taken into account in our calculations. The results are shown on figure 10. The temperature of the first samples (about 115°C) is lower than the 137°C of the reservoir rocks, which may be explained by the cooling due to the injection of freshwater. As the fluid continues to flow in the system it gets warmer and the calculated temperature reaches a value very close to 137°C.
The calculated temperatures using propionic acid as byproduct are slightly lower than those determined from ethanol because of the possible loss of propionic acid in the system. It is very important to point out that temperatures calculated from ethyl propionate and ethanol are, at the end of the investigation, in very close agreement with the reservoir temperature.

CONCLUSION

From both injection tests, mixing and water-rock processes have been studied. This was possible because of the good knowledge of the brine chemistry. In both cases, the mixing between freshwater and brine is rapid because of the presence of a large number of producing fractures and is dependent on the relative importance of the fractures. It is expected that brines with slightly different chemical compositions are involved in the mixing.

Among the processes which may occur during water-rock interactions, the dissolution of calcite, biotite and alkali feldspar was deduced from the chemical composition of the removed fluids. Moreover, silica reaches a steady state concentration because of the precipitation of a new mineral phase.

Even if injected chemical tracers have not been completely removed due to losses in the reservoir, adsorption and/or thermal instabilities, the results are very encouraging for their use in geothermal systems at temperatures close to 140°C. Some progress concerning the reactive tracers injection technique such as the material of the container remain necessary. Nevertheless, the test was successful since the temperatures calculated from ethyl propionate concentrations are in very close agreement with the reservoir temperature.
REFERENCES


SESSION 2 - CURRENT STATUS OF HDR TECHNOLOGY
THE U.S. HOT DRY ROCK PROGRAM

Dr. John E. Mock

Director, Geothermal Technology Division
United States Department of Energy, Washington, D.C.

ABSTRACT

Hot Dry Rock (HDR) research, initiated in the U.S. in 1970, has been strongly supported by the government because: it is an indigenous resource secure from fuel interruptions; it can provide price stability during periods of rapid escalation of fuel prices; it is a large resource; and it is environmentally benign.

The U.S. Department of Energy’s (DOE) outlook on geothermal energy production and its plans for future geothermal research are discussed. Current use of geothermal energy to generate electricity and to serve as a source of heat is also described.

DOE has initiated a study to compare several independent evaluations of the economics of prospective HDR systems. Some possible directions for advanced research and industrial development are presented.

INTRODUCTION

It is unusual when a group recognizes that it is participating in the creation of an important new technology. That is the case for us at this Symposium. We have gathered to confirm and extend our awareness that the planet’s Hot Dry Rock resources are large, exploitable, and valuable. The technology we are developing will someday open those resources to economic and environmentally benign uses.

Recent serious mishaps in the U.K. and the U.S. with respect to petroleum energy remind us of the importance of speeding the use of other indigenous forms of energy, including HDR. Production-platform explosions and huge oil spills are true disasters. They impel us to renew our personal commitment to develop safer alternative sources of energy.

The U.S. has been studying the extraction of energy from HDR geothermal energy resources since 1970, when an exploitation concept was conceived at Los Alamos National Laboratory. Research progress on HDR technology has been good and is now proceeding on at least three continents.
The arrangement of a simple conceptual HDR system is shown in Figure 1. HDR systems "mine heat" from hot rock through oil-well-like boreholes. Cold water is pumped into a man-made fractured reservoir in the hot rock. Heated water is continuously drawn from the reservoir and used for heating or to produce electricity.

**FIGURE 1**
HOT DRY ROCK CONCEPT

**ATTRACTIONINESS OF HOT DRY ROCK**

Hot Dry Rock is an attractive domestic energy resource, secure from interruptions, which can provide price stability during periods of rapidly rising fuel costs. The lack of significant emissions, including CO₂, makes geothermal energy in general, and HDR in particular, an attractive alternative for future energy production.

The size of the U.S. Hot Dry Rock (HDR) resource is very large. One working estimate is that there are at least 500,000 quads (1 quad = 10¹⁵ BTU) of useful heat in HDR beneath the U.S. at accessible depths. Economical recovery of even a small fraction of the heat would contribute significantly to U.S. energy needs. The situation is similar in many other countries.

Because HDR represents an essentially inexhaustible supply of thermal energy almost everywhere in the planet, the U.S. HDR program has attracted much international interest and participation. Parallel and complementary HDR R&D programs have been started in several other nations, including the Federal Republic of Germany (FRG), France, Japan, Sweden, the Soviet Union, and the U.K.
The U.S. R&D program has concentrated on electricity-quality HDR resources. It is likely that many of the most economic uses will be for urban district heating systems in Europe, Japan, and perhaps the Northeast U.S.

THE U.S. HOT DRY ROCK-RESEARCH PROGRAM

HDR research in the U.S. is managed by the Geothermal Technology Division (GTD) of DOE. Work on hydrothermal, geopressed, HDR, and magma-related technologies is integrated across the GTD program to ensure that R&D objectives are cross-fertilized and that technology improvements can be employed quickly across the resource types.

The main objectives of the GTD R&D program are to develop cost-cutting exploitation technologies, and to transfer these advanced technologies to the geothermal industry. The overall GTD budget for FY 1989 is $19.6 million, of which the HDR portion is $3.6 million.

Since 1975, the Fenton Hill, New Mexico, HDR test site has served as the world's initial laboratory for creating a man-made closed-loop heat exchanger system in deep, hard, hot rock. Cooperative research funding agreements with the FRG and Japan ensured that the work and lessons of this pioneering project would be shared broadly. Scientists from other nations, including the U.K., have also participated.

The first HDR energy loop was completed at Fenton Hill in 1977. It was enlarged in 1979 by additional hydraulic fracturing, and operated successfully for more than a year. This "Phase I" system operated at about 3000m and a rock temperature of about 185°C. It brought to the surface water at 135°C to 140°C at heat rates of about 5 MWt (thermal megawatts). Some of the heat was used to operate a small binary cycle power plant. System operation was essentially trouble-free, and there were no detectable scaling, plugging, corrosion, or environmental effects.

Work on the deeper, hotter, and larger "Phase II" HDR system was begun at Fenton Hill in 1979. The first hydraulic fractures were made in the Phase II reservoir in 1982 through 1984. The fracture systems produced were three-dimensional ("volumetric") rather than the expected planar fractures, and did not meet to connect the two wells hydraulically.

Redrilling one of the wells in 1985 produced the required connections. This allowed an initial closed-loop flow test for 30 days in 1986. Surface temperature of 192°C and a heat rate of 10 MWt were achieved. The reservoir was then shut down for needed repairs to the EE-2 production well, which were completed in 1988.
The Phase II reservoir is being prepared for a flow test of about one year's duration, scheduled to start in September, 1990. It is designed to produce significant temperature drawdown in the reservoir. Analyses of reservoir performance should be completed in 1992-1993.

A great deal of what was learned at Fenton Hill has been applied fruitfully to the Rosemanowes, U.K., reservoir; the second promising major HDR site. The work at Rosemanowes, including the by far longest flow test of a HDR system -- about three years to date -- has furnished the independent confirmation of the technical feasibility of HDR systems.

U.S. GEOTHERMAL ENERGY DEVELOPMENT

Development of the U.S. hydrothermal geothermal resources provides a basic context for understanding what is possible for HDR. That development appears to have proceeded in two distinct waves.

In geothermal Wave I, U.S. industry initiated the development of the large dry-steam field at The Geysers, Ca. Firms with oil-patch experience developed the well fields, while the local regulated electric utility designed and capitalized the power plants. Starting with 11 MWe in 1960, 396 MWe were in operation by the end of 1973.

Geothermal Wave II began with the first round of openings of U.S. hot-water fields in 1973, the year of the first oil price shock. During the next 10 years about $1 billion in Federal funding went into geothermal R&D, and industry interest in hot-water fields increased markedly.

By the end of 1983 about 950 MWe of new geothermal plants had been added, 97 percent of which could be attributed to Wave I construction of additional dry-steam plants at The Geysers. A total of 33 MWe had been installed at four liquid-dominated sites.

Some Federal R&D funds went to The Geysers to improve hydrogensulfide abatement methods. Geothermal Wave I essentially ended in 1988, with startup of the 130 MWe Cold Water Creek plant for a total of nearly 2,000 MWe installed at The Geysers.

Wave II results started appearing in 1980 with two 10 MWe field-opener plants in the Imperial Valley, Ca. This has increased today to 750 MWe installed outside of The Geysers. Of that, 630 MWe is sited in just two areas, Imperial Valley and Coso. Most of the 750 MWe is serving California demand. Some of this electricity is transmitted 250 miles.
Most of these "hot-water" plants are selling electricity at incentivized prices (about 7 to 8 cents/kWh) that benefited from the Federal "PURPA" regulatory response to the second oil-price shock of 1979. It is probable that only about half of these 750 MWe would have been developed in the absence of the PURPA "avoided-cost" price boosts.

New power sales contracts at such high prices are not now available. Therefore, hydrothermal electricity costing above about 5.5 cents/kWh is at a temporary development standstill. We anticipate electric demand growth in the Southwest to bring more hydrothermal into the market in the mid-1990s. A new oil price boost or environmental shock could, of course, reactivate development at any time. We think industry has confirmed approximately 10,000 MWe of near-economic hydrothermal reserves.

U.S. direct heat uses of hydrothermal resources have also grown, but relatively slowly. Use in 1988 was estimated to be about 18 trillion BTU. The growth rate suffers from relatively weak co-location of hydrothermal resources and dense urban markets. It is likely that some of the HDR resource in many countries will be better located.

The hydrothermal R&D and price incentives have paid off, but not instantly. Similarly, R&D on Hot Dry Rock is an investment in the future. Our first task is to develop the technology. Our second task, equally important, is to clarify the system costs and associated financial risks.

**IMPROVEMENTS IN HDR TECHNOLOGY**

A number of significant improvements in HDR technology have already emerged.

- We now understand that reservoir geometry will be dictated by pre-existing complex stresses and strains in the rock. The fractures will seldom be vertical thin disks. We will often get volumetric rather than planar fractures.

- We have much better tools for locating fractures as they are being formed. Analysis of microseismic data collected from downhole geophones during the hydraulic fracturing allows highly accurate targeting of the intersecting well(s). This is one of the most significant advances in HDR technology. Figure 2 shows some typical results.
FIGURE 2

SEISMIC PLOTTING

Locations of the microquakes during hydraulic fracturing of Hot Dry Rock at Fenton Hill. The quakes show the outline of the fractured reservoir and thus guide the drilling that connects the two wells.

- Drilling costs for HDR are now much lower than when work at Fenton Hill began. Mud formulations for HDR are greatly improved over the earlier water-dominated muds copied from hydrothermal practices in the U.S. The first well in a couplet may be drilled vertically, without deviated inclination.

- We also have much better tools for precise location of where fractures intersect the wellbore. The borehole acoustic televiewer resolves fractures as small as about one millimeter. It will eventually aid in precise selection of individual fractures to inject or produce.

- We have developed and are continuing to improve temperature-sensitive chemical tracers. These are beginning to allow us to measure the temperatures of different flow paths in the reservoir.

- Much attention is being paid to modeling production behavior of fracture-dominated and mixed-permeability reservoirs, rather than those dominated by porous permeability. The modeling is physical and numerical and is related to both HDR and hydrothermal reservoirs. These more realistic models will provide better analysis of flow test, tracer, and production data, and will improve predictions of the economic value of production decisions.

In addition, certain projects sponsored under the "Hydrothermal" category of GTD's research will have strong applicability to HDR. GTD has been conducting an
R&D program that is well-integrated across the various forms of geothermal energy. Some of the cross-impacting advances are:

- Drilling technology improvements, both for hole-making and hole-analysis. For example, high-temperature cements continue to be improved.

- Improvements in the cost-effectiveness of binary electric power cycles. We estimate a 25 to 30 percent reduction in the amount of fluid flow needed to make a desired net electricity output. Viewed in another way, these improvements will allow a binary power plant of a given cost to extract power from a fluid supply of lower temperature, thus reducing the depth and cost of the HDR reservoir.

THE ECONOMIC OUTLOOK FOR HOT DRY ROCK

GTD has started a two-pronged process to clarify HDR costs. Dr. Jefferson Tester of M.I.T. is comparing six major published evaluations of the economics of HDR electric systems, to try to make some better crosscutting sense out of what has been done already.

Table 1 shows some aspects of the studies. Because of vagaries in currency exchange rates, the cost shown as "percent of coal" probably allows better comparisons than the "1986 U.S. cents/kWh" value. All of the studies tend

<table>
<thead>
<tr>
<th>Study Source</th>
<th>EPRI</th>
<th>LANL</th>
<th>Shock</th>
<th>CRIEP</th>
<th>Armstead &amp; Tester</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fractures</td>
<td>Flat</td>
<td>Flat</td>
<td>Flat</td>
<td>3-D</td>
<td>3-D</td>
</tr>
<tr>
<td>Gradient, °C/km</td>
<td>40</td>
<td>60</td>
<td>35</td>
<td>120</td>
<td>67</td>
</tr>
<tr>
<td>Depth, km</td>
<td>4.0</td>
<td>4.3</td>
<td>7.0</td>
<td>2.5</td>
<td>3.0</td>
</tr>
<tr>
<td>Temperature, °C</td>
<td>160</td>
<td>260</td>
<td>245</td>
<td>300</td>
<td>200</td>
</tr>
<tr>
<td>Cost per KWH:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Cents, 1986</td>
<td>7.1</td>
<td>4.7</td>
<td>9.6</td>
<td>7.8</td>
<td>5.9</td>
</tr>
<tr>
<td>- % of Coal</td>
<td>140</td>
<td>120</td>
<td>140</td>
<td>140</td>
<td>130</td>
</tr>
</tbody>
</table>
to agree that HDR should be cost-competitive. However, more detailed analysis is needed to understand why such a wide range of geothermal gradients results in roughly the same estimate of system costs.

The most recent U.S. study was done by Bechtel National, on the feasibility of a commercial HDR project at Roosevelt Hot Springs, Utah. The results were detailed, well structured, and optimistic.

Some of the preliminary conclusions from reviewing the studies are:

- Penetration rates for drilling are now higher than in the early 1980s, due to improved mud formulations, bits, and drilling plans. Improvements here will continue, since world total experience in drilling hot hard rock is limited.

- Anticipated mishap rates will be much lower than experienced and estimated to date, since most of each well will be drilled straight, assuming volumetric rather than planar fractures for systems at great depth.

- Preliminary results from improved reservoir models suggest longer useful production lives for the same volume of rock fractured.

- The specific cost per fractured volume or surface area remains one of the greatest uncertainties in the whole process. Only extensive testing of large HDR reservoirs will resolve this uncertainty.

In the meantime, another group of system and cost analysts is developing detailed conceptual and costing models of how specific advances in the component technologies might lead to cost breakthroughs in HDR.

POSSIBLE DIRECTIONS FOR RESEARCH AND DEVELOPMENT

Even though the story on reservoir performance and system costs is not yet complete, it is clear that significant advances in HDR technology can be made. Some of the improvements that appear to be feasible and worthy of study are described here.

- When cold water short-circuits occur along relatively short flow paths in a particular reservoir, can a means be developed to plug the short circuits and force the flow through longer, hotter channels?

- It is imperative to understand what is happening to all of the water that is injected. Both long-term flow tests and improvements in chemical tracer techniques will be especially important.
- Test the use of high-pressure viscous-fracturing operations on the production-bore side of the reservoir to minimize the output flow impedance.
- Investigate thermal spallation drilling as a method of choice for penetrating hard crystalline rock. Drilling costs might be halved by such methods.
- Improve wireline stress-measurement logging tools to enhance prediction of the direction and extent of fracture propagation over short depth intervals.
- Test the effectiveness of shock-induced hydraulically-driven fracturing to combine the best effects of both hydraulic (long fractures) and explosive methods (multiple fractures).
- Develop triaxial seismic fracture mapping tools to locate fractures by using just one or two seismic stations.

CONCLUSION

The Bechtel study flagged a need for continued Federal research on the productivity of large HDR reservoirs: "To a commercial geothermal resource developer, the technical risks associated with HDR technology and the high cost ... to obtain the needed data are prohibitive." "Demonstration of multiple fracture technology, and prolonged thermal drawdown experiments are required to develop a sufficient information base for commercial development. Therefore Federal funding is needed to advance HDR technology with these industrial experiments."

GTD's planned involvement in the flow testing at Fenton Hill will be completed in 1992 or 1993. Plans for subsequent work at the Fenton Hill reservoir or other Hot Dry Rock research have not been formulated by the U.S. Government, nor to our knowledge by industry.

We believe that when economic conditions are right, Hot Dry Rock energy development for electricity production and direct heating will become a commercial "boomer". Our job at U.S. DOE and the other worldwide research and development agencies is to create the technological base for such a future expansion of Hot Dry Rock use. We hope that what we have accomplished so far will find acceptance and economic use within industry.
REFERENCES


THE BACKGROUND TO PHASE 3 OF THE CAMBORNE SCHOOL OF MINES GEOTHERMAL ENERGY PROJECT

Roger Parker, Project Director
CSM Geothermal Energy Project, Rosemanowes Quarry, Herniss, Penryn, Cornwall TR10 9DU

ABSTRACT

The objectives of the Camborne School of Mines Hot Dry Rock (HDR) Geothermal Energy Project have been concerned mainly with development of the technology of reservoir creation in a jointed granite environment. The Project, sponsored to a large extent by the UK Department of Energy, has not aimed to demonstrate the exploitation of the energy extracted.

Phase 1 (1977-1980) demonstrated the feasibility of connecting boreholes drilled to a depth of 300 m, using hydraulic stimulation of existing joints to improve the reservoir rock permeability. Phase 2 (1980-1988) aimed to investigate HDR reservoir development under conditions which were more closely related to those which would be required for commercial exploitation of the technology in Cornwall. Three boreholes were drilled to a depth of between 2 and 2.6 km in the Carnmenellis granite. Hydraulic stimulation using a viscous gel rather than water as the stimulating fluid produced a more compact reservoir with lower impedance and lower water losses. Continuous circulation of this reservoir (1985-88) allowed its characteristics and performance to be studied at different injection flow rates (5 to 35 litres/second).

During Phase 2, there was a significant development of instrumentation for use in the present system at Rosemanowes. Work on instrumentation suitable for use at greater depths (6 km in Cornwall) commenced, in preparation for work leading up to a commercial system. Resource assessment, using heat flow modelling, seismic reflection surveys, magnetotelluric investigations and environmental restriction analysis, has led to the conclusion that there are many sites in Cornwall suitable for HDR development.

Phase 3A commenced in October 1988, with three major objectives. The first is to investigate methods of treatment which would seek to improve the characteristics and performance of a HDR reservoir. Using the present well-documented Rosemanowes reservoir, it is intended to investigate the placement of proppants in joints close to the production wellbore, the selective stimulation of a zone of the production well which is currently not flowing, and the possibility of sealing off short circuits. The second objective is to develop instrumentation to the stage where it can be used to create and operate reservoirs at greater depths in Cornwall. The third objective is to participate in the conceptual design of a prototype of a commercial system.

In 1990, there will be a review of the status of the technology, and a decision will be taken whether or not to construct this prototype in Phase 3B.
INTRODUCTION

The objectives of the Camborne School of Mines (CSM) Hot Dry Rock Geothermal Energy project in the period 1977-89 have been concerned mainly with the technology of the development and characterisation of Hot Dry Rock (HDR) reservoirs in a jointed granite. There has been no attempt to demonstrate the exploitation of the energy extracted. The UK Department of Energy has been responsible for providing most of the funding, but the Commission of the European Communities provided significant support until 1986.

In Phase 1 (1977-1980), boreholes 300 m deep were drilled in the Carnmenellis granite at Rosemanowes Quarry, near Penryn in Cornwall. It was demonstrated that it was possible to connect the boreholes by hydraulic stimulation of natural joints in the granite, and to circulate water through these joints (Batchelor, 1982).

Phase 2 (1980-1988) was carried out in three parts at Rosemanowes, with the aim of investigating reservoir development at a depth of about 2 km, which was considered to provide conditions reasonably representative of those expected at the greater depths required for commercial exploitation. Hydraulic stimulations using water and a medium viscosity gel were used to create the reservoir, and long periods of circulation of the reservoir were used to establish its hydraulic and thermal characteristics.

Phase 3 began in 1988, having as its main objective the development in Cornwall of a prototype of a commercial system for generating electricity. This would probably require the design specifications summarised in Table 1, but the conceptual design of the system in Phase 3A (1988-90) will probably produce revised design assumptions and targets.

<table>
<thead>
<tr>
<th>TABLE 1 DESIGN ASSUMPTIONS FOR DEVELOPMENT OF A PROTOTYPE COMMERCIAL HDR RESERVOIR FOR ELECTRICAL POWER GENERATION IN CORNWALL</th>
</tr>
</thead>
<tbody>
<tr>
<td>System lifetime : 25 years</td>
</tr>
<tr>
<td>Initial mean reservoir temperature : 210°C</td>
</tr>
<tr>
<td>Production flow rate (single injection, single production well) : 75 kg/s water</td>
</tr>
<tr>
<td>Thermal drawdown : 25°C in 25 years</td>
</tr>
<tr>
<td>Reservoir depth : about 6 km, depending on the site chosen</td>
</tr>
<tr>
<td>Reservoir fracture area : 5 million m² minimum (or 10 million m² heat transfer area)</td>
</tr>
<tr>
<td>Reservoir rock volume : 300 million m³</td>
</tr>
<tr>
<td>Reservoir impedance : 0.1 MPa/kg/s</td>
</tr>
<tr>
<td>Reservoir water loss : 10%</td>
</tr>
</tbody>
</table>
HDR ENVIRONMENT AT ROSEMANOWES

Throughout the programme, the aim has been to produce a technology which is as widely applicable as possible. Return from investment in HDR exploitation is unlikely to be high enough to justify high exploration costs, and therefore the technology must be capable of adapting to the geological environment in which it is placed. If there is a need to incorporate specific localised geological structures in creating the reservoir, exploration costs (and the chances of a sterile operation) increase. Conversely, there is a need to avoid such structures in choosing the site, if they would tend to jeopardise the operation.

Rosemanowes Quarry was chosen because it was on the exposed Carnmenellis granite, and did not have a major geological feature (such as a fault) at the surface. The absence of sedimentary or metamorphic cover rock has made installation of the comprehensive microseismic network cheaper and more effective.

The rock is granite, with textures changing from porphyritic to equigranular at about 2 km. The base of the granite extends well below a depth of 9 km. In situ mechanical properties are:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uni-axial compressive strength</td>
<td>103 MPa + 32 MPa/km</td>
</tr>
<tr>
<td>Young's modulus</td>
<td>54 GPa + 4 GPa/km</td>
</tr>
<tr>
<td>Poisson's ratio</td>
<td>0.22-0.27</td>
</tr>
<tr>
<td>Density</td>
<td>2640 kg/m³</td>
</tr>
</tbody>
</table>

Two main vertical joint sets (NE-SW, parallel to the trend of tin/copper lode mineralisation, and NW-SE, parallel to post-granite extension and strike slip faults known as "cross-courses") have been identified from surface mapping. These joint sets (although with a broad range of strikes) have been identified on BHTV logs to a depth of 2.6 km, and microseismic data indicate their continuation to at least 3.5 km. Randall et al (1989) report further on the evaluation of jointing in the Carnmenellis granite.

The relationship of stress distribution to depth has been measured at Rosemanowes in considerable detail to a depth of 2.5 km, and these measurements have been complemented by measurements in local tin mines. Pine and Batchelor (1984) summarised the relationship for in situ stresses (in MPa) in the Carnmenellis granite with depth \( z \) in km:

\[
\begin{align*}
\sigma_h &= 15 + 28z \\
\sigma_h &= 6 + 12z \\
\sigma_y &= 26z
\end{align*}
\]

Subsequent measurements at 2.5 km confirmed this relationship. Green et al (1989) consider in situ stress measurement in deep wells.
Three-dimensional heat flow models, based on extensive heat flow measurements and gravity surveys, indicate an almost linear dependence of temperature on depth in the upper 7 km of crust over large portions of the Cornubian granite batholith. With an average surface temperature of 10°C, this results in a relationship for regions close to Rosemanowes:

\[ T = 10 + 35z, \]

where \( T \) is the temperature in °C at a depth of \( z \) km (CSM, 1989).

In situ hydraulic properties have been measured at Rosemanowes at depths up to 2 km, before major hydraulic injections commenced. Low flow rate hydraulic tests at low injection pressures indicated permeabilities between 1 and 10 μD at up to 0.7 MPa fluid overpressure. Then permeabilities rose to 60 μD, prior to onset of significant discontinuous behaviour at over 5 MPa.

**PHASE 2: RESERVOIR CREATION AND CHARACTERISATION**

In Phase 2A (1980-83), two wells (RH11 and RH12) were drilled to a depth of 2100 m entirely through granite, deviated to an angle of 30° from the vertical in the lower section. They were separated vertically by 300 m at full depth, where a bottom hole temperature of 79°C was recorded. Explosives were used to pre-treat the well to allow better water access from the borehole into the granite, but the joint stimulation was hydraulic, using 26 000 m³ of water injected into the injection well (RH12) at flow rates up to 100 l/s, generating a wellhead pressure of 14 MPa (Batchelor, 1983; CSM, 1987).

This hydraulic stimulation established a poor connection between RH12 and RH11 and created a large stimulated region, below the two wells, whose predominantly downward growth persisted throughout the subsequent circulation of the reservoir during Phase 2A. The importance of the installation of a comprehensive microseismic sensing system in the monitoring of these stimulation and circulation developments cannot be over-emphasised. Baria and Green (1989) consider the importance of microseisms in the context of the Rosemanowes project.

Circulation following the main stimulation gave an average water recovery of 31% at an average injection flow rate of 24 l/s. The highest injection flow rate was 32 l/s, at which the recovery was 26%. Impedance (pressure drop across the reservoir measured at the wellheads divided by the production flow rate) was high (1.8 MPa/kg/s average), but there was no measurable thermal drawdown in the production temperature (52°C at surface). Tracer tests using sodium fluorescein showed considerable dispersion with long breakthrough times, implying a very large system with low permeability. The overall envelope of the microseismic cloud located during Phase 2A contains a volume of about 800 million m³ of rock, but it is clear that water flow through this volume was mainly lost, and an unacceptably low proportion was returning to the production well.

Pine and Batchelor (1984) have provided an explanation for this downward growth of the reservoir during hydraulic stimulation and
circulation, and have related it to the changes of in situ stress anisotropy with depth in Cornwall.

A third well (RH15) was drilled in Phase 2B of the CSM Project (1983-86). The aim was to intersect the microseismic zones which had indicated downward growth of the reservoir from RH12 in Phase 2A. Subsequent analysis of the spatial distribution of these microseismic events has shown that the new well did not pass through the regions of intense microseismicity on its spiral trajectory to a depth of 2600 m, at which the bottom hole temperature was 100°C (CSM, 1988a). In order to achieve a good connection with the injection well (RH12), it was necessary to stimulate the system from RH15, which was to be the new production well. To reduce the tendency to leak-off, and to increase the chance of jacking open the joints, rather than shear-slippage, 5500 m$^3$ of an intermediate viscosity gel (50 cp) was injected into RH15 at an average flow rate of 200 l/s. The injection wellhead pressure was 14 to 15 MPa. Microseismic activity was much lower, and was confined to a more restricted tube-shaped envelope extending vertically mainly between RH15 and RH12 (Parker, 1989a). The volume of this microseismic envelope was one million m$^3$, and subsequent experience with circulation of the reservoir created indicates that an effective reservoir rock volume of five million m$^3$ was produced by this viscous gel stimulation in 1985.

The remaining part of Phase 2B (1985-86) and the whole of Phase 2C (1986-88) were concerned with a continuous circulation of the reservoir stimulated in 1985, using a number of diagnostic methods to characterise the reservoir. This work has been reported recently (Parker, 1989b), and represents the longest continuous circulation of any HDR reservoir.

This extended circulation programme can be divided into three stages:

I A gradual increase in the injection flow rate, using periods of up to six weeks at each flow rate step increase, to allow approximately steady-state conditions to be achieved at each step. Water losses remained fairly constant throughout, at about 20%, and impedance reached a minimum of about 0.5 MPa/kg/s at the maximum injection flow rate of 35 l/s. At flow rates as high as this, requiring an injection pressure of 11.5 MPa, the rate of water loss increased and microseismic activity indicated downward reservoir growth similar to that experienced in Phase 2A. It appeared that the optimum performance of the reservoir was at an injection pressure of 10 MPa, producing an injection flow rate of 24 l/s and an impedance of 0.6 MPa/kg/s. Nevertheless, this was a much more satisfactory connection between the wells than had been achieved in Phase 2A.

II A downhole pump was used to lower the pressure in the production well (RH15) by 4.5 MPa. This produced evidence of "pinching in" of joints close to RH15, resulting in a significant rise in impedance. Proppants placed in these joints might reduce this effect, and in Phase 3A (1989), a proppant placement is being used in conjunction with a downhole pump to test this proposition.
III Thermal drawdown had been of the order of 1°C per month since 1986, and thermal modelling had indicated the possibility of a short circuit (Nicol, 1989). In 1988, tracer runs were carried out involving fluorescein injection at specific points downhole in RH12 and continuous sampling downhole in RH15. This flowpath characterisation indicated a short circuit between the bottom of RH12 and the upper flowing zone of RH15 (Richards et al., 1989). Plans are being made to attempt to seal this short circuit in Phase 3A (1988-90).

In the characterisation of the HDR reservoir, a number of diagnostic techniques have been used, and developed significantly by the CSM team. These include hydraulic well testing, tracers, radon dissolution modelling, vertical seismic profiling and crosshole seismics (Stewart & Jones, 1989), tracers and thermal modelling.

INSTRUMENT DEVELOPMENT

Throughout the CSM Project, it has been found unsatisfactory to rely totally on commercially available instrumentation for monitoring the creation and development of the HDR reservoir, and for its characterisation. In particular, microseismic instruments, production logging tools and, more recently, downhole tracer experimentation tools have been an important field of development in the research programme. Commercially available instruments and tools have been substantially modified, and completely new items designed and built. The associated system software has been developed mainly in-house, and software for the interpretation of proprietary logging data (eg BHTV, FMS) has been developed by the Project.

A set of production logging tools (to measure temperature, pressure and flow rate downhole) is available, with downhole electronics able to operate at ambient temperatures up to 125°C. Tracer tools capable of injecting and sampling downhole have been built, and a conductance tool and fluorimeter tool capable of sensing for tracer purposes have been purchased and modified.

An earlier review of the borehole tool requirements for the Project's future revealed the need for tools operating downhole at temperatures around 200°C and pressures about 140 MPa (see Table 1, above). Passive cooling using vacuum barrier flasks and low melting point eutectic materials to provide a negative heat store are adequate where equipment requires only a relatively short time in the well (eg production logging). Where a seismic tool is required for passive monitoring for long periods, active cooling devices will be necessary. Work on thermoelectric cooling has developed a system operable at an ambient temperature of 220°C, with a cooling differential of 40°C. A database has been built up on electronic components available and capable of operating at 180°C for over 3000 hours (CSM, 1988a).

The use of seismic equipment downhole was the subject of a Borehole Seismics Conference, held at the Camborne School of Mines in September 1988, when a number of contributions on instrument
development were made by Project staff (Jones and Baria; Halladay and Twose; Manning and Baria, 1988).

A seismic source (sparkler) is being designed, built and tested to produce a repeatable wide bandwidth source for use in deep boreholes in sedimentary and crystalline rocks. A commercial 3-axis microseismic tool was purchased and found to be severely affected by resonance. After exhaustive testing of this tool, it was decided to design and build a tool in-house. The aim is to have a tool capable of remaining long periods clamped downhole at up to 200°C, to provide accurate location of microseismic events where attenuation will decrease accuracy if sub-surface sondes are used on their own in a deep system used to develop a commercial prototype (CSM, 1988a).

RESOURCES ASSESSMENT

In preparation for the development of a prototype commercial HDR system in Cornwall, it has been necessary to explore the structure and thermal characteristics of the 14 km-thick Cornish granite batholith, together with its metamorphic cover. This should provide data for the costing and site selection for the prototype. Gravity and heat flow studies have provided important data on the HDR resource in South West England, and a model which will predict temperatures at depths up to 7 km with an accuracy of 8°C (one standard deviation) has been produced (CSM, 1989). The geothermal gradient is nearly linear over the upper crust, 35°C/km typifying the granite batholith.

A seismic reflection survey found no evidence of reflectors within the Carnmenellis granite at depths of relevance to the development of HDR (CSM, 1988b). The survey was carried out along two lines crossing over at Rosemanowes Quarry, and having a total length of 72 km. In addition to heat flow and seismic reflection studies, a magnetotelluric survey has been carried out more recently by the British Geological Survey (CSM, 1988a). The thermal modelling aspects of resource assessment are covered in a paper by workers from CSM and Imperial College, London (Willis-Richards et al, 1989).

In addition to geological studies, environmental and infrastructure restraints on potential HDR development have been studied in broad detail in Cornwall, and it is concluded that there are a large number of sites which could be investigated, should a decision be made to go ahead with development of a prototype deep system (CSM, 1988a).

PHASE 3

Having completed an extensive study of the Rosemanowes reservoir created in Phase 2, the programme had reached the stage where decisions were needed on the future of the Project. It has been shown that the reservoir characterised in Phase 2C is significantly smaller than that which would be required for a commercial application of the technology or electrical power generation (Table 1). Further work on the assessment of the engineering problems in creating a deep system shows that a properly designed stimulation should develop a reservoir system larger in volume than that produced in Phase 2 at Rosemanowes. Nevertheless, it is believed that the design assumptions in Table 1 will require a commercial reservoir to be created by stimulation in
several segments, which are connected in parallel to the injection and production wells (CSM, 1987). By this means, the increased volume can be created, while maintaining an acceptable reservoir impedance.

With this premise in mind, a Conceptual Design study has been commenced by RTZ Consultants Ltd, aiming to design a commercial HDR system, and a prototype of such a system which will demonstrate the feasibility and costs of HDR development in Cornwall. CSM is participating in this Conceptual Design study, which will be completed in 1990.

In order to provide further input data for the Conceptual Design, CSM has a Phase 3A (1988-1990) R & D programme which in addition to further instrument and microseismic system development, aims to examine techniques which may be used to manipulate a HDR reservoir to improve its performance. The most important treatment applied so far has been the placement of proppants in the joints flowing into a section of the production well. This work was carried out successfully in February 1989, and the results of the placement will be analysed following the use of a downhole pump in July 1989 to lower the pressure in the production well. If the rise in reservoir impedance is less than that experienced with a downhole pump in Phase 2C, it will have been demonstrated that proppants prevent "pinching in" of joints close to a production well in which the pressure has been lowered below hydrostatic.

The next stimulation treatment will aim to access part of the reservoir which has been located microseismically, but which is not connected to the production well. A limited "secondary stimulation" will be carried out lower in RH15 than the proppant placement, to increase the effective circulating volume of the reservoir.

It was shown in the reservoir characterisation in Phase 2C that there is an important short circuit in the reservoir, leading to excessive thermal drawdown. Plans are being made to seal the short circuit, thus improving the thermal performance of the reservoir.

An experiment to investigate the effect of major oscillations of reservoir pressure and flow rate has shown no significant improvement in performance of the system.

The importance of designing and modelling of reservoir stimulation treatments has been made clear, and the Conceptual Design study is being supplemented by work by CSM in Phase 3A covered by the papers by Nazroo et al (1989) and Nicol et al (1989).

CONCLUSIONS

After twelve years of work at Rosemanowes, the CSM Project has demonstrated that it is possible to create a large hot dry rock geothermal reservoir in granite at a depth which allows a significant understanding of the engineering problems associated with the creation, development and circulation of the reservoir. This understanding is vital for the next stage of the Project, which it is hoped will apply the lessons learned to the development of a new reservoir at a depth representative of the requirements of a
commercial system. The area which still requires considerably more experience than has been possible on this single site is the stimulation of the rock mass to create the reservoir. Modelling and design studies can only support practical experience in this field; they can never replace it. Once an experimental reservoir has been created, it is important to devote adequate effort to characterising it, otherwise the lessons to be learned for the future will be incomplete.

We believe that at Camborne School of Mines we have laid a firm foundation for future development of HDR technology, and look forward to a significant growth in experimental activity in this field. We have valued the co-operation and support we have received from HDR research teams in the USA, in France and Germany, in Japan and in Sweden, and intend that this co-operation, which is so essential to the development of a significant research effort in a field of this nature, will flourish.

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Summary

A site for HDR investigations was developed at the western limit of the Upper Rhine Graben. A borehole 2000 m deep penetrates into granite in 1377 m depth. The temperature at the basis of the sediments is 124 °C (geothermal gradient in the sediments: 63 °C/km); bottomhole temperature in 2000 m is 141 °C (geothermal gradient in granite: 28 °C/km), and geochemical thermometers indicate temperatures above 200 °C in natural fluids along their path before they enter the borehole. The anomalous high geothermal gradient in the sediments provides within the whole crystalline complex an advantage of 75 °C or 2.5 km borehole depth against areas with normal geothermal conditions. Hydrofrac measurements in the crystalline borehole section and other observations reveal a direction of maximum horizontal stress of N170E, a high anisotropy factor of 0.7, and a low minimum horizontal stress. The high anisotropy is combined with low normal stress components against hydraulically stimulated fractures, high shear stress, relatively great fracture width, which is preserved after pressure reduction due to movements along the fracture surface. During stimulation tests in 1969-2000 m depth more than 500 m³ water were injected at a constant flow rate of 3.3 l/s. Fracture propagation started at 6-15 MPa (wellhead uncorrected for friction losses in tubing), shut-in pressure 3-6 MPa. All stimulated fractures were connected to natural hydraulic systems near the borehole. The specific yield of the existing joints was improved considerably from 0.06 to 0.18 l/s bar and it seems likely that it can be increased still much more by massive hydraulic fracturing.

The typical Graben tectonic is dominated by subvertical natural joints striking N170E, they indicate good transmissivities, which may be included into artificial fluid circulation systems. The existing artesian pressure in the natural hydraulic systems favours high production rates and low waterlosses during an artificially imposed circulation.

A seismic network was installed in boreholes adjacent to the 2000 m hole. Four sets of three directional seismometers capable of temperatures above 125 °C were cemented in three 840, 960 and 1360 m deep holes at distances between 200-400 m from the geothermal hole. These holes and many more are the relics of an abandoned oil field.
Several site specific properties at Soultz favour this location for a European HDR project aiming at the demonstration of a scientific HDR prototype. The stress field is typical for a young Graben; it facilitates the stimulation of fractures and circulation through it at high flow rates. These benefits have to be set into relation to existing natural hydraulic systems, which could cause high losses but do offer the chance to be included in an artificially stimulated heat exchange system. In comparison to other HDR projects, the development of a HDR reservoir at Soultz would reveal the role of specific stress properties upon the HDR performance of the underground.

Introduction

Near Soultz in the Northern Alsace, at the western rim of the Upper Rhine Valley, a European Hot Dry Rock (HDR) project has been set up in 1987. The site is situated close to the centre of a vast geothermal anomaly with an extension of 200 km * 20 km, covering French (Hagueau) and German (Landau) territory. From measurements in the old oil field "Pechelbronn" and other available holes it was known (Hoffmann & Hass 1926), that the geothermal gradient in the sedimentary cover is more than twice the normal value. From numerous oil wells and extensive seismic observation surveys the stratigraphy and structure of the sediments as well as the topography and main tectonic elements of the crystalline basement are well known.

A 2 km deep geothermal investigation hole was drilled at the end of 1987, which penetrates more than 600 m into the granitic basement. During 1988/89 a program was accomplished, which reveals geothermal, rock mechanic, hydraulic and geochemical properties and parameters of the crystalline complex, which are necessary for the planning and pre-evaluation of a HDR reservoir. At present considerations are proceeding to construct a HDR-heat exchanger with the following characteristics: average rock temperature 175 °C (approx. 3.5 km depth); effective flow rate 25 - 35 l/s; hydraulic impedance 0.3 MPa/l/s; exchange surface 0.5-1 km²; acceptable water losses during circulation. This task is the first step within a European Project aiming at the construction of a scientific prototype of a HDR demonstration plant. Research at Soultz offers the possibility to reach rock temperatures high enough for the industrial use of heat at depth, which are almost 2.5 km less than in geothermal normal areas. Inspite of these geothermally favourable conditions, the location is not within a volcanic active zone and therefore is representative for the petrographic and tectonic situation within the basement in many areas in central and northern Europe. Tectonic forces which are forming the Graben cause an anisotropic stress field with a very low minimum horizontal stress component. This can be an
advantage for generation of fractures and is a challenge to master the problems of uncontrolled fracture growth and water losses during circulation.

A further advantage of the site is the existence of subvertical joints with a great continuance of NS direction (max. horizontal stress), which predicts the direction of stimulated zones and which is favourable regarding a stress situation where fracture opening or extension is suppressed.

Within the context of HDR requirements and for the planning of the depth and temperature of the reservoir the following investigations were performed:

- measurements of undisturbed rock temperatures, geothermal gradients and terrestrial heatflow in the sediments and in the granitic basement;
- conductive and convective heat transfer in rocks and formations adjacent to the borehole and global geothermal modelling of the heat anomaly.

For the creation and monitoring of a future HDR exchanger:
- assessment of natural fracture network and determination of its suitability to be included in an artificial circulation system
- in-situ measurements of stress field and especially its anisotropy
- determination of hydraulic features and joints by injection /production tests
- evaluation of results of active seismic measurements for information about tectonic features (faults, fractures, joints) in the granitic basement and preparation of seismic network for the location of zones, which are stimulated during hydraulic fracturing
- development of new geochemical tracer techniques

For the evaluation of problems arising in connection with the operation and maintenance of the HDR reservoir:
- determination of the geochemical reactions and the interactions between circulating fluids and rock wall in a stimulated fracture as well as the chemical composition and origin of natural fluids from the granite
- Studies on corrosion phenomena in the casing and other tools, which are in contact with the circulating fluid

The experimental results are integrated in models, which reveal the costs for energy from HDR plants and allow sensitivity analyses of the production costs for variations of cost determining factors (i.e. geothermal gradient, depth, diameter of holes, reservoir extension, reservoir impedance) (see: Smolka & Kappelmeyer in this volume).
**Fig. 1:** Geological section, rock temperatures and well completion in geothermal well at Soultz sous Forêts
Funding and Organization

The funds for the project are supplied by:
- Commission of the European Communities DG XII-4, Brussels
- BMFT (Bundesministerium für Forschung und Technologie), Bonn
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and individual contributions of other partners.

The work has been entrusted to:
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  Bundesanstalt für Geowissenschaften und Rohstoffe, Hannover
  Niedersächsisches Landesamt für Bodenforschung, Hannover
  Befeld Mess System, Bochum
  Stadtwerke Bad Urach
  Geothermik Consult, Passau
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  centre
  the Materials Studies Department of EDF (French Electricity
  Board) and various laboratories in the CNRS (French National
  Centre for Scientific Research) and other Universities,
  mostly coordinated by PIRSEM (Interdisciplinary Program of
  Research on Energy and Raw Materials)

Results

Borehole and Geology

The borehole GPK-1 was drilled at the end of 1987. The total
depth is 2000 m. Below the sedimentary cover it penetrates in
1375 m depth into granite (fig. 1). Tubing and completion of
the hole allow injection tests at high pressure and production
at alternating temperatures.

A description of the petrography of the 635 m long granitic
borehole section from 1375 – 2000 m depth is given in fig. 2.
The interpretation is based upon 6 cores, cuttings sampled
every meter and borehole logs. Very useful was a new
developed technique allowing a real time monitoring of the
chemical composition of the drilling fluids (see: Criaud,
Vuataz, Brach, Fouillac in this volume). The orientation of
the joints and the direction of the maximum horizontal stress
are demonstrated in fig.3. Acoustic teviewer logs were used
for studies of the fracture system intersected by the well
(see: Tenzer, Mastin, Heinemann in this volume).
Fig. 2: Petrographic description of granitic bore hole section from 1375-2000m depth in geothermal well at Soultz
Fig. 3: Orientation of joints and direction of max. horizontal stress in geothermal well at Soultz.
Hydraulic and Rock Mechanics

Several small or medium scale hydraulic fracturing tests were performed in the deepest part of borehole GPK-1 between 1946 m and 2000 m to induce artificial fractures or to stimulate natural joints. After each fracturing test the hydraulic properties of the stimulated fractures and their hydraulic connections to the natural fracture network, were investigated. In the deepest part of the borehole between 1969 m and 2000 m a large fracturing test was conducted combined with seismo-acoustic recording in the three seismic observation holes for fracture mapping. A tracer test with reactive and non reactive tracers done in the same interval was aimed at additional information about the size of fractures, the fluid rock interactions and the mixing of injected fluid and formation water.

The test sections were carefully selected using the existing logs especially the acoustic televIEWer logs. In three cases single fractures of different orientations were tested using inflatable straddle packer arrangements with a spacing of 3.6 m. In one case (large stimulation test) a single packer was used. During the straddle packer tests some 10 m³ of water were injected with different flow rates up to 3.3 l/s. During the large stimulation test 524 m³ of water were injected at constant flow rate of 3.3 l/s. Flow rate, wellhead pressure, wellhead temperature, downhole pressure and downhole temperature were continuously recorded during the tests.

The fluid pressure for fracture propagation observed in the four test sections ranged from 8 MPa to 15 MPa (wellhead pressure, uncorrected for friction pressure losses in the tubing). Very low shut-in pressures, from 3 MPa to 6 MPa were recorded after the stimulation tests, indicating that the least compressive horizontal stress is low down to at least 2 km depth. All stimulated fractures have connections to large confined or unconfined natural fracture zones, which exist close to the borehole. The most productive connection was established during large stimulation test at a depth of 1991 m, where according to the acoustic televIEWer log two natural NNW - SSW striking and 75° dipping joints intersect the borehole. The specific yield of these joints of about 0.07 l/s bar measured after stimulation was about the same as the specific yield of an artesian producing fracture at 1812 m. The specific yield did not or only slightly decrease after-releasing the fluid pressure. This means that the flow path forming the connection to the natural fracture zone remains open after pressure release. An explanation for this phenomenon is that shear slip produces a permanent opening of the fractures.

The total specific yield of the borehole which was 0.06 l/s bar just during the first tests after drilling was increased by a factor of about 3.5 during the hydraulic tests performed in 1988 and it seems likely that it can be enlarged considerably more by application of massive hydraulic fracturing (more details will be published by R.Jung).
Fig. 4:  Seismic Studies: Situation map

Fig. 5:  Typical seismic event observed on probe inside Well 4616
Stress Field

Six natural joints were tested by hydrofrac stimulation. By using the "shut-in pressure" in connection with the PSI method the principal horizontal stresses could be measured. The results yield rather low stresses with an anisotropy factor of 0.7, which is characteristic for Graben tectonic with normal faulting (more details will be published by F. Rummel).

Seismic

Three sets of three directional borehole seismometers were cemented at the bottom of abandoned petroleum wells in 840; 960 and 1360 m depth (fig. 4) The borehole equipment is capable of temperatures above 125 °C; amplifiers, surface filters, transmission network and the digital acquisition system were tested by surface shots which served also to define the orientation of the seismometers in the hole. During pump tests in GPK-1 more than 60 seismic events were recorded (fig. 5).

Active seismic surveys were aimed at recognition of faults, fractures or hydrothermalized zones, which could affect the hydraulic behavior of the basement and provide connections into the sediments. The results show, that the major hydrothermalized zones identified in the borehole at about 1600 m and 1800 m depth are good reflectors. There are indications in the seismic records, that below 2000 m a few less developed hydrothermalized zones could exist (more informations will be published by A. Beauch).

Address of authors:

Dr. A. Gerard – BRGM/IMRG, BP 6009, F-45060 Orleans/France
Dr. O. Kappelmeyer – Geothermik Consult, Nikolastr. 18, D-8390 Passau/FRG
A TREND OF NEDO's HOT DRY ROCK PROJECT

Seiichi HIRAKAWA, Tsuneto TOMITA
Michio KURIYAGAWA, Toshihiko SUEYOSHI

ABSTRACT

This paper will try to explain a trend of NEDO's Hot Dry Rock Projects including Yakedake Project, Joint Research Fenton Hill Project and Hijiori Project. Consideration is concentrated on hot dry rock engineering.

INTRODUCTION

NEDO established in 1980 by the government and private sector plays the main role in promoting national energy development. The first stage of NEDO's HDR from 1980 through 1984 is the Yakedake Project in Gifu Prefecture. Joint Research Fenton Hill Project is the second one of NEDO's HDR from 1980 to September 1986. With the experiences at Yakedake and progressing information of Fenton Hill project, the third HDR project started in 1985 at Hijiori has been carried out by NEDO, private contractors and fundamental supports of National Research Institute for Pollution and Resources. The objectives of the Hijiori Project is aimed to develop elementary component technologies such as development of an artificial geothermal reservoir, instrument development for fracture mapping and well logging and heat extraction technique from the reservoir.

As the result, a short term circulation test was conducted at Hijiori in 1988 and high temperature water and steam were produced. However, NEDO still has problems which must be cleared.

This paper will try to explain a trend of NEDO's HDR Project, and consideration is mainly concentrated on the followings;

(1) geology in Hijiori area
(2) directional drilling, cementing and coring of HDR-1 well
(3) development of new triaxial geophone double sonde
(4) confirmation of fractures between SKG-2 well and HDR-1 well

Drilling of new well HDR-2 and hydraulic fracturing at 2200m in depth of HDR-1 are planned at this moment.

REVIEW OF NEDO'S HDR ENGINEERING

The first stage of NEDO's HDR from FY 1980 through FY 1984, is the Yakedake Project in Gifu Prefecture.

The geology in Yakedake area can be divided into the Hirayama formation and Quarternary andesite. The former, Permian sandstone and basaltic pyroclastic rocks, unconformably covers the later. Following the regional survey, the natural fractures can be identified into 3 systems, N-S, N45°W and N60°E. In experiment site, Paleozoic formation consists of medium-fine grained graywacke sandstone, slate, and their alternation. It is not associated with fracture and mineralization except for minor joint, calcite and quartz vein. Young andesite is, however, highly cracked and associated with iron oxide and its hydroxide.

In Yakedake Project, the following studies were carried out to obtain the basic information on fracturing and for fracture mapping; that are field hydraulic fracturing tests, acoustic emission observation, micro-seismicity observation and so on. The HDR experiment in low temperature and shallow sedimentary rock (about 70°C and 300m in well depth) finished with successful results in confirmation of passage between wells, and the development of high temperature logging tools and micro-seismic observation systems.

In U.S.A., basic R/D of HDR was launched at Fenton Hill, New Mexico by the Los Alamos National Laboratory in 1972. A joint research arrangement was set off under the IEA agreement in 1980 for USA and FRG, and later in February 1981 Japan joined the agreement through NEDO. This joint research Fenton Hill project (Phase 2) was the second one of NEDO's HDR from FY 1980 through September 1986. At the Fenton Hill Project, more than ten hydraulic fracturing experiments have been conducted to stimulate a HDR reservoir. Two hydraulic fracturing attempts, Exp.2059 and Exp.2082, established successfully a large fracture system
between two wells in July 1985. The desired flow connection paths from EE-3A well to EE-2 well were confirmed by a circulation test during April to June 1986. The purpose of Phase 2 is accomplished through clarification of a closed-loop flow test performance.

With the experience at Yakedake and progressing information of Fenton Hill project, NEDO made a new research plan to conduct experiments at higher temperature and in deeper rock. Several promising site were surveyed and finally Hijiori field in Yamagata Prefecture was chosen as a site for HDR experiments. This project had started in 1985. In 1986, an artificial reservoir was created by hydraulic fracturing, then in 1987, the new well HDR-1 was drilled to intersect this reservoir and in 1988 a circulation test was carried out between two wells, which continued for about 20 days producing hot steam and water from the production well.

HDR ENGINEERING IN HIJORI PROJECT

At Hijiori, two wells, SKG-1 and SKG-2, had been drilled with the aim of hydrothermal reservoir exploration by private company before 1984. However, promising hydrothermal reservoir had not be found even though the bottom hole temperature of SKG-2 well reached 253°C. Formation rock near the bottom was granodiorite and temperature profile of the well showed that heat conductive type geothermal resources might be existed. These are the reason that NEDO selected this well SKG-2 as the test well for HDR development.

The plan established at the beginning of the project was as follows:
(1) estimation of existing SKG-2 well condition
(2) reconstruction on SKG-2 for hydraulic fracturing
(3) creation of monitoring system to detect micro-seismic emission during fracturing
(4) development of instruments available under condition at bottom hole of SKG-2
(5) drilling of new well to intersect fractures created by the hydraulic fracturing
(6) practice on a short term circulation test to estimate reservoir characteristics

(a) Geology
Hijiori is situated in a young caldera which belongs to the inner arc of north-east Japanese islands, "Green Tuff Region", which is a term characterized by the active submarine volcanism in Neogene Tertiary. HDR site is located on the south edge of the caldera that is inferred to be formed about 9,000 years ago and approximately 3 Km in diameter.

The wells of HDR project penetrate to a basement rock, granodiorite, at about 1,500m depth from the surface. It underlies recent pyroclastic rocks and Green Tuff formation. Although SKG-1 well located about 650m north from the HDR site and some wells in the caldera were drilled over 1,800m, they could not reach the basement rock, but still stayed in the lower Miocene members. It reveals that HDR site seems to be in the caldera in topography, but outside of on the one of the steps of its rim.

The basement rock, granodiorite, consists of quartz, plagioclase, K-feldspar, biotite and hornblende as primary minerals and chlorite, epidote and calcite as secondary minerals. Although the thermal gradient measured in the wells are high enough to crystallize such secondary minerals, alteration are considered to take place repeatedly from Miocene.

Isotopic age determination on the same types of granodiorite around Hijiori area indicate from the late Cretaceous to Early Paleogene age. Since the dating on HDR specimen is not supposed to trusted because of its complex thermal history, these data may be supported to imagine a epoch of intrusion of plutonic rocks.

b) Drilling and coring of HDR-1 well

Based on the fracture mapping results, HDR-1 well was drilled in 1987 at the south of SKG-2 well site to confirm the artificial fractured reservoir created by the hydraulic fracturing in 1986. The directional drilling was started with a cylindrical in-situ target having a radius of 15m and centering on a location 30m south of SKG-2. Well trajectory orientation was corrected with a downhole motor (NAVI Drill) of the tip driving type, and the correction was started at a depth of 400m. The downhole motor was subsequently used several times by single shot to vary the orientation and
inclination of the well and correct the trajectory. In the bottomhole interval, the downhole motor was used between depths of 1698m and 1707m, and between 1725m and 1734m. HDR-1 was completely drilled according to the well plan, but its trajectory was complicated in well completion engineering.

The 95/8" casing was installed in HDR-1 from the surface to a depth of 1500m, and below this level to the bottom 81/2" borehole was left open. A depth 1500m means penetration into granodiorite as deep as about 50m. At that point, the main issue was what would be the most suitable cementing method for the 95/8" casing to make cement sufficiently withstand high loads during a hydraulic fracturing operation. The single stage cementing was adopted, and the inner string method was used in HDR-1. After cementing, cement bond logging was run. It was found that the cement had been placed over about 800m interval with the head depth of about 700m. In the 1988 hydraulic stimulation test, a trouble of water boiling in uncemented annulus came into question. The first discussion was whether the cementing should be of a single stage process or double stage process. The double stage cementing is more likely to bring up the level of the liquid cement close to the ground surface. However, the double stage cementing will leave some suspicious after the cementing, such as, whether seals of casing pipes can withstand hydraulic fracturing, and whether a cement gap might be formed between the first and second stage cement blocks.

After the short term circulation test in 1988, HDR-1 well was drilled deeper again to a depth of 2200m and a polished borehole receptacle was tried to inset in the well for a hydraulic fracturing that will be conducted at interval between 2150m and 2200m of the well.

During the drilling of HDR-1 in granodiorite base rock, several ordinary (non-oriented) and oriented corings were conducted to investigate thermal conductance, permeability and other physical properties of rocks. In particular, if the orientation of the cores are identified, the magnitude and direction of main stress will be obtained by the differential stress curve analysis (DSCA) method. DSCA will be a relatively novel technique, used by the Los Alamos National Laboratory in U.S.A. for calculating the direction and level of main earth stress from cores obtained on EE-3A well. For this reason, the oriented corings were tried in
the HDR-1 well, using Hycalog and Diamond Boart Strabit tools. The first oriented coring ranged from a depth of 1643m to 1644.9m, the second one from 2140m to 2141m, the third one from 2180m to 2181m and the fourth one from 2204m to 2205m. The bit used for the first oriented coring was NL-Hycalog CH-20, having an outer diameter of 8\(\frac{15}{32}\)" and inner diameter of 3\(\frac{1}{2}\)", with a 1/7 carat diamond inserted in the matrix. When a core barrel was recovered after drilling down about 1.7m from a depth of 1643m, only a core of 0.7m was recovered, and the bit including its matrix was found completely worn out. After the start of coring, the electronic survey instrument (ESI) that detects orientation functioned normally till about 20 minutes later, when ESI was damaged by increased violent vibration of the drilling pipe. Scribing knife was found slipped off, and the recovered core had entirely no notch. Although oriented cores were obtained by the second through fourth corings, something was poor with these coring efficiency, because of the damage of the core catcher by inner barrel rotation.

C) Instrument development

The new triaxial geophone double sonde system was developed and prepared in order to detect the fractures in the lower reservoir after completion of the additional drilling of HDR-1. This system is to constitute a downhole seismic survey network to record AE signals by a set of four downhole stations with triaxial geophone and hydrophone tools.

The system consists of the following:

1. the main sonde containing both a geophone that measures three components of coordinates and a steering unit
2. the subsonde containing a geophone that measures both the up and down components
3. a 250m-long intermediary calbe that connects these two sondes

The maximum resistance limit in pressure is 350Kg/cm\(^2\), and that in temperature is 260°C (for 8 hours). The performance test results of this system show the followings:

1. The conventional fixed-arm driving mechanism with open spring was replaced by a hydraulically driven arm mechanism having a high-temperature hydraulic motor that withstands 260°C, so that the force of the sonde arms to press the sonde on well wall may be strengthened, and removing and
refixing operation may be simplified. Upper and lower fixing arms are now provided around the main sonde to secure tighter contact with well wall.

(2) Geophone sensors are Mark Products high-temperature geophone. In the main sonde, four geophone sensors are installed in series for each three components of the coordinates, and in subsonde eight sensors are provided in series.

(3) The electric section being protected by a heat-insulated chamber and a heat sink has demonstrated its continuous operation of at least eight hours in laboratory test in an environmental temperature of 250°C.

(4) The system has been verified in the field tests at Hijiori that it satisfies the required design specification in heat-resistance, pressure-resistance, the signal-receiving capacity of the geophone sensors, and overall operation performance.

d) Confirmation of fractures between two wells

A circulation system has been made between SKG-2 well and HDR-1 well even if details of fractures has not been cleared. In this section, NEDO try to pigeonhole data which concern fractures information given through several logging, injection and circulation tests.

Series of hydraulic operation in two wells are as follows;
(1) injection test of SKG-2 well to clarify feed points of open hole section of the well (1985)
(2) hydraulic fracturing of SKG-2 well (1986)
(3) drilling of the HDR-1 well to investigate fractures created by hydraulic fracturing conducted 1986 (1987)
(4) communication test between 2 wells (1987)
(5) pressurizing test of reservoir from SKG-2 well (1988)
(6) circulation test between two wells (1988)

FY 1986
(a) Spinner survey during the injection test conducted prior to the hydraulic fracturing of SKG-2, indicated that almost all of injected water was permeated into formation at depth of 1790m which result in existence of a natural fracture at this depth.
(b) Although the numbers of seismic event were about 30 to 40 for two system (the surface networks and the triaxial geophone), it might be evident that the fracture mainly extended upward from the injection point of SKG-2 well and
the direction was nearly SWE-NEN.

FY 1987
(a) By spinner survey during injection tests, 30% of injected water was penetrated into formation rock at 1789m in depth and other 70% of injected water was penetrated in a section of 1789-1800m of SKG-2 well. Borehole televiwer log showed that natural fracture intersected the well at 1789m and new longitudinal fracture was created whole along the open hole section of the SKG-2 well.
(b) While the HDR-1 well was drilled, the water level in SKG-2 well was monitored, which indicated that water level increased three times when the well depth were 1694m, 1760m and 1805m. The pressure response was thought to be delayed, but it became evident that some weak communication were existed between 2 wells.
(c) Depending on data of electrical log and sonic log, fractured zone and/or deteriorated zone were estimated at depth of 1715m, 1745m, 1785m and 1800m.
(d) Borehole televiwer log carried out after completion of HDR-1 well showed that there existed 14 main fractures which intersected the HDR-1 well and a long longitudinal fracture exposed along the wall between casing shoe(1507m) and about 1600m of which orientation was almost E-W.
(e) The communication test in SKG-2 injection well indicated that only 1% of injected water was produced from HDR-1 well. The temperature logging during its communication test made it clear that there were two temperature anomalies at 1743m and 1786m of HDR-1.

FY 1988
(a) The short term circulation experiment indicated that about 40% of injected water produced from HDR-1 well, and pressurizing test which injects about 2000m³ improved the impedance of fractures between two wells.
(b) PTS log during a circulation test clarified that there were 6 temperature anomalies at 1530m, 1626m, 1742m, 1761m, 1788m and 1800m. Feed ratio of production water volume along the open hole section of HDR-1 were 15% at 1530m, 30% in span between 1530m and 1788m, 55% from 1788m to 1800m.
(c) Temperature anomalies detected by PTS log correlate well to the depth where natural fractures are founded by BHTV log along the HDR-1 well.
(d) Resistivity tomography between two wells showed that 2 and/or 4 paths.
(e) Electrical logging with ultra-long spacing in HDR-1 well
indicates that fractured zones were qualitatively detected in depth of 1710m-1740m.
(f) Microseismic events occurred during the pressurizing experiment were located along direction of ENE-WSW from the injection point of SKG-2 well. A volumetric fracture was estimated which was almost vertical.

FUTURE TREND AND CONCLUDING REMARK

NEDO's future study tasks in HDR engineering may be summarized as follows;
(1) development and/or practical use of resistivity, electrical logging with ultra-long spacing, borehole radar, and other fracture evaluation techniques.
(2) detailed studies on the basis of earth stress, that is measurement of magnitude and direction of main stress in oriented cores.
(3) drilling of new well HDR-2 and hydraulic fracturing at about 2200m of HDR-1 well.
(4) research and development of a long term circulation test.
(5) establishment of HDR dual extraction system ---- for example, upper fractured reservoir at a depth of 1800m between SKG-2 and HDR-1, and lower one at about 2200m depth between HDR-1 and new HDR-2 well.

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6) Sunshine Project Promotion Headquarters
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HEAT EXTRACTION FROM LOW-TEMPERATURE FRACTURED PETROTHERMAL RESOURCES

Yuri D. Dyadkin
Heat-Physics Dept
Leningrad Mining Institute
Leningrad, USSR

Paul Kruger
Stanford Geothermal Program
Stanford University
Stanford, CA USA

ABSTRACT

A research program is underway in the Soviet Union to develop technology for economic heat extraction from low-temperature geothermal resources located throughout the USSR. The first artificial circulation system for geothermal energy extraction in the Soviet Union is underway in the Russkie Komarovtsy area of the Zarkapate region in the Ukrainian SSR. The experimental system will consist of an injection-production well module with three vertical hydrofractures creating flowpaths in the interval between depths of 1900 and 2700 m. The formation consists primarily of a granodiorite intrusion at a mean temperature of 124 °C. The experiment is designed to produce thermal water at a constant flowrate of 96 md/hr to an abandonment temperature of 110 °C. At an estimated thermal extraction rate of 40 GJ/hr, the resource is expected to have a useful lifetime of about 10 years. The investment in this type of module is estimated as 2.4 million rubles, providing a hot water resource at a mean cost of 1.87 ruble/GJ. The success of this experiment should provide reliable data for development of low-temperature geothermal resources in other regions of the Soviet Union. Comparison of heat extraction from the Russkie Komarovtsy field is made with the Cholpon-Ata field in Kirgizia.

INTRODUCTION

Research is underway in the Soviet Union to accelerate development of alternate energy resources for electric power generation and district heating, especially in remote areas. One of the more promising sources is the indigenous heat contained in the earth's crust. Geothermal energy has been under investigation for many years, but early estimates of geothermal resources in the Soviet Union were not encouraging. For example, Mavritsky and Shpak (1985) published a description of the thermal water resources in the USSR. They estimated the total hydrothermal resource extractable from about 10 major regions of the Soviet Union for thermal waters to a depth of 3500 m and at temperatures above 50 °C as about 20 million Gcal/yr for artesian flow and about 88 million Gcal/yr for pumped-well exploitation. They estimated these resources would provide a savings in fossil-fuel consumption of about 12.5 million tons/yr for district heating. In the eastern regions of the Soviet Union they estimated that the steam reserves in areas of recent volcanism could provide generating capacity of about 1000 MWe. Tikhonov. et al (1986) noted that utilization of geothermal resources in the USSR was comparatively small.
It was noted by Ramey, Kruger, and Raghavan (1973) that the major fraction of heat is contained in the rock massive of geothermal deposits rather than in the interstitial fluid. Studies have been underway since 1962 to evaluate methods for heat extraction from such rock massives. The first evaluation of petrothermal resources in the USSR from studies at the Kiev Institute of Technical Thermophysics, the Leningrad Mining Institute, and other Soviet research institutes was published in the Proceedings of the Soviet-American Scientific Seminar (1978) based on the heat extraction model of Boguslavsky (1984). In contrast to the small value of estimated hydrothermal resources, the extractable heat from petrothermal deposits suitable for district heating at a temperature greater than 100°C was reported by Dyadkin (1985) as $30 \times 10^{12}$ tons of standard fuel with heat content of 30 GJ/ton. Thus, this large potential resource of petrothermal deposits in the Soviet Union is of interest for future energy resource development. A description of potential petrothermal resources evaluated as a function of type of extraction technology was published by Dyadkin (1987). These included artesian flow from hydrothermal resources and both artesian flow with reinjection recharge and artificial circulation systems for petrothermal resources. The data showed that the use of artificial circulation systems, in contrast to the earlier estimates for hydrothermal and petrothermal artesian flow even with reinjection heat sweep, markedly increases the potential resources to an economic quantity. The analysis by Dyadkin (1987) indicated that with artificial circulation systems in hydrofractured resources, the potential for space heating was a saving of 28 rubles per ton compared to the combustion of fossil fuel. A study was made of five promising sites from among an initial list of sixteen as candidate petrothermal deposits for experimental investigation of the technology to produce hot water for municipal heating systems with hydrofractured reservoirs and artificial circulation systems. Table 1 summarizes the results of this study based on a single extraction module consisting of a production-injection well pair with permeable fracture volume and heat transfer surface area created by three hydrofractures.

This report extends the study with further description of the two most promising sites selected for experimental technical and economic analysis. The two sites are the Russkie Komarovtsy field in the Zakarpate region of the Ukraine SSR near the city of Uzhgorod and the Cholpon-Ata field in the Issik-Kul region of the Kirgizia SSR. The first artificial circulation system will be constructed at Russkie Komarovtsy. A comparison of the fields is given for the heat extraction model developed at the Leningrad Mining Institute. It is expected that the results from the Russkie Komarovtsy experimental program will provide technical and economic data useful for evaluating the potential for economic heat extraction from other low-temperature petrothermal resources in many regions of the Soviet Union.

CIRCULATION SYSTEM HEAT EXTRACTION MODEL

The calculation of thermal power, production lifetime, and economic return for a 'geothermal circulation system' (GCS) in a given location requires much input data, which are compiled after careful geographic, geologic, geothermal, and economic analysis for the given region. Dyadkin (1989) describes a model to estimate these factors for both electric power stations and direct use of thermal power. Figure 1 shows a schematic diagram of a heat exchanger system to use the thermal power as a clean-
Table 1
Candidate Sites for the First Hydrofractured Geothermal Hot-Water Supply Experimental Facility*

<table>
<thead>
<tr>
<th>Candidate Site</th>
<th>Location</th>
<th>Open Casing Interval (m)</th>
<th>Rock Type</th>
<th>Rock Temp (°C)</th>
<th>Aband Temp (°C)</th>
<th>Flow Rate (m³/h)</th>
<th>Heat Rate (GJ/h)</th>
<th>Life Time (yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Russkie Zakarpate</td>
<td>Ukraine</td>
<td>1900-2700</td>
<td>grd</td>
<td>124</td>
<td>110</td>
<td>96</td>
<td>40</td>
<td>10</td>
</tr>
<tr>
<td>Komarovtsy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cholpon-Ata</td>
<td>Issik-Kul</td>
<td>1800-2800</td>
<td>grn</td>
<td>90</td>
<td>80</td>
<td>100</td>
<td>30</td>
<td>5</td>
</tr>
<tr>
<td>Kalinin-grad</td>
<td>Baltic Sea</td>
<td>2750-3800</td>
<td>cb</td>
<td>100</td>
<td>90</td>
<td>90</td>
<td>30</td>
<td>12</td>
</tr>
<tr>
<td>Razdan</td>
<td>Armenia</td>
<td>2000-3000</td>
<td>ic</td>
<td>168</td>
<td>130</td>
<td>75</td>
<td>40</td>
<td>18</td>
</tr>
<tr>
<td>Kirovabad</td>
<td>Azerbaijan</td>
<td>2200-3200</td>
<td>grd</td>
<td>90</td>
<td>80</td>
<td>75</td>
<td>20</td>
<td>17</td>
</tr>
</tbody>
</table>

*from Dyadkin (1987), after initial evaluation of 16 sites in 1986.
** grd = granodiorite, grn = granite, cb = crystal basement, ic = intrusive complex

Water municipal heat supply with an auxiliary fossil-fuel source to maintain constant water-supply temperature. The parameters used in the GCS technical analysis include:
- Mean depth to hydrofracture zone
- Well diameter in zone
- Fluid flowrate
- Initial rock massive temperature
- Abandonment temperature for hot-water supply
- Temperature augmentation by fossil-fuel combustion
- Number of hydrofractures (or crushed zones)
- Equivalent radius of each fracture (or zone)
- Temperature drop across heat exchanger
- Length of surface piping to energy use site
- Diameter of surface piping
- Thickness of surface piping insulation
- Length of return flow piping
- Diameter of return flow piping
- Temperature of return flow water.

For the given characteristics of the rock block massive and the selected surface facilities, the important GCS operating parameters include:
- Thermal power produced per well-pair module
- Number of modules needed for given utilization
- Thermal power needed for temperature augmentation
- Number of blocks and sections between heat exchanger
- Water pressure losses due to drop across heat exchanger
- Injection pump
Figure 1. Schematic plan for geothermal circulation system for clean hot-water supply at constant temperature.

production well
main zone of hydrofractures
non-Darcy turbulent zone near wellbore
from total head needed for main circulation pumps
power needed for electric motor drive.

For the economic analysis of the GCS, costs are classified into capital and operating and maintenance costs. The capital costs include: drilling and well completion
hydrofracturing
pumps and installation
heat exchanger for clean hot-water supply
hot and cold water surface piping and insulation
maintenance and cleaning building
auxiliary fuel installation.

The annualized operating costs and income recovery include:
price of heat charged to consumers
geothermal heat production
cost of supplementary fossil fuel
consumption of electric power
water and materials
care of service personnel
amortization of capital
services, maintenance, and repairs

The main economic index is the reduction in cost per unit of heat production (in rubles/GJ) based on the production cost per joule of useful geothermal energy compared to alternate energy sources at the effective rate of return for capital investment (12% per year).

The calculations of hydrodynamic and heat exchange processes are carried out with the methods of Dyadkin and Gendler (1985) derived from numerical computer models and experiments in the LMI granite polygon. These calculations provided the values for pump pressure, hot-water temperature at the GCS outlet and heat exchanger as a function of production time. The total GCS service period is estimated based on maintaining constant hot-water temperature by makeup of thermal decline with augmented heat until the process is no longer profitable.

The economic indices of total capital cost, total annual expenses, unit cost of geothermal heat, and cost savings are calculated with standard Soviet prices and empirical relationships obtained from statistical analysis of actual costs for drilling wells, hydrofracturing, construction of turboconductors, and other heavy equipment.
The economic-mathematical model, developed at LMI as a computer program to optimize the many listed GCS parameters (Boguslavsky, 1984) can be used to select the final input conditions, constrained to the best combination which provides the best assurance for secure minimal level cost.

LMI METHOD FOR ESTIMATING HYDROFRACTURE PARAMETERS

The most difficult aspect in creating a hydrofractured petrothermal reservoir in hard-rock formations with specified dimensions of fractured or crushed zones is the design of fluid (hydro) pumping pressure at a given pumping rate, the overall volume of filtration flow, and the total pumping time. At LMI, a model for hydrofracturing is under development (Dyadkin, 1985, 1988, 1989) for homogeneous rock masses possessing characteristic modular structure and a minimum of two mutual secant systems of contact joints, definite permeability, and low resistance to external loading. Under these conditions, the coefficient of structural weakness depends essentially on the orientation of the contact joints with respect to the direction of strain propagation or deformation shear. The undisturbed stress field is viewed as gravity-tectonic, while the hydrofracturing problem is hydromechanical. The model takes into account and calculates the filtration flow from the well open interval into the surrounding formation and the time needed for water injection, the radius of the filtration zone before initiation of hydrofracture, unloading (from compressive stress) effect, length of the forward growth of fracture by the infiltrating wedge, length of the zone of extended tension in front of the crack apex, the intensity dependence on liquid flowrate, its viscosity and matrix permeability, as well as the size of the growing fracture, caused by distribution of hydraulic pressure over its area.

In the calculation of change in hydraulic pressure by its filtration into the propagating hydrofracture, the turbulent flow and head drop near the wellbore are taken into account, as well as the very significant increase in water pressure due to heat transfer from the hot rock. As a condition of rock crushing at the peak of fracturing, the model uses the well-known energy criteria of Griffiths, for which at small depth or for very monolithic rock, the measure of its resistance to rupture is heard at the limit of ultimate strength on uniaxle tension, and at great depth or in weakened blocks, its degradation under compression in various directions is accounted for by the size of the deformation pattern.

Three possible cases of hydrofracture development are considered:

a) vertical fractures over the matrix structure of the block (working against the minimum compressive strength)

b) fractures separated by contact with the structure of the block (working against the minimum resistance to reduced contact strength)

c) shear fracture of adjacent blocks in planes of contact (development of deformation on incomplete unloading of compressive strength).

The most probable case is realized by minimum hydraulic pressure at peak fracturing by the principle of minimum energy expense. Depending on existing conditions, it would be one of the above three cases. The method will be confirmed in the forthcoming experimental GCS.
## Table 2
Input Data for Calculating Hydrofractures in Rock Massives at the Two Experimental Sites

<table>
<thead>
<tr>
<th>Experimental Site</th>
<th>Komarovtsy Ata</th>
<th>Russkie Zakarpate Issic-Kul Kirgizia</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Description</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Type of rock formation for reservoir</td>
<td>Horizontal intrusion into sandstone-clay</td>
<td>Basement massive under sediments</td>
</tr>
<tr>
<td>Reservoir rock type</td>
<td>Granodiorite</td>
<td>Granite</td>
</tr>
<tr>
<td>Formation thickness, m</td>
<td>740</td>
<td>1800</td>
</tr>
<tr>
<td>Mean depth at horizon, m</td>
<td>2240</td>
<td>2400</td>
</tr>
<tr>
<td>Rock permeability, m²</td>
<td>150x10⁻¹²</td>
<td>500x10⁻¹²</td>
</tr>
<tr>
<td>Rock temperature, °C</td>
<td>124</td>
<td>91</td>
</tr>
<tr>
<td>Azimuth angle/contact fracture slope of block structure</td>
<td></td>
<td></td>
</tr>
<tr>
<td>main system, °</td>
<td>0 / 75</td>
<td>10 / 80</td>
</tr>
<tr>
<td>secant system, °</td>
<td>70 / 75</td>
<td>90 / 80</td>
</tr>
<tr>
<td>Total rock pressure, MPa</td>
<td>58.2</td>
<td>61.9</td>
</tr>
<tr>
<td>Joint pressure, MPa</td>
<td>18.27</td>
<td>23.38</td>
</tr>
<tr>
<td>Normal tensor component gravity-tectonic stress and orientation, MPa / dir</td>
<td></td>
<td></td>
</tr>
<tr>
<td>maximum</td>
<td>36.3 / vert</td>
<td>57.6 / horiz</td>
</tr>
<tr>
<td>minimum</td>
<td>9.6 / horiz</td>
<td>14.2 / horiz</td>
</tr>
<tr>
<td>Size of unit structural block length x width, m</td>
<td>0.2 x 0.2</td>
<td>0.05 x 0.1</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>0.01</td>
<td>0.019</td>
</tr>
<tr>
<td>Rock density, kg/m³</td>
<td>2650</td>
<td>2630</td>
</tr>
<tr>
<td>Young's modulus, Pa</td>
<td>4x10¹⁰</td>
<td>1.7x10¹⁰</td>
</tr>
<tr>
<td>Poisson ratio</td>
<td>0.2</td>
<td>0.27</td>
</tr>
<tr>
<td>Compressive strength, MPa</td>
<td>120</td>
<td>150</td>
</tr>
<tr>
<td>Tensile strength, pre-frac, MPa</td>
<td>10</td>
<td>3.7</td>
</tr>
<tr>
<td>Joint shear strength, MPa</td>
<td>5</td>
<td>3</td>
</tr>
<tr>
<td>Coefficient of structural weakness, of block fracture</td>
<td>0.3</td>
<td>0.5</td>
</tr>
<tr>
<td>block shear</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>contact shear</td>
<td>0.3</td>
<td>0.2</td>
</tr>
<tr>
<td>Coefficient of friction on contact shear of main system</td>
<td>0.4</td>
<td>0.3</td>
</tr>
</tbody>
</table>

Calculation of the economic aspects of the experimental GCS shows considerably favorable indices: unit heat cost of 1.9 ruble/GJ heat produced vs 3.9 ruble/GJ for fuel boilers prevalent in this region. Furthermore, accounting for associated costs (roads, transmission lines, and water supply) as well as significant expenses for the experiment itself, the total cost of the project is budgeted for about 6 million rubles. The planned construction of hothouse-hotbed combines in connection with the GCS for using the heat produced allows not only rapid payback of the budgeted expenses, but also provides a profit of about 10 million rubles over the calculated service period.
CALCULATIONS FOR THE FIRST EXPERIMENTAL GCS

During 1988-89, LMI (together with the All-Union Scientific Research Institute for Geothermics (in Makhachkala) is preparing, for the first two experimental sites listed in Table 1, a detailed plan for the experimental project based on the detailed study of the site representative geologic materials of geophysical investigations and drilling of exploratory wells. From these two studies, the necessary input data, shown in Table 2, were compiled. The resulting calculated parameters for the rock hydrofracturing obtained with the LMI modular given in Table 3. A comparison of the calculated data for the two experimental GCS sites with the data from several prior experiments in other countries is given in Table 4. The data show a reasonable agreement between the data observed elsewhere and those calculated for the two low-temperature Soviet sites.

As noted, the first experimental site is the Russkie Komarovtsy field, located in the Zakarpate region of the Ukraine near the town of Uzhgorod. The GCS artificial reservoir will be created in a massive of granodiorite, situated almost horizontally in a young intrusive of 740 m thickness, integrated into a thick sedimentary layer of rock terrain. The top of the intrusive body is at depth of 1900 m and the bottom (2644 m) is underlain by ductile argillites. It is expected that the orientation of the hydrofractures will be vertical to the intrusive boundaries without 'interaction' with the sedimentary rock. However, creating the first GCS module as a pair of wells in the sloped lower interval, intersecting a set of vertical fractures is deemed non-expedient because of the insufficient thickness of the granodiorite layer, even though that scheme has already been demonstrated in other experiments (Garnish, 1987).

For Russkie Komarovtsy and regions with similar local conditions, a new scheme, illustrated in Figure 2, is proposed. A vertical well is drilled through the whole thickness of the intrusion. On hydrofracturing along the axis of the open interval, it is expected that a vertical fracture with wings of 500 m width on each side and height of 740 m will be produced. Then one of the fracture wings is intersected by a vertically inclined well drilled through the fracture wing to the bottom of the intrusion. After initiating circulation, a second well is drilled parallel to the first (about 75 m) and then a third vertical well. From these two additional wells, parallel vertical fractures are created with dimensions of 1000 x 740 m, each intersecting along the lower flank of the vertically inclined well. After demonstrating the 'single-wing' GCS with the three parallel fractures, a second vertically inclined well is drilled on the other wing, which intersects the three vertical fractures on that wing. By this construction method, the overall water flowrate in the experimental GCS will be increased to 300-360 m³/hr, and the thermal power output to 110 GJ/hr (30 MWth).

The proposed scheme, under GCS conditions analogous to Russkie Komarovtsy, has a number of advantages:

a) it sharply facilitates establishing an azimuth of vertical fracture for reliable selection of well spacing of the circulation pattern
b) it avoids turbulent flow and steep pressure drop at the 'axial crack' fractures at the well bottom
c) on changes of filtration location in injection or production wells, it allows control of thermal power and water temperature on changes in consumer heat demand, resulting in optimum reservoir exploitation.
### Table 3
Calculated Parameters of Hydrofracturing to Create Experimental Circulating Systems

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Experimental Facility Site</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Russkie Komarovtsy</td>
<td>Cholpon-Ata</td>
</tr>
<tr>
<td>Mean hydrofracture depth, m</td>
<td>2240</td>
<td>2400</td>
</tr>
<tr>
<td>Open-casing interval, m</td>
<td>100</td>
<td>30</td>
</tr>
<tr>
<td>Uncased well diameter, m</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Hydraulic pumping rate, m^3/s</td>
<td>0.022</td>
<td>0.044</td>
</tr>
<tr>
<td>Initiating hydraulic pressure at interval, MPa</td>
<td>43.8</td>
<td>53.1</td>
</tr>
<tr>
<td>after pump unit, MPa</td>
<td>21.8</td>
<td>29.6</td>
</tr>
<tr>
<td>Filtration radius around well before frac initiation, m</td>
<td>0.105</td>
<td>0.113</td>
</tr>
<tr>
<td>Hydraulic pressure (MPa) at end of frac required for next frac jump, in form of:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>vertical frac across block</td>
<td>34.2</td>
<td>38.9</td>
</tr>
<tr>
<td>fracture in tensile plane</td>
<td>41.4</td>
<td>54.4</td>
</tr>
<tr>
<td>shear frac in contact plane</td>
<td>95.4</td>
<td>30.3</td>
</tr>
<tr>
<td>Probable type of fracture</td>
<td>vertical,</td>
<td>vertical zone,</td>
</tr>
<tr>
<td>secant to sheared joints</td>
<td>intrusive</td>
<td>intrusive</td>
</tr>
<tr>
<td>Mean radius of frac zone, m</td>
<td>500</td>
<td>300</td>
</tr>
<tr>
<td>Hydraulic pressure change during filtration in frac zone, MPa</td>
<td>7.28</td>
<td>4.02</td>
</tr>
<tr>
<td>including:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>near-well turbulent flow</td>
<td>0.19</td>
<td>0.12</td>
</tr>
<tr>
<td>main zone of laminar flow</td>
<td>16.24</td>
<td>9.94</td>
</tr>
<tr>
<td>gain from heat transfer</td>
<td>9.31</td>
<td>6.04</td>
</tr>
<tr>
<td>Hydraulic pressure after pump unit for completed fracture, MPa</td>
<td>19.54</td>
<td>10.8</td>
</tr>
<tr>
<td>Pumping duration, hours</td>
<td>6.3</td>
<td>16.8</td>
</tr>
<tr>
<td>Pumped water volume for three fractures in reservoir, m^3</td>
<td>3505</td>
<td>4002</td>
</tr>
</tbody>
</table>

It is noted that in spite of the very profitable geothermal conditions, preliminary calculations do not show an economic benefit for creating condition for a future geothermal electric power plant by deepening the artificial reservoir to depth of rock temperatures of 200-220 °C. The value of the generated electricity is indicated to be not less than 4-6 kopek/kWh, which is considerably more expensive than obtained from fossil fuel.

In addition to the sites listed in Table 1, other perspective regions for constructing a GCS are being evaluated by LMI with other institutes with the rational of using circulation systems to open up resources recently discovered in the Baltic geothermal anomaly, in the health-resort region of Lithuania, and in the Caucasus, near Elbrus for a heat supply to be used in the Tmimiauskus tungsten-molybdenum combine, where exploratory wells at depth of 3.4 km disclosed granodiorite at.
<table>
<thead>
<tr>
<th>Location, Group, Site, Year</th>
<th>Working Depth (m)</th>
<th>Type of Rock</th>
<th>Rock Temp (°C)</th>
<th>Pumping Rate (1/s)</th>
<th>Press (MPa)</th>
<th>Type of Fracture</th>
<th>Size of Fracture Zone (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA, LANL Fenton Hill 1975</td>
<td>2928</td>
<td>grano-diorite</td>
<td>197</td>
<td>20</td>
<td>12.5</td>
<td>single</td>
<td>240</td>
</tr>
<tr>
<td>same</td>
<td>2758</td>
<td></td>
<td>185</td>
<td>20</td>
<td>12.3</td>
<td></td>
<td>140x60</td>
</tr>
<tr>
<td>USA, LANL Baca, 1981</td>
<td>1500</td>
<td>tuff</td>
<td>315</td>
<td>25</td>
<td></td>
<td></td>
<td>600x500</td>
</tr>
<tr>
<td>USA, LANL Fenton Hill 1975</td>
<td>3960</td>
<td>grano-diorite</td>
<td>320</td>
<td>111</td>
<td>55</td>
<td>50 zone displac</td>
<td>1050x150</td>
</tr>
<tr>
<td>UK, GSN Rosemanoees 1986</td>
<td>2800</td>
<td>granite</td>
<td>91</td>
<td>260</td>
<td>11</td>
<td>vertical zone</td>
<td>2500x</td>
</tr>
<tr>
<td>Japan, NEDO Yakedake, 1980</td>
<td>200</td>
<td>sandstone</td>
<td>22</td>
<td>200</td>
<td>27</td>
<td>single frac, 62</td>
<td>150</td>
</tr>
<tr>
<td>Japan, NEDO Hijiiori, 1986</td>
<td>1802</td>
<td>grano-diorite</td>
<td>253</td>
<td>100</td>
<td>15.6</td>
<td>vertical system</td>
<td>200x100</td>
</tr>
<tr>
<td>France, ITR M.deMont, 1981</td>
<td>840</td>
<td>granite</td>
<td>30</td>
<td>15</td>
<td>30</td>
<td>horiz fracture</td>
<td>200x100</td>
</tr>
<tr>
<td>Bavaria, W.Ger. Falkenberg, 1985</td>
<td>255</td>
<td>granite</td>
<td>23</td>
<td>100</td>
<td>30</td>
<td>vertical plane</td>
<td>250x50</td>
</tr>
<tr>
<td>USSR, LMI Expt. Kolima 1981-83</td>
<td>7-15</td>
<td>frozen sand/gravel</td>
<td>10+</td>
<td>1-2</td>
<td>0.5-10</td>
<td>single horizon</td>
<td>10-15</td>
</tr>
<tr>
<td>USSR, LMI Erkiliya 1983</td>
<td>20</td>
<td>granite</td>
<td>7</td>
<td>1-3</td>
<td>22</td>
<td>single horizon</td>
<td>7x15</td>
</tr>
</tbody>
</table>

**CALCULATED BY LMI MODEL:**

| USSR, LMI Russkie Komarovtsy | 2240 | grano-diorite | 124 | 22 | 19.5 | 3-single vertical fractures | 740x          |
| USSR, LMI Cholpon-Ata        | 2400 | granite      | 91  | 44 | 10.8 | 3-vertical zones of crushed blocks | 800x          | 400x 50 |
temperatures greater than 185-190 °C. Following the recent catastrophic earthquake in Armenia, efforts are underway to evaluate the potential for an artificial GCS based on recent observations of high-temperature rock in this Republic.

It is emphasized that in all of these low-temperature petrothermal regions, it is assumed that geothermal energy extraction is for heat supply. LMI is also working on the development of new methods for subsurface energy extraction, including cascading GCS, magma energy (e.g., at the Mutnovsky Volcano area of Kamchatka, and on a combined geothermal-coal technology with in-situ combustion of fractured seams to intensify geothermal steam temperature to high levels, which could result in effective development of geothermally generated electricity. These new technologies would accelerate the utilization of geothermal resources in the Soviet Union.
CONCLUSION

Despite the fact that the Soviet Union is endowed with very few high-temperature hydrothermal resources, considerable efforts are underway to maximize the utilization of its many low-temperature petrothermal resources. LMI, together with several other research institutes, is working to provide economic technology for extracting commercial quantities of heat for municipal heating systems and industrial use and for generating electric power. Long-term research is underway to understand and use hydrofracturing technology to create pre-designed artificial reservoirs with controlled circulation systems. Two experimental sites have been chosen for GCS demonstration. Plans are to initiate construction of the first GCS at Russkie Komarovtsy in 1989-90 for creating a large-volume artificial reservoir. Design of the second experiment at Cholpon-Ata is underway. Several other sites are being evaluated. More advanced technologies are being investigated, including magma resources and combined geothermal-coal thermal energy extraction.

Acknowledgment

The authors wish to acknowledge Novosibirsk University for providing the opportunity for Prof. P. Kruger to participate in the LMI geothermal program under the Novosibirsk–Stanford Agreement for Academic Exchanges.

REFERENCES

1. INTRODUCTION

The extraction of heat from rock masses at high temperatures has so far been obtained by production of hot waters present underground in natural hydrothermal systems. The number and size of such systems is however limited, and thus it is necessary to look at the possibility of increasing recovery of the heat reserves contained in the earth's crust. The main possibility is the development of HDR projects.

Research and experimentation in this direction is in an advanced stage of development in various countries around the world and has led to significantly increased knowledge in this field. While many interesting results have been achieved and several important R&D activities are still being carried out or are in program, it is recognized that HDR systems tapping very high temperature rocks (above 250°C) at moderate depth have a stronger chance of being economic.

Italy is among the countries where these conditions are present and where testing is planned.

2. THE ITALIAN GEOTHERMAL SITUATION

Italy is at the center of the Mediterranean sea, an area of intense geodynamic activity and high seismicity in rapid geological evolution, corresponding to the collision belt between the African and Eurasiotic plates.

The structural setting of the Mediterranean area is very complicated; it is subdivided in a number of "microplates" some of which are under compression, other under distension and other still under rotation.

The most evident results of these geodynamic processes are the

(1), ENEL; (2) AGIP
orogenic Alpine and Appennine mountain belts, as well as the opening of the Tyrrenhian basin and consequent crustal thinning of the area, with concurrent upsurge of mantle rocks.

Such features characterize especially the Preappenninic Tyrrenhian belt. This area, in the last 5 million years, was the seat of important tensional tectonic movements (with the formation of graben and rifts) and of intense magmatic activity, caused by the above phenomena and evidenced by intrusions of predominantly acid type (Tuscany) and by several effusive episodes, mainly of alcaline-potassic type (Latium, Campania).

These phenomena are the cause of the large heat anomalies typical of the pre-Appenninic tectonic belt with values sometimes exceeding tenfold the average terrestrial heat flow (Fig. 1).

From the geothermal point of view, Italy can thus be divided in two main areas:
- the western (Tyrrenhian) hot area
- the eastern (Adriatic) cold belt.

All the high temperature geothermal fields are located in the Tyrrenhian side and are used for electricity production, the present installed capacity being 548 MW, most of which in the Larderello field.

Exploration for geothermal resources in the Tyrrenhian belt has evidenced the existence of three very important thermally anomalous zones: one in Tuscany and Latium, extending to Rome and somewhat southwards, for an area of over 10,000 km²; another centered North and West of Naples (with an area of 500 km²); a third one in the Eolian islands.

Drilling in these areas has evidenced hydrothermal systems of limited extent and very high temperature bordered by large areas of impermeable rocks with quite high temperatures starting at depth of about 2000 m.

While heat extraction from hydrothermal systems can be easily undertaken, the only possibility to recover heat contained in the high temperature impermeable formations bordering the existing hydrothermal fields is to develop HDR systems.

3. ITALIAN EXPERIENCE RELATED TO AN HDR PROJECT

Even if Italy has not carried out any HDR experiments, AGIP (the national oil company) and ENEL (the national utility) have
FIG. 1 - HEAT FLOW MAP OF ITALY AND GEOTHERMAL FIELDS

HEAT FLOW ANOMALY
( greater than 150 mW/m² )

* GEOTHERMAL FIELD

(From EC "ATLAS OF GEOTHERMAL RESOURCES IN THE EC, AUSTRIA AND SWITZERLAND", 1988).
performed laboratory core testing for planning hydraulic fracturing of limestone and volcanic rocks; the tests were conducted in very high temperature and pressure conditions.

Fracturing and stimulation operations in hot tight wells within some geothermal fields, for the purpose of creating or improving permeability, have been carried out and drilling in extremely hot environment (over 300°C) and logging in very severe temperature conditions were successfully undertaken.

Numerical models have been developed by ENEL which can simulate tensional and deformational state consequent to cooling of a fracture by cold water injection in hydraulic fracturing conditions. AGIP on the other hand uses MINIFRAC model analysis in oil fields for estimating the amount of fluid loss to the reservoir under fracture in the steady state regime, which could be applied to HDR stimulation.

Substantial experience was also developed in the field of seismic monitoring of fracture growth during injection operations. Triaxial geophones are used by AGIP in wells for underground gas storage and water reinjection monitoring in oil fields.

ENEL, in the framework of an agreement with DOE, has participated to an exchange of information on the Los Alamos HDR project.

4. PROSPECTS FOR HDR IN ITALY

Given the situation described above, there is an opportunity to pursue actively in Italy and R&D effort concerning HDR. The National Energy Plan drawn by the government and currently under discussion at the Parliament provides specifically for an effort to be carried out up to the year 2000 in this field.

Carrying out an HDR program could generate innovative technology which could be of use, beside to geothermal operations, in different sectors like oil drilling and production and others.

Two companies are involved in Italian geothermal activities: ENEL, which owns all the geothermal fields now in production and AGIP, with large experience in deep drilling and in high temperature and high pressure production for oil and gas. The two companies operate in joint-venture in all the areas of geothermal interest outside Tuscany.

Programming and operations related to an Italian HDR R&D project
could involve the two national companies above mentioned as well as other organizations like C.N.R. (the National Research Council) and ENEA (the Alternative Energies Institute) and some universities.

The project should be mainly government-funded because of the technical uncertainties still existing, notwithstanding the long research effort carried out especially by USA and Great Britain, and in consideration of the fact that an industrial outcome is in any case quite far away in time.

EC contribution will be sought as well as international cooperation, especially with countries interested the HDR problem that have similar geologic setting and comparable targets.

We believe that a reasonable approach to HDR experimentation in the EC could include the simultaneous pursuing of one low-temperature project of the type currently going on in Great Britain and in France, and a new high-temperature/shallow depth project as planned in Italy (similar to the HDR experimentation in Japan).

For the Italian project, beside the classical loop between two tight wells artificially connected, one could consider injecting water in artificially fractured wells and recovering it from a nearby hydrothermal field under exploitation; alternatively one could envisage an artificial heat extraction system from low permeability formations.

The concept of draining heat from low permeability systems has been considered on a theoretical basis by "Armstead and Tester ("Heat Mining", 1987) and deserves preliminary study for the Italian situation, provided the original volume of drainage by the natural fractures and their artificial extension is contained within the new system to be created. The same condition applies to tying an artificially fractured well to a producing geothermal field.

Both these two non classical approaches are similar to the techniques applied in oil and gas water flooding and low permeability reservoir stimulation.

POSSIBLE LOCATION FOR AN HDR PROJECT IN ITALY

The choice of the location of the Italian HDR project will be based on several factors including:
- geological setting of the area
- surface and underground distribution of the temperature gradient
- availability of unproductive wells suitable for HDR experimentation
- geomechanical characteristics of subsurface rocks
- availability of water for the injection operations and for loop testing
- environmental impact.

Due attention will be dedicated to the option of fracturing deviated wells versus vertical ones, given the fact that most fractures in the geothermal areas are subvertical.

At the moment, the following two geographical areas could have priority in a preliminary way, all factors considered: Latera area (Latium), Flegrei area (Campania). Both areas are under lease by the joint venture AGIP-ENEL.

A brief outline of these two areas, as well as of some wells which could be utilized for the first HDR project, is given hereunder.

- Latera area

The Latera geothermal field is located west of lake Bolsena in the Monti Volsini region (northern Latium). Fig. 2 shows the location of the wells and a cross-section of the field. The producing level is a fractured limestone of Mesozoic age with very low intrinsic permeability very high secondary (tectonic) permeability.

On the basis of already available information obtained from the exploration activity, which includes the drilling of several wells, the most appropriate area for an HDR project is the western part of the field where wells L1, L5, and L6 were drilled. These wells, which were dry, have evidenced the existence of temperatures of about 300°C at a depth of around 2500 m; they did not encounter the producing limestone formation present to the East, but basically a series of metamorphosed limestone and syenitic intrusions.

Taking as an example well L5, (Fig. 3) the stratigraphic section is as follows:

- 0 - 1320 m - Volcanics: Quaternary
- 1320 - 1560 m - Polygenic volcanic breccia (flysch elements): Quaternary
- 1560 - 1750 m - Tectonic breccia (Mesozoic limestone elements): Miocene?
- 1750 - 2070 m - Recrystallized limestones (very fractured
**FIG. 2 - LATERA AREA**

**Cross-section**

- Dry hole - non commercial
- Production - reinjection well

**LATERA CALDERA RIM**

**CROSS-SECTION**

### FIG. 3 - LATERA 5 - SECTION AND TEMPERATURE PROFILE

<table>
<thead>
<tr>
<th>AGE</th>
<th>STRATIGRAPHY</th>
<th>EXTRAPOLATED TEMPERATURE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>QUATERNARY</td>
<td>Tuffs and lavas; clays</td>
<td>240</td>
</tr>
<tr>
<td>QUATERNARY</td>
<td>Volcaniclastics</td>
<td>940</td>
</tr>
<tr>
<td></td>
<td>Lavas</td>
<td>1320</td>
</tr>
<tr>
<td></td>
<td>Volcanic breccia (flyash elements)</td>
<td>1560</td>
</tr>
<tr>
<td></td>
<td>Tectonic breccia (Lias lms elem.)</td>
<td>1750</td>
</tr>
<tr>
<td></td>
<td>Recrystallized limestones</td>
<td>2070</td>
</tr>
<tr>
<td></td>
<td>Syenitic intrusion</td>
<td>2651 (TD)m.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>87°C</td>
</tr>
<tr>
<td></td>
<td></td>
<td>111</td>
</tr>
<tr>
<td></td>
<td></td>
<td>160</td>
</tr>
<tr>
<td></td>
<td></td>
<td>238</td>
</tr>
<tr>
<td></td>
<td></td>
<td>297</td>
</tr>
</tbody>
</table>
and cemented) with magmatic intrusions:
Mesozoic
2070 - 2651 (T.D.) - Syenitic intrusive body (Quaternary age).

The temperature gradient indicates a conductive pattern from 1500 m downward and maximum extrapolated temperature at bottom hole is 297°C.
Injection testing confirmed that the deep formations are tight.

The well completion profile is the following:
16" 5/8 casing 0 - 210 m (cemented to surface)
13" 3/8 casing 0 - 942 m (cemented to surface)
9" 5/8 casing 0 - 1768 m (cemented to surface)

In this well the formation to be stimulated would be the syenite body, while in wells L1 e L6 metamorphosed limestones should be the target.

For what concerns logistics, the area has a favourable setting, both taking account availability of water (from Mezzano lake) and because of the existence of specific infrastructure and services (like microseismic monitoring) related to the drilling and production activities in the Latera field as well as to the geothermal power plants, presently under procurement.

**Flegrei area**

This zone is located a few kilometers West of Naples and is the seat of a caldera generated 35,000 years ago where volcanic activity surged during various phases. A geothermal field (Mofete) with multiple reservoirs in volcanic tuffs was discovered at the Western margin of the caldera by the AGIP-ENEL joint-venture. Reservoirs are between 550 and 1900 m and temperature of the field waters range between 210° and 340°C.

In a more central position in respect of the caldera, some 6 km to the East of Mofete field, four wells were drilled which encountered substantially impermeable hot rocks (Fig. 4).

One such well is Cigliano 1 (Fig.5) (a deviated well with TD at about 1400 m from vertical) which will be briefly described hereunder.

The section is as follows:
0 - 2802 m (T.D.) (corresponding vertical depth 2430 m) -
Volcanics(tuffs,breccias and lavas with subintrusive
FIG. 4 - MOFETE-CIGLIANO 1D AREAS

S. VITO-MOFETE LOCATION

CROSS SECTION

S. VITO AREA

MOFETE FIELD

POZZUOLI

GULF OF POZZUOLI

CAMPI FLEGREI CALDERA RIM

LICOLA 1

MOFETE FIELD

AVERN 10

MF 70

MF 60

SV 1

SV 3

SV 8

C 10

Cross-section

Wells
FIG. 5 - CIGLIANO 1D: WELL SECTION AND TEMPERATURE

\[\text{\# Measured maximum temperature} \quad \Delta \text{Extrapolated values}\]
latites and phonolites). The formation becomes gradually metamorphosed at depth.

Extrapolated temperature at 2780 m (vertical depth 2415 m) is over 349°C. The measurements indicate a conductive non-permeable section; a production test confirms that the formations are tight.

The casing profile is as follows:
- 20" casing from 0 to 205 m (cemented to surface)
- 13 3/8" casing from 0 to 1084 m (cemented to surface)
- 9 5/8" casing 0 - 2488 m (cemented to surface)
- 7" liner hanger m 2336–2801 m (slotted interval 2488–2801).

The well is located in an area dedicated to industrial development and which is relatively less densely inhabited than the Mofete area, so that operations would not have an adverse environmental impact.

Stimulation for an HDR project in well Cigliano 1 would involve a part of the volcanics, possibility above the 7" liner, where temperatures are adequate and well conditions satisfactory.

6. CONCLUSIONS

Italy presents optimal conditions for development of an HDR project.
The great number of wells drilled for exploratory and development purposes have evidenced the presence, at the margin of all the hydrothermal fields, of large volumes of impermeable rock systems with a temperature of about 250°-300°C at a depth of 2000-2500 m.

The only way of utilizing the available heat of these rock masses is to develop HDR projects which could consist of either a system of two or more tight or low permeability wells artificially connected or injecting water in an artificially fractured well and recovering it from a nearby geothermal field under exploitation.

Italian HDR experimentation could be pursued simultaneously with another ongoing European project at lesser temperature, hopefully with EC patronage.
HDR RESOURCE IN SOUTH WEST ENGLAND

J Willis-Richards\textsuperscript{1}, A Thomas-Betts\textsuperscript{2}, M Sams\textsuperscript{2}, J Wheildon\textsuperscript{2}

\textsuperscript{1} Camborne School of Mines, Rosemanowes Quarry, Herniss, Penryn, Cornwall, TR10 9DU, UK

\textsuperscript{2} Geophysics Group, Department of Geology, Imperial College, Prince Consort Road, London, SW7 2BP, UK.

ABSTRACT

Numerical models of heat flow and temperature distribution in SW England have been developed independently by the Camborne School of Mines HDR Project and by the Geophysics Group at Imperial College.

The thermal structure of the region is dominated by the high radiogenic heat production and large size of the Cornubian granite batholith (c 285 m y). Good constraints on the numerical models are provided by 3-D gravity survey interpretations of the space form of the batholith and by nearly 50 well determined heat flow values. These average close to 120 mW/m\textsuperscript{2} on the batholith outcrop, about twice the regional value.

The sensitivity of the thermal resource to drilling and geothermal gradient cutoffs is examined. Under the land area of SW England the resource that could potentially be available for geothermal electricity generation exceeds 5 \times 10^{20} Joules for the most conservative of criteria, and may be as much as 2 \times 10^{21} Joules if HDR geothermal reservoirs are developed as deep as 7 km below the surface.

1 SOURCE OF THE THERMAL ANOMALY

The near-surface geology of SW England is dominated by a major late Variscan granite batholith intruded at high crustal levels into folded and thrust thickened sequence of Devonian and Carboniferous basin sediments which probably developed on thinned continental crust. The partly exposed granite batholith extends for 200 km along the spine of SW England, and probably extends further to the west across the continental shelf. Post-Variscan extensional basins with Permian and Mesozoic infill flank the peninsula to nroth and south, obscuring relationships with the European Hercynides.

Exposed granite cupolas are characterised by heat flows of between 110 and 135 mW/m\textsuperscript{2} compared to regional values of 60-65 mW/m\textsuperscript{2} (Tammemagi and Wheildon 1974, Francis 1981), Figure 1.
Radiogeologic studies (Tammemagi and Smith 1975) show that the granite batholith that underlies much of the region is unusually radioactive. The radiogenic internal heat production of granite samples averages about 5.0 microW/m², compared to country rock values close to 2.0 microW/m². No significant variation in radiogenic heat production is observed down the 2.6 km vertical section of the deepest well at the Camborne School of Mines Geothermal Energy Project (CSM 986a, 1986b, 1987). This lack of vertical fraction of the radiogenic heat producing elements is likely to be a general property of peraluminous S-type granites such as that found under SW England (Webb et al 1985, Sawka 1986). If the heat productivity contrast between the granite and the country rocks measured near the surface is maintained over the entire 10-15 km thickness of the granite batholith (Tombs 1977, Al-Rawi 1980) then the heat flow anomaly can be attributed entirely to the high heat productivity of the granite batholith, without any contribution from either the lower crust or mantle.

The pattern of high heat flow over the granite is reasonably regular, without the extreme variation over short distances expected if convection was important (Fehn 1985, Sams et al 1988a). At present, therefore, it appears that conduction is the dominant heat transfer mechanism.

2 MODELLING THE THERMAL STRUCTURE OF THE CRUST

Figure 2 shows the modelling sequence needed to establish the HDR resource in SW England.
Firstly, the shape of the granite batholith is determined from gravity data and rock density measurements, assisted by seismic information where available. The iterative technique of Cordell and Henderson (1968) was used to generate the model of CSM (1989), Figure 3, whilst an existing model for the shape of the granite (Tombs 1977) was adopted by Sams and Betts (1988).

The shape of the granite model is verified against the observed gravity field, the outcrop of the granite, borehole intersections with the upper surface of the granite and the mapped extent of the metamorphic aureole.

To the 3-D batholith models are added measurements of and inferences concerning rock thermal properties, a schematic model for the depth distribution of heat producing radioelements and an estimate of the cross MOHO heat flow. These enable the three dimensional heat conduction problem to be solved. Both finite element (Sams and Thomas-Betts 1988, Thomas-Betts et al 1988) and finite difference approaches have been taken (CSM, 1989), with each group using different models for the shape of the granite.

Cross validation of the two mathematical approaches was undertaken using a geometrically simple 2-D model, but with realistic internal heat production and temperature dependent thermal conductivity (Thomas-Betts et al 1988).
Surface heat flow measurements were compared to the predictions of each of the thermal models, and adjustments were made to either the gravity, thermal or heat production properties until a satisfactory match was achieved. Uncertainty in the distribution of heat producing elements, both laterally and with depth, and the complex thermal conductivity structure of the country rocks, means that the thermal models can not be used as a detailed check on the gravity interpretation.

Figure 4 shows contours of the modelled surface heat flow from the model of CSM (1989).

Figure 5 shows the model temperature distribution at 6 km depth in the Carnmenellis region taken from models produced independently at Imperial College and at the Camborne School of Mines. There is good agreement between the two models in both the predicted temperatures and the shape of the thermal anomaly associated with the granite. Figure 6 extends the temperature section at the same depth, to cover the whole of SW England.

3 estimation of hdr geothermal resource

The thermal resource can be expressed most usefully in the geothermal equivalent of a 'grade-tonnage' chart. This expresses the amount of useful heat that is contained in rocks above a given bottom hole depth, counting only those areas where the bottom hole temperature is
FIGURE 4  ISOMETRIC VIEW OF SURFACE HEAT FLOW

DEPTH = 6 KMS  + = ROSEMANOWES HDR EXPERIMENTAL SITE

FIGURE 5  TEMPERATURE AT 6 KMS, CARNMENELLIS AREA; BOTH MODELS
above a given value considered 'economic'. The stored heat values for a range of drilling depths and cut-off temperatures are contoured in Figure 7.

Under the land area of SW England the resource that could be potentially available for geothermal electricity generation exceeds $5 \times 10^{20}$ Joules for the most conservative of criteria, and may be as much as $2 \times 10^{21}$ Joules if HDR geothermal reservoirs are developed as deep as 7 km below the surface. Deviated drilling, to take advantage of the geothermal resource underlying the coastal margins, can add to this total.

This is perhaps as far as one should prudently try to extend his models. The uncertainty in the thermal resource figures is approximately a factor of two, a great improvement over earlier estimates (see for example, Shock 1986) which varied by up to an order of magnitude. The remaining uncertainties required to turn this estimate of thermal resources into an estimate of electrical resources are likely to be large, and relate to engineering, planning, water use and social constraints.

Provisional estimates of these 'non-geological' constraints on the efficiency with which the thermal resource can be realistically turned into electricity vary from about 0.2% to 1%. By taking the worst case and low values for the thermal resource from Figure 7, and electrical resource of about 260 TWhr is implied. This compares with the annual production of the South Western Electricity Board (serving a region several times larger than the study area) of about 10 TWhr. There exists the potential for a significant regional electricity production from the granite batholith of SW England, if the technical problems facing the research team at the Camborne School of Mines can be overcome economically.
4 SUMMARY

The thermal resource available in SW England for exploitation by Hot Dry Rock geothermal technology has been estimated on the basis of three dimensional heat conduction models. These models have a sound basis as the result of many years of effort by numerous researchers gathering gravity, heat flow, heat productivity, seismic and thermal conductivity data. Two groups, deriving their models independently, obtain results in good agreement with each other.

ACKNOWLEDGMENT

The models presented in this paper utilise data from many workers, gathered over the past 30 years; their hard work is gratefully acknowledged. The work described herein was carried out at or for, the Camborne School of Mines Geothermal Energy Project, under contract as part of the Department of Energy's Renewable Energy Research and development programme, managed by the Energy Technology Support Unit (ETSU). The views and judgements expressed in the paper are those of the authors and do not necessarily reflect those of ETSU or the Department of Energy.
REFERENCES


HOT DRY ROCK GEOTHERMAL ENERGY COST MODELLING:
DRILLING AND STIMULATION RESULTS

by N.D. Mortimer and S.T. Minett

INTRODUCTION

Work began on the development of a H.D.R. geothermal energy system cost model in the United Kingdom in October 1986. Modelling of the cost of reservoir creation, by drilling and stimulation, has been conducted at Sheffield City Polytechnic, whilst modelling of the cost of surface plant and the performance of the complete H.D.R. geothermal energy system has been undertaken at Sunderland Polytechnic. The model which is formulated as a spreadsheet programme written on SMART software for an Olivetti M24 personal computer, can either be run as an integrated package or as individual components. Although preliminary versions of the cost model have been completed, development will continue until June 1990. This work is funded by the United Kingdom Department of Energy, through the Energy Technology Support Unit, and by the Commission of the European Communities.

An essential aim of any cost model is to provide a convenient method of predicting the costs of any project under a chosen set of circumstances. This assists project management by offering a means of conducting design optimisation studies and performing sensitivity analysis. Cost models for energy systems are also appropriate for resource analysis since they can be used to classify the energy available in economic terms or cost bands. The cost model for H.D.R. geothermal energy systems has been designed with these applications in mind. To achieve this, the model must be relatively flexible and be able to accommodate suitable range of diversity. In particular, the final version of the drilling and stimulation cost model will be able to account for the affect of varying:

- depth
- geothermal gradient
- geology, in terms of subsequent rates of penetration and bit life
- borehole breakout
- thickness of sedimentary cover
- well design, including configuration, angle of deviation and casing programme
- reservoir characteristics, such as volume, shape and number of stimulated zones.
Other factors that will be taken into consideration include the type of logging and coring programmes selected and the general drilling market conditions which affect the cost of drilling supplies and services.

MODEL FEATURES

In order to present an easy-to-use standard format, the model has been developed as a spreadsheet programme. This is based on SMART software which runs on an Olivetti M24 personal computer. Individual components of the model are written as separate spreadsheets. The relationship between the drilling and stimulation cost spreadsheets and the rest of the model is demonstrated schematically in Figure 1. When the model is run as an integrated programme, the user can enter certain design parameters for the particular system under consideration by means of a number of spreadsheets which include the well data and reservoir geometry spreadsheet. These common input spreadsheets contain the basic design parameters required for estimating drilling and stimulation costs. In many instances, these parameters can consist of either user-defined or default values. An indication of the type of information needed is given in Figure 2 which also summarises a set of design parameter values that form the basis of an example used throughout this paper. The details of this example are described later.

The cost of drilling and stimulation depend, fundamentally, on the time taken to complete these operations. Consequently, time estimation is a central feature of the model. In the latest version of the model, eighteen separate time elements are specified and these are summarised in Table 1. The drilling time elements are calculated in the time element spreadsheet and the stimulation time element is derived from the reservoir stimulation spreadsheet. Costs are divided into twenty six separate groups and these are summarised in Table 2. The drilling cost groups are obtained from the costing spreadsheet and all stimulation cost estimating takes place in the reservoir stimulation spreadsheet. The cost estimating procedure in either of these spreadsheets consists of combining the design parameters, the estimated time elements and other, subsequently derived technical information with appropriate price and charge data obtained by means of a regular survey of drilling supply and service companies. Such surveys have been conducted for a number of years and sufficient data has been collected to reflect the substantial fluctuations that have occurred in the drilling market in recent times.

In addition to drilling and stimulation costs, other sub-surface system capital and operating costs can be calculated by means of the additional costs spreadsheet. These include the costs of initial studies, casing surveys and periodic reservoir testing, seismic
activity monitoring system construction and operation, and eventual
decommissioning of the injection and production wells. Although the
costs of these items are relatively small in comparison with drilling
and stimulation costs, they are included to ensure that the model
completely describes the system under consideration. The final part
of the model consists of gathering together the results of all the
spreadsheets and presenting them in the model output spreadsheets.

A BASIC EXAMPLE

The essential assumptions incorporated into the model can be best
described by considering some illustrative results. For this, a
basic example must be selected. The design parameters of this
example have already been given in Figure 2. This example refers
to an injection well and a production well, forming a commercial
H.D.R. doublet system, drilled to a total vertical depth of 6
kilometres in granite with similar drilling characteristics to
those found at Rosemanowes in Cornwall in the United Kingdom.
There is no sedimentary cover and it is assumed that the
phenomenon of borehole breakout is not encountered. The
reservoir is created between the inclined sections of the wells
which are drilled at an angle of 30° from the vertical for 1300
metres and separated from each other by a vertical distance of
400 metres. The reservoir is formed by three stimulated zones
which give a total reservoir volume of 180 million cubic metres.
The wells are completed with 7 inch (0.1778 metre) liners in 8.5
inch (0.2159 metre) holes. The model is formulated so that these
and other design parameters can be changed within practical
limits by the user.

ASSUMPTIONS AND RESULTS: TIME ELEMENTS

Subsequent estimates for the time elements of this example of a
doublet system are given in Table 1. It will be seen that these
estimates are presented in the form of averages with associated
standard deviations which have been generated by a simple propagation
of errors procedure. This assumes, of course, that all the values
used in the calculations follow normal probability distributions.
The same assumption and procedure is adopted in the current version
of the model for evaluating the accuracy of the cost group estimates.
Future versions of the model may incorporate more sophisticated
methods of assessing the accuracy of results.

A further illustration of the estimated time elements given in Table
1 is provided by Figure 3. This emphasises the conclusion that the
majority of the time involved in creating this H.D.R. doublet system
is accounted for by just three elements: rotating time, tripping time and stimulation time. The rotating time is the time taken by the drilling bit to actually penetrate the rock. The tripping time is the time involved in replacing a drilling bit after it has reached the end of its useful life. As defined here, the tripping time consists of the time required to remove and disconnect the drill string from which the drilling bit is suspended in the hole, and re-connect and lower the drill string with a new drilling bit attached so that drilling can recommence. Both the rotating time and the tripping time depend on the rate of penetration during drilling. The tripping time also depends on the life of the drilling bit. Assuming best drilling practice, both the rate of penetration and the bit life tend to be functions of the drilling characteristics of the rock formations encountered.

Measurements of the rate of penetration and the bit life can be obtained from the bit records of drilling reports. These are very important sources of information for drilling cost modelling. Previous work involving the analysis of drilling reports from a variety of sedimentary rock regions has indicated that rates of penetration decline with increasing depth until compact sedimentary or basement rock is encountered, whereupon relatively constant rates of penetration are observed (Ref. 1). Consequently, at relatively shallow depths, up to about 3 kilometres, in sedimentary rock regions, the rotating time increases in a non-linear manner with depth. In fact, this variation can often be described by one or more exponential functions. This has a fundamental influence on the variation of total drilling costs with depth since the rotating time affects the total drilling time which, subsequently, governs the payments to drilling contractors. This is an important cost group, as will be explained later.

The tripping time also increases in a non-linear manner with depth. Analysis of bit records from drilling reports indicates that, as a first approximation, the bit life can often be treated as a constant. Even if the rate of penetration is also constant, the depths from which trips are made accumulates as an arithmetic series. If the rate of penetration is declining exponentially, as likely in uncompacted sedimentary rocks, the non-linear increase in tripping time with depth is reinforced further. This enhances the effect of rotating time on the variation of total drilling costs with depth. The combined effect of both the rate of penetration and bit life through the rotating and tripping times is very influential on drilling costs because other factors are either less significant or vary linearly with depth. Hence, because the majority of drilling occurs in sedimentary rocks, for hydrocarbon exploration and production, the statistically-derived variation of drilling costs with depth is normally expressed as some form of exponential equation. However, this is not wholly appropriate for drilling in hard rocks, such as granite.

Analysis of bit records for the few deep boreholes that have been
drilled in hard rocks clearly demonstrates that, provided the drilling engineer maintains constant operating conditions, the rate of penetration is fixed and does not vary significantly with depth (Refs. 2 and 3). This is illustrated in Figure 4 which shows the variations of the rotating time with depth for the three Rosemanowes boreholes, the four Fenton Hill boreholes in New Mexico, U.S.A., the Gravberg borehole in Sweden, the Kola borehole, U.S.S.R, and the Soultz-sous-Forets borehole in France. Since rotating times are plotted against vertical depth in Figure 4, it was necessary to make appropriate adjustments to data from any deviated sections of these boreholes. Apart from this, the data were not otherwise adjusted. The derived values of constant rates of penetration for each borehole are summarised in Table 3. It should be noted that these rates of penetration only apply to those sections of the boreholes which were drilled in hard rock. Constant rates of penetration were not observed in the overlying volcanic and sedimentary cover of the Fenton Hill boreholes (0 to 730 metres) and the Soultz-sous-Forets borehole (0 to 1400 metres), respectively. In addition, a marked change in the rate of penetration occurs at 4 kilometres in the Gravberg borehole. This was due to a change in operating conditions, namely an increase in mud weight, which was necessary to control the effect of borehole breakout at this depth.

Analysis of the bit records for these nine hard rock boreholes also suggests that there is no consistent variation of bit life with depth. For modelling purposes, the characteristic bit life in a given rock formation can be treated as fixed and the derived values for the boreholes considered are also summarised in Table 3. The assumption of a constant rate of penetration and a constant bit life in the model means that the variation of the simulated total drilling time with depth only departs slightly from a linear trend as depth increases. This is shown in Figure 5 which gives results for single vertical wells drilled in granite with similar properties to that observed at Rosemanowes. In this example, it is assumed that no borehole breakout is encountered and increasing temperature with depth has no influence on drilling times. Future versions of the model will enable these assumptions to be altered. Similarly, the effect of changes in the assumption of a constant rate of penetration will be accommodated in future versions of the model. However, at present, the assumed constant rate of penetration ultimately results in an almost linear variation of drilling costs with depths, as will be seen shortly.

ASSUMPTIONS AND RESULTS: COST GROUPS

Estimates of the cost groups for the basic example of a H.D.R. doublet system adopted here were shown previously in Table 2. A further illustration of these results is given in Figure 6 which emphasises that the majority of costs are accounted for by just five groups; stimulation costs, payments to drilling contractors, the cost
of stabilisers and reamers, casing costs and the cost of drilling mud. All these costs are calculated using quotations obtained from the 1988 drilling supply and service company survey which reflects the relatively low drilling market that existed at that time. In the present version of the model, some cost groups are based on a fairly detailed job specification. An example of this is the casing costs which are calculated by combining information on casing diameters, grades, unit weights and lengths from the chosen well design and geometry with appropriate quoted prices. Other cost groups, such as the cost of stabilisers and reamers, are estimated by means of simple algorithms derived from suitably adjusted costings from actual boreholes and independent prognoses (Refs. 4 and 5). As an alternative to these two types of modelling method, all remaining cost groups are calculated using a combination of both approaches. For example, payments to drilling contractors are based on the detailed simulation of drilling time, described earlier, and a relatively simple expression relating drilling rig day rate charges to depth. This expression is derived from quotations from drilling companies. In future versions of the model, drilling rig requirements will be specified in more detail than just depth capability and rig day rates will reflect whether the rig is hired or owned as part of an integrated H.D.R. geothermal energy operation.

Another cost group which will be evaluated in more detail in future versions of the model is the cost of drilling muds. At present, an algorithmic approach is adopted which only accounts simply for increasing temperature with depth. This incorporates the assumption that, if the bottom hole temperature rises above about 120°C (at a depth of approximately 3.5 kilometres at Rosemanowes), special lubricant must be used and mud cooling equipment must be installed. In future versions of the model, the mud programme will be specified more thoroughly so that the effects of increasing temperature and borehole breakout can be simulated more reliably. The assumptions for the drilling mud costs incorporated in the current model result in a discontinuity in the variation of total drilling costs with depth. This is demonstrated in Figure 7 which shows the total cost of drilling, without stimulation, for H.D.R. doublet systems at Rosemanowes. The costs are given in 1985 £ sterling values, reflecting a relatively high drilling market situation, to enable direct comparison with the more frequently quoted drilling cost curve for H.D.R. doublet systems (Ref. 6). This curve is adapted from U.S. statistics on deep drilling in sedimentary basins. It can be seen that this curve is, in fact, a relatively slowly varying function incorporating an exponential term. Figure 7 indicates that this curve does not differ substantially from the nearly linear trend generated by the model.

The latest estimates of the costs of both drilling and stimulation are presented in Figure 8. These costs are given in 1988 £ sterling values and results are provided for a range of depths between 3 and 8 kilometres and for up to five stimulations in the reservoir region. As indicated earlier the cost of stimulations makes a very important contribution to the total cost of creating a H.D.R. doublet system.
The costs included in Figure 8 are based on an initial stimulation programme which was first considered for preliminary costing purposes in July 1988 (Ref. 7). As shown in Figure 9, the main direct costs of the stimulation programme are the cost of the stimulation materials, including gel, and the cost of perforating the liner in the reservoir region with explosive shots. Although the gel which was specified for this preliminary attempt at costing stimulations was suitable for the pressures likely to be experienced, it was known that the gel would not be able to withstand the high temperatures encountered in deep H.D.R. doublet systems. Consequently, the present stimulation costs only act as an initial guide and more realistic stimulation programmes will have to be designed, costed and incorporated into later versions of the model.
MODEL DEVELOPMENT

In order to assist the advance of H.D.R. geothermal energy research and subsequent project management, the drilling and stimulation cost model will continue to be developed and refined. Particular attention will be given to the implications of:

- increasing bottom hole temperatures
- borehole breakout
- different drilling mud programmes
- technological drilling improvements
- integrated drilling supply and service arrangements
- alternative stimulation programmes

This should enable the model to be applied to a wide range of H.D.R. geothermal energy resource sites. It is hoped that such further work can incorporate the progress in knowledge achieved by the various research teams engaged in H.D.R. and related areas of study, such as the H.D.R. geothermal energy projects at the Camborne School of Mines, Urach and Soultz-sous-Forets, and the K.T.B. project in West Germany. The continued assistance of commercial drilling supply and service companies will also prove to be influential.
References


Table 1  List of Time Elements

<table>
<thead>
<tr>
<th>Element</th>
<th>Time (hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotating</td>
<td>2417 ± 384</td>
</tr>
<tr>
<td>Reaming</td>
<td>283 ± 52</td>
</tr>
<tr>
<td>Coring</td>
<td></td>
</tr>
<tr>
<td>Tripping</td>
<td>1640 ± 398</td>
</tr>
<tr>
<td>Connecting</td>
<td>215 ± 23</td>
</tr>
<tr>
<td>Bottom Hole Assembly</td>
<td>138 ± 59</td>
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<tr>
<td>Circulating</td>
<td>71 ± 25</td>
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<tr>
<td>Logging</td>
<td>908 ± 246</td>
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<tr>
<td>Casing</td>
<td>319 ± 91</td>
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<tr>
<td>Cementing</td>
<td>306 ± 102</td>
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<tr>
<td>Waiting on Cement</td>
<td>75 ± 65</td>
</tr>
<tr>
<td>Drilling on Cement</td>
<td>64 ± 41</td>
</tr>
<tr>
<td>Mishap</td>
<td>407 ± 208</td>
</tr>
<tr>
<td>Rig Maintenance</td>
<td>37 ± 14</td>
</tr>
<tr>
<td>Well Testing</td>
<td>73 ± 5</td>
</tr>
<tr>
<td>Wellhead Installation</td>
<td>55 ± 19</td>
</tr>
<tr>
<td>Stimulation</td>
<td>1680 ± 168</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>557 ± 98</td>
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</tbody>
</table>

Total 9244 ± 693

6 km doublet with 3 stimulations and drilling conditions similar to Rosemanowes, Cornwall, United Kingdom.
Table 2  List of Cost Groups

<table>
<thead>
<tr>
<th>Group</th>
<th>Cost (£:1988)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Civil Engineering</td>
<td>226,000 ± 339,000</td>
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<tr>
<td>Rig Moves</td>
<td>92,000 ± 24,000</td>
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<tr>
<td>Payment to Drilling Contractors</td>
<td>1,922,000 ± 226,000</td>
</tr>
<tr>
<td>Directional Drilling</td>
<td>320,000 ± 32,000</td>
</tr>
<tr>
<td>Surveying</td>
<td>66,000 ± 5,000</td>
</tr>
<tr>
<td>Downhole Motors</td>
<td>428,000 ± 49,000</td>
</tr>
<tr>
<td>Stabilisers and Reamers</td>
<td>952,000 ± 108,000</td>
</tr>
<tr>
<td>Rock Bits</td>
<td>831,000 ± 121,000</td>
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<tr>
<td>Drilling Muds</td>
<td>792,000 ± 280,000</td>
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<tr>
<td>Casing</td>
<td>1,038,000 ± 56,000</td>
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<tr>
<td>Wellhead</td>
<td>108,000 ± 38,000</td>
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<tr>
<td>Cementing</td>
<td>301,000 ± 90,000</td>
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<td>Christmas Tree</td>
<td>432,000 ± 153,000</td>
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<tr>
<td>Logging</td>
<td>289,000 ± 20,000</td>
</tr>
<tr>
<td>Coring</td>
<td></td>
</tr>
<tr>
<td>Testing</td>
<td>84,000 ± 10,000</td>
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<tr>
<td>Fuel and Lubricants</td>
<td>194,000 ± 21,000</td>
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<tr>
<td>Water Supply</td>
<td>37,000 ± 4,000</td>
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<tr>
<td>Supervision</td>
<td>450,000 ± 32,000</td>
</tr>
<tr>
<td>Transport</td>
<td>112,000 ± 8,000</td>
</tr>
<tr>
<td>Abnormal Drillstring Wear</td>
<td>233,000 ± 51,000</td>
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<tr>
<td>Inspection</td>
<td>168,000 ± 36,000</td>
</tr>
<tr>
<td>Fishing Tools and Services</td>
<td>280,000 ± 155,000</td>
</tr>
<tr>
<td>Labour</td>
<td>75,000 ± 5,000</td>
</tr>
<tr>
<td>Stimulation</td>
<td>6,004,000 ± 901,000</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>884,000 ± 160,000</td>
</tr>
<tr>
<td>Total</td>
<td>16,318,000 ± 1,086,000</td>
</tr>
</tbody>
</table>

6 km doublet with 3 stimulations and drilling conditions similar to Rosemanowes, Cornwall, United Kingdom.
Table 3  Rates of Penetration and Bit Lives for Hard Rock Drilling

<table>
<thead>
<tr>
<th>Site</th>
<th>Rate of Penetration (metres per hour)</th>
<th>Bit Life (hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rosemanowes, U.K.</td>
<td>5.1 ± 1.2</td>
<td>16.0 ± 3.5</td>
</tr>
<tr>
<td>Fenton Hill, U.S.A. (≥0.7 km)</td>
<td>2.8 ± 0.8</td>
<td>20.9 ± 9.3</td>
</tr>
<tr>
<td>Siljan, Sweden (≤4.0 km)</td>
<td>3.2 ± 0.9</td>
<td>30.2 ± 21.0</td>
</tr>
<tr>
<td>Soultz-sous-Forets, France (≥1.4 km)</td>
<td>1.6 ± 0.6</td>
<td>21.3 ± 11.4</td>
</tr>
</tbody>
</table>
Figure 1  The Hot Dry Rock Geothermal Energy Cost Model

MAIN MODEL

DRILLING AND STIMULATION COST MODEL

WELL DATA SPREADSHEET

RESERVOIR GEOMETRY SPREADSHEET

OTHER SPREADSHEETS FOR MAIN MODEL

MODEL OUTPUT SPREADSHEETS

MAIN TITLE SPREADSHEET

HDR DCM DATA TRANSFER SPREADSHEET

TIME ELEMENT SPREADSHEET

COSTING SPREADSHEET

RESERVOIR STIMULATION SPREADSHEET

ADDITIONAL COSTS SPREADSHEET
Drilling Conditions:
Rate of penetration = $5.07 \text{ m hr}^{-1}$
Bit life = 15.99 hr

Reservoir consisting of 3 stimulated zones, each comprising of full horizontal discs, with individual volumes of $6 \times 10^7 \text{ m}^3$, separated by 50 m along the wells
Figure 3  Breakdown of Time Elements

TRIPPING: 68 days
18%

ROTATING: 101 days
26%

STIMULATION: 70 days
18%

OTHER: 146 days
38%

6 km. doublet with 3 stimulations drilled under similar conditions to those at Rosemanowes, Cornwall, United Kingdom.

Total Time = 385 days
Figure 4  Variation of Rotating Times with Depth for Hard Rock Drilling

<table>
<thead>
<tr>
<th>Location</th>
<th>Code</th>
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<tbody>
<tr>
<td>Camborne</td>
<td>RH11</td>
</tr>
<tr>
<td>Camborne</td>
<td>RH12</td>
</tr>
<tr>
<td>Camborne</td>
<td>RH15</td>
</tr>
<tr>
<td>Fenton Hill</td>
<td>GT-2</td>
</tr>
<tr>
<td>Fenton Hill</td>
<td>EE-1</td>
</tr>
<tr>
<td>Fenton Hill</td>
<td>EE-2</td>
</tr>
<tr>
<td>Fenton Hill</td>
<td>EE-3</td>
</tr>
<tr>
<td>Siljan</td>
<td>Gravberg-1</td>
</tr>
<tr>
<td>Kola</td>
<td>SG-3</td>
</tr>
<tr>
<td>Soultz-sous-Forets</td>
<td>GPK1</td>
</tr>
</tbody>
</table>

TOTAL VERTICAL DEPTH (km)

ROTATING TIME (hours)
Figure 5  Variation of Simulated Total Drilling Time with Depth

Single vertical wells in drilling conditions similar to those at Rosemanowes, Cornwall, United Kingdom.
Figure 6 Breakdown of Cost Groups

- **Payments to Drilling Contractors**: £1.922m (12%)
- **Casing**: £1.038m (6%)
- **Stabilisers and Reamers**: £0.952m (6%)
- **Rock Bits**: £0.831m (5%)
- **Drilling Muds**: £0.792m (5%)
- **Stimulation**: £6.004m (37%)
- **Other**: £4.779m (29%)

6 km. doublet with 3 stimulations drilled under similar conditions to those at Rosemanowes, Cornwall, United Kingdom.

Total Cost = £16.318m
Figure 7  Comparison of the Variation of Total Drilling Costs with Depth
Figure 8  Variation of Drilling and Stimulation Costs with Depth
3 stimulation zones, each with a volume of $6 \times 10^7$ m$^3$.

Total Direct Costs = £4.896m

Total Costs (including extra rig time) = £6.004m
1) Introduction

In 1986, as part of an early assessment, ETSU published the results of a series of calculations by Richard Shock (Ref 1) on the economics of HDR systems. Now, in order to assist it in its future assessment of HDR technology, the UK Department of Energy has funded a study to develop a full engineering cost model of electricity producing HDR systems which includes all surface and subsurface systems and components. Sunderland Polytechnic are the main contractors for this work and Sheffield City Polytechnic are subcontractors working on the costs of drilling and reservoir creation. The development of the main model is close to completion and although work will continue enhancing the model and investigating sensitivities it is possible to report progress at this stage.

As no complete operating HDR system exist, the model is based upon a conceptual design of such a working system. This conceptual design summarises the best understanding which can be formed to date, of the likely form which commercial HDR technology will take. This is in turn based upon experience from the experiments which have been carried out for the geothermal energy project at the Camborne School of Mines, as part of the UK Department of Energy "Renewable Energy Research and Development Programme" (Ref. 2). Obviously many uncertainties surround the nature of the technology which may be employed in HDR development, the costs which may be incurred and the resources which may be made available if developments are successful. The purpose of the model is to provide a method by which the economic prospects of HDR technology can be assessed in relation to the uncertainties which exist. Specifically the aims are;

- to produce reliable estimates of the capital and operating cost of HDR systems.
- to simulate the possible performance of HDR systems.
- to calculate the unit costs of electricity from HDR systems, to identify optimum configurations, and

HDR Cost Modelling

R HARRISON, P DOHERTY
I COULSON
to investigate uncertainties through sensitivity studies.
- to assist in the assessment of HDR resources.

The scope of the problem is very wide. The main issues are well known and these concern the size and configuration of the reservoir, its impedance and thermal performance in relation to the costs of creating it.

Thus:
- large reservoirs are required which can deliver large flows for long periods of time without suffering excessive thermal drawdown.
- high temperatures are required, and these are only obtained at low cost in geological settings which have high thermal gradients.
- low impedance reservoirs are required if the problems of high parasitic losses and pressure induced seismicity, which can limit flow, are to be avoided.

In addition to these major issues relating to the reservoir, a variety of power plant options is possible. The result is a system with a large number of variables which affect costs and performance in interactive ways.

2) The Subsurface Concept

It is assumed that the crystalline rocks which will form the HDR reservoir are divided in vertical and horizontal planes by natural fissures or joints which are spaced at intervals of between 5 and 100 metres. These joints are confined vertically by the weight of the overlying rocks, this is often called the overburden pressure. In the horizontal direction the joints are confined by pressures transferred through the rocks from adjacent geological structures. It is assumed that the reservoirs will be created at depths where the overburden pressures are greater than the horizontal pressures.

The reservoirs are created by stimulation operations whereby water or viscous gels are pumped at high pressures into uncased sections of the well and the result is to open up joint sets which are predominantly perpendicular to the minimum stresses in the rocks. As the minimum stresses are horizontal the joint sets which are stimulated are predominantly vertical.

The experience of the stimulation events at the CSM Geothermal Project indicates that it is not possible to create a large enough reservoir from a single
stimulation operation. A series of stimulation operations, between three and five, will probably be required. The resulting arrangement of the wells and stimulated zones is illustrated in figure 1. The wells are deviated in the region of the reservoir and the stimulated regions are located at different heights. The higher zones are cooler than the deeper ones.

In production, the joints which have been opened up by the stimulation events form a heat transfer surface which is swept by the circulating water. However, not all of the joint sets are opened in the stimulation process. Those which are, are swept with varying degrees of efficiency. In general it must be assumed that joint sets interact thermally and thus the thermal effect is to extract heat from a volume of rock rather than from isolated heat transfer surfaces.

The impedance of the reservoir gives rise to a dynamic pressure drop across it during production, and friction losses in the wells cause additional pressure drops. The difference between the weights of the columns of water in the injection and the production wells contribute a force which assists the circulation. Nevertheless, some pumping is required and this is a parasitic load which must be subtracted from the output of the power station.

Absolute pressures in the system are also important. High pressures give rise to high water losses and also, if the confining horizontal stresses are exceeded, seismic events can be initiated. The highest pressures occur at the reservoir inlets (at the bottom of the injection well). Thus this effect also is linked with impedance.

3) The Model

An initial specification of a system, within the context of the subsurface concept described above, defines a range of first and second level input variables. These drive a series of physical calculations of pressures, flow rates and temperatures in the subsurface system. The results of these calculations complete the specification.

The input variables - well depth, thermal gradient, number of stimulated zones, dimensions of stimulated zones, injection flow rate, water loss fraction, power plant approach temperatures, are used to calculate the producer well head temperature. Th return temperature is calculated first, and then the way the flow splits between the stimulated zones is analysed. This leads to the calculation of the water temperature at the bottom of the production well, and the production flow rate. After correcting for heat loss from the production fluid
to the surrounding rock, the well head temperature is obtained. When the well head temperature and the production flow rate are known, the specification of the power plant is complete. Calculation of system pressures leads to the specification of the well pump and so on.

From the complete specification of the system the capital costs can be estimated. The depth, angle of deviation and some variables are used to cost the wells. The size and number of stimulated zone are used to cost the stimulations. Well head temperatures, production flows, approach temperature and dead state temperature are used to cost the plant.

An important calculation is the thermal production profile of the reservoir - i.e. the way in which the well head temperature falls as the reservoir cools. This is used to estimate the variations in the output of the power plant over the lifetime of the scheme. Indeed the thermal drawdown may determine the lifetime of the system.

The 'core' of the physical model lies in the model of the subsurface system. The starting points here are the assumptions regarding the size and the geometry of the stimulated zones.

2.1) Reservoir Geometry

It is assumed that there is some maximum length of well section, the stimulation length 'l' over which a single stimulation event can be effective. Also it is assumed that the stimulation fluid can penetrate only fixed distances from the well, the stimulation distance 's'. These two parameters define the size of a stimulated zone. However, to calculate its volume requires assumptions about the shape of the stimulated zones which result. Little is known about the shapes, and a variety of possibilities exists. Currently, the most favoured shapes are discus shaped zones which have a circular section at right angles to the plane of the wells and an ellipsoidal section in the plane of the wells. The volume of these discus-shaped zones is given by:

\[ V = K \cdot s^2 t \times 3.142 \]

Where \( K = a \) constant \(<1\) which corrects for the ellipsoidal shape.

\[ t = \text{stimulation thickness} \]

\[ t = l \sin A \]

\[ A = \text{the angle of deviation of the well}. \]
With this concept the stimulation distance 's' is an important variable which affects the average reservoir temperature, and hence the well head temperature. Thus if it is required to develop a reservoir of $300 \times 10^6$ m$^3$ with a stimulation thickness 't' of 200 m and with $k = 0.9$ then this can be achieved with one stimulation if $s = 730$ m or with five stimulations if $s = 325$ m. The effect on the geometry is major, the average reservoir temperature when $s = 325$ m being significantly lower than that for $s = 730$ m.

Thus geometrical considerations have a significant effect on average reservoir temperatures and hence ultimately upon system performance. Previous calculations have often assumed that the HDR reservoir is entirely located at the deepest point in the system (e.g. Ref 1) and hence this study is significantly less optimistic in this regard. The only way that these conditions could be approached, using the subsurface concept which is the basis of this model, would be to drill the lower part of the well sections horizontally when the reservoir horizon had been reached. Horizontal drilling is routinely achieved in some sedimentary sequences but it is not clear whether it would be feasible in crystalline rocks at significant depths. Even if it were feasible the result would be very long wells in terms of drilled length and the costs would be very high.

It is possible to conceive of circumstances in which the subsurface concept outlined above would not apply. Thus very near the surface it may be that the horizontal stresses in the rocks could be greater than the vertical stresses and stimulations would tend to open up horizontal joint sets. This would tend to produce stimulated zones which extended over small vertical distances. Also, it is possible that open flowing fractures exist in crystalline rocks at depth, as has been found in the Soultz borehole (ref. 3), and stimulation operations would connect the wells to very extensive hydraulic systems. The simple geometrical considerations, as outlined above, would not apply in these cases. The reservoirs would resemble existing natural geothermal reservoirs and the technical problems would thus be similar to those which are routinely encountered in natural geothermal fields world-wide. The risks of exploration and the development of reservoirs would replace the risks of engineering reservoirs.

Once the geometrical arrangement of the reservoirs have been fixed in the model the thermal and hydromechanical calculations follow.

2.2) Thermal Performance

The temperature of the stimulated zones is determined by their depth and the thermal gradient in the rocks.
However, the calculation of the production fluid temperature is slightly more complex. Firstly, because the pressures are different across each stimulated zone and the impedances may also be different, the injected water does not split equally between the zones. The lower zones carry higher flows than the upper zones. This flows splitting is calculated in the model, and the temperature of the mixture at the top of the reservoir in the production well is calculated. Secondly, as the production fluid flows up the production well, some heat is lost to the cooler rock and wellhead temperature is slightly lower than the reservoir temperature. This standard calculations are also carried out in the model. A more difficult problem, is to accurately simulate the way in which the well head temperature fall as the reservoir cools over time. This is determined by the volume of rock involved, the number of joints which have been opened in the reservoir, the heat transfer area and the fluid flow. If only a small number of joints are opened and they are widely spaced, then the amount of heat extracted from the rock volume as a whole will be low, and reservoir temperature will fall further with high flow rates. If many joints are opened and these interact thermally then the amount of heat extracted from the rock volume as a whole will be higher and reservoir temperature will vary much less with flow rate. In real reservoirs a mixture of behaviours can be expected. Not all joints will be opened up in the stimulation process and those which are will conduct the water flow in non uniform ways. There could be sub-zones with small numbers of flowing joints which do not interact thermally and hence may drawdown relatively quickly. There could also be subzones with large number of flowing joints interacting thermally but overall drawing-down more slowly. The reservoir drawdown behaviour is vital to the performance and to the economics of the system. The model will simulate the behaviour by assuming that each stimulation is made up of a number of sub-zones which are carrying different fractions of the flow which flows through parallel joints which interact thermally. However, it must be recognised that the actual behaviour which will occur is still largely unknown.

2.3) Hydromechanical Behaviour

At the cost modelling level, the HDR system is a simple hydromechanical system. Friction losses in the wells can be calculated from the well diameter, the flow rates, the viscosity of the fluids and by assuming turbulent flow conditions. The static pressures of the columns of liquid can be calculated from their heights and densities. The dynamic pressure drop across the reservoir zones themselves can be easily calculated from their impedance. The difficulty lies with the impedance itself. This is not well understood in this context. The nature of the impedance is conjectural. Thus it is likely that major flow paths in the main body of the
reservoir carry fluid at low velocities and hence that
flows are laminar here. In the vicinity of the well
bores velocities are likely to be high and flows may be
turbulent. Impedance may vary with the fluid pressure
in the reservoir. Higher pressure may dilate the flow
paths reducing impedance. Impedance may vary with
depth, flow paths may tend to be narrower in deeper
zones giving higher impedance. This may be offset to
some extent by lower viscosity which would
significantly reduce the laminar components of the
impedance. Also, as reservoirs cool with time,
impedance is likely to change. Finally the actual
levels of impedance are uncertain within wide limits.
It is relatively simple to accommodate a number of
options in the model which describe the behaviour of the
impedance with pressure and temperature in different
ways. However, the overall uncertainty in the level of
the impedance probably masks all of these and at this
stage it is more appropriate to assume the impedance of
the zones to be a fixed quantity and for this value to
be an input variable.

Impedance is important for two reasons, it results in
parasitic losses and also it increases the absolute
pressures at the bottom of the injection well. High
pressures are a problem because as they approach the
confining horizontal stress water losses become high and
also the possibility of seismic events becomes
important.

2.4) Plant Performance

It is assumed that the fluid produced at the well head
is a liquid at the saturation pressure which corresponds
to the wellhead temperature. There are two basic ways
in which this can be used to generate electricity.

- Steam cycles; here the liquid pressure is reduced
in a chamber and it undergoes 'flashing' boiling
which converts a proportion of it to steam. The
unflashed liquid can be reduced in pressure
again to generate more steam. If two flash stages
are used then this is termed a 'double flash'
process. The steam is expanded through a steam
turbine to generate electricity. Figure 2 shows
a schematic diagram of the process. These are
well understood cycles which have been
successfully applied in geothermal plants for many
years.

- Binary cycles; here the heat is transferred from
the liquid across a heat exchanger to a secondary
fluid - usually an organic liquid. It is this
liquid which vaporises and drives the turbine or
other machines. Figure 3 shows a schematic
diagram of the process. This is the basic cycle of
the Organic Rankine Cycle used in 'Ormat' turbines
and also of the so called Trilateral Wet Vapour
Cycle which was examined by Shock (Ref 1). These are more novel cycles and there is less experience of building and operating them.

All power cycles are governed by the same thermodynamic principles and these can be used as a basis for modelling performance.

Thus the available work which a perfect cycle would extract from the geothermal fluid is given by:

\[ W_0 = m_f (h_i - h_o) - T_0 (s_i - s_o) \]  \hspace{1cm} (1)

See ref 5.

Where \( m_f \) = geothermal fluid massflow kg/s.

\( h_i \) = specific enthalpy of the wellhead fluid J/kg

\( h_o \) = specific enthalpy of the return fluid J/kg

\( s_i \) = specific entropy of the wellhead fluid J/kg/°C

\( s_o \) = specific entropy of the return fluid J/kg/°C

\( T_0 \) = ambient temperature K

Analysis of this equation shows that the available work is very sensitive to supply temperature and ambient temperature with return temperature being much less important.

However, all of the available work cannot be developed for the following reasons.

- Turbines cannot operate in a perfect manner. Vapour leaves the exhaust with a significant velocity and transfer of energy to the blades is not perfectly efficient.

- There is a loss of availability in generating the vapour, either in the flashing process in the steam cycles or in the heat exchanger in the binary cycle.

- The heat is not rejected at the ambient temperature but in a condenser supplied by cooling water from a cooling tower which is therefore somewhat above ambient temperature.

The result is that the actual work developed in the cycle can be written as

\[ W_C = m_f E_m E_h (h_i - h_o) - T_c (s_i - s_o) \]  \hspace{1cm} (2)

Where
The overall machine efficiency of the cycle. This must take account of the feed pump inefficiencies in the binary cycle and turbine leaving loss is important for steam turbines.

1 - E\textsubscript{E} is the loss of available work in the heat exchanger or in the flashing vessels.

T\textsubscript{e} is the temperature at which the vapour condenses.

There is a variety of performance and cost advantages to both cycles. Thus,

Analysis of a wide range of detailed engineering science calculations for both cycles shows that approximately,

\[ E\textsubscript{E} = 0.8 \text{ for binary cycles.} \]
\[ E\textsubscript{E} = 0.7 \text{ for double flash steam.} \]

The turbine efficiencies are comparable in both cycles but in order to reduce turbine exhaust areas to reasonable values, leaving loss can be between 5% and 10% for steam turbines. High work ratios of 10% and above can have a significant effect on the overall machine efficiency of binary cycles.

Steam cycles will tend to use direct contact condensers, whereas binary cycles will use surface condensers. The result is that, for identical cooling conditions, the condenser temperatures for steam cycles are lower than for binary cycles.

Both cycles have parasitic loads in addition to the well pumps.

- Cooling water is pumped to the top of the cooling towers.
- Cooling towers may be assisted by fans.
- Air leaks into the steam turbines and must be extracted from the condensers.
- There is a variety of other small pumps in the power station.

All of these must be subtracted in order to obtain the net power of the power station. Overall it is possible to design binary cycles to give a higher performance than steam cycles.

2.5) Costs

Subsurface costs dominate the system costs in a major
way and are thus considered in some detail. Indeed, developing the methods of estimating the costs of drilling the wells and of stimulating the reservoirs has been a major part of this study. Drilling cost estimates are derived from simulation of the drilling process. A major element in the drilling cost routine is the payments to drilling contractors which depend upon the time taken to drill the wells, together with the hire rates of the drilling rigs used. Drilling times are estimated as accurately as possible using the best information available on rates of penetration and bit lives. Assumptions are also made about the efficiency of the drilling crews as reflected in the tripping rates etc. Rig hire rates can vary with the level of demand, in the market place, for drilling services. The model can accommodate different market assumptions. Substantial quantities of materials are also consumed in the drilling operation. Casing quantities, number of rock bits and drilling fluids quantities are all estimated in detail from the well design and the nature of the drilling operation. Once again market conditions can affect the price rates which apply and the model can accommodate different assumptions. Stimulation operations are also major cost centres; again a detailed approach is taken. Thus a stimulation programme is defined and the rig and equipment hire and material costs are all estimated independently of each other. Finally, it is possible that the subsurface system would require a significant degree of maintenance during its lifetime. Thus the costs of 'workovers' would be substantial.

Plant costs are a significant element in overall scheme costs. In the model these are estimated by building up the cost from the main items of equipment. The heat exchanger costs are estimated from the heat transfer and the approach temperatures. The steam turbine costs are estimated from exhaust area and hence from steam flow, condenser temperature and leaving velocity. Where possible, the weights of the machines have been calculated based upon the design specifications and these have been converted to costs by cost per unit weight multipliers.

3) Interim Results

When reporting interim results from our incomplete model, many caveats must be made. Levels of cost can change and model behaviour can also change as the model is enhanced, better data are used, and the interpretation of runs reveals errors and inconsistencies which must be resolved. The results reported here must be examined bearing these caveats in mind. They serve to indicate likely levels of cost and model behaviour and to display the capability which is being developed.
3.1) Cost Breakdown

Figure 4 shows a cost breakdown for a single doublet base case defined as follows:

- **Depth:** 6 km
- **Thermal Gradient:** 35°C/km
- **Water loss:** 2%
- **Injection flow:** 75 kg/s
- **Impedance:** 0.1 MP/kg/g
- **Reservoir Volume:** 360 x 10^3 m^3
- **Thermal Drawdown:** 5% - 25 years
- **Condenser temperature:** 38°C
- **Plant:** Double Flash Steam.

The wellhead temperature in this case is 195°C and the net power sent out is 4.3 MW. The resulting unit cost is about 8 pence per kWh.

In this calculation the drilling costs amount to £11.4 x 10^9 and have been estimated assuming that the current low market demand for drilling supplies and service persist. If this changes and demand rises in relation to the capacity of the industry, as must be expected, then drilling costs could be substantially higher than this. The costs of the stimulations have been calculated assuming that viscous gels have been used -(see ref 6.) If water can be used then significant reductions in cost are possible. The wellhead temperature is significantly below the bottom hole temperature of the injection well (220°C) because the reservoir extends over a significant vertical distance.

3.2) Variation in Unit Cost with depth and gradient

Figure 5 shows how unit costs vary with depth in settings with different thermal gradients. Clearly higher gradients give lower costs at each depth due to the higher wellhead temperatures, but the model does not predict very low costs in any setting. Currently the model is limited to bottom hole temperatures of about 310°C to reflect the difficulty of drilling and stimulating at high temperatures. Also it is not clear whether there will be many regions which are suitable for HDR development in which high gradients persist to great depths. Bottom hole temperatures in the region of 300°C may represent the maximum which could be attained in European settings away from the wellknown high temperature areas where natural high enthalpy geothermal fields are found.

The trend of cost with depth indicates further reductions beyond the deepest systems allowed. Temperature effects on drilling costs are difficult to allow for and the drilling model is probably optimistic in this regard. As this is improved it is expected that unit costs will level out with depth and indeed begin to
rise again when high temperatures are reached.

3.3) **Sensitivity to impedance**

Figure 6 shows how unit cost may vary with impedance and flow. At fixed impedance, increasing flow initially produces lower unit costs due to the extra production. Eventually parasitic losses at high flows reduce output and unit costs again begin to rise.

In figure 7 the data are replotted to show the effect of increasing impedance at fixed flow. Costs are relatively insensitive to impedance initially but there is a threshold above which extremely high costs are obtained. The basic data on these graphs have been plotted assuming that no pressure limits apply. In practice it will not be possible to exceed the maximum horizontal stress confining the reservoir when operating the system. Otherwise water losses would become unacceptable and seismic events could be triggered. The result is a restriction on the combinations of impedance and flow which can be allowed in practice. Figure 8 shows a replot of figure 7 but with all cases which exceed pressure limits omitted. Clearly, target system flow and impedance are determined by pressure limits rather than by the parasitic losses.

3.4) **Sensitivity to Heat Production and Reservoir Size**

Figure 9 shows how unit costs vary with the heat production from the rocks. Here number of stimulations refers to separate stimulated zones each of which is 60 x 10^6 m³ in volume. It is important when investigating the effect of reservoir size on costs that the effect of flow is investigated. Reservoir volume, flow thermal drawdown and the definition of system lifetime interact in a way which can have important effects on costs. Figure 12 shows how unit costs vary with different sized reservoirs as different amounts of heat are produced by injecting different flows. The effects of pressure limits have not been included in this case. Clearly with larger reservoirs more heat can be extracted and this brings down unit costs. However, diminishing returns are eventually reached when adding new zones in the shallowest, coolest part of the system does not produce sufficient heat to justify the additional costs. These particular results do not indicate this but suggest that it may be cost effective to add an additional zone. It is the modelling of thermal performance which is likely to change most during the final development phase and consequently the nature of these results is also likely to change substantially.

**Conclusions**

The cost modelling is in an advanced stage and it is already revealing valuable insights into the costs and
behaviour of HDR systems.

REFERENCES


Fig. 1 - Example of Well and Reservoir Geometry

Reservoir consisting of 3 stimulated zones, each with individual volumes of $60 \times 10^6 \text{ m}^3$ separated by 50 m along the wells

Drilling Conditions:
Rate of penetration = 5 m/hr
Bit Life = 16 hr

NB: Not drawn to scale
where:-

$I_1$ - Fractional loss of availability in machines ("0.15)

$I_2$ - Fractional loss of availability in the heat exchanger ("0.2)

$E_h$ - Loss of availability in flash vessels ("0.3)

$L_t$ - Turbine leaving loss ("0.1)

Net electrical power = $E_g.W_c - W_{co} - W_b - W_t - W_a$

heat extracted from fluid (Pg)

$P_g = Z.M_f.(H_i - H_o)$

cycle net power (Wc)

$W_c = Z.M_f.E_t.(1 - L).E_h.((H_i - H_o) - T_c.(S_i - S_o))$

where:-

1 - $E_m$ - fractional loss of availability in machines ("0.15)

1 - $E_h$ - fractional loss of availability in the heat exchanger ("0.2)

$E_t$ - Turbine adiabatic efficiency

$E_h$.loss of availability in flash vessels ("0.3)

$L_t$.turbine leaving loss ("0.1)
Fig. 4 - HOT DRY ROCK COST BREAKDOWN

Capital Cost (SS) £21.08M
Capital Cost (SP) £5.78M
Other Costs £2.18M
O & M (SP) £1.52M
O & M (SS) £7.18M

SS = Subsurface
SP = Surface Plant

Fig. 5 - Unit Cost v Depth

Unit Cost (p/kWh)

5 stimulations
75 kg/s, 0.5 MPa-s/kg

Thermal Gradient as shown
Fig. 6 - Unit Cost v Flow Rate

Fig. 7 - Unit Cost v Impedance

Fig. 8 - Unit Cost v Impedance

Fig. 9 - Unit Cost v Heat Extraction
ECONOMICAL ANALYSIS OF HDR FOR SPACE HEATING IN FRANCE

P IRIS

CIG - Ecole des Mines de Paris

This paper resumes the actual results of a study which has been undertaken in order to evaluate the HDR potential for space heating in France in relation with the existing space heating urban networks.

This study is financed by and for the Agence Française pour la Maîtrise de l’Énergie.

The objective of this work is to answer to the following main questions in the hypothesis of a technical success for the HDR technology:

1- What would be an estimate cost of the HDR delivered heat?
2- What is the potential market of it regarding the existing district heating networks in France?
3- In the case of an experimental doublet in Soultz-sous-Forêt in Alsace, is it possible to valorize the delivered heat on the site?

COST ANALYSIS

We have developed a simplified model taking into account the main physical phenomena such as hydraulical losses in the underground exchanger density effect in the wells, thermal decreasing (integrating Smolka-Kappelmeyer modelling results: HDR.EC) etc... Then taking into account technical parameters (depth, flow rate, etc...) and costs (for investment and maintenance) we obtain the cost of the thermal produced MWH by a cost analysis with actualisation.

The main question is to choose correctly the values of the key parameters. Of course the actual state of the art does not insure that they will be obtain. In that field, we assume the technical success of the HDR technology: the values of hydraulical impedance and losses, for example, are chosen according to the theoretical objectives of the scientific community and the actual field results. A range of variation of these parameters has been also defined in order to evaluate the HDR cost as a function of the quality of the technical success.

A HDR thermal operation deals with surface installation: the HDR doublet is integrated in an urban heating network, as “base” energy, working at its own nominal power for a long time in the year.
The reference case has the following parameters: (1 US$ 89 = 6.2 FF - HT means without VAT)

<table>
<thead>
<tr>
<th>PARAMETER</th>
<th>REFERENCE CASE</th>
</tr>
</thead>
<tbody>
<tr>
<td>geothermal gradient</td>
<td>30°C/km</td>
</tr>
<tr>
<td>init. produc. temp.</td>
<td>180°C</td>
</tr>
<tr>
<td>reinj. temp.</td>
<td>90°C</td>
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<tr>
<td>heat exchange area</td>
<td>2 km²</td>
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<tr>
<td>production flow rate</td>
<td>70 l/s</td>
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<tr>
<td>hydraulic impedance</td>
<td>0.2 MPa/l/s</td>
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<tr>
<td>water losses</td>
<td>10 %</td>
</tr>
<tr>
<td>failure rate</td>
<td>10 %</td>
</tr>
<tr>
<td>annual load factor</td>
<td>70 %</td>
</tr>
<tr>
<td>initial annual delivered heat</td>
<td>2.5 MF + 3 % of surface instal. cost</td>
</tr>
<tr>
<td>well costs</td>
<td>7.5 P.exp(0.1P) MF/well (P=depth)</td>
</tr>
<tr>
<td>water cost</td>
<td>1 F/m³</td>
</tr>
<tr>
<td>electricity cost</td>
<td>400 F/MWh</td>
</tr>
<tr>
<td>site installation cost</td>
<td>5 MF</td>
</tr>
<tr>
<td>development cost</td>
<td>15 MF</td>
</tr>
<tr>
<td>maintenance cost</td>
<td>2.5 MF + 3 % of surface instal. cost</td>
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<tr>
<td>surface instal. cost</td>
<td>0.4 MF/thermal MW</td>
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<tr>
<td>actualisation rate</td>
<td>8 %</td>
</tr>
<tr>
<td>duration of calculation</td>
<td>20 years</td>
</tr>
<tr>
<td>construction duration</td>
<td>3 years</td>
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<tr>
<td>operating duration</td>
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<td>average depth</td>
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<tr>
<td>production rate</td>
<td>63 l/s</td>
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<tr>
<td>initial power</td>
<td>24 MWh</td>
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<tr>
<td>power after 17 years</td>
<td>12 MWh</td>
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<tr>
<td>initial electrical power</td>
<td>962 MWh</td>
</tr>
<tr>
<td>initial annual delivered heat</td>
<td>145 TWh</td>
</tr>
</tbody>
</table>

investment costs

| wells                           | 161 MF (HT) (84 %) | 26 M US$ |
| surface installation           | 11 MF (5.5 %)      | 1.8 M US$ |
| site installation              | 5 MF (2.5 %)       | 0.8 M US$ |
| underground development        | 15 MF (8 %)        | 2.4 M US$ |
| total                          | 192 MF             | 31 M US$ |
| maintenance cost               | 2.8 MF/an          | 0.45 M US$ |
| pumping cost year 1            | 2.4 MF/an          | 0.35 M US$ |
| water cost                     | 0.15 MF/an         | 0.02 M US$ |

HDR MWH cost for a none actualized benefice:

a) $302 F/MWH \approx 50$ US$/MWH$

HDR MWH exploitation cost (without investment):

b) $55 F/MWH \approx 9$ US$/MWH$
Cost a) has to be compared with classical fuel prices as natural gas or oil which are about half this cost in France nowadays. Coal is cheaper (about one third) but also needs higher installation costs which makes the comparison more difficult.

Figure 1 shows cost analysis for different situations around this reference case, taking into account the following parameters, every others being conserved (see ref. case):

- low technical success: $S^-$
  - impedance = 0.6 MPa/l/s
  - losses = 20%
  - flow rate = 50 l/s
  - surface = 1 km$^2$
  - favorable gradient: $G^+$
    - gradient = 40°C/km

- high technical success: $S^+$
  - impedance = 0.1 MPa/l/s
  - losses = 2%
  - flow rate = 70 l/s
  - surface = 4 km$^2$
  - favorable network: $R^+$
    - load factor: 85%
    - network return temp.: 65°C

As a conclusion, it appears that:

In an average case of "reasonable" technical success (which as not already been reached), HDR provides an energy cost about two times the actual price of classical fuels, which is in the order of magnitude of energy cost before the heakdown of 1986.
Better results can be obtained in the case of:
- higher geothermal gradient,
- urban networks with:
  - high annual load factor (summer needs),
  - low return temperature.

MARKET ANALYSIS
The market analysis takes into account two major elements:
- statistics about French urban heating networks,
- deep underground estimated temperature from the European atlas of underground temperatures.

Concerning the networks, we have selected those with nominal power over 50 MW, and with classical fuels as energy sources. The power of the associated HDR operation being around 20 MW, and about 25% of the peak power of the network itself. For large district heating systems, the HDR disposal can have several doublets.

Each doublet is supposed to be similar to the reference case doublet.

The cost of the produced HDR MWH is calculated region by region (France is divided in 20 regions) according to the estimated local geothermal gradient.

The global results are the following:

- total number of heating networks in France ................. 278
- number of networks over 50 MW .......................... 83
- selected networks over 50 MW for HDR .................... 60
- number of potential HDR doublets ......................... 86
- total HDR thermal power ...................................... 1700 MW
- annual HDR heat ................................................ 8.7 TWH

This represents about 3% of the total domestic heat demand in France.

- HDR MWH : 350F to 400F .................. 19% of the doublets
- HDR MWH : 300F to 350F .................. 72% of the doublets
- HDR MWH : 250F to 300F .................. 9% of the doublets

Alsace appears to be an interesting region, due to its high geothermal gradient and its HDR potential.

Figure 2 represents the results for each region.

CASE OF SOULTZ-SOUS-FORETS
The last part of our study is to estimate thermal needs around the experiment site of Soultz-sous-Forêts where a primary HDR well has already been drilled. This question has not already been treated in details. Rough information can be presented.
Figure 2.

It appears that an interesting consumer is located near by the site: a factory which thermal annual needs are about 240 tons of oil equivalent. This consumption is planned to increase significantly in the next years.

The connection to an eventual future doublet on the site would make necessary to change the distribution system inside the factory which consists in warm air generation.

A rough analysis indicates that a doublet of 2 MW with the following parameters could provide a significant part of this demand:

- production temperature .................. 110°C
- return temperature ..................... 80°C
- flow rate .............................. 16 l/s

Such a disposal represents about one tenth of an industrial HDR feature.

Other consumers (schools, little industries, hotels, etc...) do exist at Soultz, but would need an important length of network in respect to their thermal needs.

CONCLUSION

This study has shown that, in the case of utilizing HDR for space heating in France, a technical success could lead to a cost of the delivered heat, about twice the cost of the actual classical fuels.

The market for large scale existing urban network represent about 3% of the total heat demand in France for space heating and a little less than 100 HDR doublets of about 20 thermal MW each.

Compare to electricity, the thermal utilization of HDR technology avoids the conversion factor, which dramatically decreases the effective utilized heat.

On the other hand, this application for space heating is not obvious according to the scale effect: the selected urban network have an average power between 50
MW and 100 MW which is not very high; the demand is scattered and in general each operation would require one or two HDR doublets. So the notion of HDR field exploitation, with scale effect on prices and on underground recognition means, this notion does not fit, with space heating application. In that sense the thermal utilization for HDR resources is more accurate than electricity production.

REFERENCES
- KAPPELMEYER-SMOLSKA model HDREC.
Heat extraction from impervious hot rock sections in some thousand meters depth (HDR systems) implies a complicated and expensive technological procedure, where various site specific geological and geophysical parameters as well as design criteria of technical installations determine the costs of the produced energy (electricity or space heat).

Within the frame of the Soultz Project a cost benefit model for an economic appraisal of industrial electricity producing HDR power plants was developed. In this model the costs for construction and operation of the HDR system and the power station are determined and considered in respect of the revenues received from the sale of the produced electricity. The economic approach comprises comprehensive modelling of the performance of the HDR reservoir as well as a detailed economic cost evaluation.

The model is realized in the computer program HDREC (HDR Economic Cost evaluation program). This program can be used as an excellent tool for sensitivity analyses of the energy production costs. It serves for an evaluation of cost limits and a definition of research goals for an improvement of the economic performance of HDR systems as well as for the exploration of suitable natural conditions in the underground. In this paper it is applied for a preliminary economic appraisal of a HDR power plant in Soultz sous Forets.

1. Introduction

In a cost benefit model the costs for construction and operation of a HDR power plant are determined and considered in respect of the revenues received from the sale of the produced electricity. The components of the plant: a doublet of deep boreholes, the stimulated HDR reservoir and the surface installations including pumps for fluid circulation and the power station, are defined and compiled into a structure diagram which reveals the mutual interactions between various cost determining parameters (Fig. 1).
Figure 1  Technical and Financial Structure of a HDR Plant

Compiled by: K. Smolka
October, 1988
2. Cost Benefit Model

The approach in the cost benefit model consists of four sequential stages:
- determination of HDR specific parameters describing the conditions at a specific site and specification of the criteria defining the technical design of the HDR plant
- modelling of the performance of the HDR reservoir
- determination of the investments of the HDR system and the power station and the costs of its operation as well as of the revenues
- economic cost evaluation

2.1 Parameters and Criteria

The site specific natural input parameters of the model: geothermal gradient, rock temperature, in-situ stress, physical properties of rocks and joints, have to be obtained by measurements in a borehole.

The technical design criteria: depth, geometry and completion of the boreholes as well as the production rate and production period are closely related to the demands for acceptable flow impedance, temperature and thermal power of the HDR reservoir, electric capacity of the power station and tolerable drawdown of the energy production.

2.2 HDR Reservoir

The central component of the HDR circulation system is the HDR reservoir. It is created artificially by massiv hydraulic fracturing, consisting of stimulated natural joints and newly generated fractures. This network of hydraulic paths serves as heat exchanger, but imposes a considerable flow resistance during a fluid circulation. Its thermal efficiency is determined by the rock temperature, the size and geometry of the fracture network and the flow rate of the circulation. Another property, which is decisive for the economy, is the hydraulic impedance of the network, determined by the transmissivities of the individual hydraulic components of the reservoir. Fluid losses during circulation can be high and have also to be taken into account.

Various sophisticated analytical and numerical models considering the thermal, hydraulic and mechanic behavior of a stimulated multi fracture system for evaluation of the reservoir performance are incorporated in the economic model. The hydraulic characteristics of the flow paths are derived from a model describing the hydraulic behavior of fractures in crystalline rocks (JUNG, 1987). The thermal power of the reservoir and its drawdown in the course of time are evaluated from a heat exchange model, which
considers the flow and pressure potential between inlet and outlet of the reservoir as well as the superposition of cooling effects between adjacent fractures (HEUÈR, 1988).

2.3 Power Station

The temperature of the geothermal heat is far from ideal for heat power conversion. Best efficiencies at these relatively low temperatures are obtained with ORC systems. Power stations based upon an ORC design are considered (MILORA & TESTER, 1976). The utilization efficiency of heat for power is derived from the model of HARRISON (1989). ORC systems are problematic regarding the environment (FCKW). It is desirable to develop high efficient power stations using working fluids, which are compatible with environmental demands.

2.4 Financial Model

2.4.1 Investments and Operation Costs

The capital investment for:
- the boreholes is mostly determined by the depth, which depends upon the geothermal gradient and the envisaged reservoir temperature for heat production (GARNISH, 1987)

- reservoir stimulation is determined by the stimulation time and the necessary power of pumps, which depends upon the in-situ stress, the rock permeability, the transmissivities of joints and, of course, the size of the envisaged reservoir. The stimulation time is estimated from a fracture mechanical model describing the propagation of fractures driven by a constant fluid pressure with homogeneous fluid losses into the host rock (RUMMEL, 1987)

- pumps, which may be necessary to drive the fluid circulation through the overall circulation system: injection borehole, HDR reservoir, production borehole. Their power demand is determined by the flow resistances in all parts of this circulation system. Due to the difference of densities between the fluid in the injection and production borehole a buoyancy drive occurs, which favours the circulation and diminishes the power demand

- the power station, which is fixed by its capacity

The costs for operation of the HDR plant include:
- costs for general maintenances of the boreholes and the reservoir, which are assumed to be a certain portion of the relevant investments
- costs of water for compensation of losses during circulation, which depend upon the in-situ stress and the hydraulic characteristics of the joint system
- energy costs for the pumps for water circulation, which are determined by their power demand
- costs of operation of the power station, which are fixed by its electric capacity

2.4.2 Economic Cost Evaluation

The economic cost evaluation is based upon the NET PRESENT VALUE METHOD and the PRESENT VALUE METHOD. Their criteria for an economic appraisal are: NET PRESENT VALUE of the investments and LEVELIZED LIFE CYCLE ENERGY COSTS. The principles of the financial methods are discussed in detail by JAGER (1982); the algorithms for the determination of their criteria are described by HARDIE (1981). Additionally the specific energy cost and the outstanding capital debt in each production year can be determined.

Within the cost evaluation, time variable operation costs as well as time variable revenues are considered. The time dependance is due to the drawdown of the produced electricity and an annual escalation of the operation costs. Furthermore a simple taxation model is included and reinvestments for plant components can be taken into account.

3. Computer Program HDREC

The cost benefit model is realized in the computer program HDREC (HDR Economic Cost evaluation program). It is written in FORTRAN and can be executed on PC/AT micro computers under the operating system MS/DOS.

HDREC is a dialogue orientated, fully menu driven program composed of interacting modules. Its robust, but flexible code structure enables a very user friendly operation. HDREC is a very versatile program. In particular it can be used as an excellent tool for sensitivity analyses of the energy production costs. They can be evaluated as a function of decisive natural input parameters, technical installation criteria or financial parameters.

The algorithms for determination of all results of the cost benefit model as well as the computational facilities and the use of the program are described in detail in a comprehensive user manual (SMOLKA, 1989).
4. Economic Appraisal of a HDR Plant in Soultz sous Forets

The application of HDREC is demonstrated in the following economic appraisal of a hypothetic HDR power plant at the site of Soultz sous Forets.

The data of the geological and geophysical input parameters were obtained from the borehole measurements in GPK 1. A geotherm al gradient of 80 °C/km in the sediments and of 30 °C/km in the crystalline basement is used. The technical design of the HDR circulation system i.e. depth, geometry and completion of the injection and production borehole, is considered according to the proposed design of the scientific HDR prototype (GERARD and KAPPELMeyer, 1989). A HDR reservoir consisting of three heat exchanger modules, which are equivalent to discs with a size of 1 km\(^2\) and a width of 2 m, is assumed. The fluid is circulated with a injection rate of 90 l/s (30 l/s per module) and a production rate of 75 l/s. A injection temperature of 50 °C and a initial production temperature of 175 °C are considered. Heat losses in the injection and production borehole are neglected.

![Graph showing the distance between fractures and production temperature over time.](image)

**Figure 2** Thermal Behavior of a HDR Reservoir
3 Modules; 1 km\(^2\) each; 25 l/s per Module
Fig. 2 shows the production temperature and the thermal power of the HDR reservoir and their drawdown in the course of time for distances between the fractures of 1 m, 10 m, 50 m and infinite. The drawdown increases dramatically with decreasing distance.

The hydraulic performance of the HDR system is demonstrated in Fig. 3. The hydraulic power demand of pumps, which is necessary for fluid circulation through the overall system and through the reservoir, as well as the impedance of the system are calculated as a function of the transmissivity of the reservoir. The power demand strongly decreases with increasing transmissivity. For transmissivities lower than 300 Dm the power demand is mainly determined by the flow resistances in the reservoir; for higher transmissivities the influence of the flow resistances in the boreholes dominates.

The results of the economic appraisal are given in Fig. 4 and 5.
Figure 4 Sensitivity Analysis Energy Costs / Depth

Figure 5 Costs of Power Production during Lifetime of the Plant
Fig. 4 shows a sensitivity analysis of the levelized life cycle energy costs as a function of depth for production rates per module of 15 l/s, 25 l/s and 30 l/s. The energy costs decrease with increasing depth up to an optimum depth between 4 and 6 km depending on the production rate and increase again for greater depth. The decrease is due to the reduction of the specific investments of the plant per installed electric capacity of the power station. For depths greater than the optimum depth the increase of the costs of boreholes dominates.

Fig. 5 gives a detailed cash flow analysis of the specific energy costs in each production year for the case of minimum levelized energy costs i.e. a depth of 4.8 km and a production rate per module of 25 l/s. The increase of the costs in the course of time is due to a decrease of the produced electricity and an escalation of the operation costs (an escalation rate of 1% per year is assumed).

5. Acknowledgements

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6. References


Author's address:

K. Smolka and Dr. O. Kappelmeyer, Geothermik Consult, Kappelmeyer GmbH, Nikolastr. 18, D-8390 Passau
SUMMARY

This paper describes a novel binary system developed specifically for the recovery of electrical power from liquid dominated geothermal resources and especially Hot Dry Rock. It is based on the successful development of efficient two phase expanders for organic working fluids and can yield outputs considerably higher than from ORC or double flash steam systems. Results of a detailed design study show that for a brine flow of 75 kg/s at 200°C from Cornish Hot Dry Rock, the nett recoverable rate of electrical power is 6.75 MW, for a total installed cost of £7.35 million, corresponding to $11.76 million at 1987 prices.

1. INTRODUCTION

In all geothermal power generation systems there is an economic trade off between cost and conversion efficiency or power output. In general, the best power system is that which minimises the total cost per unit power output, where total cost includes both the brine recovery and the surface power plant. It follows that in HDR systems, where the cost of brine recovery is very high, first consideration must be given to the efficient conversion of the available heat to power rather than to minimise the cost of the surface plant only.

Ideally the best method of converting the available heat in the brine into power is to expand the entire brine flow adiabatically and reversibly to the temperature of the available coolant. Flash steam systems expand part of the brine adiabatically but have the disadvantages of large losses in available energy or exergy, in the flashing processes required to obtain steam from the hot water, relatively low turbine efficiencies due to the increasing wetness of saturated steam as it expands in the turbines and relatively large auxiliary power requirements for deaeration of the condensers. Various attempts have been made to improve on the basic flash steam concept which include multi stage flashing, total flow systems[1], and the replacement of the throttle valve and flash separation chamber by a biphase turbine[2]. Two stage flash steam plant produces 20-30% more power than single stage plant and is now widely used but neither total flow systems nor the biphase turbine have hitherto made any impact. This is basically because two phase expanders of water steam mixtures need to have an adiabatic efficiency of at least 70% in order to compete with conventional turbines and to date such

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1 Reader in Mechanical Engineering, City University, London
2 Engineering Director, TFC Power Systems Ltd.
efficiencies have not been attained. The alternative approach is to use a binary system where the brine is cooled at approximately constant pressure to heat a more volatile fluid contained in a closed system which normally operates in some form of the Rankine cycle. The volatile fluid system incorporates dry vapour expansion in the turbines and the resultant higher expansion efficiencies thereby achieved compensate for the loss of availability due to irreversible heat exchange. In effect, purely from the thermodynamic viewpoint, there is not a great deal of difference between a two stage flash steam system and an Organic Rankine cycle binary system since the overall losses due to flashing and lower turbine efficiencies are roughly equal to those due to heat exchange in the organic fluid boiler. The Trilateral Flash Cycle system is effectively a binary system which requires less irreversibility in the primary heat exchanger than any other so far proposed while using an expansion system with efficiencies close to those of dry turbines. Overall it is therefore capable of a significantly higher power output and hence produces electricity at lower cost.

2. THE IDEAL CYCLE

The requirements for ideal power recovery from a single phase heat source such as HDR brine can be expressed in a variety of ways but are most easily understood by reference to the classical Carnot cycle originally demonstrated as the ideal heat engine to operate between an infinite heat source and sink. Cooling brine exchanging heat with the atmosphere can be considered ideally as utilising a succession of infinitesimal Carnot cycles to maximise power recovery as shown in Figure 1, on Temperature-Entropy co-ordinates. In the limit this can be shown as a single cycle with a varying source temperature as shown in Figure 2 which has been described[3] as an Ideal Trilateral cycle. It can be shown quite simply from the assumption of the Carnot efficiency at each stage integrated over the cooling range of the brine that the maximum conversion efficiency of such an ideal heat engine can be expressed as:

\[
\text{Cycle Eff.} = \frac{T_1}{\frac{(T_1 - T_2)}{T_2}} - \frac{T_2}{\frac{(T_1 - T_2)}{T_2}} \ln \frac{T_2}{T_1}
\]

The same result can also be derived by considering the exergy change of the brine as it cools from its initial state to ambient temperature.
3. PRACTICAL REALISATION

A binary system to meet the requirements of an Ideal Trilateral cycle would in reality have to appear as shown in Figure 3 including the entropy change of the brine, working fluid and coolant. It can be shown from exergy considerations that the loss in available power due to the temperature rise of the cooling water is quite small and attempts to minimise this by increasing the cooling water flow are self destructive since they lead to huge auxiliary pump power requirements. The main need is therefore to make the slopes of the cooling brine and heating working fluid as nearly equal as possible. The temperature difference between them can then be made as small as is economically permissible by the size and cost of the primary heat exchanger. A variety of methods have been attempted to achieve this.

![Figure 3](image1.png)

**Figure 3.**

![Figure 4](image2.png)

**Figure 4.**

The first of these is to use a fluid with a relatively low latent heat as in the subcritical ORC system as shown in Figure 5. This can be further improved by the greater complexity of a series of subcritical ORC systems each operating in series at a different evaporating temperature. A further and simpler method is to use a supercritical ORC system as shown in Figure 5. This has a less obvious disadvantage of generally requiring a large feed pump power.

![Figure 5](image3.png)

**Figure 5.**

![Figure 6](image4.png)

**Figure 6.**

A further and more recently publicised method is to use a Kalina cycle, a simple form of which is shown in Figure 6[4]. This works on a rather more complex thermodynamic principle and involves the boiling of a rich water ammonia solution and the condensation of a
dilute solution. The change in concentration is due to internal heat transfer similar to that involved in absorption refrigerators. The disadvantage of this system is the large number of heat exchangers required to effect it and its rather sensitive control.

Another method is to utilise the properties of volatile fluids in a slightly different way and that is to heat the fluid to its boiling point only and then to expand it adiabatically as a two phase mixture which flashes into vapour as the pressure drops. This is shown in Figure 7. The advantages of this system are that it achieves the closest matching of all in the primary heat exchanger yet requires only four basic components, as in the ORC, namely, the primary heat exchanger, expander, condenser, and feed pump, as shown in Figure 8. In addition by cooling the brine more effectively than any other binary system the thermosyphon effect of reinjection is maximised and hence the auxiliary power required for brine circulation is minimised. Its disadvantage is that two phase expansion is required. This was originally called by the authors a Trilateral Wet Vapour cycle15] but for brevity this was later changed to Trilateral Flash cycle or TFC.

Figure 7.

4. TWO PHASE EXPANDER DESIGN FOR THE TRILATERAL FLASH CYCLE

Serious attempts to produce efficient two phase expanders were made in the U.S.A. during the 1970's in order to develop Total Flow systems. The main inspiration for work in this field was the proposal by Sprankle6] to use a Lysholm type screw machine as a direct two phase expander of geothermal brines. Two difficulties were discovered with this. The first was the enormous size of screw machine required for complete expansion of the brine, which was many times that of the largest screw compressor ever built. The second was the disappointingly low adiabatic efficiencies achieved with small and medium sized screw expanders in total flow simulation and true total flow experiments. An alternative approach was therefore tried to develop two phase turbines7] using either steam for total flow or organic fluids in what was effectively a TFC system. The results of the turbine development program were equally disappointing and it was difficult to predict efficiencies of greater than 65% with steam and possibly 70% with organic fluids on large scale machines.
In 1981 one of the authors was consulted by the C.E.G.B. on what type of ORC system might be the most suitable for a proposed HDR plant. Geothermal technology was at that time novel to the author, and as a result of his association with another and unrelated study on Liquid Metal Magnetohydrodynamics carried out at the same time, the TFC principle was conceived independently of any American work. A preliminary analysis of the relative merits of water and a variety of organic fluids assuming a condensing temperature of 35°C, was first performed, the results of which can be summarised as follows:

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Brine Temp. (°C)</th>
<th>Volumetric Expansion Ratio</th>
<th>Exit Flow Rate per Unit Output (cu m/s /MW)</th>
<th>Relative Net Output (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>100</td>
<td>1500</td>
<td>125</td>
<td>100</td>
</tr>
<tr>
<td>Organic</td>
<td>50</td>
<td>10</td>
<td>10</td>
<td>98</td>
</tr>
<tr>
<td>Water</td>
<td>200</td>
<td>5000</td>
<td>50</td>
<td>100</td>
</tr>
<tr>
<td>Organic</td>
<td>160</td>
<td>5</td>
<td>5</td>
<td>95</td>
</tr>
</tbody>
</table>

It was concluded that the very large reduction in both expander size and volumetric ratio achievable with organic fluids more than compensated for the small performance penalty. A programme of work to develop an efficient two phase organic expander was therefore undertaken.

An experimental study of Lysholm screw expanders using organic fluids expanding from either saturated liquid or the wet vapour condition was carried out and the results were surprisingly good, with peak adiabatic efficiencies of 72% and average efficiencies of 65% attained over a wide range of operating conditions on a 204 mm rotor machine with a built in volumetric ratio of 5:1 at power outputs of up to 30 kW. This was far better than the results obtained with similar machines using water and led to predictions of expander efficiencies of 75% or more on larger machines. On the strength of these and other studies a detailed study was carried out on how to design an efficient expander for a HDR application assuming an initial brine temperature of 200°C.

Detailed studies of Lysholm screw characteristics, made with the aid of experienced manufacturers and confirmed by further experiment and compressor experience, showed that a built in volumetric ratio of 5:1 with a pressure drop across the rotor not exceeding 10 bar is probably the upper limit for high efficiency operation. A further feature of the study was that the overall volume ratio achievable in a screw expander is considerably larger than the built in ratio due to significant pressure drops in the expander inlet port and at the rotor inlet. These much exceed the values associated with dry gas compressors because of the high fluid density.

At higher brine temperatures it is possible to expand some organic fluids adiabatically from saturated liquid to dry or even superheated vapour, as shown in Figure 9. On this basis an expander train can be constructed in which the initial wet vapour expansion can be carried out in one or two screw expanders in series followed by expansion to dry vapour in a conventional radial inflow turbine nozzle ring and
hence a final turbine rotor stage with an efficiency equal to that of the best ORC system. Such a system was examined as the expander for a hot dry rock power plant in which brine at 200°C leaves the production well at a rate of 75 kg/s and is shown schematically in Figure 10. This is described in detail in Ref. [8].

A revised specification and performance estimate based on updated studies is as follows:

**Working fluid:** n-pentane  
Working fluid inlet temperature: 182°C  
Working fluid mass flow rate: 120 kg/s

**High pressure screw expander:**  
Rotor diameter: 450 mm  
Rotational speed: 1650 r.p.m.  
Rotor pressure drop: 9.8 bar  
Built in volume ratio: 3.3:1  
Estimated adiabatic efficiency: 74%  
Power output: 900 kW

**Low pressure screw expander:**  
Rotor diameter: 700 mm  
Rotational speed: 1650 r.p.m.  
Rotor pressure drop: 6.8 bar  
Built in volume ratio: 3.2:1  
Estimated adiabatic efficiency: 78%  
Power output: 2400 kW

**Turbine:**  
Pressure drop: 4.1 bar  
Overall pressure ratio: 6.1  
Estimated adiabatic efficiency: 85%  
Power output: 6000 kW

**Overall Expander Power:** 9300 kW  
**Overall Expander Efficiency:** 83%

It should be noted that:

1) The built in volume ratio of the screw expanders is well within the normal limits of screw compressor designs.
2) The pressure drop across the rotors is less than 10 bar as recommended and the larger screw which produces more power has the lower pressure drop and hence the higher efficiency.
3) The screw expander sizes are within the limits of normal large screw compressors.
4) Both expanders rotate at the same speed and hence can be directly coupled in tandem.
5) Nearly 65% of the power is developed in the turbine and hence the overall expansion efficiency is not too dependent on the screw expander outputs meeting their design specification. Thus, if the high pressure expander only attains an efficiency of 70% the gross power output will be reduced by only 50 kW, i.e. about 0.5%. Hence the confidence measure of the design output being attained is very high.
6) The working fluid is a plain hydrocarbon with neither the thermal stability nor environmental pollution problems associated with halogenated hydrocarbons.

5. SPECIFICATION OF A COMPLETE TFC SYSTEM FOR HOT DRY ROCK POWER RECOVERY

A complete specification for power recovery from a HDR reservoir using a TFC system operating in Cornwall, U.K., has already been reported.[8] The principal parameters of concern in evaluating electricity generation costs are as follows:

Resource Details:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brine flow</td>
<td>75 kg/s</td>
</tr>
<tr>
<td>Brine Supply temperature</td>
<td>200 °C</td>
</tr>
<tr>
<td>Mean Annual cooling water temp.</td>
<td>19 °C</td>
</tr>
</tbody>
</table>

Performance:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Gross Electrical power output</td>
<td>8840 kW</td>
</tr>
<tr>
<td>Average Continuous Auxiliary power</td>
<td>1735 kW</td>
</tr>
<tr>
<td>excluding geothermal brine pump</td>
<td></td>
</tr>
<tr>
<td>Nett Average Electrical power output</td>
<td>6750 kW</td>
</tr>
<tr>
<td>excluding geothermal brine pump</td>
<td></td>
</tr>
</tbody>
</table>

Because the TFC system utilises a higher proportion of the heat in the circulating brine than comparable systems such as the Organic Rankine cycle, the brine return temperature is lower. Thus the return temperature is typically 40°C compared with 70°C for an ORC. As a result the thermosyphon effect due to differences in the density of the brine in the flow and return wells, the reinjection pump differential is reduced by 7.75 bar for a reservoir depth of 6 km. For a flow rate of 75 kg/s the power thereby saved is approximately 80 kW. Thus using the estimates for brine pressure losses given in ref.[9]:

Additional pumping power for geothermal fluid 355 kW<sub>e</sub>

Hence

Nett average Electrical power output 6750 kW<sub>e</sub>
Cost Based on November 1987 prices:

<table>
<thead>
<tr>
<th>Item</th>
<th>Cost £</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment</td>
<td>2,780,390</td>
</tr>
<tr>
<td>Equipment installation</td>
<td>28,110</td>
</tr>
<tr>
<td>Piping</td>
<td>395,000</td>
</tr>
<tr>
<td>Piping installation, fabrication &amp; testing</td>
<td>775,000</td>
</tr>
<tr>
<td>Electrical including installation</td>
<td>379,000</td>
</tr>
<tr>
<td>Instruments</td>
<td>388,000</td>
</tr>
<tr>
<td>Instrument installation</td>
<td>85,000</td>
</tr>
<tr>
<td>Steelwork</td>
<td>187,670</td>
</tr>
<tr>
<td>Steelwork erection</td>
<td>167,330</td>
</tr>
<tr>
<td>Civils including labour costs</td>
<td>955,000</td>
</tr>
<tr>
<td>Insulation, fireproofing, etc.</td>
<td>45,000</td>
</tr>
<tr>
<td>Design, Engineering &amp; Licence testing</td>
<td>1,166,000</td>
</tr>
</tbody>
</table>

Plant Installed Cost

7,352,000

This corresponds to a cost of $11.76 million at the November 1987 rate of exchange.

ACKNOWLEDGEMENTS

The authors wish to acknowledge with thanks the financial assistance and support given by TFC POWER SYSTEMS Ltd., formerly Solmecs Corporation (U.K.) Ltd and especially its Chairman, Mr.P.Kalms; K.E. International; The City University, London; the U.K. Department of Trade & Industry; the U.K. Atomic Energy Commission Energy Technology Support Unit; Howden Compressors; Rolls Royce (Belliss and Morcom); Dr.C.A. Aldis, Mr.M. Abubaker and Mr.Z.G. Xu of The City University whose continuing efforts over this seven year programme have helped to prove the feasibility of the entire system.

REFERENCES

SESSION 4 – RESERVOIR CREATION
STIMULATION MODELLING

David A C Nicol, Matthew M Randall & Timothy W Hicks.

Camborne School of Mines Geothermal Energy Project, Rosemanowes Quarry, Herniss, Penryn, Cornwall, TR10 9DU.

ABSTRACT

A successful Hot Dry Rock (HDR) geothermal system requires the development of a large reservoir within a rock mass of enhanced permeability. The system's structure must provide a sufficient area of heat transfer and an acceptable impedance to flow. A number of experimental reservoirs have been created by the hydraulic stimulation of natural fractures. To date, none of these systems has met the criteria for a commercial HDR geothermal system.

The future success of HDR will depend on the consistent stimulation of commercial reservoirs. The development of this capability presents the major challenge currently facing HDR technology. This challenge will only be met through the understanding and control of the physical processes involved in reservoir stimulation. Numerical modelling of the fluid flow through stressed and jointed rock masses can provide much information essential in achieving this.

Considerable progress has been made, both conceptually and numerically, in understanding the role of natural fractures in stimulations. The FRIP family of codes has been developed to specifically model the fluid rock interaction. In conjunction with these codes, standard oil industry fracturing models have been used to describe processes such as complex rheology and proppant transport which the FRIP codes currently cannot handle.

INTRODUCTION

THE ROLE OF STIMULATION

The major challenge facing Hot Dry Rock (HDR) technology is to be able to create successful geothermal reservoirs consistently. Stimulation must provide access to a zone for heat transfer through enhancement of the permeability of the natural fracture network and increase in the effective drainage area of the producing well.

The objectives of permeability enhancement can be summarised as:

i) Create a uniform reservoir to maximise the effective volume swept by water flow.

ii) Minimise the reservoir impedance or pumping pressure for a given flow rate.
Allow a controlled thermal drawdown over the project life. Minimise the parasitic power consumption and environmental demands on the water supply by limiting water loss.

The required permeability enhancement depends on economic factors, but is likely to require an impedance of the order 0.1 GPa m\(^{-3}\)s (the target which has been set for the Camborne School of Mines (CSM) project). It is difficult to quantify "reservoir uniformity", but essentially it means the avoidance of major flow short circuits and minimise reservoir wastage. It may be difficult to create a reservoir which has low impedance and does not have short circuits.

**THE CSM EXPERIENCE**

Preliminary investigation of the natural permeability of the Carmenellis granite used four wells each drilled to a depth of 300 m. Subsequently, two wells (RH11 and RH12) were drilled each to a depth of 2 km. (A recent review of the CSM program is given in CSM(1987).)

In the initial stimulation of the reservoir (Phase 2A) 18500 m\(^3\) of water was injected into RH12 at flow rates of up to 90 l s\(^{-1}\). This resulted in a poor hydraulic connection between the two wells, but indicated a stimulated volume of some 20 x 10\(^6\) m\(^3\).

Subsequently, a further 230 x 10\(^6\) m\(^3\) (net) of water was injected into RH12 creating a stimulated zone of around 170 x 10\(^6\) m\(^3\). Over 5000 seismic events were located during this circulation. The predominant trend of growth of the reservoir during the circulation was downwards (Pine & Batchelor, 1984).

It should be noted that it is extremely difficult to accurately size the stimulated volume of a geothermal reservoir, and that estimates of size can vary by a factor of two or three. All the estimates of size in this paper have been obtained on a consistent basis.

In an attempt to improve the productivity of well RH11, some 400 m\(^3\) of a cross-linked gel with a nominal viscosity of 1 Pa s was injected at flow rates of up to 193 l s\(^{-1}\). Subsequent logging and TV inspections showed that axial fracturing had taken place over most of the open hole length of the well. However, no proppant was used and the net effect on water recovery was nil.

The impedance of the Phase 2A system was an order of magnitude too large and varied in the range 1-2 GPa m\(^{-3}\)s. There was also a significant water loss (approximately 70%) throughout the entire circulation, although much of the 'lost' water would have been used in the continuous creation of the ever enlarging Phase 2A reservoir.

Following this experience a new system was created at CSM in Phase 2B. It involved the drilling of a new well, RH15, to beneath the existing two wells. This system was stimulated from RH15 with the injection of 5000 m\(^3\) of gel with a viscosity of 50 mPa s. This created a reservoir of about 5 x 10\(^6\) m\(^3\), with a reduced impedance of 0.5-1.0 GPa m\(^{-3}\)s and reduced water loss. Circulation of the reservoir during Phases 2B and 3A has shown preferential channelling which has accelerated the thermal depletion of the reservoir (Nicol and Robinson, 1989).
In Phase 3A, the RH15 recovery well was re-stimulated with a highly viscous gel containing proppant in an attempt to improve the performance of the well. After the completion of this stimulation the proppant kept the fractures open, and so the hydraulic characteristics of the reservoir were changed.

NUMERICAL MODELLING

THE ROLE OF MODELLING

The modelling of the stimulation of a naturally fractured rock mass is intrinsically difficult. There is a major lack of geological information; knowledge of the joint distribution at relevant depths is necessarily limited and the nature of such joints' behaviour under stress is uncertain.

Practical experience in hydraulic stimulation can be used to refine existing models. The oil industry routinely carries out many stimulations of sandstone and limestone formations every year, permitting the growth of a large body of practical and, in turn, modelling experience. However, although large scale injections of water and viscous gel have been carried out by CSM, at Los Alamos, U.S.A, in Sweden and in Japan, the experience of stimulating crystalline rocks is extremely limited. Such experiments are costly, and it will only be possible for there to be a small number of extra stimulations on which to base the design of the first commercial HDR system.

Modelling must be used to supplement this limited practical experience in fracturing granite. It can help to minimise the risk and capitalise on the data that is available by defining the operating boundaries and determining the key parameters. Future efforts and experimentation can then be focused on these areas.

EXISTING HDR MODELS

The models applied to traditional hydrothermal reservoirs are in the main inapplicable to hot dry rock reservoirs. Typically these models address the problem of two phase (water and steam) flow, in which the reservoir is represented either by an equivalent porous media model or by a double porosity model. Such models, with particular reference to geothermal systems, are discussed by Grant et al, (1982).

One such model, the Finite Element Heat and Mass Transfer Code (FEHM) (Zyvoloski et al, 1988) has been used to model a 30 day test of an existing Hot Dry Rock reservoir (Birdsell and Robinson, 1988). However, although these models can be complex and include some pressure dependent permeability terms, they do not address the problem of the growth of HDR reservoirs.

Many researchers have studied flow in random fracture networks, with particular emphasis on radioactive waste disposal (Rouleau and Gale, 1985). Typically, Monte Carlo techniques are used to assess the effects of the characteristics of the joint sets (eg. orientation, trace length, aperture, spacing) on hydraulic properties, and to assess when fractured rock could be treated as an equivalent porous medium. This technique has some value in looking at the hydraulic
properties of the unstimulated reservoir, but in most studies, the fractures are rigid, and do not contain the necessary physics to describe the stimulation of an HDR reservoir.

The oil industry has developed many models which describe the fracturing operations carried out in intact rock in which fracture propagation is dependent on the tensile strength of the rock. These conditions may be met for a highly viscous injection and in the immediate vicinity of the wellbore. However, far from the wellbore in a naturally fractured reservoir, flow will tend to follow the natural fractures and shearing will be important. This is particularly true in crystalline rocks in which high stress anisotropies commonly occur (McGarr, 1980) and will always result in shearing at pressures below the hydraulic fracturing pressure (Murphy, 1982).

Thus the oil industry's models are of little value in describing the behaviour of the far field where shear effects have a substantial role to play. They are also of little value in describing the bulk stimulation of the reservoir, as carried out in Phase 2A, where the stimulation is dominated by the physics of fractures at pressures below those required to support the minimum principle earth stresses.

The oil field codes have, until now, maintained their place in stimulation design, due to their ability to model the complex rheology of the stimulation polymers, and the physics of proppant transport in fractures.

It is fortuitous that there is a point of contact between models describing fracturing of intact rock, and the flow of fluid in continuous joints without shear (Spence & Sharp, 1985). However, to model these important shearing effects and the behaviour of joints at pressures below those required to jack them open, one must turn to the discontinuum codes.

The discontinuum codes were developed for modelling jointed rock for applications in civil engineering and mining. A two-dimensional program, the Universal Distinct Element Code (UDEC), was developed to include within one package all of the features and experience gained from previous use of distinct element models (Cundall, 1980). Based on the UDEC code, the computer code FRIP (Fluid Rock Interaction Program) was then developed to include fluid flow. Modelling using this code has been reported by Pine and Cundall (1985). Subsequently, fluid flow has also been added to the UDEC code, and a three dimensional version of that code - 3DEC - has been written (Cundall and Hart, 1985).

Experience with the two dimensional code FRIP at CSM, and the downward growth of the Phase 2A reservoir, has emphasised the three dimensional nature of the stimulation problem. This led to the decision to build a full three dimensional version of FRIP. A preliminary version of this code (FRIP/3D) and associated graphics package now exists and is undergoing a programme of extensive testing.

A general simulator of one dimensional joints FBED (Frip test BED) has been written to act as a test vehicle for examining the physics of a single joint. It can also be used to assess and improve the numerical method employed in these codes (Cundall and Nicol, 1989). This code
contains joint models which have been developed through experience with both UDEC and FRIP, and has the flexibility to include the latest ideas on flow in fractures and the deformability of fractures (for example see Cook (1988)).

Other related work in this field includes the model of Kafritas and Einstein (1987). This model, which is similar to UDEC, has been used to investigate the seepage in the jointed rock foundation of a dam.

Asgian (1988) developed a code FFFLOW (Flexible Fracture Flow) based on the displacement discontinuity boundary element technique. This model was used to study fluid flow in naturally fractured reservoirs. FFFLOW uses a joint model which includes both the FRIP joint model and the UDEC joint model as special cases.

The disadvantage of these discontinuum codes is their computational expense. Despite the use of sophisticated adaptive acceleration algorithms for equilibrating the stress continuity relationships (Cundall, 1982), the explicit nature of the codes leads to limited time steps, and long computer run times.

The nature of these codes makes them unsuitable for the vector processor type architectures commonly available in machines like the Cray. It has been shown that the FRIP code is best suited to state of the art computing machines, such as the Meiko Computing Surface, which run in parallel (Nicol and Scholes, 1988). The FRIP code has now been parallelised, leading to dramatically reduced computer run times.

MODELLING APPLICATIONS

Murphy (1982) examined the hydraulic stimulation of jointed rock with the FRIP code. He obtained agreement with a simple theory of classical hydraulic fracturing by using a FRIP model without shear stress, and obtained the appropriate dendritic fracture patterns for the relevant models with shear stress.

Murphy (CSM, 1982) also used FRIP to model a series of injections and shut-ins in well RH12 with a total duration of over 1000 hours. These tests were all conducted before the major stimulation of the RH11/RH12 system. It was reported that the analyses were not feasible by traditional reservoir modelling techniques because of the dependence of the secondary permeability on the effective stress within joints.

The effect of discontinuous joints on the formation of the growth pattern in a reservoir was demonstrated by Pine and Cundall (1985) using FRIP, and subsequently by Harper and Last (1989) using a modified version of UDEC. It was concluded that discontinuous jointing can lead to highly anisotropic flow, with enhanced values of permeability in the out of plane direction. Thus strong geometrical effects can be seen in the results of fluid injection into blocky reservoirs. A FRIP run showing the effect of discontinuous jointing is presented as Figure 1.

To help with the design of the fluid injections in Phase 2B, a simple model (SON1) was developed, based on the GdK hydraulic fracturing model (Geertsma and de Klerk, 1969). It included a modified treatment of leak-off within a jointed rock mass (Pine, 1987).
Similarly, FBED was used in the design of the Phase 3A viscous injection, but in this case with the inclusion of the effects of shearing. The relationship between the leak-off velocity, joint orientation and fluid viscosity was explored and a leak-off coefficient was derived. Subsequently, FBED was used to simulate the minifracture and ensuing shut in.

When used in this fashion, the FBED code is essentially similar to the GdK type models, but has the inclusion of a shear dilation mechanism. This makes it more applicable to the simulation of naturally fractured reservoirs.

FUTURE MODELLING AT CSM

The major requirement of FRIP and its related codes is that they should aid the design of Hot Dry Rock reservoir stimulations. To this end, a program of research has been planned at CSM, which will systematically examine many of the phenomena that experimentation has already revealed. This will involve extensive scoping tests and further development of the FRIP codes. The considerable information provided by the modelling of flow in jointed reservoirs at CSM will provide the foundation for re-examination of tests and stimulations. Despite its limited orthogonal geometry, the three dimensional model will be able to verify the geometrical effects already noted in the two dimensional simulations of FRIP and UDEC.

It is intended that this modelling should aid the design of a deep prototype of an HDR reservoir in Cornwall. Since the precise rock conditions underground will always remain unknown, the target must be to design a stimulation which is relatively insensitive to variations...
in joint spacing, initial joint aperture, joint connectivity and insitu stress conditions.

Recent investigations of joint clustering (Randall et al., 1989) will enable large scale FRIP models to be constructed which mimic the statistical joint patterns observed in Cornwall. The efficiency of the parallel version of FRIP permits the modelling of such configurations. A typical realistic joint set which can be successfully modelled by FRIP is presented as Figure 2.

The developments in FBED, of both the algorithms and the joint models will be incorporated into FRIP and FRIP/3D. In addition effects such as non-orthogonal jointing will be introduced. A major feature which has not been examined substantially is the effect of cooling, and the consequent induction of thermal stresses, on the development of an HDR reservoir over its lifetime. The incorporation of thermal effects into FRIP is currently being examined.

CONCLUSIONS

The modelling of stimulations in fractured reservoirs is limited both by a shortage of field data and a lack of understanding of the physical processes involved. This is mainly due to the complexity of the natural geological environment. However, substantial progress has been made by a linked process of model development and feedback from the available field data.
It is an extremely ambitious aim to design a stimulation that will create a Hot Dry Rock reservoir at a depth of six kilometres. The limitations in the field experience make it essential that modelling tools are used to their fullest to assist in this design process.

ACKNOWLEDGEMENTS

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STOCHASTIC MODELLING OF FRACTURED RESERVOIR
A. THOMAS, J.L. BLIN-LACROIX

ABSTRACT
In this paper, the authors present a brief review of a complete system of fractured reservoir modelling. This system was built for three-dimensional stochastic modelling of fractured rock masses and the software has been applied for a hot dry rock geothermal site and also for fractured oil reservoirs.

Main innovations lie in following points: the first in digital data collection on bore profiles (either bore sample photographs, or bore geophysical measurements), the second on the analytical treatment of fracture geometry, the third on the fractal generation of stochastic models and the last on the methods of spatial simulations of the fracture field.

For each step of modelling, examples of the displayed results are given on the geothermal research site of Mayet de Montagne (France) and on various oil reservoirs.

Introduction
The topologically complex structure of fracture fields needs spatial stochastic descriptions which involves several probability laws for the orientation, the width, the extent, the frequency, the shape and occasionally the connectivity of fractures. The determination of these parameters and probability laws, described hereafter, requires the collection of a large number of spatial data. When data sets have diversified origin (outcrops, open cuts, mining galleries or boreholes), it is rather easy to determine spatial parameters and to control them on several areas. Spatial modelling from bore data is more difficult and requires special methods. According to the method of bore data collection, this bore may be considered as the result of a special vertical sampling similar to a linear sampling on a rock wall or as a long cylindrical sample which allows the determination of 3D parameters. Then the main problem when data come from boreholes lies in three points: the reliability of vectorial parameters measurements, the accuracy of spatial extrapolation of orientations to large areas and volumes, the estimation of densities in large volume from series of quasi linear sampling sites.
Definitions and basic assumptions

We are obliged here to a short presentation. So more information and detailed discussion about these assumptions can be found in Thomas et al. (1985), Thomas (1986) and Blin-Lacroix (1988).

All fracture elements are seen as volumes full of gaseous, fluid or solid matter, characterized by a very small dimension (width or aperture) in comparison with the two other dimensions defining the extent. Thus, a fracture orientation is defined by a simple vector, as for a plane. The study of fracture fields requires a directional sorting which discriminates the whole population in orientation sets. Mathab et al. (1972) have shown that the Arnold's normal hemispheric law fits very well with the distribution of a such set. In practice, an approximation of this law by two independent linear gaussian laws, one on strikes and the other on dips, is sufficient in most fracture fields.

The term of width is assigned here, in an optical sense, to the distance between fracture walls whatever its filling is. Aperture is equivalent but is rather used in hydraulic applications when fractures does not contain solid matter. The previous assumption about the plane pattern leads to assign a constant value (average) of width to each fracture. It is necessary to sort fractures into width scale ranges before studying fracture distributions. This scale sorting is performed with self-similar processes called fractal processes.

A plane fracture element is located on an infinite plane called "support-plane". On this support-plane, the fracture element is defined by a curve $F$ bounding an area $S$, and $F$ is usually assumed to be circular or elliptic (Fig.1) $F$ may be defined in polar coordinates by a 

![Fig.1 - Characteristics of a planar fractural element.](image)

barycenter $G$ and a radius $\rho(\theta)$ function of the polar angle $\theta$. Extent is then : $L = 2\rho_m(\theta)$ where $\rho_m(\theta)$ is the mean radius. This parameter can not be directly measured but calculated from the length of the visible traces of the fractures
Relative frequency, or density, is a parameter to be determined for each orientation set. It can be expressed as a ratio, either on a plane with cumulated length of traces (lengths $L_i$) by unit area: $d = \left( \frac{\sum L_i}{A} \right)$, or in space with cumulated fracture area ($S_i$) in a unit volume: $\delta = \left( \frac{\sum S_i}{V} \right)$.

It may be expressed as well, on a normal scanline to the fracture set, as an average frequency (denoted $d_s$) of fictitious "support-lines" carrying fracture traces on the plane, or of fictitious support-planes carrying fractures in space (noted $\delta_s$). The most frequently observed law is the Poisson's distribution which corresponds to a negative exponential law for spacings (Priest and Hudson, 1976), (Baecher and Lanney, 1978). Relations between $d$, $d_s$, $\delta$, $\delta_s$, depending on the fracture extent are important for the interpretation of bore densities.

The connectivity can be expressed by some numerical parameters (cross points in plane, cross lines and triples points in space) and some topological crossing features ($X,Y,T$) (Gray et al., 1976). These quantities usually deduced from stochastic models and the shape, described by a fractal process, are not treated here.

**Patterns of a fracture field**

In a dip ($P$) and strike ($A$) system, the distribution of the spatial density of fractures may be considered as a set of values assigned to series of discrete ($A_i$, $P_j$) ranges sweeping through the cubic space (Fig.2). These spatial density values form a matrix $[\delta_{ij}]$, the dimension of which is denoted ($n_A$, $n_P$). Each orientation class $(i,j)$ is characterized by its density $\delta_{ij}$, by its average orientation ($A_i$, $P_j$) and by its dimensions taken constant over space: $d_A = 180/n_A$ and $d_P = 180/n_P$.

![Cartesian representation of the distribution of the spatial density.](image-url)
In the example of the figure 2, \( n_A = n_P = 18 \) and \( d_A = d_P = 10^\circ \). The cross-section of the fracture field on a plane \( P_n \) is a set of straight linear traces. In the plane \( P_n \) the spatial class \( (i, j) \) gives a set of patterns defined by an average planar direction \( \theta_{nij} \) and a density \( d_{nij} = V_{nij} \cdot \delta_{nij} \), where \( V_{nij} \) is a vectorial operator depending only on the angle between \( P_n \) and \( (A_i, P_j) \). When bore samples are cut along a diametral planar section, data are collected on photographs of these sections which are thin planar strips vertically sampled of the fracture field. From such a data set, it is possible to compute a spatial distribution only if the orientation of diametral cross section is well known and varies along the bore profile. This is quite rare.

So the best way of collecting bore data lies either on analysis of a bore telewiever picture, or on wind off photographs taken around the bore samples (such as the system Autocar developed by S.N.E.A.(P.) (Fig. 3a). Thus, fracture patterns are sinusoidal traces on which strike and dip may be computed easily. Photographs are scanned and the computation is made directly on the numerical picture with a simple micro-computer. An automatic threshold treatment allows a simultaneous sorting of fracture in different size ranges.

This method has been also applied to the recorded curves of an electric logging apparatus (developed by Mosnier, C.N.R.S., Orléans, France) (Fig. 3b)

![Fig. 3 - Nature of the information in boreholes.](image)

- a) Wind off photograph of a bore sample (system AUTOCAR of S.N.E.A.(P.).
- b) Electric logging (system of Mosnier, C.N.R.S.)
which gives developed fracture traces along a bore profile by measurement of conductivities on 24 points all around the borewall.

**Interpretation of bore fracture profiles**

The above analysis gives a global distribution of orientations which may be displayed in a dip and strike coordinate system in orientation sets (Fig. 2). A statistical model discrimination leads to a stochastic model of orientations for the whole fracture population, whatever the size range is (Fig. 4). Then for each orientation set, the density distributions are selected by size range.

![Fig.4 - Stochastic model of the spatial density obtained with the data of Fig. 2.](image)

For various orientation sets, when plotting, on a logarithmic coordinate system, the cumulated normal linear density (δ) of fracture computed for several average fracture widths (u), mostly, diagrams show a good linear adjustment of points over a large scale range. This was observed on many fracture fields, either in sedimentary or in igneous rocks, when the assumption of homogeneity of the studied field was possible or previously tested (Fig. 5).

![Fig.5 - Relation between the cumulated density (δ) and the width u.](image)
The width of the scale range over which the linear adjustment of the law \( \log \delta = f(\log u) \) is quite good varies with the tectonics features of the fracture field and the size of the volume wherein the homogeneity assumption is possible. Most of the curves show a decreasing slope towards small scale ranges \((u < 0.01 \text{ mm})\).

Then when working on mean or upper width ranges \((0.1 \text{ mm} < u < 1 \text{ m})\) the density distribution is scaled like a fractal law. A model for such a structure was proposed by Thomas (1987); using a construction derived from a Cantor's process and a calculation of the fractal dimension \(D_c\) derived from a Mandelbrot's model, whose value is given by either the relation:

\[
L \delta u = L \mu (D_c - 1) = L D_L \mu
\]  

(1)

or the relation:

\[
L \delta = L \lambda u (1 - D_c) = L \lambda u D_L
\]  

(2)

where \(\delta = \delta (u \geq u)\) is the linear density of fracture whose width \(u\) is upper or equal to \(u\),

\(L\) is the length of investigation,

\(\lambda\) is a constant \((\lambda = 1)\),

\(\mu\) is a constant \((\mu = 1 - 1/\log 2)\),

\(D_c\) is the fractal dimension of fracture Cantor's process,

\(D_L\) is the fractal dimension of spacing Levy's process, with \(D_L = 1 - D_c\).

For studies where lower size distributions are required, we propose a semi-fractal model, similar to the one proposed by Rigaut (1987) in biomathematics, whose expression, depending on two parameters (upper dimension value \(D_m\) - asymptotic value of density \(L_m\)), is:

\[
\delta = \delta_m [1 + (ku)^{1 - D_c}]^{-1}
\]  

(3)

where \(\delta_m\) is the asymptotic value of \(D_c\) when \(u \to 0\) and \(k\) is the value of \(u^{-1}\) when \(\delta = \delta_m / 2\).

Fig.6 shows the adjustment of one of the curves corresponding to the site AP of the figure 5 with this model. On this figure the bold straight line represents in logarithmic coordinates the values of \(\log [(N_m - N) N^{-1}]\) versus \(\log u\) according to the relation:

\[
\log [(N_m - N) N^{-1}] = (1 - D_c) [\log u + \log k]
\]  

(4)

equivalent to the relation (3)

Of course, this scaled distribution of fractures in the most important aspect of the fracture field modelling, but two other elements are required for spatial simulations:

First, a verification of the spacing distribution laws (if possible for several size ranges). This is easy to realize along the bore profile through some simple
Semi-fractal adjustment of the relation $\delta(u)$ (bold straight line) and model corresponding to the site AP of Fig.5 (curve).

treatment by analytical geometry. Most of the random distributions fit with Poisson's processes.

Secondly, pertinent assumptions have to be made about the extents laws and the statistical relations between extent and width by size range. Obviously this is the main approximation of the modelling procedure, because often there is no possibility of direct field verification of these assumptions. Actually the influence of extent variance seems to be negligible in an assumed homogeneous volume. Nevertheless statistical indirect controls are possible with simulations, when several bores are available in the fractured field, and experience shows that it is difficult to discriminate the contribution of the extent variance among the total density variance.

Simulations

The fracture field model is actually a set of distribution laws with all their adjusted parameters. Strictly, the aim of simulations is to allow posterior controls and to provide numerical random samples of the fracture structure to be used in others calculations such as hydraulic or mechanical ones.

Besides the possibilities to use these simulations for building numerical samples of fracture fields for such external models, often users need graphic displays of the results, such as those proposed in the figure.7 or more simply want various and eloquent displays of the fracture field aspect. Such applications of simulations require use of various analytical treatments and drawing technics according to the user's requirement.
Fig. 7 - Examples of linear, planar and spatial simulations.
Conclusion

Obviously, such scale-variant modelling techniques are quite important for all the problems involving the scale properties of the fracture field, i.e. all the problems of water or oil flow in fractured rock masses.

Despite the briefness of the above presentation it is clear that the fracture field modelling is a very complex operation which needs a lot of data and a great number of various treatments, using statistics, probabilities, analytical geometry, numerical calculation, picture analyses, advanced computer graphic procedures. This is illustrated by the process chart of our modelling software FRAC-LTFA (Fig.8). But in such a modelling, everyone must be aware of the absolute necessity of a good previous information about local geological features of the studied sites, and general information about the statistical properties of fracture fields, about the structural and mechanical properties of various fractured rocks, especially in hot dry rocks where it is always difficult to attempt relevant assumptions about the physical environment of the studied rock mass.

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Fig. 8 - Process chart of the software FRAC.LTFA
THREE-DIMENSIONAL STOCHASTIC FRACTURE NETWORK MODEL

MC CACAS - D BRUEL
CIG - Ecole des Mines de Paris

INTRODUCTION

Three major scales can be defined when studying fractured rock-masses. The small local scale is that of a single fracture. The intermediate scale is the scale at which the fractures are regarded as a network. The largest scale is the scale at which the medium can be considered as a continuous porous medium.

Of these three scales, the intermediate one seems to be of concern in H.D.R. experiments, according to the variability of the fracture density profiles which are usually observed in deep boreholes. At this scale, the hydraulic properties of the jointed-rock are rather heterogeneous. This behavior is due to the connectivity of the fracture system: therefore a better understanding of the fracture's connectivity is important.

To this end, a discrete-stochastic model that generates a fracture network based on the statistical properties of the real fracture network and simulates flow and mass-transport has been developed by Cacas (1987).

One of the assumptions in the development of this model is that hydraulic pressure are not stress dependant. This is adequate when the water pressure field is small. However, this hypothesis may not be valid for HDR simulation and the impact of the in-situ stress regime at elevated fluid pressure has to be considered.

Taking advantage of the previous flow computation, thermal effects are coupled in order to evaluate the geothermal potential of a given reservoir.
THE MODELLING TECHNIQUE

THE FRACTURE NETWORK GENERATION

Obviously the exact geometry of the fractured network involved in the HDR projects can't be fully observed in a single borehole. Our modelling technique consists in generating three-dimensional mesh of numerical fractures to fill the unknown regions of the fractured medium. The network geometry is statistically similar to the real one deduced from in-situ measurements. If necessary to be realistic, the observed real fractures are also modelized accordingly to their own characteristics.

The fractures are represented by disks randomly located in space (Beacher, 1977) (Figure 1), according to a given density called "fracture density". Directional sets of disk are available and are individually generated. Each set is characterized by its own statistical distribution of orientation and radii.

THE FLOW MODELLING

The fluid flow through the domain is governed by hydraulic conditions prescribed on the boundaries and the hydraulic resistance of the fractures. The flow inside each generated disk is relevant from the "channeling phenomenon" that has been observed by many authors (Gentier, 1986; Neretnieks, 1986). According to this phenomenon, the flow is supposed to take place through monodimensional bonds joining the centers of the connected disks (Figure 2). These bonds are assumed to be equivalent to the set of channels inside the fracture which ensure the hydraulic linkage with the connected fractures (Tsang et al, 1987). An equivalent hydraulic conductivity is assigned to each bond and flow rate are proportional to hydraulic gradients.

The piezometric head is then computed at the fracture centers by solving a mass-balance equation in each disk.

FLUID-ROCK INTERACTION MODELLING

The hydraulic conductivity that is to be assigned to each disk results from the combination of a remanent hydraulic conductivity and an incremental part due to fluid-rock interaction including compliance and shearing effects.

The remanent part is derived from a given statistical distribution whose mean and standard deviation are parameters. They have to be fit on in-situ local injection tests at low pressure and low flow rate. This probability distribution function provide undisturbed hydraulic parameters of the jointed rock which are related to the in-situ stress field (Cacas, 1987).

For higher injected flowrates, the change in net closure stress across each fracture will induce a different geometry of voids and asperities in contact. Moreover it is well known that stiffness is stress dependant (Gentier, 1986; Cook, 1988; Myer, 1988). For consistency, hydraulic conductivities will increase while closure stress
decreases. In order to handle normal compliance, we intend to use a degree of separation coefficient (Gentier, 1987). This coefficient tends to one when water pressure grows up to the applied normal stress value. If a critical water pressure is to be reached, depending on stress anisotropy, disk orientation and shear strength, shearing may initiate, according to the classical Mohr's failure theory. The release of shear stresses is then accompanied by an irreversible dilation (Pine, 1984; Barton, 1985).

The ability to describe such modifications in void geometry with changes in normal stress should result from specific studies and are regarded as given constitutive laws.

THE THERMAL EFFECT MODELLING

The aim of this section of our model is to simulate the rock matrix disturbance induced by a cold fluid circulating through the fractured network. Both time and space are discretized. Each fracture represents a planar heat exchanger, where the effective heat transfer area is likely to be much smaller than the geometric area. In experiments (Barton, 1985) involving normal and shearing stresses, it was observed that the ratio effective/real area could be related to the stress/strength ratio. We intend to use such a relation.

The heat exchange between the fracture and the rock matrix is then limited inside two opposite troncated cones (Figure 3). This volume behaves as a no heat-flux boundary. The truncated cone height is given by the average half distance between the disks.

Heat conduction is assumed in the matrix normal to the fracture plane. For each fracture and time step, an implicit finite differences method is used to calculate the temperature profile in the rock. The conduction equation in the matrix is coupled with advection along the fracture plane.

The method was applied to simple case. Comparison to analytical solutions in ideal heat exchangers provide satisfying agreement.

THE SOLUTE TRANSPORT MODELLING

A particle transport simulator is coupled to the flow model, based on a particle following method using a random-walk algorithm. Microscopic dispersion in the fracture and retardation effects due to uneveness of the flow paths are taken into account. The macroscopic dispersion is controlled by the network geometry and the variability of the hydraulic conductivities of the network elements.

This transport model has been applied on a large scale experiment (waste isolation) in fractured rock (Cacas, 1988) and appears to be able to account for large channeling phenomenon observed in situ. Its dispersive properties are reasonably comparable to those of the real site.
GEOMETRICAL DATA

The data required to a statistical study of the fracture network geometry are usually obtained from analysis of classical electric or sonic borehole logs.

- Fracture orientations

The number of sets and the average direction of each one is required for the modelling. The statistical distribution of the fracture directions in the sets are also needed.

- Fracture density

For each directional set, we need the fracture density in terms of a number of fracture centers per unit volume. If fracture sizes are known, density in terms of number of intersections per unit length can be helpful. In case of strong density heterogeneities, the very high or very low density zones must be characterized and taken into account in the model.

- Fracture sizes

As the fractures are represented by disks, the disk radii in terms of a radii probability density function, associated to each set, are a model input. A method providing fracture extents from aperture measurements along the borehole has been proposed (Thomas, 1987).

HYDRAULIC DATA

With our "bond model", no in-situ geometrical measurements can be directly interpreted in terms of bond conductivity. Then the remanent part of the conductivity is considered as a parameter, defined by a probability density function that as to be fit as in-situ hydraulic tests.

The in-situ measurements that are required consist in numerous local permeability tests at low pressure to get information about the permeability heterogeneity and its average value.

MECHANICAL DATA - FLUID-ROCK INTERACTION

The knowledge of the in-situ stress field is required. The relation between the "degree of separation" coefficient and the normal stress is regarded as a data and will provide the normal compliance effect. As the shear strength is assumed to be controlled by the effective normal stress acting on the joint, a total friction angle is needed.

Concerning the dilation effect, corresponding shearstress-displacement and dilation-displacement curves should be of great interest. At the stage of development of our model, a stiffness coefficient and a dilation angle are assumed to be sufficient.
MODEL CONTRIBUTION FOR FURTHER STUDIES

The model will first be aimed at a better interpreting of measurements performed all through experiments. On a mechanical point of view, we hope the model to be useful at understanding global behavior of a reservoir, for instance, it is generally observed that the global impedance of a system decreases while the injection flowrate increases.

Then the model should be used as a predictive tool, at each stage of a HDR reservoir engineering research program. Such a model should help us, for instance, to determine the suitable location for the second well of a HDR program at a further stage of development numerical simulations will provide indications for the design of large stimulation experiments.

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Figure 1. The fracture network generation

Figure 2. The flow modelling

Figure 3. The thermal effect modelling
A Discrete Fracture Model for a Hot Dry Rock Geothermal Reservoir

Bruce A. Robinson
Earth and Space Sciences Division
Los Alamos National Laboratory, Los Alamos, NM 87545

Abstract

Modeling results are presented for the Fenton Hill Phase II reservoir using a two-dimensional steady state simulator of fluid flow and solute transport in fractured porous media. Fluid flow and tracer response data are simulated using a fracture flow model in which the fracture apertures are strong functions of pressure. The model is used to match the available steady state data of pressure drop versus flow rate and the tracer data. Various schemes for improving reservoir performance, such as high backpressure, chemical etching, stimulation using a viscous fluid, and the drilling of a second production wellbore, are then examined.

Introduction

The creation of a Hot Dry Rock (HDR) geothermal reservoir is usually a process of hydraulically stimulating a set of preexisting joints to increase the permeability of an otherwise impermeable rock mass. When operated in the circulating mode, the reservoir must contain a large number of fractures with flow well distributed throughout the rock mass, rather than channeling in a few joints. Thus, a central question facing reservoir developers is how to create a zone of low permeability which at the same time possesses good heat transfer characteristics.

Clearly, since fractures play such a dominant role in the behavior of the system, reservoir models must properly account for the role of fractures in controlling the fluid flow and solute transport. In the present study, fracture network modeling is used to simulate the behavior of a HDR reservoir. The flow system is assumed to consist of a network of interconnected fractures connected to injection and production wells. After the flow field is determined, tracer transport can be calculated using particle-tracking techniques, which follow the progress of a representative sample of tracer molecules through the network.

In a previous paper (Robinson, 1988) a fracture network model was used to simulate the behavior of the Fenton Hill Phase I reservoir. The capabilities of this model have been extended in two important areas. First, the fracture network is now generated randomly based on a set of statistical parameters of the fracture sets, rather than assuming a regular grid of fractures, as in the previous study. Second, the fracture aperture is now assumed to be a function of pressure, which is necessary to explain the flow impedance behavior of the Phase II reservoir, and which is observed in almost all laboratory joint deformation studies.
Conceptual and Mathematical Models

Details of the fracture network model FRACNET are described in Robinson (1989). This section briefly outlines the important assumptions of the model as well as several features of the model not presented in this earlier work.

Fracture Network Generator: A fracture network generator similar to that developed by Long et al. (1982) has been employed to simulate steady-state flow between two wellbores with a no-flow outer boundary. A two-dimensional, interconnected network of fractures is generated within a rectangular region of arbitrary dimensions, called the flow domain. The wellbores are simulated as constant-pressure line segments within the region. The network consists of two sets of fractures, each with a preferred orientation. The center of each fracture is located randomly in space, and then its orientation and length are generated from the given statistical distributions.

Solution for Fluid Flow and Pressure Field: Assuming fracture flow can be modeled as laminar flow between parallel plates separated by distance \( w \), the fracture aperture, the volumetric flow rate per unit depth of fracture \( q \) is

\[
q = wu = \frac{-w^3\Delta P}{12\mu L}.
\]

Witherspoon et al. (1979) showed that Eqn. (1) is valid for flow in fractures at low Reynolds number. The aperture \( w \) is an equivalent hydraulic aperture accounting for the effects of fracture roughness and flow constrictions. This aperture is a strong function of the effective stress on the joint, \( \sigma - P \), which in a HDR reservoir will vary greatly as a function of position, joint orientation, and pressure. The fracture opening law used in the present study is the so-called "bed-of-nails" model of Gangi (1978), depicted schematically in Figure 1. The model assumes that under compression the fracture faces are held open by asperities which leave residual permeability and porosity. Gangi modeled the asperities as elastic rods which could be characterized by a power-law distribution. Gangi derived the following law for fracture aperture versus effective stress for \( P < \sigma \):

\[
w = w_0[1 - \{(\sigma - P)/P_{\text{ext}}\}^m]
\]

In Eqn. (2), \( w_0 \) represents the fracture aperture when the fracture is fully open, \( P_{\text{ext}} \) is the stress required to completely close the fracture, and \( m \) is an exponent between 0 and 1 which is controlled by the constant in the power-law distribution of asperity heights. In reality, these parameters are simply obtained by fitting laboratory data of aperture versus effective stress (Brown, 1989). The effective stress on a joint is computed from its orientation in relation to the magnitudes and directions of the two principle stresses on the two-dimensional fracture network. For \( P > \sigma \), the situation becomes much more complicated, with the potential for jacking of the fracture and additional shear displacement. Currently, the model assumes a linear increase in aperture with
pressure, with the slope set as an adjustable parameter by the user. The simulations presented below assume this slope to be zero, or a constant aperture for \( P > 0 \). Further work is required to justify this assumption or to provide a better approximation for this regime.

To solve the pressure and flow fields, an equation for the pressure at each intersection of two fractures, or node, is obtained from a mass balance of fluid entering and leaving the node using Eqn. (1). The pressures of the source and sink nodes are set constant. The resulting nonlinear equation set is solved using a Newton-Raphson solution procedure. The equation set at each Newton iteration is solved using incomplete factorization with a conjugate gradient technique (see Zyvoloski et al., 1988) to speed up the convergence.

**Particle-Tracking Technique:** The assumption underlying the particle tracking technique is that the tracer response can be approximated by passing a large number of individual tracer molecules through the system, measuring the residence time of each, and accumulating the overall response as the residence time distribution of the individual molecules. Robinson (1989) showed how matrix diffusion could be incorporated into the particle tracking formulation using the model of Starr et al. (1985) for plug flow in a fracture surrounded by a porous matrix only by molecular diffusion of tracer.

When the calculation for a single molecule is repeated, say 10,000 times, a distribution of residence times is obtained. The histogram obtained is the residence time distribution, equivalent to the response of the system to a short slug of tracer injected at the inlet.

One additional complication is the effect of fracture roughness on the fluid flow and tracer transport laws. The aperture calculated from Eqn. (1), the hydraulic aperture \( v_h \), is a weighted average accounting for the distribution of apertures encountered by fluid passing through the fracture. Because of the \( v^{-d} \) dependence on flow rate, the narrow apertures will contribute the most to the pressure drop, and \( v_h \) will be much smaller than the value obtained from an arithmetic average of the aperture. On the other hand, since tracer molecules sample the entire flow volume, the tracer aperture \( v_t \) is a straight average of apertures encountered in the flowpath. In general, the tracer aperture \( v_t \) should be larger than \( v_h \).

Gelhar analyzed four published field tracer tests in single fractures in crystalline rock, determining a range of values of \( f_r \) from 5.5 to 19. Additional flow and tracer experiments in cores and in the field in single fractures are needed to determine the true relationship between \( v_t \) and \( v_h \) and to examine scale effects. At present, the computer code FRACNET assumes that the ratio \( f_r = v_t/v_h \) is constant for all fractures in the network, and the value is set by the user as input.

**A Fracture Network Model of the Fenton Hill Phase II Reservoir**

The Fenton Hill Phase II reservoir was created by a large hydraulically stimulation experiment called the massive hydraulic fracturing (MHF) experiment in December of 1983 (Fehler et al., 1987) and by several smaller tests during the redrilling of the wellbores. Subsequently, this system was tested as a flowing reservoir during the Initial
Closed-Loop Flow Test (ICFT) in May and June of 1986 (Dash et al., 1989). The two periods of constant flow rates and pressures that were established are summarized in Table 1. A small increase in the pressure drop (a factor of 1.17) resulted in an increase in the outlet flow rate of 1.56, suggesting that the permeability of the reservoir was greater at the higher injection pressure (and the impedance was lower).

Table 1. Pressures and Flow Rates During Two Steady State Stages of the ICFT

<table>
<thead>
<tr>
<th>Stage</th>
<th>Inlet Flow Rate (kg/s)</th>
<th>Outlet Flow Rate (kg/s)</th>
<th>Inlet Pressure (MPa)</th>
<th>Outlet Pressure (MPa)</th>
<th>Impedance (MPa·s/kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>11.1</td>
<td>7.9</td>
<td>26.9</td>
<td>2.41</td>
<td>3.1</td>
</tr>
<tr>
<td>2</td>
<td>17.3</td>
<td>12.3</td>
<td>32.0</td>
<td>3.45</td>
<td>2.3</td>
</tr>
</tbody>
</table>

The microseismic event locations determined during the MHF are shown in a three-view plot in Figure 2. The dimensions of the stimulated region are not equal in the three directions: the dimensions of the seismic cloud are large in the vertical and north-south directions, but only about 250 m in the east-west direction. The fluid appeared to travel preferentially vertically and north-south from the injection point, which is consistent with the estimate of Burns (1989) of the direction of the minimum compressive stress of N111°E.

To determine joint orientations, Fehler et al. (1987) have developed a technique, called the three-point method, for determining the location of planes along which a set of microseismic events fall. They believe that these planes represent zones of weakness which fail by shearing during hydraulic stimulation. These planes would presumably also provide pathways for fluid flow during hydraulic stimulation and interwell flow testing. Most planes found by the three-point method trend roughly north-south and dip between 15 and 30 degrees from the vertical (Fehler, 1989). Assuming that the joints strike perpendicular to the least principal compressive stress and must open against a portion of the vertical stress, the range of opening pressures would be from 13 to 23 MPa. Brown (1988), from analysis of pressure-transient tests, showed that at least one set of fractures appear to open at about 22 MPa, roughly consistent with the expected opening pressure of these joints.

There is also ample evidence for a set of fractures which open against the least principle earth stress of about 10 MPa. Brown (1988) showed that pressure transient data revealed a break in the pressure buildup curves at about this value. Furthermore, Fehler (1989) presents a calculation that shows that only a small fraction of the seismic energy was observed that would be expected if all water were stored in fractures formed by shearing. He hypothesized that the majority of injected fluid is being stored in fractures which fail in tension and thus do not produce microseismicity. These joints would be vertical and oriented in the north-south direction. An alternative mechanism for storing large amounts of injected fluid without inducing seismicity is that the porosity of the rock matrix increases with pressure due to the opening of microcracks. Both mechanisms are probably important in the Phase II reservoir.
Given the previous discussion, the conceptual model developed to describe the reservoir consists of two joint sets oriented roughly north-south which intersect each other because one set is roughly vertical and the other dips at an angle of 15 to 30°. The first set, termed the shear features, require about 22 MPa to open completely, while the second set, called the tensile features, open against 10 MPa. Using the two-dimensional fracture network model it is difficult to represent this geometry exactly. Since we must take a cross section of the reservoir and assume a depth in the vertical direction, fractures oriented in the same direction cannot intersect. On the other hand, three-dimensional fracture network models would be extremely difficult to develop and expensive to run.

As a compromise, the two-dimensional network geometry such as that shown in Figure 3 has been selected to capture the essential features of the Phase II reservoir. Two vertical fracture sets are assumed, with orientations chosen subject to a Gaussian distribution of angles about a mean angle. The tensile features strike north-south. The shear features are represented as vertical fractures striking at an average angle of 45° to the tensile features. This provides the connectivity between the two fracture sets which we believe in reality to be due to the different dips on the fractures. Then, the two-dimensional stress field is set so that the shear features are fully open at about 22 MPa and the tensile features are open at 10 MPa. This approximate representation of the reservoir incorporates the information on fracture opening pressures and provides connectivity between fractures of the two sets.

The shape of the flow domain in Figure 3 is rectangular to represent the oblong shape of the seismic cloud. The reservoir depth is assumed to be roughly 250 m, which is roughly the vertical distance over which the wellbores pierce the seismic cloud. Although the vertical dimension of fractured reservoir is roughly 1000 m (see Figure 3), the majority of the flow will be concentrated in the region of rock between the wellbores, and thus two-dimensional simulations should use the smaller number.

Finally, the steady state code does not allow for a changing reservoir boundary, even though microseismicity was observed during the ICFT. Figure 4 shows that these microearthquakes were virtually all located to the south of both wells. Furthermore, most of these events occurred after increasing the injection pressure to 32 MPa. We postulate that this is because the pressure at the southern boundary, due to the influence of the injection well, is large enough to cause shearing of previously unstimulated fractures. The boundaries in the model are fixed, no-flow boundaries, and the flow rates matched in the modeling are the production flow rates. However, to be consistent with this element of the seismic data, we should examine the pressure at these boundaries to ensure that the model predicts pressures high enough to induce seismicity in the southern portion of the reservoir, especially at the higher injection pressure.

**Simulation Results**

The fracture network generated in Figure 3 was used to obtain a match to the existing pressure drop versus flow rate data. The thick
vertical lines represent the two wellbores, each of which intersect about 7 fractures (the injection wellbore is on the left in the figure). The value of \( w_0 \) was assumed to be the same for both fracture sets, and its value was adjusted to match the outlet flow rate during the two stages of the ICFT (Table 1). Other parameters used in this simulation are given in Table 2. When the reservoir depth is selected to be 244 m to match exactly the outlet flow rate in Stage 1 (7.9 kg/s), the flow rate is predicted to increase to 13.1 kg/s, compared to the measured value of 12.3 kg/s. With constant fracture apertures independent of pressure, the flow rate change would be proportional to the change in pressure drop, and the flow rate predicted during Stage 2 would be only 9.2 kg/s. Thus the pressure-dependent aperture model is needed to simulate the observed data. At the injection pressure of 24.1 MPa planned for the early stages of the upcoming Long-Term Flow Test, the predicted production flow rate is 5.1 kg/s.

### Table 2. Fracture Network Parameters Used to Obtain a Match to the ICFT Data

<table>
<thead>
<tr>
<th></th>
<th>Tensile Fractures</th>
<th>Shear Fractures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of fractures</td>
<td>500</td>
<td>300</td>
</tr>
<tr>
<td>Average Length (m)</td>
<td>50</td>
<td>100</td>
</tr>
<tr>
<td>Std. Dev. of Length (m)</td>
<td>8</td>
<td>15</td>
</tr>
<tr>
<td>Average orientation (radians)</td>
<td>0 (N-S)</td>
<td>0.7854 (N45°W)</td>
</tr>
<tr>
<td>Std. Dev. of Orientation</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>( w_0 ) (µm)</td>
<td>51</td>
<td>51</td>
</tr>
<tr>
<td>( m )</td>
<td>0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>( P_{ext} ) (MPa)</td>
<td>35</td>
<td>35</td>
</tr>
</tbody>
</table>

Other Parameters

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>0.00017 for Stage 1, 0.00023 for Stage 2.</td>
</tr>
<tr>
<td>( f_r )</td>
<td>11</td>
</tr>
<tr>
<td>( D_r )</td>
<td>( 4.56 \times 10^{-8} ) (m²/s)</td>
</tr>
<tr>
<td>( \tau )</td>
<td>0.65</td>
</tr>
<tr>
<td>( \mu )</td>
<td>( 1.17 \times 10^{-10} ) (MPa-s)</td>
</tr>
</tbody>
</table>

The comparisons of simulated and experimental tracer response curves for the two stages are shown in Figures 5a and b. The peaks of the tracer responses exited at about the correct time, but the fractional recovery of tracer was less than predicted for both cases. Additional simulations for different fracture networks (with identical statistical parameters) showed that the shape of the simulated response was a strong function of the positioning of fractures in the network, even while impedance remained about the same. To achieve good fits to the tracer response data, fractures would have to be placed manually in the flow domain, with relatively few tensile features directly between the wellbores. This process was not undertaken in the present study.

Figures 6a and b show the pressure as a function of position for the simulations of the two stages of the ICFT. As expected, the pressure at the southern boundary is highest in both cases, reaching about 25.5 MPa for Stage 1 and about 29.5 MPa for Stage 2. Since little seismicity was observed at the lower injection pressure, the pressure at the boundary of the reservoir required to induce seismicity is
probably at an intermediate value of about 27 MPa. An alternative explanation is that at the lower flow rate, which was carried out first, the existing joints were being reinflated, and thus seismicity did not occur until these fractures were filled. One goal of the LTFT is to answer this question of when new fracturing starts more precisely.

One concern about the performance of the Phase II reservoir is the high flow impedance, requiring large pressure drops and injection pressures to circulate fluid. Since Figures 6a and b show that large pressure drops are occurring near the production well, methods to reduce the overall impedance have focused on attacking this so-called exit impedance. The simplest method is to increase the pressure at the production well. Although the overall pressure drop across the reservoir is lowered, the fractures near the production well are more open, lowering the pressure drop through these joints. The model results of Table 3 show that for the Phase II reservoir, moderate backpressures of 13.8 MPa could be applied with only a small decline in the production flow rate, and the pumping power requirements would drop accordingly. This idea remains to be tested before the Long-Term Flow Test.

Table 3. The Effect of Production-Well Pressure on Flow Rate

<table>
<thead>
<tr>
<th>Production-Well Pressure (MPa)</th>
<th>Pressure Drop (MPa)</th>
<th>Flow rate (kg/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.41</td>
<td>24.5</td>
<td>7.9</td>
</tr>
<tr>
<td>6.90</td>
<td>20.0</td>
<td>7.9</td>
</tr>
<tr>
<td>10.35</td>
<td>16.6</td>
<td>7.8</td>
</tr>
<tr>
<td>13.79</td>
<td>13.1</td>
<td>7.2</td>
</tr>
<tr>
<td>17.24</td>
<td>9.7</td>
<td>6.2</td>
</tr>
<tr>
<td>20.69</td>
<td>6.2</td>
<td>4.6</td>
</tr>
</tbody>
</table>

Viscous stimulation and chemical etching have also been proposed to decrease the pressure drop near the production well. To simulate a viscous stimulation, the same fracture network was generated with one additional north-south-trending fracture placed through the production wellbore, with L=100 m and w=5.1x10^{-4} m, 10 times larger than the fully open apertures of the natural fractures. The production flow rate at the Stage 1 conditions was then calculated to be 8.3 kg/s, only a factor of 1.05 increase for these very optimistic assumptions about the efficiency of the stimulation. This fracture, being oriented in the same direction as the preexisting joints, intersects very few other fractures and thus has little effect on the flow characteristics. If a fracture could be driven in the East-West direction, the situation would improve considerably. A simulation assuming a viscous fracture oriented east-west with identical properties as that described above resulted in a 33% improvement in flow rate.

The effect of chemical etching near the production well was simulated by assuming that at a given distance from the well the apertures are made larger at the low fluid pressures at which the etching would be carried out, but that the fully open aperture w remains constant. This is equivalent to increasing m and leaving \( \beta_{\text{ext}} \) and \( w_0 \) constant.
Table 4 shows that when the chemical etching is carried out only near the production well, the improvement is modest. However, if virtually the entire reservoir could be chemically attacked to open the fractures even at low fluid pressures, the improvement of the reservoir would be substantial. The values in the table represent an increase in the parameter $m$ from 0.25 to 0.75, chosen to create an increase in the aperture by a factor of about 2.5 at high effective stress (15 MPa). The actual benefit of a chemical etching treatment would depend on the ability to efficiently dissolve the appropriate minerals to increase the aperture while leaving behind a structurally sound rock which holds the fracture open against the prevailing earth stresses.

<table>
<thead>
<tr>
<th>Distance from Production Well Where Etching is Carried Out (m)</th>
<th>Flow Rate (kg/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>7.9</td>
</tr>
<tr>
<td>25</td>
<td>8.8</td>
</tr>
<tr>
<td>50</td>
<td>9.8</td>
</tr>
<tr>
<td>100</td>
<td>12.9</td>
</tr>
<tr>
<td>200</td>
<td>14.9</td>
</tr>
<tr>
<td>1000</td>
<td>15.4</td>
</tr>
</tbody>
</table>

Clearly, the most ideal treatment for reducing impedance would be one which dramatically increased the value of $v_0$. The fully open hydraulic aperture of our fractures appears to be on the order of 50 μm, which ultimately requires large pressure drops to achieve commercially acceptable flow rates. Hydraulic, viscous, or chemical stimulation techniques must be developed to increase the fracture apertures of the preexisting joints, probably by inducing larger shear displacements to make the two fracture faces less correlated. Currently, the HDR research community has not developed a proven technique for overcoming this problem.

Given a reservoir with fractures of small aperture, one potential strategy is to operate the system at high enough pressures to inflate the fractures and lower their impedance. Unfortunately, for a two-well system, injecting at too high a pressure induces reservoir extension and increases water loss at the reservoir boundary, as described earlier. A solution to this problem is to drill a second production wellbore to create a flow sink and lower pressures at the boundaries. To demonstrate this concept, a third wellbore was placed 150 m south of the injection well. The second wellbore allowed the reservoir to be operated at a much higher pressure without inducing fracturing. Figure 7 shows the pressure profile for a three-wellbore system with an injection pressure of 35 MPa and production pressure of 15 MPa. Note that the pressures at the boundaries are lower than the 27 MPa required to induce unwanted reservoir extension, yet the flow rate was computed to be a factor of 2.8 higher than that for Stage 1. Furthermore, the overall pressure drop was lower for the three-well system, in which we would take advantage of the benefits of moderate backpressures of 15 MPa. Thus, proper placement of a second production well appears to be a promising strategy for
improving the flow rate through the reservoir without encountering runaway fracture growth and water loss.

Conclusions

A fracture network model has been developed to model the Fenton Hill Phase II reservoir. The fracture apertures are functions of pressure to simulate the observed pressure-dependent impedance of the reservoir. Starting with a conceptual model consisting of two joint sets which open against different stress conditions, a two-dimensional idealized network was created within a region of dimensions determined by microseismic data, and fracture parameters were adjusted to achieve a match to the steady state flow rate and tracer data. Strategies for improving reservoir flow characteristics were then evaluated. Viscous fracturing is unlikely to improve the system considerably. Chemical etching can provide a lower impedance, provided the entire reservoir is treated rather than simply the region near the production wellbore. Moderate backpressures up to about 15 MPa can be placed on the production well with relatively little decline in the steady state flow rate, while at the same time cutting pumping costs considerably. The placement of a second production wellbore to arrest fracture growth would allow the reservoir to be operated at higher flow rates without inducing unwanted seismicity and water loss.

Acknowledgements

This work was performed under the auspices of the U.S. Department of Energy, Geothermal Technology Division. The author wishes to thank Bob Potter, Don Brown, and Steve Birdsall for many helpful discussions during the development of this model, and George Zyvoloski with supplying the equation solver used in the model.

Nomenclature

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$D_f$</td>
<td>free molecular diffusion coefficient of solute in water (m²/s)</td>
</tr>
<tr>
<td>$f^*$</td>
<td>ratio of tracer to hydraulic aperture</td>
</tr>
<tr>
<td>$L^w$</td>
<td>fracture length (m)</td>
</tr>
<tr>
<td>$m$</td>
<td>exponent in the fracture opening law</td>
</tr>
<tr>
<td>$P$</td>
<td>pressure (MPa)</td>
</tr>
<tr>
<td>$P_{ext}$</td>
<td>stress at which the fracture is completely closed (MPa)</td>
</tr>
<tr>
<td>$q$</td>
<td>volumetric flow rate per unit depth (m²/s)</td>
</tr>
<tr>
<td>$v_f$</td>
<td>fracture aperture (m)</td>
</tr>
<tr>
<td>$v_h$</td>
<td>hydraulic aperture (m)</td>
</tr>
<tr>
<td>$v_t$</td>
<td>tracer aperture (m)</td>
</tr>
<tr>
<td>$\mu$</td>
<td>fluid viscosity (mPa-s)</td>
</tr>
<tr>
<td>$\tau$</td>
<td>tortuosity of matrix material</td>
</tr>
<tr>
<td>$\sigma$</td>
<td>effective stress on a fracture (MPa)</td>
</tr>
</tbody>
</table>

REFERENCES

Brown, D. W., "Anomalous Earth Stress Measurements During a Six-Year Sequence of Pumping Tests at Fenton Hill, New Mexico," Proc. of the


Figure 1. Schematic of "Bed-of-Nails" Model

Figure 2. Seismicity During the Massive Hydraulic Fracturing Experiment (MHF)

Figure 3. Representative Fracture Network for the Phase II Reservoir
Figure 4. Seismicity During the Initial Closed-Loop Flow Test (ICFT)

Figure 5a. Tracer Response – Stage 1

Figure 5b. Tracer Response – Stage 2
Figure 6a. Pressure Field - Stage 1

Figure 6b. Pressure Field - Stage 2

Figure 7. Pressure Field - Three-Well System.
INTRODUCTION

The purpose of stimulation in Hot Dry Rock (HDR) geothermal energy systems is to create a large heat transfer area, the reservoir, within a rockmass of very low permeability, which links two or more wells. Experience at the Camborne School of Mines (CSM) has shown that there are two dominant aspects to the successful creation of a HDR reservoir.

Creation of the main heat transfer area is achieved by a large volume fluid injection (stimulation). The fluid is water or a low viscosity gel which increases the permeability by dilating the natural joints. The stimulation has to be large enough to provide a heat transfer area which will last for the life of the system whilst allowing water to be circulated in commercial quantities.

Following the bulk stimulation it may be necessary to create localised links into the reservoir from the wells, in particular the production well, by secondary stimulations. These are smaller stimulations using high viscosity gels which provide a low impedance connection from well to reservoir. The resulting new fracture will usually need to be held open by proppants.

BULK STIMULATIONS

In a Hot Dry Rock (HDR) system fluid flow within the rockmass takes place in the joint network. In its natural state the overall permeability of the rockmass is very low; at the Rosemanowes site the initial rockmass permeability was less than 10 μd. The permeability must be increased by at least two orders of magnitude to create a reservoir with a commercial flow capacity.

The required permeability increase can only be achieved by permanently displacing the joints. This is achieved by pumping water or gel into the rockmass at high flow rates. This stimulation procedure is controlled primarily by the in situ stress levels, the joint directions and connectivities and the viscosity and flow rate of the stimulation fluid. Secondary controls are the nature of the joint surfaces and the joint spacing and the orientation of the wells with respect to the in situ stresses and the joint system. The orientation of the wells with respect to the measured in situ stresses and joint directions at the CSM site are shown in Figure 1.
The first attempt at large scale stimulation involved the use of water. At that time, 1982, the only other large scale HDR research project, which was run by the Los Alamos National Laboratory (LANL), had also used water for stimulation. At the CSM project it was recognised that joint permeability increases would probably occur as a result of both tensile and shear dilations but the contribution of each was poorly understood. In order to detect any emissions that might be caused by the stimulation, microseismic networks, operated at the project by CSM and the British Geological Survey (BGS) Global Seismology Unit (GSU), were installed. A separation of at least 200 m between the injection and production wells was considered necessary to provide space for a large enough heat exchanger, and it was considered likely that a high pressure, high flow rate water injection would link the wells over such a distance.

An initial stimulation water volume of about 11400 m$^3$ was injected into RH12 at a flow rate of about 90 l/s, followed by a further 7100 m$^3$ at flow rates of 50 to 20 l/s. At the end of the stimulation phase the reservoir volume as defined by the envelope containing the bulk of the microseismic emissions, was about 14 million m$^3$ (Batchelor et al, 1983). This is shown in Figure 2. After the stimulation a volume of more than 200,000 m$^3$ of water was injected at much lower flow rates, typically 20 l/s, during the circulation phase. About 30% of the injected water was recovered from RH11, the production well. Microseismic data from the stimulation and the circulation confirmed that strike-slip shearing was occurring.

During the stimulation, growth of the reservoir, as delineated by the microseismic event locations was slightly downwards, although there was enough upward growth to make a connection with RH11. During the long circulation phase, which involved a considerable element of continuing stimulation, because of the low returns to the production well, the growth trend of the reservoir was consistently downwards, resulting in a reservoir volume of about 800 million m$^3$ (Baria et al, 1985). The downward growth partly explained the poor connection between RH11 and RH12 and led to the conclusion that under certain anisotropic stress conditions shear dominated reservoir growth, as a result of water stimulations, would be downwards (Pine and Batchelor, 1984). This tendency would be reduced at greater depths where a smaller stress anisotropy is expected.

During this period a joint-block model FRIP (fluid rock interaction programme) developed by Cundall and others at the CSM HDR project (Cundall and Pine) was used to model the effect of in situ stress, joint orientation and joint continuity on the development of stimulated regions. An example of a stimulation pattern within a continuous joint system in a region of anisotropic stress is shown in Figure 3. In this figure the line widths are proportional to the joint width. Most of the joint width increase is caused by shear, and the sense of motion shown by the FRIP model, for in situ stress values and joint directions measured at the CSM site, was confirmed by fault plane solutions.

The results of the first bulk stimulation suggested that using a fluid with a higher viscosity than that of water would result in increased shear displacement, reduced leak-off and a more concentrated area of permeability increase. In 1985 it was decided to restimulate the
reservoir from the newly drilled well, RH15, using a medium viscosity gel of approximately 50 cp (0.05 Pa s).

A conventional fracture model, the Geertsma and de Klerk (GDK) model (Geertsma and de Klerk, 1969) was used to estimate the flow rates and volumes required to create a stimulation extending 300 m from RH15. The radial flow version of the model was used, resulting in 'penny shaped' fracture geometry. Commercial fracture simulators were also used to check the design. These simulators had more sophisticated fluid rheology modelling but gave similar results to the simpler GDK model. The fracture extent predicted by these models was considered to be an indication of the extent of stimulation of natural jointing lying close to normal to the minimum in situ stress direction (Pine, 1987).

It was expected that leak-off from the main fracture region would cause shear stimulation of off-plane joints. A numerical model (SON1), derived from FRIP was developed to show the extent of gel penetration and elevated fluid pressures in such joints (Figure 4). The results from the SON1 studies were incorporated into the leak-off calculations for the GDK runs to account for leak-off occurring along joints rather than through permeable rock.

Two minifracs were carried out to check the design in situ. The minifrac pressure declines were analysed using a method proposed by Nolte (1979) and extended by Lee (1985). This analysis allows the fracture geometry at the end of pumping, the fluid efficiency and the leak-off coefficient to be calculated. This is done by considering the fluid mass balance in the fracture which allows the pressure within the fracture to be related to the fracture width. If the fracture geometry can be approximated by an idealised model, such as the GDK, then the fracture area and width can be estimated.

The design for the stimulation was revised in the light of the minifrac results and the final design was for 5500 m³ of 50 cp gel to be pumped at 200 l/s. The microseismicity that resulted was confined (Figure 5) in comparison to that caused by the water bulk stimulation (Figure 2). The subsequent pressure decline analysis suggested that a 300 m long fracture had been created with a fluid efficiency of 30%.

The restimulated reservoir has been circulated since August 1985. Thermal drawdown measurements have shown that an insufficiently large circulating volume was created by the gel stimulation. It is thought that this is mainly due to the earlier water stimulation which resulted in preferential pathways being established. These in turn would cause the gel stimulation to be channelled resulting in a reduced heat transfer area. However, this hypothesis is unproven as the effect of a large volume, low viscosity gel bulk stimulation in previously unstimulated granite has not yet been attempted.

SECONDARY STIMULATIONS

Following a bulk stimulation it is necessary to create a local low impedance path connecting the reservoir and the wells where the fluid pressure gradients and friction losses are greatest. This is particularly important in the production well where the operating conditions might result in low fluid pressures close to the well.
This reduces joint apertures and hence their permeability close to the well.

Secondary stimulation is achieved by driving an artificial fracture away from the well into the reservoir using a very viscous fluid. This creates a tensile fracture which subsequently needs to be held open. There have been two attempts at this type of stimulation by CSM, one in RH11 and then another in RH15.

The first of these stimulations was performed in RH11 in 1983. At the time the reservoir was being circulated from RH12 to RH11. The stimulation was designed using a GDK type of model and it was hoped that the fracture might self-prop as a result of small pieces of rock spalling from the fracture faces. These would then hold the fracture open. RH11 is orientated in the direction of the maximum principal stress (Figure 1) and as expected a clear tensile fracture was created which ran along the length of the borehole causing extensive wellbore damage. There was some evidence of self-propping near the wellbore but there was no significant net improvement as a result of the stimulation. This negative result meant one of two things; either the fracture did not intersect any flowing joints or it did not self-prop sufficiently to allow any flow to pass through it.

The aim of the RH15 stimulation in February 1989 was to examine the effect of a propped fracture on the current reservoir system, where the main circulation takes place between RH12 and RH15, under various operating conditions. A section of openhole was isolated using sand below a double packer system set higher in the well, and then stimulated. In this section the well is orientated at approximately 90 to the maximum horizontal stress (Figure 1). This leads to a more complex fracture geometry near the wellbore and a tendency for the fracture to grow out of the plane of the well.

A flow rate of 100 l/s was selected for the stimulation and the gel volumes and viscosities were estimated using the GDK model, with a variety of leak-off values, to create a fracture 50-100 m long. The leakoff values were modelled using a revised version of SON1, called FBED. This model incorporates joint shear and allows the joint to be orientated in any direction with respect to the in situ stresses. Studies with FBED showed that the extent to which leak-off along a joint occurs depends on its orientation with respect to the main fracture, which is orientated in the direction of the maximum horizontal stress (Figure 6). Most of the leak-off will occur along joints orientated within 30 of the fracture.

Quartz sand was chosen as the proppant because the closure stresses in the stimulation interval were low. Two sand sizes were chosen, 20/40 mesh for the main part of the fracture and 12/20 mesh, for that part close to the well. This was so that the high permeability produced by the larger proppant could compensate for the restricted entry into the wellbore. The design was completed using the stimulation contractors' fracture simulator which took into account fluid rheology and proppant transport. The leak-off values were derived from the GDK and FBED modelling and controlled by back-calculated values from previous stimulations.
Again a minifrac was carried out to check the design in situ. The pressure decline was analysed using a variation of the Nolte method proposed by Castillo (1987). In this case the mainfrac design was not altered as a result of the minifrac and the job went ahead as originally planned. A total volume of 548 m³ of 700 cp gel was pumped at an average flow rate of 85 l/s. The proppant stages consisted of 59 tonnes of 20/40 sand, pumped at concentrations rising from 1 lb/gal to 4 lb/gal, followed by 8 tonnes of 12/20 sand pumped at 4 lb/gal.

The pressure profiles during the job were examined using the methods proposed by Nolte (1982) which allow the appropriate idealised model to be chosen for the subsequent pressure decline analysis. In this case there was a positive slope to the pressure profile (Figure 7) indicating that the fracture was growing as predicted by a confined Perkins-Kern-Nordgren model (Perkins and Kern, 1961, Nordgren, 1972). This is a vertical plane strain model which results in a fracture cross section which is elliptical. The pressure decline analysis was carried out using PKN geometry and indicated that a fracture of approximately 120 m long was created with permeability of 1270 md ft and fluid efficiency of 39%.

Following the stimulation, flow into RH15 was more concentrated and came from a joint which it is assumed had provided the main exit from the well during the stimulation. Almost 75% of the total flow into the well now comes from this point and the water losses from the system have been reduced to approximately 5% of the total being injected. In addition, in contrast to the RH11 stimulation, there was very little RH15 wellbore damage. This is consistent with theoretical considerations.

DISCUSSION

The previous sections briefly presented the stimulation experience at CSM to date. The main points are summarised and presented in Table 1, which helps emphasise the great difference between bulk and secondary stimulations. Bulk stimulations are conducted using water or low viscosity gels, are ten to twenty times larger than a secondary stimulation and result in a considerable amount of microseismicity. This allows the stimulation to be followed in real time and defines the affected rock volume. These type of stimulations are unique to HDR and their success is central to the HDR concept.
TABLE 1 SUMMARY OF STIMULATIONS CONDUCTED AT THE CSM GEOTHERMAL ENERGY PROJECT

<table>
<thead>
<tr>
<th>Test No</th>
<th>Purpose</th>
<th>Fluid</th>
<th>Volume/Flow rate</th>
<th>Microseismicity</th>
<th>Stimulated Volume/ Fracture extent</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT2046</td>
<td>Bulk stimulation</td>
<td>Water</td>
<td>11400 m$^3$ at 95 l/s, followed by 7100 m$^3$ at 50-20 l/s.</td>
<td>549 events</td>
<td>Approximately 14 million m$^3$ as defined by microseismicity.</td>
</tr>
<tr>
<td>RT2062</td>
<td>Secondary stimulation</td>
<td>1000 cp gel</td>
<td>400 m$^3$ at 95 l/s.</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>RT2B019</td>
<td>Bulk stimulation minifrac</td>
<td>50 cp gel</td>
<td>300 m$^3$ at 93 l/s.</td>
<td>21 events</td>
<td></td>
</tr>
<tr>
<td>RT2B020</td>
<td>Bulk stimulation minifrac</td>
<td>50 cp gel</td>
<td>490 m$^3$ at 95 l/s.</td>
<td>19 events</td>
<td></td>
</tr>
<tr>
<td>RT2B022</td>
<td>Bulk stimulation</td>
<td>50 cp gel</td>
<td>5500 m$^3$ at 200 l/s.</td>
<td>270 events</td>
<td>Approximately 1 million m$^3$ as defined by microseismicity.</td>
</tr>
<tr>
<td>RT3A006</td>
<td>Secondary stimulation</td>
<td>700 cp gel</td>
<td>65 m$^3$ at 93 l/s.</td>
<td>4 events</td>
<td></td>
</tr>
<tr>
<td>RT3A007</td>
<td>Secondary stimulation</td>
<td>700 cp gel</td>
<td>548 m$^3$ at 85 l/s.</td>
<td>15 events</td>
<td>Fracture extent approximately 120 m from pressure decline analysis.</td>
</tr>
</tbody>
</table>

The experience in designing and analysing stimulations at CSM has clearly shown that the major difficulties lie in the design and analysis of bulk stimulations. The relationship between the stimulation fluid volume and the affected rock volume is poorly understood. Also poorly understood is the effect of changing fluid viscosity or stimulation flow rate on the affected rock volume and the permeability increase. It is clear that geological features have a controlling effect on the outcome of a bulk stimulation. In particular they may cause flow channelling effects thus reducing the heat transfer volume. Using medium viscosity gels instead of water appears to result in a more concentrated region of permeability enhancement. This is helpful in avoiding excessive far-field leak-off but must be carefully optimised to minimise circulation flow channelling. In this respect it would be very useful to determine the effect of a relatively large medium viscosity gel stimulation in previously unstimulated rock.

In order to find solutions to these problems more experience is required. Although some answers may become available from the use of FRIP-type models, especially the three dimensional models currently being developed, feedback from the field is essential to successful stimulation design. To fully understand bulk stimulations requires
that microseismic and geological information be tied together with the pressure response during the stimulation. This information can then be used to help the modelling and design effort. It should be remembered that only a few large scale stimulations have been undertaken in hard rock for HDR development, in comparison with the thousands which have been completed for hydro-carbon production.

In comparison secondary stimulations are relatively straight forward to design and analyse, as they draw directly on conventional fracturing experience. The area where difficulties exist is that of optimisation of the treatment. For a secondary stimulation, optimisation depends on the characteristics of the reservoir created by the bulk stimulation. For a properly optimised treatment both bulk and secondary stimulations should be considered together and the system designed as a whole. It will, however, be necessary to modify the design of each stimulation in the light of the success or otherwise of its predecessor and any other stimulations with which it will have to interact.

CONCLUSIONS

The work carried out by CSM has shown that it is possible to create a HDR reservoir by bulk stimulation which can be operated continuously for several years. However, the processes by which this is achieved are poorly understood. In contrast secondary stimulations are relatively straight forward to design and carry out as the design is very similar to conventional hydraulic fracturing practice.

This contrast makes it clear that more field experience is required to improve bulk stimulation design and analysis and also to allow the overall stimulation design, which includes secondary stimulations, to be optimised.

ACKNOWLEDGEMENTS

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FIGURE 1  WELL, JOINT AND STRESS ORIENTATIONS AT THE CAMBORNE SCHOOL OF MINES GEOTHERMAL ENERGY PROJECT SITE
FIGURE 2  MICROSEISMICITY DURING THE WATER BULK STIMULATION (RT2046)
FIGURE 3 PLAN VIEW OF HYDRAULICALLY STIMULATED JOINT NETWORK FOR 2:1 HORIZONTAL EFFECTIVE STRESS RATIO
FIGURE 4  ONE-DIMENSIONAL LEAK-OFF MODEL
FIGURE 5 MICROSEISMICITY DURING THE GEL STIMULATION (RT2B022)
FIGURE 6 LEAKOFF VARIATION WITH JOINT ORIENTATION AND JOINT APERTURE.
FIGURE 7 DOWNHOLE PRESSURE PROFILE DURING THE RH15 SECONDARY STIMULATION.
Hydraulic Stimulation Experiments in High Temperature Geothermal Wells at Nigorikawa and Kakkonda Fields, Japan

Morihiko TAKANOHASHI, Shin'ichi MIYAZAKI and Masayuki TATENO

1. Introduction

The installed capacity of geothermal power station in Japan has reached a total 215.1 MWe (Figure 1). Japan Metals & Chemicals Company (JMC) has been supplying steam amounting to a total of 122 MWe to three geothermal power plants- Matsukawa, Kakkonda Unit I and Nigorikawa (Mori) -and is currently developing another 50 MWe to be designed as Kakkonda Unit II. Moreover, a direct use project is planned in Kakkonda area by the local Iwate government. To date, JMC has drilled 21 exploration wells and 109 geothermal wells with high formation temperatures (200-340°C) at a depth of approximately 1500 m for these projects. However, in several cases sufficient natural subsurface fractures were not intersected. To make these wells commercial, 47 hydraulic stimulation treatments were performed on 35 wells. 28 of these stimulations have been successful thereby improving productivity and/or injectivity. Thus, hydraulic stimulation has aided JMC's geothermal development effort.

This paper describes first of all geothermal geology and several results of hydraulic stimulation in geothermal wells at the Nigorikawa and Kakkonda fields. In conclusion, an application of the AE technique in the evaluation of geothermal reservoir based on rock fracture mechanics, extremely useful in geothermal reservoir energy development, is described.

Figure 1 Japanese Geothermal Power Stations.
2. Hydraulic stimulation at Nigorikawa geothermal field.

To make wells commercial, hydraulic fracturing treatments were performed in lieu of redrilling using gelling agents [1][2]. To date, several wells have been treated in two separate projects. Seven were treated during the fall of 1978. In the spring of 1980, four were treated and several additional wells were treated for the first time. After Operation, an additional well (ND-8) was drilled to preserve stable geothermal steam supply. However, this well did not encounter a large-scale subsurface fracture which connected to the main reservoir system. Thus, acidizing stimulation was carried out for expand natural fracture in the limestone layer.

Geothermal Geology

The Nigorikawa geothermal field is characterized by a Krakatoan type caldera which was formed by volcanic activity about 12,000 to 20,000 years ago. The caldera is filled with sediments consisting of clay, conglomerate and fall back materials (tuff and tuff breccia). The rock formations surrounding the caldera consist mainly of a pre-Tertiary Group named Kamiiso Group which is uncomfortably overlain by the Neogene Tertiary formation ranging in thickness from 300 m to 700 m. Judging from the geological analysis on circulation losses and tracer testing, occurrence of geothermal fluid is controlled by highly permeable zones provided by fault and fracture system of the Kamiiso Group composed of limestone, slate, chert, and tuff. In particular, the Nakanokawa fault, one of the faults of the Kamiiso Group, provides excellent production of high temperature water and steam. And, downhole temperature measurements reveal that the isothermal center of more than 250 degrees centigrade is consistent with the fault trending NNW-SSE having a high angle and crossing the central part of the basin (Figure 2).

Figure 2 Schematic Geological and Thermal Section of the Nigorikawa Geothermal Field.
Gel Stimulation First Program (1978)

For the first fracturing project, seven wells were selected for treatment. They had been completed earlier and production and injectivity tests revealed they were not economic. The design for each well called for 320 kl of fluid to carry 28 tons of 20/40 mesh sand in three stages. Fresh water from a nearby river was transferred to two 100 kl pits via deep well pumps. Water pH was adjusted with acetic acid, and chemically modified guar at a concentration of 5 kg per 1 kl was added continuously during the treatments. Diverting agents were fed into a proportioner where they were blended with the base fracturing fluid.

Gel Stimulation Second Program (1980)

The second fracturing program had two objectives. The first was to stimulate three completed wells after the First program and the second was to retreat wells that responded best to the initial frac program. A total of nine frac pumps and two blenders were connected to combination suction/discharge, trailer-mounted manifold. All treatments were pumped to the wellhead through 3-inch discharge lines connected to a twin-port frac head. Treating rates varied since all of the frac pumps were not available for each job. To accommodate consideration set forth after evaluating results of the first program, an inorganic gelling agent was chosen to make the frac fluid. It was prepared in 2% KCl water. The same chemically modified guar used in the first program was continuously added to the inorganic base solution as a co-gelling agent at a concentration of 2.5 kg per 1 kl. This time, treatment volume was set at 840 kl to carry 81 tons of 20/40 mesh sand in two stages. The base fluid was prepared in working pits using local river water. Deep well pumps were used for mixing and transfer of the new gel to two transit tanks before being pumped away.

<table>
<thead>
<tr>
<th>Well</th>
<th>Approximate Date</th>
<th>Injectivity Test</th>
<th>Production Test</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Rate t/h</td>
<td>Pressure MPa</td>
</tr>
<tr>
<td></td>
<td>Before Fall 1978</td>
<td>0</td>
<td>1.4</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>45</td>
<td>1.4</td>
</tr>
<tr>
<td>B-1</td>
<td>Before Fall 1978</td>
<td>69</td>
<td>0.93</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>100</td>
<td>0.59</td>
</tr>
<tr>
<td></td>
<td>Before Spring 1980</td>
<td>83</td>
<td>0.34</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>113</td>
<td>0.34</td>
</tr>
<tr>
<td>B-2</td>
<td>Before Fall 1978</td>
<td>43</td>
<td>0.49</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>120</td>
<td>0.49</td>
</tr>
<tr>
<td></td>
<td>Before Spring 1980</td>
<td>100</td>
<td>0.34</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>92</td>
<td>0.34</td>
</tr>
<tr>
<td>C-1</td>
<td>Before Fall 1978</td>
<td>15</td>
<td>1.47</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>82</td>
<td>1.27</td>
</tr>
<tr>
<td>C-2</td>
<td>Before Fall 1978</td>
<td>160</td>
<td>0.62</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>175</td>
<td>0.33</td>
</tr>
<tr>
<td></td>
<td>Before Spring 1980</td>
<td>255</td>
<td>0.34</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>D-1</td>
<td>Before Fall 1978</td>
<td>23</td>
<td>2.72</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>48</td>
<td>2.88</td>
</tr>
<tr>
<td>D-2</td>
<td>Before Fall 1978</td>
<td>103</td>
<td>2.4</td>
</tr>
<tr>
<td></td>
<td>After Fall 1978</td>
<td>210</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>Before Spring 1980</td>
<td>220</td>
<td>0.2</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>D-6</td>
<td>Before Spring 1980</td>
<td>49</td>
<td>0.67</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>220</td>
<td>0.67</td>
</tr>
<tr>
<td>F-1</td>
<td>Before Spring 1980</td>
<td>49</td>
<td>0.67</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>220</td>
<td>0.67</td>
</tr>
<tr>
<td>F-3</td>
<td>Before Spring 1980</td>
<td>64</td>
<td>0.44</td>
</tr>
<tr>
<td></td>
<td>After Spring 1980</td>
<td>64</td>
<td>0.44</td>
</tr>
</tbody>
</table>

Table 1 Well Test Data
by two independently operated blenders. The complexer was added simultaneously into both blender tubs and the system pH was closely monitored. Nine tons of flake benzoic acid were used to divert between stages and all materials were proportioned through the two blenders according to the designed pumping schedule. Examination of Table 1 reveals that the hydraulic fracturing procedure carried out in 1978 and 1980 were successful.

Acoustic emission monitoring was continued during hydraulic fracturing operation in the Nigorikawa field. The results presented suggest that acoustic emission signals could provide a useful in-situ information on the evaluation of breakdown point and on detection of the induced fracture [3].

Acidizing stimulation (1986)
In order to achieve markedly higher fracture flow within the limestone layer, an acidizing stimulation treatment of an additional production well (ND-8) was performed in Nigorikawa field [4]. This well is a completed open hole from 750 m to 1365 m in naurally fractured limestone and chert. However, the chert fracture layer is not productive as expected and the temperature of that zone is somewhat low for production (Figure 3). Thus, this well was plugged back to 1113 m to isolate the upper 360 m of the open hole interval for the treatment. The reservoir temperature at the limestone fractured zone is about 210°C.

Figure 3 Lithology, Lost Circulation, Temperature Profile and Casing Layout with Configuration for Acidizing Treatment
The stimulation technique employed was an acid etching treatment (Halliburton Services My-T-Acid) using six high-pressure pumps (HT-400) which were connected to the wellhead valve with a RTTS packer system. A 36 kl low viscosity prepad was pumped to provide cooling tubulars and formation. Following the prepad were 93 kl of high viscosity crosslinked gel fluid and 38 kl of 21 % HCl acid solution with corrosion inhibitors and sealing materials. After the acid, an additional 19 kl of low viscosity fluid was injected for displacement and overflush. After shutdown for 1.5 hours, the next acid stage was started. A 19 kl low viscosity prepad was pumped initially. Then 63 kl of 21 % HCl acid solution with corrosion inhibitors and sealing materials were injected into the formation over a period of two hours. And 13 kl of fresh water were injected in the borehole for displacement and overflush. This treatment concept is illustrated in figure 4.

Figure 4 Concept of the Acidizing Stimulation Treatment.

Fracture fluid gel pump rates of 124–362 kl/H at a surface pressure of 28–169 kg/cm² were estimated for this treatment. Immediately after the prepad was started, several small breakdowns were observed. After shutdown, the acid pump rate was 38–57 kl/H and surface pressure of zero kg/cm² was recorded.

Before the stimulation, this well produced only Hot water of about 60 t/H (well head pressure of 6.8 kg/cm²). After this stimulation, the final steam flow rate was 22.3 t/H and hot water productivity had been increased approximately 3.4 times. This confirmed the fort that the acid etching treatment created some new, high-conductivity flow paths to the main reservoir system.

3. Hydraulic stimulation at Kakkonda geothermal field.

There are impermeable zones in this field. In the case of drilling operations at high temperatures and impermeable zones, it is difficult to encounter large-scale subsurface fractures. Thus, hydraulic stimulation have often been performed as finishing drilling operations. And also the AE technique has proven a useful tool for monitoring hydraulically induced fracture in the Hydraulic stimulation of Kakkonda field.
Geothermal Geology

Geothermal fluids are controlled by highly permeable zones created by faults and fractures in Neogene sedimentary rocks. These rocks have been subdivided into four units of the Kunimitoge Formation, the Takinoue-onsen Formation, the Yamatsuda Formation, and the Osuke Tuff. In addition, dacite intrusive rocks intrude into these sedimentary rocks [5]. A profile of the subsurface structure in the field is shown in Figure 5. The lower limit of the Kunimitoge Formation has not been found yet even in the deepest well (2200 m). This shows that the Kakkonda field is situated in the NW-SE trending subsided zone.

Figure 5 Profile of the Subsurface Structure of the Kakkonda Geothermal Field

Figure 6 Temperature Profile, Circulation Loss and Lithology for the KT-208 Exploration Well.
Figure 6 shows Temperature profile, circulation loss and lithology for the KT-208 exploration well [6]. Many circulation losses occurred during drilling. The temperature log indicates some zones of different permeability. There are permeable zones, 0-300 m; impermeable zones, 300-1000 m; permeable zones, 1000-1400 m; comparatively impermeable zones, 1400-2126 m (well bottom). At the depth of 1400 m to 1500 m, the temperature increases abruptly from 266 to 332°C, because the geothermal fluid, with a temperature of about 260°C, flows into the permeable zone (1000-1400 m in depth) toward the D production site through this well. At 1400-2126 m in depth the comparatively impermeable zone remains at an almost constant temperature.

Controlled Hydraulic Stimulation using the AE Technique [7,8]:

Hydraulic fracturing of production well (KD-3) was effected in the Kakkonda field. The drilling depth of the well was 1269 m, and casing of 13 3/8” (0-360 m) and 9 5/8” (360-965 m) diameter was set into the upper part of the well. The section below 965 m was an open hole of 8 1/2” diameter. The well intersects two fracture zones at 1060 m and 1205-1269 m which were detected from lost circulation of drilling fluid during drilling operations. Figure 7 shows lithology, lost circulation, temperature profile and casing layout.

A total volume of 1720 kl of cold water was injected using three high-pressure pumps -- two 8P-80S (National Supply) pumps and one HT-400 (Halliburton) pump -- which were directly connected to the well-head valve without packer-system. The AE technique was introduced to evaluate and control the stimulation. It was assumed...
that the distribution of a created reservoir could be mapped by AE source location and efficiency of the stimulation could be determined from AE activity. The downhole AE system mentioned above was used for the AE measurement. Figure 8 shows the flow rate change, the wellhead pressure and AE activity during the stimulation.

In the first treatment, a total of 900 kl of cold water was injected. Several small breakdowns together with the AE and drops in flow impedance were observed. About 160 events were detected during and after the injection. The AE sources are distributed in the area oriented east-west. The vertical distribution of the AE sources is mainly in the area between -250 m and -500 m blow sea level which corresponds to the steam produced in the lower reservoir. From these AE analysis it was determined that the creation and distribution of an artificial crack was successful and decision was made to carry out an additional stimulation the following day.

In the second treatment, only 20 AE events were observed while the flow impedance decreased considerably. This fact suggested that the artificial crack was connected to a highly permeable reservoir. The treatment was terminated after the injection of 820 kl.

After treatments, temperature loggings and production tests were conducted in the KD-3 well. The temperature logging effected 62 hours after the treatment revealed that the cold water had been injected mainly into the section between 1205 m and 1269 m of the drilling depth. Steam production was increased 1.65 times after the stimulation. These post-analysis reveal the success of this AE controlled stimulation.

First treatment

Second treatment

Figure 8 Flow-rate, Wellhead Pressure and AE Activity during the Hydraulic Stimulation (KD-3)
4. Application of rock fracture mechanics on geothermal energy development.

It is very important to control subsurface crack extension in geothermal energy development since productivity is highly dependent upon the distribution and dynamics of reservoir cracks. Using conventional methods, it has not been possible to collect geothermal fluids if large-scale subsurface cracks have not been found during the drilling of geothermal wells. In such cases, a method for obtaining a predetermined quantity of steam through the excavation of a new geothermal well has heretofore been employed. However, high drilling costs result in increases in power generation costs which have prevented the acceleration of geothermal energy development.

In order to circumvent these problems, the rock fracture mechanics approach is being employed to provide new insights into the fracture of the rocks, especially in the design of crack-like reservoirs. A combined technique of rock fracture mechanics and the AE technique is being developed by the authors in collaboration with Tohoku University.

Figure 9 illustrates a geothermal reservoir evaluation system based on rock fracture mechanics. In the application of this method two basic measurements are performed. The first is a laboratory fracture toughness test using AE technique which yields the rock

![Fracture Toughness Test using AE technique](image)

1. Lithologic character of rock fracture toughness
2. High temperature and high pressure rock fracture toughness

![AE Measurement in geothermal field](image)

1. AE measurement during build-up test
2. AE measurement during hydraulic fracturing
3. AE measurement during drilling

![Estimation of Fracture Zone in Geothermal Reservoir](image)

![Reservoir Stability Control Based on Mechanics of Fracture Extension](image)

1. Evaluation of reservoir extent
2. Well target design
3. Design of STIMULATION
4. Restraint breakthrough
5. Fracture control

![Geothermal Reservoir Evaluation Based on Fracture Mechanics](image)
fracture properties of a geothermal environment. The second consists of AE measurements in addition to hydraulic stimulation, during build-up tests and drilling operations in geothermal wells. After these measurements have been analyzed, the results indicate the fracture zone of the geothermal reservoir and the method to control fracture extension. In addition, well stimulation design, the extension of the reservoir, well target design and restraint breakthrough fracture control design influence the evaluation of these results.

As mentioned above, the evaluation of geothermal reservoirs based on rock fracture mechanics using the AE technique reveals rock fracture properties, fracture shapes and the characteristics of subsurface fractures in geothermal fields. Therefore, a predetermined quantity of steam can be stably obtained by extending or prepping the extension of subsurface cracks. Rock fracture mechanics and the acoustic emission technique were very useful tools not only for the HDR Project, but also in the development of the natural hot water geothermal system.

ACKNOWLEDGEMENT

The authors are deeply indebted to Prof. Hideaki Takahashi, Prof. Hiroaki Niitsuma, Prof. Hiroyuki Abe and Prof. Katsuto Nakatsuka of Tohoku University for their kind suggestions. Thanks are also due to Dr. Ko Sato of Japan Metals and Chemicals Co., Ltd., for his valuable advice.

REFERENCES
New Concepts of Hydrofrac Stress Data Interpretation at GPKl, Soultz Sous Forets

J. Baumgartner (*), J. Hansen (**), P. Rummel (*)
(*) Ruhr Universität, Institut für Geophysik, 4630 Bochum 1, W-Germany
(**) Hesy GmbH, Heesmannstr. 49, 4630 Bochum 1, W-Germany

Abstract

The state of stress in the 2 km deep geothermal research well at Soultz sous Forets was estimated using a method first suggested by Cornet and Valette (1) which we will call here "Fracture Pressurization Method" or "FP-method" (Baumgärtner and Rummel (2)). This technique takes into account that boreholes intersect various types of weakness planes in the rock mass which during a hydraulic fracturing experiment may open at lower pressures as required for fracture stimulation in intact rock. The FP-method is usually based on the determination of the "far field" stress components acting across a number of arbitrarily oriented fracture planes and uses inversion techniques to calculate the principal stresses. The in situ stress measuring procedure concentrates on instantaneous shut-in pressure tests and extreme flow-rate pumping tests to determine the normal stress components.

Here, results from a first series of five fracture pressurization tests in the Soultz GPKI borehole in the depth range between 1400 m and 2000 m are discussed. Although the data base is still very small, the computed stress profiles characterize clearly the expected typical graben situation with a dominant normal faulting mode (Sy > Smax > Shmin). This stress regime with extreme low horizontal stress components is strongly supported by long drilling induced hydraulic fractures and by the complete lack of stress induced borehole breakout zones (Mastin and Heinemann (3)).

While most hydraulic fracturing data interpretations, including the FP-method, use only singular characteristic pressure values, a simple fracture mechanics approach may be applied to estimate crustal stresses based on the information included in the total pressure record. This model will be used in future testing at Soultz to verify the information derived from conventional and FP-method data interpretations.

Introduction

The purpose of this paper is to summarize various interpretation approaches for hydraulic fracturing stress measurements and to introduce first results from the Soultz sous Forets site. We would like to underline that a combination of different analysis techniques which are based on different assumptions may enhance our capability for stress estimations considerably. This becomes especially important if stress measurements are conducted in a "hostile", high temperature, high pressure environment as in Soultz where technical limitations allow only few tests.

A conventional interpretation of hydraulic fracturing stress measurements is based on three simplifying assumptions: (1) an elastic, impermeable, homogeneous rock mass, (2) a test borehole aligned with one of the principal stress axes and (3) a hydrostatic matrix pore pressure. Experiences from numerous test locations demonstrated, however, that even in cases where "intact" test zones had been carefully pre-selected, fracture initiation was actually controlled by local weakness planes in the rock mass, such as bedding and foliation planes or healed fractures (for example: Rummel and Kappelmeyer (4), Cornet (5)).
Consequently the idea to include hydraulic tests on arbitrarily oriented fracture planes in the stress determination was born. In 1984 Cornet and Valette (1) were the first who succeeded in applying an inversion technique to derive stress data from in situ fracture pressurization tests on a set of differently oriented fracture planes. We will refer to this stress measuring technique here as the "Fracture Pressurization Method" or simply as the "FP-method". The main new assumption Cornet and Valette imposed was that the components of the stress tensor are linear functions of depth - at least within certain, carefully selected depth intervals. While introducing a new restriction, the FP-method offered at the same time the first real opportunity to perform hydraulic fracturing type stress measurements in field situations where the overburden stress is a principal stress, but not aligned with the borehole axis. In addition the stress computations based on simple normal stress determinations are independent of the pore pressure level. This turns out to be very important, as the discussion on the value of pore pressure in crystalline rocks is still open (Schmitt and Zoback (6)). A comprehensive summary of experiences with FP-method testing techniques at several locations in Europe, in various geological situations is given by Baumgärtner (7). This paper discusses also the error sources of such stress computations. In conclusion, the assumption that the orientation of natural fractures observed at the borehole wall corresponds to their far field orientation seems to be the major source of inaccuracies. Baumgärtner and Rummel (2) finally showed in 1987 that fracture re-opening tests, also from inclined fracture planes, can be successfully included in FP-method stress computations if axial stresses exerted on the wellbore wall by the fracturing tool itself, shear effects on the fracture planes and the inherent inability of a straddle system to open subhorizontal fractures are considered.

A possibility to include the pressure record of the whole fracture propagation process during a hydrofrac test into the stress estimations can be provided through fracture mechanics modelling (Rummel (8), Rummel and Hansen (9)). This approach acknowledges the fact that even so called "intact" rocks contain micro-cracks or flaws into which the pressurizing fluid penetrates well before crack propagation occurs. Instability for crack propagation is then defined by the stress intensity at the crack tip and a material property, "the fracture toughness". The stress intensity is determined by the magnitude of the far-field stresses, the fluid pressure in the borehole test section and the pressure distribution within the crack. The latter is generally unknown since it depends on numerous factors such as crack geometry, fluid viscosity, temperature, fluid injection rate, turbulence effects at the crack inlet, etc.. The simple hydrofrac model described here, is an attempt to develop an additional, independent technique for the interpretation of hydraulic fracturing stress measurements.

The Fracture Pressurization Method
Detailed descriptions of the Fracture Pressurization Method for stress computations are given by Cornet and Valette (1), Baumgärtner (7), Lee and Eaiison (10) and Baumgärtner and Rummel (2). In the following, only the principal steps of the stress computation procedure are discussed.

If the stress computations are based only on the determination of the far field normal stress component $S_n$ acting across a number of
differently oriented fractures, $S_n$ is given by:

$$S_n(z_1) = \rho g z_1 \cos^2 \alpha_1 + \frac{1}{2} \sin^2 \alpha_1 (G_1 + G_2) + \frac{(61 + 82)z_1^2}{12} - (G_1 - G_2) \cos^2 (\phi_1 - \phi_2) - (61 - 82)z_1 \cos^2 (\phi_1 - (\phi_2 + \eta))$$

(eq. 1)

where

- $\alpha_1, \alpha_2$ describe the dip and strike of a fracture plane,
- $z_1$ is the depth measured from the upper end of the depth interval selected for stress computations,
- $G_1, G_2$ are the basic stress components at the uppermost depth considered for stress calculations,
- $\xi_1, \xi_2$ represent stress gradients,
- $\phi_1$ is the orientation of $G_1$ with respect to north,
- $\phi_2$ corresponds to the angle between $G_1$ and the orientation of the stress component $\xi_1$.

The derivation of equation (1) requires three main assumptions:

1) the components of the stress tensor $\sigma$ are linear functions of depth - at least within definite depth intervals;
2) the overburden stress is a principal stress, but not necessarily oriented parallel to the borehole axis;
3) the fracture orientation observed at the borehole wall corresponds to the fracture orientation far from the wellbore.

The normal stress component $S_n$ can be measured in situ through instantaneous shut-in pressure tests or - in low permeability formations - through pumping tests at extreme low injection rates. These tests are designed to determine the pressure level at which the fracture begins to open along its entire length as the injection pressure exceeds the acting normal stress. The inversion techniques used to derive stress profiles and stress field orientations concentrate on minimizing the difference between theoretically computed normal stresses ($S_n(\text{theor.})$) and the in situ measured $S_n$ values by constantly re-selecting the unknown stress field parameters $G_1, G_2, \xi_1, \xi_2, \phi_1, \phi_2$ and $\eta$. Baumgartner (7) showed that the assumption concerning the fracture orientation (no. 3) is a major source for inaccuracies. Orienting the fracture at a single point (wellbore) in the rock mass can be misleading due to the irregularity or the wavelength of natural features. Additional problems may arise if a hydraulically extended fracture plane re-orients itself according to the acting stress field. Ambiguous stress determinations may also arise from too small data bases because the inversion process usually requires a largely overdetermined equation system for reasonable stable solutions. Since equation (1) requires an absolute minimum of 5 tests ($g = 0$, no stress rotation with depth) it can be easily seen that the Soultz data base with five tests within a 500 m depth range allows only a preliminary estimation of the stress situation which has to be verified in further field testing.

Baumgartner and Krumel (2) demonstrated that the consideration of fracture re-opening pressure values may be one way to extend the data base for the final stage of FP-method stress computations. However, fracture planes with high shear stresses should not be considered to avoid an inaccurate determination of re-opening pressure values. Beside the possibility of a local stress disturbance, do shear movements along these fractures tend to cause a residual fracture width, which then leads to early fluid percolation into the fracture during pressurization. A preliminary rough estimation of the stress magnitudes at Soultz showed immediately that the stress situation is so that all steeply inclined fractures with strike
directions close to the orientation of maximum horizontal compression see high shear stresses (normal faulting mode, see below). For this reason the stress calculations presented here are restricted to the determination of the normal stress component.

Hydraulic fracturing stress measurements at Soultz

All hydrofrac stress measurements in the GPKI borehole at Soultz were performed in combination with the hydrological tests. A newly designed straddle packer assembly with a straddle length of 3 m was used for these tests. This tool is constructed for both wireline and drill string operations. If used in combination with a drill-string, as it was done in Soultz, the packer elements are pressurized through a separate hydraulic line which is clamped to the drill string with steel straps. At the Soultz site the high gas content in the borehole fluid in combination with the relative high temperature of up to 140°C caused severe technical problems. These technical problems were also the reason why the stress measurements had to be performed in two campaigns, in October (tests at 1457 m, 1494 m, 1500 m) and in November/December 1988 (tests at 1944 m, 1971 m, 1972 m). A standard high pressure rubber hose which was used to inflate the packer elements failed below a depth of about 700 m and had to be replaced by an endless steel tubing. The packer elements turned out to be another major source for technical problems. High pressure and high temperature elements normally used in oil industry applications did not perform satisfactory at the test conditions at Soultz (temperature about 140°C, high gas content, maximum packer pressure about 160 bar differential). Observed packer failures were probably caused by a combination of temperature and gas diffusion effects.

To avoid time consuming impression tests, all orientations of opened fractures were determined from borehole televiewer logs. This procedure, however, required an extensive depth calibration process, comparing impression packer pictures and borehole televiewer results to be able to correct for depth differences. A summary of the characteristic pressure values and the fracture orientations is given in table 1.

The Soultz sous Forets stress situation

The FP-method stress computations are based on a data set of five successful measurements in the depth range between 1457 m and 1968 m. It should be noted, as stated above, that the extreme small data base (five tests are the absolute minimum for a stress inversion) allows only a first preliminary analysis which needs to be verified in future testing.

Using the pressure and orientation data listed in table 1, the inversion technique yields an estimate of the stress profiles in the depth range between 1500 m and 2000 m which can be summarized by the following mean stress gradients (see Figure 1):

\[ Sh = -310 \text{ bar} + 0.29 \text{ bar/m}^2 \]
\[ SH = 83 \text{ bar} + 0.12 \text{ bar/m}^2 \]
\[ Sv = 0.235 \text{ bar/m}^2 \]

The average difference between theoretical and measured normal stress values (AVE) was in the order of 2 bar. The orientation of the maximum horizontal compression SH could be determined to NW-SE. Due to the small data base a fairly large orientation error in the order of at least +/- 30° has to be accepted.

Figure 1 shows that the stress profiles listed above characterize a typical stress regime in a graben situation with a dominant normal faulting.
mode (Sz > SH > Sh). In the upper depth range, roughly above 1700 m, the minimum horizontal stress seems to be even lower than the hydrostatic pressure (remark: The Soultz GK1 borehole is slightly artesic).

The critical stress limits for normal faulting movements along favorably-oriented fault planes can be estimated from a simple Coulomb friction model. The critical stress ratio is then given by (Jaeger and Cook (11)):

$$S_h(\text{crit.}) = \frac{(S_v - P_o)}{(\sqrt{\mu + 1} + \mu)^2} + P_o \quad (\text{eg. 2})$$

where Po is the pore pressure and the friction coefficient. A comparison of critical values for Sh, calculated for standard friction coefficients between $\mu = 0.6$ and $\mu = 1.0$ and "wet conditions" (hydrostatic joint pressure), with the computed stress profiles in Figure 1 demonstrates immediately that optimally-oriented normal faults are potentially active, even for friction coefficients which are larger than 1.0.

This picture of a stress situation with extreme low horizontal stresses is confirmed by two observations:

1) The existence of eighteen vertical fractures with a summed length of 135 m in the depth range between 1415 m and 1997 m (Nastin and Heinemann (3)). Due to the fact that many of these features do not appear in the core, it can be assumed that they were produced hydraulically during drilling. The orientations of these fractures, which should reflect the direction of maximum horizontal compression SH, cluster about a mean of 95° ±/- 12° compared to a more NW-SE oriented preliminary SH-direction as derived from our FP-method stress computations.

2) The complete absence of stress (compression) induced borehole breakouts in the whole depth range between 1500 m and 2000 m (Nastin and Heinemann (3)).

It is important to note that an extrapolation of our stress profiles to greater depths (compare Figure 1) shows clearly that the probability for drilling induced hydraulic fracturing processes as well as for normal faulting slip movements seems to vanish rapidly with increasing depth.

Fracture mechanics modelling and future perspectives

Until now most hydrofrac data interpretations for stress derivation only use singular pressure values of characteristic pressurization phases such as breakdown, shut-in or fracture reopening. Valuable information of the total pressure record for hydrofrac propagation during constant rate pumping tests is neglected. In addition, the conventional hydraulic fracturing approach per se neglects the fact that real materials such as rocks contain micro-cracks or flaws into which the pressurizing fluid penetrates well before crack propagation. Here fracture mechanics modelling offers a possibility to acknowledge the fact that rocks are not "intact" and to model the whole fracture propagation process. Instability for crack propagation is then defined by the stress intensity at the crack tip and the material property fracture toughness. The stress intensity is given by the magnitude of the far-field stresses, the hydraulic pressure in the pressurized borehole section and the pressure distribution within the crack. The latter is generally unknown since it depends on numerous factors such as crack geometry, fluid viscosity, temperature, fluid injection rate, turbulence effects at the crack inlet, etc..

Here, a simple fracture mechanics model for hydrofrac stress determination is discussed, which takes into account the specific experimental parameters of in-situ stress testing (small diameter test
holes, short test sections between the packers, small injection rates, low permeable crystalline rock, microfracturing rather than macrofracs). The model is only two-dimensional and uses analytical solutions for both stress intensity calculations and fluid transport evaluations in order to use it interactively during a hydrofrac test in the field.

The fracture mechanics approach to model hydrofrac stress testing was initiated by early work conducted by Hardy in 1973 (12). A later contribution came from Abou-Sayed et al. (13). The present model was essentially developed by Winter (14) and was recently summarized by Rmel (8). It assumes the existence of a symmetrical double crack of length a in a plate containing a borehole with radius R. The plate is subjected to the far field stresses S_H and S_h, the borehole is pressurized by p and the fluid pressure distribution within the crack is given by \( p_a(x) \). The crack is oriented parallel to the direction of S_H. Then, the critical pressure for crack instability, \( p_c \), is given by:

\[
p_c = \frac{K_{IC}}{(h_0 + h_a) R^2} + f S_H + g S_h,
\]

where \( K_{IC} \) is the fracture toughness of the rock material, and \( f, g, h_0 \) and \( h_a \) are normalized stress intensity functions with respect to \( S_H, S_h, p \) and \( p_a \). They are only dependent on the normalized crack length \( b = 1 + a/R \) and can be calculated either numerically or analytically.

For \( S_H = S_h = 0 \), the frac equation (2) reduces to

\[
T = \frac{K_{IC}}{(h_0 + h_a) R^2}
\]

which presents a fracture mechanics interpretation for the hydraulic fracturing tensile strength \( T \) of the rock. Clearly, \( T \) depends on the material properties \( (K_{IC}) \), demonstrates a size effect \( (R) \) and is a function of the crack length characteristic for the rock, and of the fluid pressure distribution, \( p_a(x) \), within the crack. The latter is somehow related to pumping rate or to fluid pressurization rate during the experiment and yields to the major problem in the application of the model to assume a realistic pressure distribution within the crack or propagating fracture. A first approximation is given by a linear pressure distribution and a pressure drop at the crack inlet:

\[
p_a(x) = \begin{cases} 
  c_1 p \left[ 1 - \frac{x-R}{R} \right] & \text{for } x \geq R+a \\
  c_1 p \left[ 1 + \frac{x-R}{R} \right] & \text{for } -R-a \leq x < R-a 
\end{cases} \quad (eq. 5)
\]

The constant \( c_1 \) takes into account the pressure drop at the inlet due to turbulence effects, the constant \( c_2 \) allows to model the change of pressure gradient in the propagating fracture and accounts for the fact that the fracture width increases with increasing fracture length.

During fluid injection elastic energy is stored in the total hydrofrac system, most of it in the pressurized fluid in the pressure lines, the sealed-off frac section of the borehole, and in the fracture itself. The stored energy will partially be released during unstable fracture growth. Episodic dynamic frac growth will cease whenever the potential energy supply is balanced by the energy demand to create new fracture surface. Modelling the fracture propagation process this way, it
is possible to compute complete synthetic pressure records which then can be compared to the in situ recorded pressure data. If a realistic pressure distribution within the fracture can be found, it should be possible in future to match theoretical and measured pressure records. That way we would obtain additional stress data as well as quantitative information on elastic energy consumption during crack growth, rock mass permeability away from the disturbed region around the borehole (fluid losses) and the hydraulic behaviour of the fracture system.

Acknowledgment

Financial support for this project came from the German Federal Ministry of Research and Technology (contract no. 032-E-6425 C) and from the EEC (contract no. EN3G-0055-D).

Literature:


(3) Mastin L.G. and Heinemann B.: "Evaluation of the Caliper and Televiewer Data from the Soultz Well between 1400 m and 2000 m Depth", report Geophysics Institute, University of Karlsruhe, October 1988


## HYDRAULIC FRACTURING STRESS MEASUREMENTS IN SOULTZ GPK1

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>natural joint</th>
<th>inclination (°)</th>
<th>opening pressure P_{op} (bar)</th>
<th>reopening pressure P_{R} (bar)</th>
<th>shut-in pressure P_{si} (bar)</th>
<th>evaluation S_{V} (bar) (\gamma = 2.35 \text{ g/cm}^3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1457.5</td>
<td>38°</td>
<td>78°</td>
<td>270</td>
<td>267</td>
<td>250 252</td>
<td>336</td>
</tr>
<tr>
<td>1494.5</td>
<td>105°</td>
<td>64°</td>
<td>221</td>
<td>219</td>
<td>206 207 207</td>
<td>345</td>
</tr>
<tr>
<td>1500.0</td>
<td>5°</td>
<td>75°</td>
<td>195</td>
<td>---</td>
<td>---</td>
<td>346</td>
</tr>
<tr>
<td>1947</td>
<td>145°</td>
<td>63°</td>
<td>340</td>
<td>---</td>
<td>295</td>
<td>449</td>
</tr>
<tr>
<td>1968</td>
<td>165°</td>
<td>90°</td>
<td>---</td>
<td>---</td>
<td>265</td>
<td>454</td>
</tr>
</tbody>
</table>

Table 1: Fluid pressure values and fracture orientation data used for stress computations
Figure 1: The stress field at Soultz sous Forêts -- preliminary results from fracture pressurization tests.

The shaded areas represent critical values for the minimum horizontal compression $S_h$ as computed for standard friction coefficients between 0.6 and 1.0 and for dry or "wet" (hydrostatic pressure) conditions. The overburden stress $S_v$ was computed for an average density of 2.35 g/cm$^3$. 
MICROSEISMS: A KEY TO UNDERSTANDING RESERVOIR GROWTH

R. Baria* and A S P Green+
*Cambridge School of Mines and British Geological Survey, UK.
+Cambridge School of Mines, UK.

ABSTRACT

The creation of a Hot Dry Rock (HDR) reservoir requires the injection of fluid (hydraulic stimulation) into a rock mass to improve the low natural permeability. At the Camborne School of Mines (CSM) HDR project, a number of hydraulic stimulations into an Hercynian granite batholith in SW England have been carried out over the past eight years. Microseismicity induced during these stimulations reveals that reservoir growth has been due predominantly to the shearing on natural joints. The interaction of the in situ stresses and jointing determine the direction of reservoir growth and the pressures required to induce growth. In addition, the influence of naturally permeable features which exist on a larger scale than the jointing also seem to play an important part in reservoir growth.

Microseismicity has also been induced during periods of medium and low flow rate circulation. The analysis of these data has been used to define the optimum operating conditions for the Rosemanowes reservoir during circulation.

INTRODUCTION

The development of Hot Dry Rock (HDR) technology for power generation requires the drilling of wells in low natural permeability rocks at depth in order to access rock having the required temperature. The extraction of energy from the rock mass requires the stimulation of existing joints and/or the creation of new fractures in order to increase the interwell flow.

The permeability of a jointed rock with low fabric porosity, such as crystalline rocks, depends on orientation and apertures of the natural joints. Permeability can be enhanced by hydraulic fracturing, which increases the joint aperture either by shear sliding on joint surfaces or by tensile failure, depending on in situ stress and joint direction. The reservoir development process during the stimulation and creation can be monitored using a microseismic monitoring technique (Baria et al 1985; Baria and Green, 1986). Microseismic monitoring can provide a rapid method of evaluating both the growth and size of the stimulated region and the mechanism of a failure at the joints.

In order to develop HDR technology it is essential to understand how the reservoir is created, in particular, the interaction of in situ stresses and joints, and the mechanism associated with reservoir growth.

After the creation of the reservoir, it is necessary to define the operating condition for a long term circulation in order to maximise the return flow with a minimum of fluid losses.

This paper will show how the analysis of microseismic data has revealed the mechanism of reservoir growth and how this is supported
by numerical modelling. It will also show how geological inhomogeneity in the rock mass can affect growth on the small scale and how microseismic data can be used to define the operating condition. The data and interpretation are specific to the Rosemanowes site but similar scenarios can be envisaged at other Hot Dry Rock sites depending on the stress, jointing and geology.

BACKGROUND INFORMATION

The HDR research project in the United Kingdom is located at Rosemanowes Quarry (Cornwall) on the Carnmenellis granite pluton. The granite is of Hercynian age and has been discussed by various authors (Ghosh, 1934; Bott et al, 1958; Bromley, 1976).

The in situ stress field in the Carnmenellis granite was measured from the near-surface to 2610 m (CSM 1986a; Green et al, 1989) and the results show a significant stress anisotropy. The principal stresses are approximately vertical and horizontal. At 2000 m depth, maximum and minimum stresses are horizontal (70 MPa and 30 MPa respectively) and the overburden stress is the intermediate stress (50 MPa).

The strikes of the natural joint system mapped near the surface are approximately orthogonal, with two main sub-vertical sets and one sub-horizontal set (CSM 1986b, Randall et al, 1989). The azimuth of the strikes of two major vertical sets are 320-340 degrees North and 240-270 degrees North.

In 1981, two wells (RH11 and RH12) were drilled to a depth of about 2100 m and hydraulic stimulation was carried out to enhance permeability of the rock mass between the wells. Microseismic monitoring was carried out using near-surface and downhole sensors. Following a year of circulation, during which the reservoir grew downwards, a third 2600 m deep deviated well (RH15) was drilled in late 1984 to intersect the seismic structure below the two wells. A hydraulic connection was found between RH12 and RH15. This connection was further improved by stimulating the connection with viscous fluid of nominal viscosity of 50 cp. This stimulation was also mapped using a microseismic monitoring system (Baria and Green, 1986). Following the viscous stimulation, the reservoir has been circulated for the last four years to characterise the reservoir, define the operation conditions and to develop remedial treatments to improve or manipulate the reservoir (Parker, 1989).

MICROSEISMICITY

Microseismic monitoring has been carried out almost continuously over the last eight years during all stages of the development of HDR technology. The monitoring system is designed to carry out three main functions:

(a) to locate the hypocentre of an event
(b) to estimate source parameters
(c) to construct fault-plane solutions.

The combination of these three functions has produced a significant understanding of the processes which occur during the development of a reservoir in a jointed rock mass.
During the reservoir creation stage, fluid under high pressure is injected into the jointed rock mass. Figure 1 shows that when fluid under high pressure is injected into a rock mass at depth, the reservoir will grow either by tensile mechanism or by shear failure on existing joints. During tensile growth, new fractures are created or existing joints are opened in the direction of maximum principal stress (OH) by overcoming the minimum in situ stress. For this to occur at the Rosemanowes site at 2000 m depth would require a minimum injection pressure of 30 MPa in the reservoir or a wellhead pressure of 10 MPa.

Seismic energy radiated from a tensile failure is very small compared with shear failure and therefore it is exceedingly difficult to track the growth of a reservoir by this mechanism. Shear failure is a very good generator of seismic energy, the seismic radiation pattern of the source is well understood and there is a residual aperture after failure.

**SHEAR FAILURE MECHANISM**

It is clear from the hydraulic and microseismic data that the reservoir grew predominantly by shearing of the naturally occurring joints. Shear failure occurs in a jointed media with an anisotropic stress, when the shear stress acting on a joint becomes greater than the shear strength. The failure mechanism between the shear stress and joint shear strength can be expressed as:

\[
\text{Shear stress } t > (r - P)\tan \phi \quad \text{eqn (1)}
\]

\[
\text{where } r = \text{Joint normal stress} \\
P = \text{pore pressure} \\
\phi = \text{friction angle}
\]

The above relationship shows that when the pore pressure due to fluid injection in a joint increases and reduces joint shear strength to less than the shear stress, the joint fails. The failure is catastrophic and the process is irreversible. This causes the seismic energy to be radiated in a well defined pattern.

(i) Hydraulic evidence

Microseismicity was first detected during low flow rate injection tests in RH12 prior to the first stimulation of the virgin rockmass in 1982. The onset of microseismicity occurred at wellhead injection pressures (over pressures) of just over 3 MPa and at injection flows of about 0.5 l/s. There is a good correlation between the injection pressure and flow perturbations and the microseismicity. For the failure mechanism at the joints to be tensile, it would require an overpressure of at least 10 MPa. This shows that the observed pressure was less than a third of that required to reduce the effective stress to zero and it was concluded that these events must have been caused by shearing motion on existing joint surfaces. This conclusion is supported by the fact that the predominant joint set is misaligned to the maximum in situ stress by about 25° and the shear strength of the joint is a minimum at that orientation.
Figure 1: Reservoir Growth Mechanisms due to Fluid Injection

Figure 2: Fault Plane Solution for Events Captured During Viscous Stimulation of RH15
The evidence of shear failure is also supported by fault-plane solutions, source parameters, microseismic locations and the numerical modelling.

(ii) Fault-plane solution

First motion data from microseismic events can be used to construct fault-plane solutions. There are a number of fault mechanisms each of which produces different far-field radiation patterns. The most commonly recognised mechanism that occurs corresponds to an infinitesimal shear dislocation that is expressed as a double-couple source without a moment, or as a system of dislocation forces acting at 45° to the dislocation plane (Bullen and Bolt, 1985). Therefore, fault-plane solutions can be used to identify failure mechanisms from the radiation pattern.

A composite fault-plane solution for all the events located during the viscous stimulation of a RH15 during 1985 is shown in Figure 2. The solution shows that most of the events fit a double-couple shear mechanism and it indicates a near vertical fault-plane with either left lateral motion on a plane striking 353°N or right lateral motion on a plane striking 263°N. These planes are both orientated near the strike of the main joint sets, as identified by borehole televiewer data from RH12 at a depth of 2000 m (CSM, 1986b) Knowing the in situ stress magnitude and direction it can be stated that the joint failure occurred by a shear mechanism on a vertical plane striking 353°N, as for the plane striking 263°N to fail would require significantly high pressures.

(iii) Source parameters

The microseismic signature from a failed joint can be used to calculate source parameters of the joint (fault) using the Brune model (Brune, 1970). Brune derives an earthquake model by considering the effective shear stress available to accelerate the sides of a fault. The model describes the far-field displacement time functions and spectra. At large distances (far-field) and large wavelengths (compared to the source dimension), the effect of the opposing sides of the fault diffracts around the dislocation surface and differentiates the far-field spectrum. This gives the long-period, large-distance equivalent source as a double-couple. Brune's model was derived for shear waves. The application of the model to P waves is not a consequence of the Brune theory but a semi-empirical relation proposed by Hanks and Wyss, 1972.

Microseismic signatures from near-surface accelerometers for each located event were used to determine source parameters from the displacement spectral density. Average values for the source parameters were calculated as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seismic energy release (kJ)</td>
<td>0.1 to 10.0</td>
</tr>
<tr>
<td>Seismic moment (MNm)</td>
<td>100 to 1000</td>
</tr>
<tr>
<td>Source radius (m)</td>
<td>10 to 20</td>
</tr>
<tr>
<td>Stress release (MPa)</td>
<td>0.01 to 0.1</td>
</tr>
<tr>
<td>Shear displacement (µm)</td>
<td>10 to 100</td>
</tr>
</tbody>
</table>
The source radii determined (10 to 20 m) are consistent with the observed joint spacing and therefore consistent with the idea of the shearing of a block of granite.

(iv) Microseismic locations

Microseismic events were located during reservoir creation and the subsequent circulation in 1982 and 1983; Figures 3 and 4 show the vertical and plan views of these microseismic events.

Fluid was injected into RH12 and the main flow exit was near the bottom. Microseismic events were located near the bottom of RH12 initially and subsequently migrated to greater depth during the following year of the reservoir development period, (Baria et al, 1985). The observed downward growth of microseismic events to a depth of 3.5-4 km is due to a shearing mechanism and can be explained by a locally high ratio of the slopes of the maximum to the minimum principal effective stresses (Pine and Batchelor, 1983).

Numerical modelling

Figure 4 is the plan view of microseismic locations, and shows that the envelope of the microseismic location is orientated approximately NW-SE. Also shown in Figure 4 is the direction of $\sigma_H$ and the joint sets. Clearly there was a strong tendency for microseismic locations to align in the plane close to the $\sigma_H$ and joint set 1 direction.

Numerical modelling using the Fluid Rock Interaction Programme (FRIP) was used to model hydraulic injections. The model is two dimensional and therefore the effect of the injection in plan was modelled. The model consists of a regular grid of elastic blocks, separated by joints which can open according to elastic compression of the blocks by fluid pressures and irreversible shear dilation.

Figure 5 shows the result of a FRIP injection based on a model for in situ joints and stress orientations for the Rosemanowes site. A grid of 40 x 40, 10 m blocks was used. The figure also shows the stress and joint constraints applied to represent in situ conditions at the Rosemanowes site. The shape of the modelled stimulation is in good agreement with that shown by microseismicity (Figure 4). The orientations of the major axes are within about 15°, which is satisfactory considering the uncertainties regarding stress and jointing conditions and the simplification implicit in the model. During the course of the model run, shearing accompanied by joint dilation occurred at fluid pressures significantly less than $\sigma_H$.

Microseismic monitoring showed that the microseismic structure created during the reservoir creation period in 1981/82 had a general NW-SE growth trend which is consistent with the prediction from FRIP modelling. This modelling shows that on a large scale, reservoir growth is dominated by the average properties of the granite. But is this view supported when looking at a much smaller scale?

GEOLOGICAL INHOMOGENEITIES

Two main fluid stimulations have been carried at the Rosemanowes site at about 2000 m depth. The first was carried out in 1982 when 18 500 m$^3$ of water at flow rates of up to 90 l/s were injected and
FIGURE 3  VERTICAL VIEW OF PHASE 2A MICROSEISMIC EVENTS

FIGURE 4  PLAN VIEW OF PHASE 2A MICROSEISMIC EVENTS

FIGURE 5  JOINT DILATION PATTERN FROM FRIP MODEL FOR LARGE HYDRAULIC INJECTION
over 5000 microseismic events were located (Baria et al., 1986). The event locations for the whole test are shown in Figure 6a and for those in the first 8.5 hours of the test are shown in Figure 6b. The result shows that the early growth was in well defined directions, probably controlled by the presence of pre-existing geological structures. The initial growth formed a tubular feature approximately 100 m beneath RH12 'B' in Figure 6b. Subsequent growth was approximately along a plane perpendicular to RH12, marked 'A' (Figure 6a). It is only after injection of larger volumes of water that the downward growth of microseismicity and the north west trend in growth became apparent as subsequently modelled by the FRIP code (Pine and Batchelor, 1984).

At the same time as the drilling of RH15 during Phase 2B, RH11 and RH12 were extended. Following the drilling of RH15 in 1984, a gas lift test was undertaken to assess the hydraulic conditions around RH15. During the test a flow profile was obtained which showed that the flow into the well was contained within the section of the well intersecting the microseismically active region (Baria and Green, 1986).

RH12 was extended so that by chance it intersected the top of lineation 'B' and also by chance RH15 passed close to the bottom of extension 'B'. It became apparent that following the stimulation of RH15 most of the flow during circulation (70%) left RH12 at the bottom and most of the flow entering RH15 (60%) occurred close to the region where lineation 'B' approaches. It therefore seems reasonable that lineation 'B' is a good candidate for being the major flow zone between RH12 and RH15. Subsequent tracer tests support this (Richards et al., 1989).

During 1985 a stimulation was carried out in RH15 using viscous gel. It was thought that water stimulation was not very effective because the low viscosity of water meant that there was significant leak off through the existing joints during the stimulation. This leak off prevented the build-up of the large pore pressures required to cause joint dilation. By using viscous gel leak off would be reduce and this would enable the build-up of higher pore pressures in the joints than would be the case with a water stimulation. The bottom of RH15 was sanded off below 2390 m measured depth, so that hydraulic energy could be concentrated on 165 m of the open well. 18500 m of viscous gel of 50 centipoise viscosity was injected into RH15 over a period of 8 hours at an average flow rate of 198 l/s.

The microseismicity located during this period is shown in Figure 7. Early microseismicity occurred at a true vertical depth of approximately 2260 m and then proceeded to move upwards towards RH12 and downwards. The events formed a vertical tubular structure approximately 70 m in diameter and 200 m high, encompassing a volume of about 0.8 m (Baria and Green, 1986).

Microseismic locations from viscous stimulation were compared (Baria and Green, 1986) with those located during the early period of the main water stimulation in RH12 in 1982. A comparison indicates that microseismicity during the viscous stimulation occurred in a previously stimulated structure (Baria et al., 1985). The overall shape of the microseismic structure during the viscous stimulation was effectively defined in the second half hour of the test.
FIGURE 6a ALL MICROSEISMIC EVENTS LOCATED DURING RT2048

FIGURE 6b MICROSEISMIC EVENTS LOCATED DURING THE FIRST 6.5 HRS OF RT2048

FIGURE 7 PLAN & VERTICAL VIEW OF MICROSEISMIC EVENTS LOCATED DURING VISCOUS STIMULATION INJECTION
The pattern of microseismicity described above is difficult to reconcile with the generation of a penny-shaped fracture orientated in the direction of the maximum principal stress and centred around the injection point of RH15. Even if the fracture growth was by tensile failure and therefore not detectable by the microseismic system, shearing ought to have been observed at the periphery of the fracture due to the low pressures required to shear on joint set 1. The asymmetry of the microseismicity around RH15, and the similarity to a microseismic zone from the water stimulation suggest that the reservoir on a smaller scale has preferential joints which give an inhomogeneity to the rockmass. Such inhomogeneities are difficult to predict and include in numerical models.

RESERVOIR OPERATING CONTROL

Analysis of microseismicity has been shown to play an important part in the creation and development of an HDR reservoir, and can also play an important part in the long-term control of a reservoir.

After the viscous stimulation of RH15 in 1985, the reservoir was circulated by injecting into RH12 and producing from RH15 and RH11. RH15 was the main production well. Earlier tests had suggested that the reservoir responded better to small and gradual changes in operating condition than to sudden or large changes. A circulation programme was designed whereby the circulation rate was increased from 5 l/s (August 1985) upwards in small steps. As the injection rate increased the production rate increased but the water losses also increased. Figure 8 shows the injection/production history and the microseismic event rate. The figure also shows that the microseismic activity increased as the injection flow rate went above about 25 l/s with a corresponding injection pressure of about 10 MPa.

Analysis was carried out on the hydraulic and microseismic data to examine the relationship between wellhead injection pressure and microseismic event rate. Figure 9 shows the relationship between the injected pressure and microseismic event rate for the period of circulation following the viscous stimulation. The plot shows that the microseismic event rate increases rapidly when the injection wellhead pressure exceeds 10 MPa. This corresponds to an injection flow rate of approximately 24 l/s. The pressure of 10 MPa (above hydrostatic) at a depth of 2000 m is close to the minimum in situ horizontal stress.

This suggests that water losses during circulating periods are determined by the minimum earth stress. Joints normal to the minimum earth stress dilate and cause increased fluid losses if the pore pressure rises too high (Figure 10). However, the pressure drop away from the well means that the pore pressure will fall below the minimum horizontal stress in a relatively short distance from the well. The effects of the high pore pressure must be localised near to the well. It is possible that when the pore pressure exceeds 10 MPa, joints, aligned in the direction of the maximum principal stress close to the wellbore that had not previously flowed, are jacked open and become a conduit for flow. If these new flow paths are not well connected to parts of the reservoir that feed RH15 then they will take fluid away from RH15, increasing water losses and providing a new path for the transmission of pressures to different parts of the reservoir that will become microseismically active. Microseismicity in this case has
FIGURE 8  FLOWRATE, PRESSURE AND SEISMIC EVENT RATE FROM 05-AUG-1985 TO 31-DEC-1988
FIGURE 9  PRESSURE AGAINST DAILY SEISMIC EVENT RATE AND NET WATER LOSS FROM 5 AUGUST 1985 TO 30 JULY 1987

FIGURE 10  MODEL OF A WATER LOSS MECHANISM
been used as a tool to formulate an acceptable operating condition of a reservoir during circulation.

The above result would imply that the in situ stress and joint properties will dictate, to a large extent, the maximum flow that can be circulated with acceptable losses.

CONCLUSION

Microseismicity is the only method that gives significant direct information on the various processes going on during the creation, development and circulation of an HDR reservoir. It can be concluded that information obtained from microseismic data:

a. Identified shear mechanism as the main reservoir growth mechanism.

b. Showed that shearing occurred on joint set 1 with strike-slip on a near vertical plane.

c. Showed the importance of joint/stress interaction for reservoir creation.

d. Quantified the volume and shape of stimulated rock mass.

e. Estimated the size of the joint being sheared and other parameters associated with the shear.

f. Gives parameters for numerical modelling and assists in the verification of the model.

g. Identified a target for the third well (RH15).

h. Defined reservoir operating conditions by showing that in situ stresses and jointing will determine fluid losses.

i. Identified inhomogeneity in the rock mass.

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SEISMIC MONITORING ON THE SOULTZ SITE (FRANCE)

A. BEAUCE*, H. FABRIOL*, D. LE MASNE*, C. CAVOIT**, P. MECHLER***, X. CHEN*

* B.G.M./I.H.R.G - BP 6009 - 45060 Orléans Cedex 2 - FRANCE
** C.N.R.S - CRG Garchy - 58150 Pouilly/Loire - FRANCE
*** UNIVERSITE PARIS VI - Laboratoire de Géophysique Appliquée

4 Pl. Jussieu - 75230 PARIS Cedex 5 - FRANCE

SUMMARY

During the first phase of the french-german Hot Dry Rock geothermal energy project of Soultz/Forêts in Alsace (sponsored by the European Community), a hydraulic stimulation test has been undertaken at the bottom (T = 140°C) of the 2000 m deep GPK1 borehole.

Important faults dipping 60° West affect the thick (1400 m) sedimentary cover and the granitic horst underneath.

The seismic network, set up by IMRG to monitor the microseismicity induced in the granite by the stimulation, is made up of three-directionnal probes (especially designed to stand the rough temperature and corrosion conditions) cemented at the bottom of the three observation boreholes. Once the seismic signals digitized in the computing system, an automatic detection and storage of the seismic events is performed in real time.

To get a precise idea of the tectonic context at depth, a VSP seismic survey has been carried out.

During the 3-day stimulation experiment, despite a rather low water flow-rate (3.3 l/s), 58 seismic events have been recorded on the network. Results show a general trend of magnitudes decreasing with time, and a spectral content within the frequency range 50-300 Hz for geophones sited 700 to 1200 m away from the stimulated zone.

Seismic activity starts 2 hours after the beginning of the stimulation. Two main focal zones are concerned and at first their activity are simultaneous: one close to the stimulated borehole, and the other one deeper than GPK1's bottom. Only the remote focal zone remains active during the whole survey.

1 - INTRODUCTION

Hot Dry Rock geothermal energy projects began at Los Alamos (USA) and Camborne (UK) in the early 1970's. In both cases, a monitoring of the microseismicity induced by hydraulic stimulation was very helpful in defining the stimulated regions and reservoir growth.

In France, the HDR site of Soultz-sous-Forêts (Alsace), sited just beneath the old oil-field of Pechelbronn, has been chosen in 1986 on top of a very large thermic anomaly (125°C at 1400 m, at the bottom of
the sedimentary cover, 140°C at 2000 m inside the granitic horst). Compared to the other HDR projects, it presents the advantage of high temperature at intermediate depth, with about sixty old oil-wells available in the vicinity.

A hydraulic stimulation at the bottom of the 2000 m deep GPK1 borehole and a simultaneous monitoring of the induced seismicity has been carried out in December 1988. The seismic sensors were three-directional geophones settled at the bottom of three oil-wells reopened in 1987. 58 seismic events, recorded either by the analogic or the numeric monitoring system, have been observed during the 3-day stimulation experiment.

The work of the geophysical team of the IMRG in this french-german project is developed in this paper as follows:

- design, construction, testing, anchoring and orientation of specific seismic probes,
- description of the acquisition and processing system,
- active seismic survey using VSP technique and shots in GPK1,
- results of the study of the microseismicity induced by stimulation.

**2 - SEISMIC NETWORK**

During the drilling of borehole GPK1 down to 2000 m, three old vertical neighbouring oil-wells have been re-opened successfully at the end of 1987 to install 3D-seismic probes at their bottom (figure 1). As can be seen on the following table, the probes were rather far away from the stimulated zone. Furthermore, only one of them (4616) was located near (20 m up) the granitic horst.

<table>
<thead>
<tr>
<th>Borehole</th>
<th>Horizontal distances to GPK1 (m)</th>
<th>Azimuth (°)</th>
<th>Depth of the probe (m)</th>
<th>Total distance to the stimulated zone (m)</th>
<th>Bottom temperature (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4598</td>
<td>323</td>
<td>N 60</td>
<td>843</td>
<td>1201</td>
<td>104</td>
</tr>
<tr>
<td>4609</td>
<td>100</td>
<td>N 135</td>
<td>963</td>
<td>1042</td>
<td>114</td>
</tr>
<tr>
<td>4616</td>
<td>422</td>
<td>N 355</td>
<td>1360</td>
<td>767</td>
<td>124</td>
</tr>
</tbody>
</table>

A prototype 3-axis down-hole seismic probe has been designed to stand high temperatures (125°C) and rough corrosion conditions during long periods (several months).

To avoid resonance, a problem which often arises when using clamping tools, it was decided to cement the probes downhole; this prevents from retrieving the probes after the experiment, but ensures a good coupling of the probe against the host rock.
Figure 1: Situation map of the project
The mechanical part of this probe is based on the seismic probe developed by IPG Paris for the HDR experiments of Le Mayet de Montagne, whereas the electronic one (including special high temperature components) was designed in cooperation with the Centre de Recherches Géophysiques de Garchy.

The analogic signals coming from the 3 (2 horizontal, 1 vertical) 20 Hz geophones (L15, Mark Products) are preamplified (gain 2000) in the probe itself, and transmitted through a 7-conductor cable (2 wires by geophone) up to the surface. After an other stage of amplification and filtering just at the well-heads, the signals are conveyed to the central recording station close to GPK1, where anti-alias filters (1500 Hz, 48 db/oct.) are applied before digitization.

The calibration of the geophones shows a fairly stable response from 20 up to 2000 Hz. The frequency band foreseen 20-1500 Hz, revealed broad enough during the field stimulation tests (main spectral content of the signals between 50 and 300 Hz).

One of the probes (borehole 4598) is cemented downhole. We are grateful to the Institut Français du Pétrole for their help in choosing the best cement formulation. The two other probes are buried downhole under a column of tiny zirconium marbles directly poured from the borehole head.

A serie of dynamite blasts in very shallow holes (2 m) has been carried out from the surface to orientate the three down-hole probes by hodogrammetry on the first arrivals of the two horizontal components of the signals. As an example, with 10 shots around borehole 4598, we obtained an approximation of ± 9° in the orientation.

3 - DATA ACQUISITION SYSTEM

The IMRG numeric acquisition system is developed around Hewlett-Packard equipment and consists mainly of:

- a fast and powerful (up to 10 channels at a sampling rate of 20 000 Hz) Analog/Digital converter (HP 3852) with a dynamic range of 120 db;
- an HP 9000/350 computer built around a 32 bits MC68020 microprocessor with 8 Megabytes RAM;
- storage units up to 260 Megabytes (2 * 130 Mby disk drives);
- magnetic tape cartridge unit for back up purposes.

The software, adapted from IMRG data acquisition experiments for the monitoring of an oil-field stimulation with the french petroleum company TOTAL, was tested during the orientation blasts and the active seismic program described further on. It allows continuous monitoring of the nine channels (3 channels * 3 probes) and detection of the seismic events recorded at a sampling frequency of 8 000 Hz per channel.

The detection algorithm used is based on the ratio of a short term average absolute value of the signal amplitude over a long term one. The detection criterion is declared true when this ratio exceeds n
times a certain threshold. Channels used for detection during the stimulation were those of the probe into well 4616. Each time a detection is declared, the system stores 1 second of the 9 channels (300 ms before the detection, 700 ms behind) and displays the signal of one channel on the screen.

During the stimulation tests, in December 1988, not only the IMRG numeric system was operating, but also a classical analogic tape recorder, installed by the Camborne School of Mines team and recording continuously during the whole experiment. A sorting out and a digitization of the seismic events recorded on these tapes were then carried out in laboratory and allowed the recovering of tiny events.

4 - ACTIVE SEISMIC SURVEY

The tectonic and geological context of the Soultz zone can be outlined as a thick sedimentary cover (1400 m at GPK1) on top of a granitic horst, with important faults striking NE-SW, dipping 60 to 70° West and affecting the whole series. Geophysical logs performed in GPK1 had already shown that possible seismic reflectors could be detected inside the granite (linked to micro-fissured areas).

An active VSP seismic survey has been carried out in order to:

- better define the extensions of the fractured zones around GPK1;
- give a velocity model allowing an accurate location of the seismic events to be recorded during the stimulation experiment.

The different field operations carried out by Schlumberger and by IMRG were the following:

- a VSP (Vertical Seismic Profile) along GPK1: 25 receiver levels (spacing 30 m) between 1250 and 1970 m (+ 6 check shots at 100, 300, 500, 700, 900, 1050 m);
- 3 OSP (offset VSP) with source offset between 500 and 900 m (see figure 1) and 17 receiver levels between 1250 and 1730 m in GPK1;
- a 1 km-long Walk-Away Seismic Profile (WA) along the NE-SW road joining boreholes GPK1 and 4598 with 26 surface sources (spacing 40 m) and 5 receiving levels every 25 m in GPK1 between 1425 and 1525 m;
- 21 CST (Core Sample Taker) shots in GPK1 between 1400 and 2000 m.

The source used for the VSP surveys was a Vibroseis. During all these operations the seismic probes at the bottom of wells 4598, 4609 and 4616 were operational and the signal recorded could be stored and analysed.

Figure 2 gives an example of the seismic section obtained for the WA profile between 900 and 1300 ms (two-way travel times), that is depths of 1400 to 2400 m. It shows clearly reflectors inside the granitic horst (with a discrepancy in the reflections for horizontal offsets varying from +30 to +130 m depending on the depth). This result affects also the seismic sections obtained from OSP1 and OSP3.
This could be due to a fault dipping 60 to 70° NE located some 100 m East of GPK1 visible in the granite between 1500 and 2200 m depth.

More detailed analysis is underway, and the current reprocessing of the granite section of the reflection surface seismic profiles (PN 84J and PN 84K, see figure 1) made by TOTAL will contribute to our knowledge of the structure of this zone.

5 - RESULTS OF THE SEISMIC SURVEY DURING STIMULATION IN GPK1

A hydraulic stimulation between packers at different levels of the granite in GPK1 had been scheduled in a former stage of the project and was to last some weeks. Delays in the progress of the program, and technical problems (due to temperature) with the packers, led to an actual duration of the stimulation of three days, on a rather long vertical section of the well (between 1970 m and GPK1’s bottom hole).

A total amount of 524 m³ of water has been injected between December the 14th at 10 a.m. and December the 16th at 11 p.m. The water-flow was nearly constant, (3.3 l/s), at least during the first
40 hours (figure 3), except during short periods of several minutes at the beginning, and the well-head pressure reached a maximum of 82 bars, corresponding to 47 bars at bottom hole.

![Graph showing stimulation tests and December 1988 data]

Fifty eight microseisms were induced by the stimulation and no event was recorded during the shut-in period. Figure 3 shows their relative distribution with time and the first event occurred after 2 hours of injection. One can observe a decrease in seismicity and in magnitude with time which can be interpreted as an evolution of the system towards a new stable state.


Window : 1 second

Figure 4 displays the seismograms for an event showing clear wave
arrivals on the 3 seismic probes. The difference in amplitude range between signals received on probes 4616 and 4598 reaches about 30 db (500 more meters of sedimentary cover for 4598 than for 4616). A very encouraging result for the method is the occurrence of very impulsive P and S wave onsets which can easily picked in this example. Nevertheless, only one fifth of the whole data set showed clear onsets on the three probes.

A first analysis of the more energetic events shows a higher spectral content (150-300 Hz) for the probe in the deepest borehole (close to granite) than for the probes located in the sedimentary cover (50-150 Hz).

Figure 5 shows a bi-modal distribution of the differences (Ts-Tp) of S and P arrival times on probe 4616 for the 58 events: 13 events with (Ts-Tp) between 91 and 95 ms, and 39 ones between 99 and 109 ms. This corresponds to at least two focal zones.

In order to locate these events, a three horizontal layers velocity model (figure 6) has been built on the basis of the results obtained by the active seismic program mentioned before. The velocity distribution deduced by the different methods (VSP, Sonic, check shots in GPK1) were consistent with variations around 1%. With this structure, the origin time of the events has been calculated and thus, P and S waves propagation times for all the probes. A 3D grid set of points surrounding GPK1's bottom borehole has been defined and theoretical propagation times from the nodes of this grid to each of the 3 probes have been calculated for P and S waves. Intersections of the surfaces representing the possible source location compatible with the observed propagation times on each probe of the net for both P and S waves define a volume zone where the event originated. The final hypocenter coordinates has been chosen at the center of this zone, the resulting dispersion being about 10 m around this value.
From the whole data set, only 12 events were selected since the other ones did not allow an enough accurate P or S wave picking on the seismograms delivered by the probes sited in the sedimentary cover. They are quite uniformly distributed during the experiment, and consequently, are representative of the whole recorded seismicity. Perturbations on the interpretation of the arrival times (± 1 ms) and on the velocity model led us to a location error estimation of about 30 to 50 m.

**Figure 6**: Soultz seismic network - Geological and velocity models.

**Figure 7**: Microseismic events distribution (for 12 events)

a) : Map view  
b) : N-E cross-section  
c) : S-N cross-section  
- : Epicenter  
■ : Borehole
Two main focal zones are observed (figure 7); one clustered near GPK1 borehole and the other one, more diffuse in space, located at 100 m deeper than the bottom hole. One can notice that the seismicity seems to propagate in the E-SE direction from GPK1, which is compatible with the maximum horizontal stress component one revealed by BHTV data analysis (N 170°) and by in-situ stress measurements (N 145°).

6 - CONCLUSIONS

Despite a rather low flow-rate (3.3 l/s) and bottom-hole pressure (47 bars), a notable seismicity was recorded during the stimulation experiment undertaken at Soultz in December 1988. This seismicity decreases with time (in number and in magnitude) indicating that the system has reached a new stable state. This result has been made possible by the proper design of unremovable specific geophones suited to the rough temperature and corrosion conditions encountered.

Location results indicate that two focal zones were concerned during the experiment: a first one close to the top of the injection zone in GPK1 borehole, and another one 100 m deeper that bottom hole. Direction of the propagation of the seismicity seems to be consistent with the maximum horizontal stress component one.

Present results of the active seismic survey reveals the probable existence of a NS fracture between 1400 to 2200 m, dipping sharply towards the East, and sited at some 100 m East from GPK1.

The feasibility of such a seismic array to follow-up the artificial fractures during their creation has been confirmed, but the results have also pointed out the necessity of at least 4 points of observation inside the granitic horst to better locate the events. This will be undertaken within the 2nd phase of the project.
1. Introduction

The technology for the development of hot dry rock power generation system has been studied under the Sunshine Promotion Headquarters, MITI since 1979 at Hijiori test site, Yamagata prefecture. Two wells, SKG-2 and HDR-1 were drilled and hydraulic fractures were created at the depth of 1,800 meters. A short term circulation test was conducted in 1988. Cold water was injected into SKG-2 and hot water and steam were produced from HDR-1. In future, larger and hotter fractures will be created at the depth of 2,200 meters and water will be circulated for more than one year.

Through the experiments at Hijiori test site until now, we are facing two technical issues; how to understand the fracture system and how to reduce the water loss.

It was revealed that we created a reservoir which consists natural and artificial fractures. When we model the reservoir, it is important to know the detail of the fracture system.

During the course of initial circulation tests for 17 days, the water loss was about 60%. It came up as another important problem to reduce the water loss.

At Hijiori, water was injected more than ten times into SKG-2 since 1979 for the purpose of hydraulic fracturing, stimulation and circulation. The average permeability of rock around an openhole section of SKG-2 was calculated using the data of the injection volume and the wellhead pressure. The permeability increased by stimulation in SKG-2, which results in the decrease of the impedance of the reservoir.

2. Analysis of permeability of rock around a well.

Diffusion of water from a well into rock during pumping is discussed. The governing equation is the radial diffusion equation:

\[
\frac{\partial P}{\partial t} + \frac{1}{r} \frac{\partial P}{\partial r} = \frac{1}{\alpha} \frac{\partial P}{\partial r} \quad (r \geq r_w) \quad (1)
\]

where \(\alpha = \frac{k}{\mu \phi c_t}\), \(r_w\) is the radius of well, \(t\) is time, \(\phi\) is the porosity of rock, \(c_t\) is the bulk compressibility of rock, \(P\) is the pressure, \(k\) is the permeability of rock, and \(\mu\) is the viscosity of water.

The initial condition is

\[
P = P_i \quad (t = 0, r \geq r_w) \quad (2)
\]
The boundary conditions are

\[ P = P_i \quad \text{ (} r = \infty \text{) } \]  

(3)

and

\[ Q = C \frac{\partial P_w}{\partial t} - 2\pi r_w h \frac{k}{\mu} \frac{\partial P}{\partial r} \quad \text{ (} r = r_w \text{) } \]  

(4)

where \( C \) represents the volume of the well fluid added to the well per unit of pressure change, and \( h \) is the length of an openhole section. At the borehole wall, the water pressure, \( P_w \) in the well is equal to that in rock.

\[ P = P_w \quad \text{ (} r = r_w \text{) } \]  

(5)

When \( t = 0 \), the following equation can be obtained.

\[ P_w = P_i \quad \text{ (} t = 0 \text{) } \]  

(6)

Define the nondimensional parameters as follows.

\[ P_d = \frac{2\pi kh}{Q\mu} \quad (P - P_i) \]  

\[ P_{wd} = \frac{2\pi kh}{Q\mu} \quad (P_w - P_i) \]  

\[ r_d = \frac{r}{r_w} \]  

\[ t_d = \frac{k}{\mu C t r_w^2} t \]  

\[ C_d = \frac{C}{2\pi h C t r_w^2} \]  

The equations (1) to (4) transformed to the Laplace plane after substituting above nondimensional parameters are

\[ \frac{\partial P_d}{\partial r_d^2} + \frac{1}{r_d} \frac{\partial P_d}{\partial r_d} = \frac{dP_d}{dr_d} \quad \text{ (} r_d = 1 \text{) } \]  

(7)

\[ P_d = 0 \quad \text{ (} r_d = \infty \text{) } \]  

(8)

\[ \frac{1}{\sigma} = C_d \left( \frac{dP_{wd}}{dr_d} \right) \quad \text{ (} t_d = 0 \text{) } \]  

(9)
where \( s \) is the Laplace transform variable. The general solution for equation (7) is

\[
\overline{P_d} = a_1 \overline{10} + a_2 \overline{K_0(s^{0.5}R_d)} \tag{11}
\]

where \( a_1 \) and \( a_2 \) are constants, \( 10 \) and \( K_0 \) are the modified Bessel function of the first kind and second kind respectively. From the boundedness shown in equation (8), \( a_1 = 0 \) is required. \( P_{wd} \) is 0 when \( t_d \) is 0. From this initial condition and from equations (9) and (10), \( a_2 \) is calculated as follows.

\[
a_2 = \frac{1}{C_d s^2 K_0(s^{0.5}) + s s^{0.5} K_1(s^{0.5})} \tag{12}
\]

Substituting \( a_1 = 0 \) and equation (12) into equation (11), following equations can be obtained.

\[
\overline{P_{wd}} = \frac{K_0(s^{0.5})}{C_d s^2 K_0(s^{0.5}) + s s^{0.5} K_1(s^{0.5})} \tag{13}
\]

\[
\overline{P_d} = \frac{K_0(s^{0.5}R_d)}{C_d s^2 K_0(s^{0.5}) + s s^{0.5} K_1(s^{0.5})} \tag{14}
\]

When \( P \) is the function in Laplace plane, the solution in the real plane is obtained by numerical inversion using the following equation.

\[
F_d = \frac{\ln 2}{I} \sum_{i=1}^{N} V_i P \left( \frac{1 \ln 2}{t} \right) \tag{15}
\]

where \( F_d \) is the approximate function in the real plane. The coefficient \( V_i \) is calculated using equation (16).

\[
V_i = (-1)^{N/2+i} \sum_{k=(i+1)/2}^{\max(1,N/2)} \frac{1^{N/2}(2k)!}{(N/2-k)!k!(i-k)!(2k-i)!} \tag{16}
\]

Wellhead pressure histories were calculated using above equations under a constant flow rate. Fig.1 show the wellhead pressure with the parameter of the permeability of rock. The slope of curves increases with the decrease of the permeability, and when the permeability becomes negligible.
3. Evaluation of the permeability of rock

The casing program of wells, SKG-2 and HDR-1 is shown in Fig. 2. HDR-1 was then drilled to the depth of 2,200m and a cemented liner with PBR was installed at the depth of 2,150m for the future hydraulic fracturing to create the larger and hotter reservoir. The distance between two wells at the depth of 1,800m is about 40m.

Injection was repeated into SKG-2 to create and stimulate fractures. A flow rate, the maximum wellhead pressure and total volume of water injected were summarized in Table 1. The maximum wellhead pressure vs. flow rate is plotted in Fig. 3.

It became clear that the maximum wellhead pressure decreases with the repeat of injection into SKG-2. In order to understand the permeability change around SKG-2 by water injection, we define the permeability \( k \) which represents the average permeability of an openhole section including fracture system. Then, pressure-time curve is calculated under the constant flow rate with the parameter of \( k \) using equations described in chapter 2. The parameter \( k \) is chosen to fit the pressure history obtained from each experiment. Fig. 4 and Fig. 5 show pressure-time curves obtained from the injection test on October 2, 1985 and on October 15, 1986 respectively with the best fit curves by numerical calculation. As is shown from these figures, the permeability \( k \) fitted for these experiments shows different values. \( k \) increased from \( 1 \times 10^{-15} \) to \( 4 \times 10^{-14} \) m². As water of 144 m³ was injected at the maximum flow rate of 9.2 l/s between these experiments, we can estimate that the rock around SKG-2 was damaged by water injection of water which results in the increase of the permeability.

4. Fracture system at 1,800 m

After hydraulic fracturing operation in SKG-2 on October 16, 1986, the openhole section was inspected using a borehole televiewer (BHTV). As shown in Fig. 6, two types of fractures, one is parallel to the borehole axis and the other is cross the borehole were observed. Before the hydraulic fracturing, the spinner was run to know the locations of natural fractures. There was no flow path except near the casing shoe where the fracture intersecting the borehole axis is located. From the facts described above, we may conclude that the fracture across the borehole axis is a natural one and the fracture along the borehole was created by the hydraulic fracturing.

While drilling HDR-1, there was no lost circulation. BHTV was run in HDR-1 on November 14, 1987 just after drilling to the depth of 1,800 meters. Fig. 7 shows the results of BHTV log. Several fractures across the borehole and one parallel to the borehole were observed. The fracture parallel to the borehole is estimated to be created by the effect of the mud pressure and the thermal stress during the drilling. Fig. 8 is
the distribution of natural joints in HDR-1 and the fracture in SKG-2 plotted on lower hemisphere. From this figure, one cluster of joints set including the fracture in SKG-2 which inclines roughly to the east is recognized.

After stimulation of fracture system by injecting 2,510 m$^3$ of water with the maximum flow rate of 102.5 l/s and the maximum wellhead pressure of 14.9 MPa, 17 days' circulation test was conducted to study the behavior of the reservoir. About 40% of hot water and steam was produced and the maximum temperature reached 180 °C. From the result of temperature survey after the circulation test, hot water flowed into HDR-1 at the depth of 1,530, 1,626, 1,742, 1,761, 1,788 and 1,800 meters. If the natural fracture below the casing shoe in SKG-2 extended without changing the orientation, this fracture may intersect at the depth of 1,744 m in HDR-1 which is very close to 1742 m where the temperature shows anomaly. The flow paths from SKG-2 to HDR-1 is illustrated in Fig. 9. It is estimated water from SKG-2 diffused into rock and reached HDR-1 at the different depth between 1,530 and 1,800 m.

5. Future plan
To evaluate the volumetric reservoir at Hijiori which may consists natural and artificial fractures, we must know how the reservoir extended from SKG-2 in detail. We are planning to drill the third well HDR-2 to the depth of 1,900 m. The trace of HDR-2 may be selected so as to intersect with fractures at the opposite site to HDR-1 regarding to SKG-2. Through the circulation test by injecting water into SKG-2 and producing from HDR-1 and HDR-2, we are expecting to have more information on the reservoir. Then HDR-2 will be drilled to 2,400 m and natural fractures are observed carefully before the hydraulic fracturing. A hydraulic fractures will be created from HDR-1 at the open-hole section between 2,150 and 2,200 m. Fractures may extend and intersect with HDR-2. By comparing the results of BHTV log before and after hydraulic fracturing, we may know the relation of natural fractures and flow paths.

Reference

1. A Moench, "Geothermal well test analysis in horizontally stratified formations including well-bore storage and skin effect", International conference on geothermal energy, pp. 267-279, Florence Italy, 1982
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Fig. 1 Wellhead pressure with a parameter of permeability of rock.

Fig. 2 Casing program of SKG-2 and HDR-1.
Fig. 3 The maximum wellhead pressure vs flow rate.

Fig. 4 Pressure-time curve obtained before injection and the best fit curve by calculation.

Fig. 5 Pressure-time curve obtained after injection of 144 m³ and the best fit curve.
Fig. 6  The result of BHTV survey in SKG-2.

Fig. 7  The result of BHTV survey in HDR-1.
Fig. 8 Lower hemisphere stereographic projection of poles of fractures.

Fig. 9 Flow paths from SKG-2 to HDR-1.
The Problem of Channelling in Hot Dry Rock Reservoirs

F.H.Comet and J.Desroches
Department of Geophysics, Stanford University, and
Laboratoire de Sismologie - I.P.G. Paris

Abstract
A forced fluid flow percolation experiment has been conducted in a granite rock mass after hydraulically stimulating some preexisting fractures. The stimulation process involved initially only the injection of gel of low viscosity (70 cp) at flow rates of the order of 1.5 m³/min. However, for some fractures, some sand was also injected at the end of the stimulation. Only the latter revealed useful in improving the production flow rate, as demonstrated by thermal logs.

Spinner logs run in the injection well showed that for large enough flow rates, some preexisting fractures are opened. However results from tilt measurements conducted either during the stimulation tests or during various circulation tests suggest that in none of these cases were the fractures opened at large distances from the borehole. This suggests that even during hydraulic stimulations, flow occurred mostly through channels along preexisting closed fractures, i.e. fractures transmitting shear stresses.

Inversion of focal mechanisms for determining the stress field yields principal stress directions which are not in agreement with those determined with the H.T.P.F. method. This is attributed to the fluid percolation process. This perturbation does not seem to be caused by the opening of fractures, but by the variation of fluid pressure in preferential directions. This is in agreement with the tilt observation and therefore is in support of the hypothesis that the percolation process through this fractured rock mass is controlled by channelling and not by significant fracture opening.

1. Introduction
An in-situ experiment on forced fluid percolation through a granite rock mass has been carried out between two vertical, uncased, 800 m deep boreholes (INAG III-8 and INAG III-9), 100 m apart. The purpose of this experiment was to investigate in-situ various methods for developing an efficient heat exchanger in a fractured rock mass. Attention was concentrated on the hydro-mechanical aspects of the problem, and the site was selected for providing the simplest rock structure as possible. It is located in the granite massif of Le Mayet de Montagne, some 25 km to the South East of Vichy, in Central France. Depth was chosen large enough that the stress field be free of topographical effects (which revealed to be noticeable down to 400 m, Cornet and Julien, 1989), but shallow enough for providing the possibility of installing a wealth of observation stations (15 three-components seismometers for the monitoring of induced seismicity, 6 stations for ground deformation measurements).

Preliminary results obtained during this experiment have been described in two reports (Cornet, 1987; Cornet, 1988); an overview has been published recently (Cornet, 1989) and detailed results are presented in many papers at this symposium. The purpose of this article is to focus attention on the process of forced fluid flow through this fractured rock mass.
After a brief description of the stimulation program initially adopted for developing the heat exchanger, results from spinner logs and from focal mechanisms of induced seismicity are discussed. Then observations of surface tilts conducted during the complete sequence of reservoir stimulation and water circulation experiments are reported and analyzed. These various observations are confronted for discussing the concept of open fracture and that of channeling.

2. On the opening of preexisting fractures

2.1 The initial hydraulic stimulation program

The concept initially considered for developing the heat exchanger was to stimulate a few preexisting fractures inclined with respect to the stress field. This was to be achieved by isolating the fractures with a straddle-packer and injecting a gel of low viscosity at a flow rate low enough for avoiding pressures which would induce true hydraulic fractures (i.e. fractures normal to the minimum principal stress direction). By increasing the interstitial pressure in these selected fractures, it was hoped that a shear motion would be induced, resulting in a certain amount of dilatancy because of the roughness of the fracture surfaces (see e.g. Barton et al., 1985). This dilatancy was assumed to be large enough to increase significantly the hydraulic conductivity of the fractures.

Accordingly, before conducting these hydraulic stimulations, some efforts were devoted to determining on the one hand the dip and azimuth of fractures intersected by the boreholes, on the other the regional stress field (Cornet, 1987, 1988).

Because the well INAG III-8 appeared to be heavily fractured, it was decided initially to stimulate only the well INAG III-9. Four stimulations were conducted in this borehole. The most superficial one (640 m) was located in a strongly altered zone (as suggested by the low electric resistivity) and the three others (721 m, 729 m and 758 m) on fractures identified on the electric log but with very low hydraulic conductivity, as measured by a preliminary low pressure pulse test. For the three upper stimulations, 100 m$^3$ of gel of low viscosity (70 cp) were injected at a flow rate of about 1.3 m$^3$/minute, followed, without interrupting the pumping, by an injection of water at the same flow rate. The volume of injected water ranged from 13 m$^3$ to 230 m$^3$ depending on the test. For the deepest stimulation (758 m), after having pumped in 70 m$^3$ of gel of low viscosity (70 cp), two tons of sand were injected with the help of a high viscosity gel.

Efficiency of these various stimulations can be evaluated from the thermal log and spinner logs run when this borehole (INAG III-9) was under injection or production condition.

2.2 Some results from spinner logs and thermal logs in INAG III-9

Because all the stimulations had been conducted in INAG III-9, it was felt that INAG III-8 should be used as injection well and INAG III-9 as production well. Since the boreholes were uncased, injection and production were to proceed through some tubing anchored on inflatable packers. The need of a tubing in the production well stemmed from the desire of conducting some back pressure testing without losing all the production flow in the more superficial fractures. Accordingly the depth of the producing fractures was identified by running a thermal log in the production well while injecting some water in the other well (INAG III-8). Results are shown on figure 1 where both the temperature and the thermal gradient are plotted versus depth. It is clearly seen on this figure that some flow occurs at 645 m, 758 m, 780 m and below 800 m, but that no thermal anomaly is observed either at 721 m or at 729 m. Interestingly, a spinner log run before any of the stimulations, when INAG III-9 was under injection condition (injection flow rate equal to 25 m$^3$/hour), showed a zone of high hydraulic conductivity at 646 m and none at 721 m, 729 m or 758 m.
It is concluded that the two stimulations at 721 m and 729 m did not bring in any significant amount of flow, but that the sand propped fracture at 758 m is very efficient. This is confirmed by a spinner log run just after this thermal log which shows strong influx of water at 760 m and at 646 m, but none at 721 m and at 729 m. Unfortunately, because of the very low flow rates, the spinner log was very noisy, so that no quantitative measurement was achieved.

The poor quality of the hydraulic connection between the wells when INAG III-8 was used as injection well was caused by a short-circuit draining back to the surface in the immediate vicinity of INAG III-8 most of the injection flow. This short-circuit was attributed to a subvertical fracture, intersected by INAG III-8 at 472 m but reaching depth of the order of 800 m to the North of this well and 350 m to the South of it, as suggested by the location of induced seismicity.

Consequently it was decided to use INAG III-8 as production well after the hydraulic connection of this well with the natural fracture network has been improved by propping with sand some of the fractures intersected below 700 m.

Figure 2 represents two spinner logs run in INAG III-9 when this well was under injection condition; figure 2.a corresponds to an injection flow rate of 30 m$^3$/hour (8.3 l/sec) and figure 2.b to an injection flow rate of 60 m$^3$/hour (16.7 l/s). Although noisy, the first spinner log clearly shows a loss of fluid around 760 m, and no significant loss between 710 m and 740 m. The second log shows clear fluid losses at 721 m and at 729 m, but nearly none around 760 m. This observation can be explained only by the fact that for the larger flow rate (11.3 MPa surface injection pressure) the fractures at 721 m and at 729 m are opened while they are closed for the lower flow rate (8.6 MPa surface injection pressure). This implies that the normal stress supported by the fractures at 721 m and 729 m is smaller than that supported by the fracture at 758 m, a result which is in agreement with both our stress determination and the fractures’ geometry observed at their intersection with the well.

It will be concluded for now that preexisting fractures can be opened near the injection well by fluid pressures larger than the normal stress supported by these fractures but smaller than the value required to develop true hydraulic fractures.

2.3 Stress determination from focal mechanisms of induced seismicity

During all injection and circulation tests, a seismic network of 15 three-components stations was operated in order first to locate the source of induced microseismic events, second to determine the source mechanisms of these events (Talebi and Comet, 1987). Results concerning the focal mechanisms have been related elsewhere (Comet and Julien, 1989), only the main conclusions will be recalled here.

For all the hydraulic stimulations reported above, no events were observed, except for the stimulation at 640 m, some 6 m above a heavily altered zone. This has been attributed, speculatively, to the fact that the injection pressure was large enough to opening the fractures in a quasistatic manner, similar to that observed in true hydraulic fractures (see e.g. Aki et all.) For the stimulation of the altered zone at 646 m, the preexisting hydraulic conductivity was large enough to accomodate the flow rate without actual opening of the fracture. As a result, the increase in pore pressure induced the shearing of local asperities distributed along this altered zone.

However during initial circulation tests and some large scale injection tests (injected volume larger than 1000 m$^3$) some seismic activity was observed. Altogether, about 200 events have been located. Most of the focal mechanisms are coherent with double couple sources suggesting that these events were caused by shear along preexisting planes.
Methods have been developed to determine the principal stress direction out of a collection of focal mechanisms (see e.g. Gephart and Forsyth, 1984; Julien and Comet, 1987). The method is based on the assumption that all events occur in a zone of uniform stress field and that the slip vector in the shearing plane is colinear with the resolved shear stress supported by this plane. This technique has been applied to a set of 14 events observed during the first circulation test and for which the focal mechanisms yield two well defined nodal planes (see figure 3). These events were selected for they occurred in a depth interval (100 m) small enough for assuming that the stress field is effectively uniform for all of them. Results of the inversion (Cornet and Julien, 1989) show that all these events are indeed coherent with a uniform stress field. The maximum principal stress is found to be oriented in the vertical direction, a result which is in agreement with the stress determination based on hydraulic tests (H.T.P.F. method). However the maximum horizontal principal stress is found to make a $60^\circ$ angle with the direction determined with the H.T.P.F. method. The nodal planes selected for each focal mechanism by the inversion algorithm is always nearly parallel to the direction of fluid flow as determined from the location of events (figures 4 and 5).

It was initially concluded from these results that flow occurred in preexisting fractured zones, and that the fluid pressure was large enough to open these fractures thus resulting in a rotation of the principal stress directions. Validity of this proposition was investigated by analyzing tilt measurements observed at the ground surface.

3 Surface tilt observations
3.1 The tilt monitoring network
Ground surface deformations were monitored with an array of 5 –temporarily 6– stations (figure 6). One of the station was located in between the wells 64 m to the North of INAG III-9 well head; the other stations were distributed around the wells at distances ranging from 120 to 300 m. A sixth station was installed temporarily during the 1987 reservoirs stimulations and for the long duration circulation test.

Each station consisted in two silica-based tiltmeters set in two orthogonal directions, with one of them pointing roughly toward the INAG III-8 well head. The tiltmeters are horizontal Zollner pendulum built entirely in silica and soldered on a silica cone fixed into the rock. A mirror carried by the pendulum reflects a light beam toward a light cell. Rotations of the pendulum are directly measured by the motion of the light spot on the cell. The motion of the pendulum is damped with a magnet (acting on a silver plate carried by the pendulum) so as to monitor its quasistatic position.

In addition, at each station, a temperature sensor provided continuous monitoring of the temperature some 5 cm below ground surface, while rain falls were monitored continuously with a digital gauge located at the central data acquisition station, less than 300 m away from the tilt stations.

Signals were transmitted in analog form to a central digital data acquisition station (built with a small Personal Computer). Data were sampled at a rate of 3 readings per minute. For each signal, the average value computed time base was stored on a floppy disk which was changed every week.

It has been showed (Blum and Gaulon, 1971) that the pendulum rotation $\xi$ is related to the ground surface tilt variation $\epsilon$ by:

$$\xi = g \frac{T^2}{4l\pi^2} \epsilon$$

where $g$ is the gravity, $l$ the pendulum length, and $T$ its period.
Accordingly, the spot displacement \( d \) on the light cell is related to the ground surface tilt variation \( \varepsilon \) by :
\[
d = 2KL^2 \varepsilon
\]
where \( L \) is the distance between the mirror and the cell, \( T \) is the pendulum period, \( K \) is a geometrical constant for the pendulum.

The cell delivers an electrical signal proportional to the displacement \( d \) of the luminous spot so that there is direct proportionality between the output voltage variation and the tilt variation. The proportionality coefficient is determined through direct calibration.

The sensitivity of the tiltmeter depends directly on the pendulum period. This period has been selected in the 7 to 8 seconds range for any tiltmeter installed, so that their sensitivity is equal to about 0.02 microradian.

The sensitivity of the thermometers was 0.03 degree Celsius and that of the rain gauge 0.2 mm of rain.

3.2 Data processing
A plot versus time of the tilt data (figure 7) shows strong dependency of tilts with respect to temperature. Efforts were undertaken to filter out these climatic effects.

If \( \omega(t) \) is the time series of the tilt records, and \( \theta(t) \) that of the temperature records, the problem is to determine the transfer function \( f(t) \) that verifies
\[
\omega = f \ast \theta
\]

If \( \Omega(\nu) \), \( F(\nu) \) and \( \Theta(\nu) \) are the Fourier transform of those series, then
\[
\Omega(\nu) = \Theta(\nu) \cdot F(\nu)
\]
and
\[
F(\nu_i) = \Omega(\nu_i) \cdot (\Theta(\nu_i))^{-1}, \text{ for all frequency } \nu_i.
\]
The different coefficients of \( F(\nu) \) were computed for various samples, each lasting four days. Results are shown on table 1. It can be observed that the transfer function is not stable in time with respect to both amplitude and frequency. Accordingly, this approach was dropped and the existence or absence of tilt induced by the various water injection phases were investigated following the coherence technique.

Since results from the spinner logs indicated that change in injection flow rate from 30 m\(^3\)/h to 60 m\(^3\)/h resulted in the opening of fractures near the injection well, the analysis was conducted for the circulation experiment described in figure 8. This test lasted from June 15, 1987 to August 19, 1987. Injection flow rate ranged from 20 m\(^3\)/h to 75 m\(^3\)/h.

First autocohereence technique (Haubrich,1965) was applied. The total time span was divided in 36 hour periods. Each 36 hour period included 432 data points, according to the data acquisition rate, which were subdivided again in 8 groups of 54 data points. For each group of 54 data points, the fast Fourier transform was computed and then the autocohereence factor \( R^2_{\tau k} \) was evaluated according to the following formula:

\[
R^2_{\tau k} = \frac{\left| \sum_{j=1}^{p} X_j(\omega_k) \right|^2}{\sum_{j=1}^{p} |X_j(\omega_\tau)|^2 \sum_{j=1}^{p} |X_j(\omega_k)|^2}, \quad \omega_\tau \in [\omega_1, \omega_2], \quad \omega_k \in [\omega_1, \omega_2]
\]
where $X_j (\omega_k)$ is the jth term of the Fourier transform of $x(t)$.

The global autocoherece $R^2$ for a given frequency band $[\omega_1, \omega_2]$ is equal to the mean of the different $R^2_{rk}$.

Unfortunately, the signals were not stationary enough to yield a significant result. However, since a correlation between tilt and temperature is quite obvious, the squared coherence technique was applied, i.e. the analysis, in the frequency space, of transient effects. The principle is as follows.

Let consider two different signals. If upon a given frequency band the signals are purely random noise, the value of the coherence is zero. If a transient of same frequency content appears on both signals, the coherence jumps ideally to one. However, because the signals are always slightly perturbed, a coherence factor close to one is taken as the sign that the same transient perturbation affects both signals. If the coherence is close to zero, the two signals are considered to be uncorrelated.

When there is no perturbation caused by pumping, at each station there should be a good coherence between temperature and tilt observations. But when some perturbation is induced by pumping, the coherence between temperature and tilt should be destroyed while that between the two tilts components should not, unless the signal is too small.

First, the fast Fourier transform was computed for all signals. Then the cross-power $P_{XY}$ of any two time series for the same station was computed according to:

$$P_{XY}(\omega) = \frac{N}{N^2} \sum_{j=-m}^{m} X(\omega-j) Y(\omega-j) \quad \omega=0,1, \ldots, \frac{N}{2}$$

where $X(\omega)$ and $Y(\omega)$ are the fast Fourier transform of $x_n$ and $y_n$; $m$ determines the estimate's resolution; it was chosen $m$ equal to 5. The coherency squared $C(\omega)$ is given by:

$$C(\omega) = \frac{\text{Real part}^2 (P_{XY}(\omega)) + \text{Imaginary part}^2 (P_{XY}(\omega))}{|X(\omega)|^2 |Y(\omega)|^2}$$

Blackman and Tuckey (1958) defined the estimate’s stability by the equivalent degrees of freedom $\nu$, which $\nu = 2 \frac{\Delta F}{\Delta f}$, where $\Delta f$ is the elementary bandwidth $\frac{1}{N}$ and $\Delta F$ the estimate’s bandwidth, here $\Delta F = \frac{1}{N} + \frac{2m}{N^2}$; hence $\nu = 2N \left( \frac{1}{N} + \frac{2m}{N^2} \right) \approx 19$. Wyatt and Berger (1980) gave the 95 confidence limit for various observed squared coherency, given true squared coherency for selected number of degrees of freedom $\nu$. This provides the computed squared coherency intervals for which the true squared coherency can be considered as being zero and that in which it can be taken equal to one.

Results are shown on figure 9 and 10 for two different stations. It can be observed that there is only some small variations in the coherence spectra except for the 25th and the 29th of June. These are precisely the date when the injection flow rate increased from 45 m$^3$/h to 60 m$^3$/h and from 60 m$^3$/h to 75 m$^3$/h. Interestingly, all the other variations in the injection rate do not yield any significant perturbation.

However when the climatic variation (as computed from an extrapolation of the observation conducted in the preceding 36 hours) is substrated from the signal, the residual tilt is found to be of the same order as the sensitivity of the measuring system. This leads us to the conclusion that although some tilt have indeed been induced at ground surface when changing the flow rate from 45 m$^3$/h to 60 m$^3$/h and from 60 m$^3$/h to 75 m$^3$/h,
these tilts remained smaller than 0.1 microradian. The same conclusion is reached for the large stimulation conducted in INAG III-8 and during which 40 tons of sand were injected below 700 m.

Discussion and conclusion
Results from the spinner log have shown that during injection, when the borehole pressure reaches values larger than the normal stress supported by preexisting fractures but remains smaller than the value required to develop true hydraulic fractures, these preexisting fractures open near the well bore. The question arises the to estimates the distances for which these fractures are indeed opened.

The stress determination computed from the inversion of the focal mechanisms may help answer this question. The strong discrepancy between the orientation of the maximum horizontal principal stress estimated from the H.T.P.F. method and that derived from the focal mechanisms suggests that the stress field has been perturbed by the fluid injections at distances larger than 100 m from the well. Since the location of the events is coherent with a general direction of flow in the North 165 degrees East direction, this would suggest that subvertical fractures oriented in this direction are being opened by the fluid pressure, thus leading to a rotation of the stress direction. However, this explanation is not fully satisfactory, for the shear planes directions are approximately parallel to the direction of the flow. If this direction was to be that of an opened fracture, then the principal stress directions in the vicinity of this zone should be normal and parallel to it. Results do not support this proposition.

The fact that the opening of preexisting fractures is probably limited to the immediate vicinity of the injection well is supported by the results from the tilt observation. Since the surface injection pressure for the 75 m$^3$/h flow rate was 12.5 MPa, it is concluded that the pressure at 650 m is of the order of 18.5 MPa, i.e. larger than the weight of overburden (17 MPa) so that the horizontal fracture observed at this depth should have been opened. Yet when one evaluates from an elastic solution (Sun, 1969) the surface tilt induced by the opening of a penny shaped fracture of radius 50 m located at a depth of 650 m and submitted to an internal pressure of 1.5 MPa, it is found that tilts should have ranged from 0.2 to 0.5 microradians at the measurement stations. Let us recall that the measurements did not show tilts larger than 0.02 microradians.

If we consider now a vertical square dislocation striking North 165 degrees to the East (as suggested with the location of induced seismicity) with a vertical extension of 100 m, centered at a depth of 725 m (mean depth for the stimulations with gel only) and submitted to an overpressure of 7 MPa (as evaluated from the stress determination with the H.T.P.F. method) then the tilts at the observation points, as computed with an elastic solution (Davis, 1983), should have reached about 0.2 microradians.

Accordingly, the tilt observation during the circulation test suggests that the opening of preexisting fractures as observed on the spinner logs have only a limited extension in space, so that flow in the rock mass occurred through closed fractures, i.e. fractures with enough solid contacts to transmit shear. Let us observe that the shear plane orientation as deduced from the focal plane solution is consistent with this proposition: since the fracture system through which flow occurs contains many solid contacts (the asperities of seismologists), the increase of internal pressure generates the shearing of these asperities, thus leading to microseismic events. The only non-consistent observation is the orientation of the principal stress direction evaluated from the inversion of the focal mechanisms. It is proposed that, because flow does not occur in an isotropic manner in the rock mass but only through the channels lying in some favorably oriented fractures, the fluid does not induce an isotropic variation of the stress field but rather a variation of both the magnitude and the orientation of the principal stresses. This will be discussed in another
Let us conclude that the observations presented in this paper show that the opening of preexisting fractures is only limited and that most of the flow occurs through channels distributed along a few channels. Although based on very different premises, this conclusion is similar to that reached by Bame and Fehler (1986) from the analysis of long periods events. Indeed, Bame and Fehler were able to model the main frequency of these signals by considering flow through channels about 20 m and 3 m long.

For the results from Le Mayet de Montagne, the limited amount of fractures is indicated by the few fractures taking fluid in the injection well (about 5), the few fractures producing water in the production well (about 10 identified on thermal logs with 5 accounting for about 75% of the flow), the location of induced seismicity limited to 3 or 4 well localized zones and the results from chemical tracer tests (Goblet and Cordier, 1989) which are consistent with 3 main flow paths.

If indeed flow occurs in a limited number of fractures and if this flow is limited to a few channels within these fractures, then the actual model based on flow through well distributed, planar fractures may lead to significant overestimates of the life time of future Hot Dry Rock reservoirs.

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FIGURE 1: THERMAL LOG

This log was run in INAG III-9 when injection was proceeding in INAG III-8 at a 30 M$^3$/H flow rate.

A) THERMAL GRADIENT (IN DEGREE CELSIUS PER METER)
B) ABSOLUTE TEMPERATURE (IN DEGREE CELSIUS)
FIGURE 2.A: SPINNER LOG

This log was run in INAG III-9 at a logging speed of 20 m/min when injection in this well proceeded at 27 m³/h.
FIGURE 2.B: SPINNER LOGS

These logs were run in INAG III-9 when injection in this well proceeded at 60 M$^3$/H; A: logging speed is 10 M/Min; B: logging speed is 20 M/Min
FIGURE 3: FOCAL MECHANISMS

FOCAL MECHANISMS OF INDUCED MICROSEISMIC EVENTS TAKEN INTO ACCOUNT FOR THE STRESS DETERMINATION. NUMBERS CORRESPOND TO CHRONOLOGICAL ORDERS OF APPEARANCE. THESE EVENTS ARE PART OF THE LOWER CLUSTER INDICATED IN FIGURE 5.

61 IS THE MAXIMUM PRINCIPAL STRESS. THE SMALL PATCH INDICATED AT ABOUT 45 DEGREES FROM HORIZONTAL NEARLY IN THE NORTH DIRECTION AND LABELED 61 CORRESPONDS TO A POSSIBLE SOLUTION BUT NOT TO THE MOST LIKELY ONE.

FIGURE 5: LOCATION OF INDUCED MICROSEISMIC ACTIVITY OBSERVED DURING THE EARLY RESERVOIR DEVELOPMENT.

A) PROJECTION IN HORIZONTAL PLANE. THE CIRCLE IS CENTERED ON THE TOP OF THE WELL INAG III-8, ITS RADIUS IS 100 M. BLACK DOTS ARE SEISMIC STATIONS.
B) PROJECTION IN A VERTICAL PLANE PASSING THRU THE HEAD OF INAG III-8 AND STRIKING TO THE NORTH.
TABLE 1: VARIATION OF THE TRANSFER FUNCTION COEFFICIENTS.

DETERMINATION OF THE AMPLITUDE AND THE PHASE OF THE COEFFICIENT CORRESPONDING TO A PERIOD OF 24 HOURS. THE TRANSFER FUNCTION HAS BEEN COMPUTED FOR STATION 5 FOR 8 PERIODS OF 4 DAYS DURING WHICH NO INJECTION OCCURRED.
FIGURE 7: EXAMPLE OF TILT AND TEMPERATURE RECORD (STATION 9)

THE TIME AXIS IS GRADUATED IN DAYS. TILTS ARE EXPRESSED IN MICRO-RADIANS WHILE TEMPERATURE IS IN DEGREES CELSIUS. THIS EXAMPLE CORRESPONDES TO THE PERIOD STARTING 09/10/1987 AND ENDING 09/29/1987.
FIGURE 8: VARIATIONS OF INJECTION FLOW RATE (IN INAG III-9) AND PRODUCTION FLOW RATE (IN INAG III-8).

THESE VARIATIONS WERE RECORDED DURING THE CIRCULATION TEST FOR WHICH THE SURFACE TILTS HAVE BEEN ANALYSED.
FIGURE 9: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 5

RECALL THAT WHEN A SIGNAL IS PRESENT IN THE TWO TIME SERIES CONSIDERED FOR THE ANALYSIS? THE SQUARED COHERENCY IS 1 AND ZERO WHEN THE TWO SERIES ARE INDEPENDENT.

A) RADIAL COMPONENT VERSUS TEMPERATURE.
FIGURE 9 B: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 5

TANGENTIAL COMPONENT VERSUS TEMPERATURE.
FIGURE 9 C: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 5

RADIAL COMPONENT VERSUS TANGENTIAL COMPONENT.
FIGURE 10: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 9

A) RADIAL COMPONENT VERSUS TEMPERATURE.
FIGURE 10 B: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 5

TANGENTIAL COMPONENT VERSUS TEMPERATURE.
FIGURE 10 C: RESULTS OF THE SQUARED COHERENCY ANALYSIS FOR STATION 5

RADIAL COMPONENT VERSUS TANGENTIAL COMPONENT.
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SESSION 5A - RESERVOIR DEVELOPMENT
FRACTURE FILLING MINERALOGY AND GEOCHEMISTRY AT THE SWEDISH HDR RESEARCH SITE.

T M Eliasson, E-L Tullborg & O Landström

ABSTRACT

A study of the fracture filling mineralogy has been conducted in the 511 m long drill core of the second 500 m deep well at the Hot Dry Rock research site in the Bohus granite, south west Sweden. Ocular standard core logging together with XRD, trace and major element analyses (INAA) were carried out on different fracture filling minerals. Stable isotope analyses of O and C were made on calcite samples from open as well as sealed fractures at different depths. Geochemical analyses were also performed on fresh and altered granite samples.

The dominating fracture filling minerals are calcite, smectite (mainly Ca-smectite), hematite, chlorite, quartz, biotite, muscovite, epidote and rust (FeOOH). The study shows that the fracture filling material provides information about e.g. water conducting fractures and redox potential in the indigenous groundwater in the bedrock.

Textural evidence, isotopic and geochemical data show that the hematite/chlorite and calcite mineralisations occurred principally during the same hydrothermal event. The smectites were formed by in situ weathering of the host rock granite during a later event. Four major episodes of fracture generation and/or activation can be distinguished.

INTRODUCTION

A research site for Hot Dry Rock (HDR) experiments has been established in the Bohus granite on the Swedish west coast. At the site, located close to the village of Fjällbacka (Fig. 1), high pressure hydraulic injections were performed in the 500 m deep well Fjbl at a depth interval between 447 m and 478 m, sealed by an inflatable straddle packer (Eliasson et al. 1988 a,b). Based on the distribution of induced microseismicity, tectonic and geohydraulic information a second 500 m deep well was drilled inclined (10° of vertical), aiming to intersect to stimulated fracture system. Hydraulic connection was established at a fracture at 468 m depth at a lateral distance of 100 m from Fjbl (Sundquist et al., 1988). The roughly horizontal hydraulic flow between the wells is at present (May 1989) tested resulting in flow recovery of about 50% at an injection flow rate of 1.8 l/s.

The high pressure fluid injections performed at the Swedish HDR research site resulted mainly in stimulation of preexisting horizontal natural fractures. An overall horizontal flow regime between the wells was thereby established on a large scale.

In this paper a description will be presented on the characteristics of
the fracturing and the fracture fillings in the bedrock at the site. The study deals mainly with fracture filling material from the 511 m long drill core obtained during the drilling of the second 500 m deep well (Fjb3). The study of the fracture fillings provides information about e.g. water conducting fractures, redox potential, fracture strength etc. in the bedrock. Since creating an HDR reservoir commonly means stimulation of natural fractures, the fracture filling material comes into contact with the stimulation and circulation fluids. Consequently knowledge about fracture filling material and the circulation fluid is of importance for the design and operation of a HDR system.

FIGURE 1. a) Generalised geological map showing the location of the Fjällbacka HDR research site. b) Plan view of the wells.

HOST ROCK DESCRIPTION

The Bohus granite

The Bohus granite is a composite granite massif consisting of a number of compositionally slightly different granitic intrusions. These were emplaced at the final stage of the Sveconorwegian (Grenvillian) orogeny at about 900 Ma (Skiöld, 1976; Eliasson, 1989) and thus cut all deformation structures in the wall rock gneisses (Daly et al. 1982). The granite itself has not suffered from any regional metamorphism and its post-tectonic setting is shown by its magmatic texture although minor shear zones exist as a result of younger brittle tectonics.

The different granite magma surges resulted in widely variable textures and colours. However, the Bohus granite is by composition practically limited to the field of monzogranite (Fig. 2). The major minerals are quartz, perthitic microcline, plagioclase with normally 25-30% An, biotite and some muscovite (commonly of secondary origin). A variety of accessory minerals, such as magnetite, apatite, zircon and monazite are generally found. Garnet, sphene, prehnite, calcite and chlorite occur only locally. The three latter are of secondary origin.

The whole granite body is characterised by enhanced concentrations of U and Th, c. 10 ppm and 50 ppm, respectively (Landström et al., 1980, Eliasson, 1987). Thus the mean heat flow of about 58mW/m² is somewhat higher than normally found in the Fennoscandian shield.
Site geology

The bedrock at the site is rather heterogeneous showing many types of Bohus granite and associated pegmatites. Furthermore, enclaves of older gneisses are frequent. In Fjb3 and Fjbl, gneissic material totals about 15% with a concentration to the depth interval 125-315 m. Thin amphibolitic layers are often found within the gneisses or as discrete lenses within the granite.

There are principally two types of Bohus granite at the site; a) Greyish-red medium grained, slightly K-feldspar porphyritic granite. A rather well developed mineral orientation (magmaic flow structure) is often developed in this type. b) Red medium to coarse grained granite with low contents of biotite and other mafic phases. This salic granite is often found as dykes or veins in the former type. The modal composition of some representative granite samples are shown in Fig. 2. The granites have monzogranitic compositions, whereas the xenoliths are composed of a wide range of rock types.

Zones in the bedrock contain hydrothermally altered fracture zones with extensive epidote, silica or calcite impregnation. Furthermore, the uppermost part (above 270 m) of the Fjb3 core contains zones where extensive hematization occurs (cf. Fig. 4).

![Modal classification diagram](image)

**FIGURE 2.** a) Modal classification diagram after Streckeisen (1976). Data from Asklund (1947), Landström et al. (1980) and Eliasson et al. (1988a). b) Alumina saturation-silica diagram of the granite varieties and xenoliths from the drillcore Fjb3. The boundary line of I-type and S-type granites according to Chappell and White (1974) is also shown.

Geochemistry

38 samples of the host rock granite, unaltered as well as hydrothermally altered, and xenoliths in the drillcore Fjb3 were collected for petrographic and geochemical investigation. A core length of at least 15 cm (> 0.55 kg) was sampled for the chemical analyses. The major elements as well as some trace elements were analysed at Swedish Geological AB (SGAB) in Luleå by ICP-spectroscopy. Great care was taken...
to get petrographically homogeneous and representative samples. This was necessary since the magmatic flow structure causes an inhomogeneous distribution of heavy accessory minerals. These phases are hosting a great part of the REE and thus play a significant role for the REE distribution pattern (Eliasson, 1987).

The unaltered granite samples from the site have a rather restricted range of SiO₂ from about 67 wt% to 76 wt% (cf. Fig. 2). The other main elements consequently show a limited variation. However, at hydrothermally altered fracture zones the granite mineralogy and chemistry have been greatly modified (cf. Fig. 2).

Four granite samples were selected and analysed for their trace element contents by using INA at Studsvik AB in Nyköping. These analyses are used as normalisation of the trace element content in the fracture filling. Their chondrite normalised REE patterns are similar to what is generally found in the Bohus granite. They are characterised by LREE enrichment and significant Eu depletion. Furthermore, the total REE content falls continuously from "low" to high silica granite types.

**Tectonics and fracture orientations**

In the Fjällbacka area the orientation of the most prominent lineaments (large fracture zones) is in a NE-SW direction. Subordinately, N-S and NW-SE to NNW-SSE striking lineaments occur. The vertical fracturing at the site, dominated by three sets striking roughly NE, NW and N-S (see Fig. 3), respectively, thus parallels the lineament directions.

Fractures showing evidence of water seepage (hydraulically open) in Fjb3 belong mainly to the NW striking set together with the horizontal/subhorizontal fracture set (Fig. 3). This observation is thus in agreement with the rock stress situation in the bedrock, with the largest principal horizontal stress direction in NW and the least principal stress approximately vertical down to about 500 m (Wallroth, 1989).

**FIGURE 3.** a) Strike of vertical/subvertical fractures at the surface. b) Fracture poles of hydraulically open fractures in Fjb3.
GEOHYDROLOGY AND HYDROCHEMISTRY

Single-hole packer tests show that the permeability of the rock mass was pronouncedly anisotropic \((K_h \geq K_v)\). This is in accordance with expectations based on the stress data \((\sigma_{mv} < \sigma_{mah})\) and fracture data (Sundquist et al. 1988).

The hydrochemical investigations in drillhole Fjbl identified basically three well distinguished ground water zones in the bedrock; an upper fresh water \((\text{HCO}_3^- - \text{Na}^+ - \text{Ca}^{2+})\) aquifer followed by, at 200-250 m, a saline zone. This saline water, with salinity in excess of 20 g/l, has almost the same composition as the coastal seawater at Fjällbacka except for \(K^+\) which is depleted and \(\text{Ca}^{2+}\) which is enhanced (Eliasson et al., 1988a). At depths greater than about 350 m an aquifer with "relict" saline water is found. It has depleted concentrations of \(\text{Mg}^{2+}\), \(\text{K}^+\), and \(\text{SO}_4^{2-}\) whereas \(\text{Ca}^{2+}\) is enhanced compared with the saline water of sea water composition. The chloride values in the two saline ground water zones are up to about 13,000 mg/l. It should be noted that the general picture of the ground water characteristics established in Fjbl is also valid for Fjb3.

FRACTURE FILLINGS

Investigation methods

Fracture fillings were mapped ocularly during the surface mapping and the drill core investigation. In order make do a more detailed mineralogical study, fracture fillings were investigated using microscopy and X-ray diffractometry. The XRD analyses were carried out at SGAB.

The samples used for the geochemical analyses were scraped off the fracture surface; care was taken to minimize host rock contamination. Geochemical analysis on the fracture powder was carried out using INA at Studsvik AB. Principally four types of fracture fillings were sampled: fractures dominated by 1) hematite, 2) calcite, 3) clay minerals and 4) mixed fillings (mainly calcite-hematite-clay).

Fractures mapped as hydraulically open show evidence of water seepage. This is shown by the occurrence of low temperature water weathering/alteration manifested as e.g. 1) red-brown staining of Fe-oxyhydroxides, 2) occurrence of clay minerals. The orientation of all major open fractures were obtained by drillhole TV camera inspection (cf. Fig 3).

Mineralogy

Fracture filling minerals identified by the drill core mapping consist mainly of calcite, clay minerals (shown by XRD to be mostly Ca-smectite and illite), hematite, chlorite, quartz, biotite, muscovite, epidote and some rust (FeOOH).

Tectonic reactivation as well as formation of new fracture minerals have occurred along several fracture planes intersected by the drillhole. This is shown by e.g. formation of low temperature minerals like smectite in fractures filled with hydrothermal deposits.

Calcite, generally occurring together with hematite, is a frequent
mineral in the core. However, there is a slight depletion of calcite in fractures mapped as hydraulically open in the upper part of the Fjb3 core. This due to downward percolation of low pH and calcite undersaturated surface water which dissolve calcite.

Chlorite occurs generally together with hematite. This is interpreted as a coeval and cogenetic formation of these minerals. In addition, although in subordinate amount, chlorite is also found in smectite filled fractures. This shows that chlorite was formed at low as well as high temperature conditions.

A pervasive low temperature alteration of the fracture network has resulted in an widespread formation of smectite. Smectite is also found in presently healed fractures. This point to an event with intense water circulation at slightly elevated temperatures (<80°C) which resulted in a formation of primary smectite.

The distribution of fractures coated with Fe-oxyhydroxide (rust) may give an indication of the redox potential in the bedrock. Fig. 4 shows that FeOOH coated fractures generally are restricted to occur above 250 m depth. This supports an intense water circulation of oxidising surface water within open fractures down to this depth.

The mineral assemblage of the fracture fillings show that basically the following four generations of mineralisations occur: 1) Pegmatite, quartz +/- epidote, 2) Hematite + chlorite + calcite, 3) Clay minerals (mainly smectite) + calcite +/- chlorite 4) Fe-oxyhydroxide precipitation.

![FIGURE 5. Lithology, frequency of "open" and FeOOH coated fractures versus depth in Fjb3.](image-url)
Geochemistry

Granite normalised REE pattern for the 21 analysed fracture fillings samples are displayed in Fig. 5. The samples were also analysed for the elements Na, Fe, Ca, Cr, Co, Rb, Ba, Cs, Hf, Th and U. There is no pronounced enrichment of trace elements in the fracture fillings, except for Cs in the clay minerals and U in the hematite bearing samples.

All calcite have samples similar patterns showing LREE depletion and HREE enrichment. The change of the Yb/La ratio is a result of an increase in the Yb content due to a successively lower temperature of the hydrothermal fluid and less complexes capable of transporting the HREE (see further discussion below). Some calcite samples have small positive Eu anomalies. Furthermore, one sample exhibits a small but significant negative Ce anomaly. This is in accordance with the sensitivity of these elements to redox conditions. The fluorite sample resembles the calcites, although it has a positive Ce anomaly.

The hematite and the mixed samples have rather similar granite normalised REE patterns. Although all these samples have somewhat higher concentrations of LREE compared to the calcite samples, which is a consequence of the capacity of these minerals of hosting greater amounts of LREE, the general REE pattern is similar which suggests a deposition from a common hydrothermal fluid. One hematite sample has highly enriched REE contents. This fracture filling is sampled in a hydrothermally altered zone in the core, and thus the REE concentration is not representative for the hematite group. The sample with the Ce anomaly is also from a slightly altered zone in the core.

The four clay minerals show no fractionation relative to the granite, which implies that the REE have not been mobilised. This shows that the smectites where formed by in situ weathering of the host rock granite, which is also evidenced shown by the characteristic irregular feldspar weathered fracture surfaces together by the occurrence of zircon and sphene as restitic phases in the clay filled fractures.

FIGURE 5. REE in fracture coatings normalised against granite reference.
Analyses of $\delta^{13}C/\delta^{18}O$ in fracture filling calcites

17 drillcore samples containing open as well as sealed fractures were selected from drillhole Fjb3 in order to analyse $\delta^{13}C$ and $\delta^{18}O$ in fracture calcites. 21 samples were prepared for stable isotope analyses of which 14 belonged to open fractures. Sample depths range from 13.26 to 490.77 m. In addition to the sampled calcite the fractures contained minerals like chlorite, hematite, smectite, epidote and goethite.

Results of the stable isotope analyses are shown in Fig. 6 where $\delta^{13}C$ has been plotted versus $\delta^{18}O$. Recorded $\delta^{13}C$ values ranges from -13.2 to -5.2 %, whereas $\delta^{18}O$ exhibits values within a narrower range (-11.3 to -6.1 %). As can be seen in the figure calcites from the hematite/chlorite coated fractures all exhibit $\delta^{13}C$ values between -7.5 and -5.2 % (indicative of magmatic fluids). In contrast, calcites from the smectite coated fractures show much larger variation in $\delta^{13}C$ (-13.2 to -5.9 %). $\delta^{18}O$ values varies within the same range for both groups (cf. Fig. 1). It is known (cf. Sverensky, 1981) that changes in oxygen isotope composition can take place at lower water/rock ratios than for carbon isotopes. The large variation in $\delta^{18}O$ can therefore be due to reequilibration of oxygen isotopes, whilst the carbon isotopes to a larger extent have preserved their original signatures. The difference in $\delta^{13}C$ intervals of the two groups is thus regarded as a primary feature and reflects differences in conditions which prevailed during periods of calcite precipitation.

$\delta^{18}O$ vs $\delta^{13}C$

![Diagram](image)

**FIGURE 6.** $\delta^{13}C$ versus $\delta^{18}O$ for calcite samples from drillcore Fjb3.

Fig. 7 shows $\delta^{18}O$ versus depth. As can be seen fracture calcites from open fractures within the fresh water zone have undergone oxygen isotope redistribution, which has resulted in uniform $\delta^{18}O$ values (-6.5 to -6.1 %) in the calcites. These values are in accordance with the expected values in calcites formed from present precipitation in the Fjällbacka area (Burgman et al., 1987). Thus, the redistribution of
isotope values in these fracture calcites is a result of fresh water circulation down to the saline water, appearing at 200-250 m. The calcite samples from the saline water section show a weak decrease in $\delta^{18}O$ with depth which may be a mixing zone with fresh water. Below this zone there is no difference in the isotope composition of fracture fillings from healed and open fractures, respectively.

Concerning $\delta^{13}C$, large variations including the lowest values recorded (-13.2 and -11.7 %) can be seen in the most nearsurface samples (Fig. 3). This can be due to a more intensive meteoric water circulation close to the surface, but can also reflect varying carbon isotope composition in water circulating within the fresh water zone.

![FIGURE 7. a) $\delta^{18}O$ in fracture calcites versus depth. b) $\delta^{13}C$ in fracture calcite versus depth.](image)

When plotting the Yb/La ratios versus the $\delta^{18}O$ values for the samples from Fjällbacka a positive trend is obtained i.e. higher $\delta^{18}O$ values and thus lower temperatures during precipitation of the calcites are correlated to the highest Yb/La ratio. Moller et al. (1979) have observed an increase in Yb/La ratio in the final stage of a period of mineralisation. This supports a common origin of the calcites analysed for trace element composition. Futhermore, these calcites correspond isotopically with the group of calcite coprecipitated with hematite/chlorite, i.e. a distinct period of hydrothermal circulation of fluids has caused extensive mineralisations of calcite, hematite and chlorite.

In conclusion, the calcite accompanied by low temperature minerals like smectite contains carbon of more organic origin (lower $\delta^{13}C$) than the calcites from the hematite/chlorite group. Furthermore, recent fresh water interaction has affected the $\delta^{18}O$ values in the calcites in the open fractures within the fresh water zone.

DISCUSSION AND CONCLUSION

The information gained from the investigations carried out at the site regarding the fracture pattern and its mineralogical and geochemical characteristics provides a temperature-tectonic record of the Bohus
granite history. It shows that four major episodes of fracture generation and/or activation have occurred.

1. Fracturing close to the cooling of the granite body resulting in fractures with short trace lengths and undulating fracture planes. Fillings are usually quartz and pegmatite.

2. Post consolidation fractures with high temperature filling; hematite, chlorite, calcite some quartz and epidote.

3. Low temperature mineral formation (mainly smectite) due to alteration of host rock or older fracture filling material.

4. Precipitation of Fe-oxyhydroxid in water bearing fractures in the upper part of the bedrock associated with some calcite dissolution.

Textural evidence shows that the hematite/chlorite and calcite mineralisations occurred principally during the same hydrothermal event. The oxidizing character of the hydrothermal fluids are shown by the occurrence of Fe(III)-minerals and the behavior of Eu and Ce. REE and isotopic data could fit a model with hematite/chlorite and calcite precipitated from similar hydrothermal fluids, whereas the smectites were formed by in situ weathering of the host rock granite. It is possible that the clay mineral formation has taken place during a period of somewhat increased temperature like a e.g. burial metamorphism during the late Paleozoic.

The occurrence of Fe-hydroxide (rust) in hydraulically open fractures above 200-250 m depth indicates that oxidising conditions exists at present in the downward percolating ground water. This is in accordance with the stable isotope data of calcites from the upper part of the bedrock, which show redistribution of O and C isotopes due to interaction with surface water.

The occurrence of smectites and chlorite as fracture fillings within the HDR reservoir has to be considered in the forthcoming circulation experiment. Problems may arise (e.g. swelling and/or migration of clay minerals, oxidization of chlorite and redeposition of Fe-hydroxide etc.) causing increasing flow resistance during the introduction of fresh water into the previously saline and reducing reservoir. The circulation will probably not affect the stability of calcite or hematite. The low concentration of uranium in the fracture filling will not cause any problem when exposed to oxidizing circulation fluids.

Analyses of the incompatible trace elements in the production fluid during the forthcoming circulation may give qualitative information about mineral reactions in the reservoir.

ACKNOWLEDGEMENTS

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LONG TERM PERFORMANCE OF GEOTHERMAL CIRCULATION SYSTEM
- SIGNIFICANCE OF WATER/ROCK INTERACTION -

T. SHOJI, K. WATANABE, H. TAKAHASHI

ABSTRACT

This paper describes a simulation of the long term performance of geothermal circulation system, based on water/rock interaction. During the long term circulation of geothermal fluid through the crack-like reservoir, the crack aperture can be changed by dissolution and/or precipitation of rock minerals. These changes give a significant effect upon the flow impedance of the system, and under some specific condition, precipitation from fluid can lead to plugging of the crack-like reservoir.

INTRODUCTION

Recently geothermal energy extraction from the earth's crust, Hot Dry Rock has been received much attention as a new energy extraction technique. This energy extraction can be attained by circulating fluid through artificial subsurface cracks formed in HDR. Because the crack-like reservoir is filled with geothermal fluid, it is important to examine the effect of water/rock interaction on the performance of fluid circulation system caused by the changes in the crack aperture.

Fluid temperature and its change during the circulation is one of most important variables for the chemical reactions such as dissolution and precipitation. In this paper, experimental results of rock dissolution performed by use of an once-through type autoclave at various temperature are reported and the influence of temperature on water/rock interaction was found to be crucial for dissolution and precipitation characteristics. In order to apply the experimental results to geothermal circulation system, two dimensional model was developed for analysis of the distribution of water temperature along the flow path, and simulate the changes in the crack aperture with time. Based on numerical results, the significance of water/rock interactions on changes in flow impedance of circulation system with operation time is demonstrated.

WATER/ROCK INTERACTION : CHARACTERIZATION OF DISSOLUTION BEHAVIOR OF GRANITIC ROCK

Extensive research have been performed on dissolution behavior of rock and individual minerals [1]-[3]. By use of the facility shown in Fig. 1, experiments on the dissolution kinetics of granitic rock were conducted that include temperature effects on the reactions. The
facility is a once-through type autoclave and loop and, therefore, demineralized fresh water is supplied continuously to the test section for dissolution. These experiments were performed at 250°C, 300°C, 330°C and 350°C. The results are plotted in Fig. 2, where weight loss per unit area are plotted as a function of testing time.

RATE OF DISSOLUTION AND PRECIPITATION

The following description of the model and experimental results are based on the supposition that the reaction of granite can be regarded as a single mineral representing an averaged reaction behavior. The hydrothermal reaction of a rock is subject to the differential rate equation written as

\[
\frac{dC}{dt} = \frac{A}{M} (k_+ - k_- C)
\]

where \(C\) is concentration of rock (wt\%) and \(t\) is time. \(k_+\) and \(k_-\) are the rate constant for dissolution and precipitation, respectively expressed as

\[
\begin{align*}
\text{Rock} + n\cdot\text{H}_2\text{O} &\rightarrow \text{Aqueous species} \\
\text{k}_+ &\quad \text{k}_-
\end{align*}
\]

\(M\) is the amount of water concerned with reaction, and \(A\) is interfacial area between water and rock. Considering that \(k_+/k_-\) must be equal to saturated concentration, the interfacial area, \(A\) is assumed to be a hundred times larger than the apparent surface area, which result in a reasonable \(k_+\) values. This may be due to roughness of surface and porosity of granite.

In this experiments, pure water is supplied continuously into autoclave and we can assume \(C=0\) and transform eq. (1) to

\[
\frac{dC}{dt} = \frac{A}{M} k_+
\]

and eq. (2) can be rearranged to

\[
\frac{d}{dt} \left( \frac{W}{A} \right) = k_+
\]

where \(W\) is weight loss of rock. Integration of eq. (3) under a initial condition that \(W=0\) at \(t=0\) given

\[
\frac{W}{A} = k_+ \cdot t
\]

The value of \(k_+\) can be obtained applying eq. (4) to Fig. 2 based on least square method. The results are plotted in Fig. 3, and it is necessary to approximate \(k_+\) as a function of temperature. In this paper \(k_+\) is approximated as a power function of temperature as expressed below

\[
\log k_+ = a_0 + a_1 \cdot T^{n_1} + a_2 \cdot T^{n_2} \quad (T,K)
\]

By least square method, we determined the coefficients

\(n_1 = 3, \quad n_2 = 5,\)
Fig. 1 Test facility for water/rock interaction study.

Fig. 2 Influence of temperature on dissolution rate of granite.
The curve of eq. (5) is shown in Fig. 3. It is shown in Fig. 3 that \( k_+ \) exhibits the maximum at about 300°C and above that it decreases with increasing temperature.

Precipitation may be subject to aqueous silica, so the rate constant for precipitation for all silica phases reported by J. D. Rimstidt [4] is adopted as \( k_- \) of this study approximated as following function.

\[
\log k_- = -0.707 - 2.598/T \quad (T,K)
\]  

(6)

ANALYSIS OF HEAT TRANSFER IN HDR

In order to analyze the heat transfer in HDR, we consider an ideal two-dimensional crack model shown in Fig. 4. In this model, fluid temperature is supposed to be equal to crack surface temperature at anywhere along the flow path in the same way of the analysis by A. C. Gringarten [5], expressed as

\[
T_W(X,t) = T_R(X,0,t)
\]

(7)

where \( T_W(X,t) \) and \( T_R(X,Z,t) \) stand for fluid temperature and rock temperature, respectively. According to the Fourier's low, the equation for heat balance between water and rock at infinitesimal area \( \Delta X \) can be written as

\[
C_w \rho_w (Q \Delta t) \cdot \Delta T = 2 \cdot \lambda R \cdot \Delta X \Delta t \frac{\partial T_R(X,Z,t)}{\partial Z} \bigg|_{Z=0}
\]

(8)

where \( \Delta T \) is the change in fluid temperature at a incremental time, \( \Delta t \), \( C_w \rho_w \) and \( \lambda R \) are specific heat, density of water and thermal conductivity of rock, respectively. Letting \( \Delta t \to 0, \Delta X \to 0 \), we can obtain a partial differential equation written as

\[
\frac{\partial T_W(X,t)}{\partial X} = \frac{2 \cdot \lambda R}{C_w \rho_w Q} \frac{\partial T_R(X,Z,t)}{\partial Z} \bigg|_{Z=0}
\]

(9)

The equation of heat conduction for two dimensional model can be written as

\[
\frac{\partial^2 T_R(X,Z,t)}{\partial Z^2} = a \left( \frac{\partial^2 T_R(X,Z,t)}{\partial X^2} + \frac{\partial^2 T_R(X,Z,t)}{\partial Z^2} \right)
\]

(10)

where \( a \) is thermal diffusivity of rock. Using eq. (7), we can solve eq. (9) and eq. (10) numerically by finite difference method. According to a preliminary calculation of heat transfer in infinite granite, the temperature at a distance of more than 100m from heat source hardly changes in a time scale of 10 years. So we use isothermal boundary and fix the distance to boundary from crack expressed as

\[
X_E = L + 100 \quad (m), \quad Z_E = 100 \quad (m)
\]

Following model was chosen to calculate the changes in fluid
Fig. 3 Experimentally determined dissolution rate constants, $k_+$. 

Fig. 4 A model of crack-like reservoir and coordinate system.
temperature in the crack against time.

\[ L = 50 \text{ (m)}, \quad T_R(X,Z,0) = 300 \text{ (°C)}, \quad T_w(-L,t) = 200 \text{ (°C)}, \quad Q = 0.1 \text{ (m}^3/\text{hr} \cdot \text{m}) \]

The result is shown in Fig. 5. Where the distribution of fluid temperature along flow path become linear and its gradient decrease gradually. Changes in fluid temperature against time show different behavior when the amount of flow changes. This result also makes it possible to calculate the electrical power which can be extracted from water. This power expressed as

\[
E(t) = C_w \cdot \rho_w \cdot Q \cdot (T_w(L,t) - T_w(-L,t))
\]

The result is shown in Fig. 6. It shows that the electrical power drops rapidly in early stage of operational years, and also shows that the amount of flow has little effect on electric power except the case in which \( Q \) is extremely few. This profile is almost equal to the result analyzed by Y. Shibuya et. al [6].

**NUMERICAL RESULTS AND DISCUSSION**

In this paper, following two boundary conditions were adopted as typical examples for numerical evaluation. In order to make it easy to compare the results obtain from two boundary conditions, the same amount of flow, \( Q \) was used for calculation in both cases as to be 0.1m\(^3\)/hr for unit thickness of rock. And the recovery rate of water from the crack-like reservoir and initial crack aperture were assumed to be 90% and 1mm, respectively.

(a) In order to simulate the behavior of HDR reservoir performance, we chose following boundary condition which is rather common in Japan.

\[ T_R(X,Z,0) = 300 \text{ (°C)}, \quad T_w(-L,t) = 200 \text{ (°C)} \]

The result is shown in Fig. 7. This result shows that the aperture of crack-like reservoir become larger linearly with distance from inlet and also with a operation time. This behavior may due to the increase of \( k_+ \) with increasing temperature.

(b) Secondary, we chose the boundary condition with higher temperature than case (a) where \( k_+ \) show maximum on the way from water inlet to outlet depending upon the amount of flow.

\[ T_R(X,Z,0) = 350 \text{ (°C)}, \quad T_w(-L,t) = 250 \text{ (°C)} \]

In this case, the crack is plugged by precipitation at a distance of 46m from inlet after a operation of 16 days. This behavior may be caused by rapid decrease in \( k_+ \) of granite above 300°C as shown in Fig. 3.

We define the flow impedance expressed following equation in order to evaluate the performance of water circulation system.
Fig. 5 Changes in temperature of fluid along crack path.

Fig. 6 Changes in electrical power with operation time.
Fig. 7 Crack aperture changes with operation time, case (a).

Fig. 8 Crack aperture changes with operation time, case (b).
where $\text{CA}(X,t)$ is crack aperture, and $v$ is viscosity of water.

Using the results in Fig. 7 and Fig. 8, the changes in flow impedance against time were calculated as shown in Fig. 9 and Fig. 10. In case (a), flow impedance, $\text{FI}(t)$ decrease against time. On the contrary, in case (b), $\text{FI}(t)$ increase against time. It express that precipitation has large effect on flow impedance.

Hence, as described above, water/rock interaction has crucial effects upon the long term stability and performance of reservoir of HDR. Specially, the amount of water loss in a system and its control, if possible, hold a key for establishing a economic and high performance HDR systems.

CONCLUSION

The crack-like reservoir in HDR may be subjected a various chemical problem at different temperature and other parameters. In the system like case (a), water/rock interaction result in beneficial condition such as decrease in flow impedance. However HDR system more than 300°C, water/rock interaction cause an increase in the flow impedance and plugging of the crack. For development the high temperature HDR geothermal energy extraction system, it is important to establish the technology for minimize a water/rock interaction.

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Fig. 9. Change in flow impedance of case (a).

Fig. 10. Change in flow impedance of case (b).
THE GEOCHEMICAL ASSESSMENT OF POTENTIAL CIRCULATION FLUIDS FOR A 200°C HDR RESERVOIR IN GRANITE.

D SAVAGE, K BATEMAN, A E MILODOWSKI, M R CAVE, C R HUGHES
British Geological Survey, UK

An important consideration in the development and operation of a Hot Dry Rock geothermal system is the selection of a heat transfer fluid and the chemical composition of this fluid during circulation. The chemical reaction of the circulation fluid with the reservoir rock may lead to the undesirable corrosion or scaling of the reservoir itself, or associated engineering structures.

This communication describes laboratory experiments aimed at the characterisation of the chemical reaction of a number of potential circulation fluids (surface streamwater, NaCl fluids, seawater) for use in a deep (200°C) HDR system in granite. "Batch" autoclave experiments have been carried out at 200°C, reacting candidate fluids with granite, in order to assess the chemical evolution of the fluid phase with time, as well as to characterise the amount and type of solid reaction products.

The results of the study will be discussed in terms of the suitability of each of the fluids as a heat exchange medium for a HDR system in granite.

(Note: this will be a presentation only; no paper will be submitted).
EVALUATION OF AN ARTIFICIAL GEOTHERMAL RESERVOIR FOR HOT DRY ROCK DEVELOPMENT THROUGH INJECTION AND CIRCULATION TEST

Hideo Kobayashi, Susumu Okubo
Tsuneto Tomita, Toshihiko Sueyoshi

INTRODUCTION

Since fiscal year 1985, the New Energy and Industrial Technology Development Organization (NEDO), Japan, has been working for the development of elementary technology related to hot dry rock power generation system at Hijiori, Yamagata prefecture, Japan. In the Hijiori Project, the temperature and pressure conditions under which our HDR heat extraction system is being constructed are similar to those for a practical scale system, and in the course of forming such a system, we are trying to establish elementary technique necessary for HDR geothermal development, including the creation of artificial geothermal reservoir, taking well logs, surveying acoustic emissions, and extracting heat from a geothermal circulation loop. In August 1988, we carried out a short term circulation test to evaluate geothermal reservoir which had been created and stimulated before in granodiorite. The flow rate and temperature of the produced water during the test were different from those we had expected. So there still remains several uncertainties that we must examine. This report discusses on characteristics of the geothermal reservoir at Hijiori depending on several data such as PTS logs, AE monitoring, resistivity tomography and so on, which are conducted during a stimulation and a short term circulation tests.

DETAILS OF RESERVOIR EVALUATION IN FY 1988

The research plan for FY 1988 was as follows;

1) A pressurizing test will be conducted to inject about 2000m$^3$ water from SKG-2 in order to intensify hydraulic communication between SKG-2 and HDR-1. Some minor injection tests of lower flow rate will be performed before and after the pressurizing test, for the purpose of evaluating changes in the permeability of the well-to-well flow channels.

2) After having intensified the communication, a short-term circulation test will be carried out to measure pressure, flow rate and temperature at both wellhead and downhole points in order to determine the properties of the created reservoir. Two times of resistivity tomography and other survey means will be taken to estimate the conditions of fractures between both wells.

3) Surveys of acoustic emissions will be made during the
pressurizing test and circulation tests to determine the zonal range of the fracture network, and analyze fractures by the recorded waveform of acoustic emissions.

4) Accuracy of AE mapping will be enhanced by additional installation of surface stations and by newly developing the triaxial double geophone sonde. Heat-insulating chamber for detonation shooting under condition at bottomhole of SKG-2 will be developed.

5) After completion of the circulation test, preparation for creating the planned lower reservoir will be started by extending HDR-1 down to a depth of 2200m, in which the polished-bore receptacle with cemented-in liner will be inserted.

The progress of Hihiori Project made during FY 1988 were as follows:

1. Minor injection test July 19
2. Stimulation test July 19-21
3. Minor injection test August 2
4. Short term circulation test August 2-25
5. Additional minor flow test October 1-2
6. Extending the HDR-1 well Sept.3-Nov.18

STIMULATION OF PRESENT RESERVOIR

<Objectives of The Test>
Temperature logs from HDR-1 well during the test made in 1987 to confirm hydraulic communication between the two wells showed that some of the water injected into SKG-2 flew into HDR-1 at depth of 1743m and 1788m of the latter. However, the flow rate of the production water constituted only below 1% of that of the injected water. For assessing heat extraction from the created reservoir, higher recovery percentage should be achieved by stimulations for greater hydraulic communication, so as to record a notable extent of temperature drawdown during the circulation test period. Thus, a pressurizing test was carried out primarily for enhancing the recovery percentage and for enabling such assessment of the reservoir.

<Test Results>
Histories of pressure, flow rate and temperature with time at both wellheads during the pressurizing test are shown in Fig.1-a and Fig.1-b. During the pressurizing test, surging tests were made six times by temporarily shutting in the wellhead of the production well in order to raise a pressure level in the fractures. In Fig.1-a, the surging tests are reflected by the six boosted parts of the pressure curve from 6.5hr point to 10.6hr point after the start of pressurizing. Such boosting curves are seen increasingly steeper, suggesting that the repeated surging injection into SKG-2 helped to make more sensitive responses at the HDR-1 wellhead to pressure.

Production flow upon completion of the injection marked
6m³/hr, and was equivalent to about 1/60 of the injection flow upon that moment. This level of production flow was not deemed to be enough to evidence distinct effects of the stimulation work. However, as abrupt increase of production flow occurred about 3 hours after the stop of injection, with a mass release of steam and hot water, recording a flow rate of beyond 100m³/hr at maximum, and a wellhead temperature of 180 °C at the production well. This mass jetting overflow for short period was followed by several periods of intermittent minor increase of outflow, and at about 45 hours from the injection stop, another mass outflow took place in a scale similar to the proceeding one. Although reasons for such intermittent occurrence of outflows from the production well are not known, we believe that the well-to-well communication has now been successfully stimulated.

Minor injection tests into SKG-2 were conducted, one test before and one after the pressurizing test, in order to see changes in permeability characteristics between two wells. In each tests, injection was made in six stages of flow rate. Total water volume injected amounted to 260m³ in the before test, and 290m³ in the after test. The transmissibility and storativity of the fractures were estimated by matching the measured HDR-1 wellhead pressure changes with that from calculation under an assumption that fractures between both wells are a fractured zone in the shape of a disk. Resulting values estimated for each test are as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Before Test</th>
<th>After Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmissibility</td>
<td>1.42×10⁻⁹</td>
<td>1.37×10⁻⁹</td>
</tr>
<tr>
<td>Storativity</td>
<td>4.48×10⁻⁸</td>
<td>5.59×10⁻⁹</td>
</tr>
</tbody>
</table>

Such a reduction in the post-test storativity indicates that the well-to-well communication was improved by the pressurizing test.

In 1988, two additional AE stations, ST-9 and ST-10, were set up to reinforce the network of the existed eight stations for improving the accuracy of AE event locating. The number of AE event recorded by the surface network during the pressurizing test, exceeded 100, and about 70 of them were received simultaneously by at least four stations. A remarkable feature noted as to relations between AE event occasions and injection flow rates was that the event occurred more frequently than otherwise when water was being injected at a high flow rate and in addition, after a considerable volume of fluid has been injected. Very few AE events occurred after the wellhead was shut in when the injection of 2000m³ water was completed this year. To the contrary, after the 1986 hydraulic fracturing with about 1000m³ water, some AE events took place even after the shut in of the wellhead of the injection well.

The distribution of AE sources determined are shown in Fig.2. AE events are located around a point slightly to the south of SKG-2, and covered a zone extended in the east-west
direction, with its major axis about 400m long. In terms of depth, most of such AE events were found between 1600m and 1800m, namely the levels shallower than the pressurized interval. Supposed that these events represent fractures, horizontal direction of these fractures are believed to run along a line of ENE-WSW. The thickness of fractured zone is estimated as about 100m by projecting AE events along the major axis direction.

SHORT TERM CIRCULATION TEST

<Objectives of The test>

a) To verify whether heat extraction data to be obtained by the circulation test can match with the results of the heat-extraction simulation, which was made about the well-to-well communication feed points indicated in 1987 on the assumption that the fractures type were a penny shape.
b) To monitor any further extension of the fractures during the circulation test.
c) To determine temperature, pressure, flow rate and other data in production well by PTS logs to be taken during the circulation test.

<Test Results>
The circulation test was implemented continuously for a period of 15 days, commencing August 2, 1988. Injection flow rate was varied: 0.5m$^3$/min from the outset of the test to the 10th and half days, and after then all the time 1.0m$^3$/min, with a wellhead pressure of about 30 and 60Kg/cm$^2$ respectively. Fig.3 showed that the production flow rate changed sporadically, and a cyclic time tended to become shorter with time. Temperature of the production water scarcely dropped throughout the circulation test period, with discrepancy from a prediction based on the simulation of heat extraction. This discrepancy made it impossible to evaluate the effective heat-exchanging surface of the reservoir, to predict long-term heat exchanging capacity and determine other heat-extracting properties of the reservoir.

During the flow test a total of 13,430m$^3$ water was injected and about 35% of injected water (including the estimated volume of steam) was recovered from the production well. If further recovered volume after the stop of injection is added to this, about 44% water of the injected water may be recorded as returned to the surface.

 Thermal output from the production well during the circulation test was estimated by two alternative methods. First, the output was obtained by calculation from PTS log data measured at a depth of 1490m in the production well (enthalpy of production hot water was 250KCal/Kg) was 3.3MWt in average) after neglecting a lifting friction loss, and deducting the latent heat of the injected water (30 C). Alternatively, the thermal output was obtained from flow
rate, temperature and pressure at the wellhead of the production well during the test. The output fluctuated with time, with an average of 1.3MWt over the test period.

In the circulation test, the periodic outflow occurred as shown in Fig.3. Histories of pressure, flow rate and temperature of a certain production cycle measured in discharged line connected to the production well are shown in Fig.4-a with the normalized time. In this figure, a steep increase of production is observed in the early part of each cycle, which is followed by a gradual decrease and then, by a period of no production flow out in the late part of each cycle. To the contrary, at the depth of 1490m in the production well HDR-1, the temperature, pressure and spinner logs were as shown in Fig.4-b. Temperature was almost constant at 145 C, indicating that no flashing occurred at this depth and lower. The lowest pressure level was seen in the middle part of each cycle, suggesting that this was the time when the flashing point reached the lowest.

<Simulation of downhole flowing>
The change of flowing manner in HDR-1 well during a single flow cycle was simulated in order to pursue the reasons for the sporadic flow out experienced during the test. A program cord employed for the simulation was WELBORE. It was assumed that, over an interval between a depth of 1490m (the depth where the PTS logs were taken, Fig.4-b) and the wellhead of this well, the low of the conservation of mass, that of momentum and that of energy are always applicable. The results of the simulation may be summarized as follows;

1) At a depth of 1490m, flow rate is stable as compared with the fluctuating flow rate at the wellhead, although a minor peaking behavior was observed in the middle of the cycle.
2) Wellhead pressure levels are almost equal to measurements.
3) The depth level of flashing in the well lowers gradually as sporadic output continues, and reaches about 1100m in the middle of a cycle. The flashing level in the end of the cycle was not able to be estimated.
4) The simulation results showed that the sporadic flowing out is caused by the flashing in the production well, not in the reservoir.

<PTS logs taken in minor flow test>
After the additional drilling of 40m to extend HDR-1, the assessment of feed points was attempted by a minor flow test from SKG-2 to HDR-1, and an injection test into HDR-1, and PTS logs were taken in HDR-1. Temperature recovery behavior of this well after the stop of its drilling work was monitored, and also, temperature logs in HDR-1 after the start of injection from SKG-2 was carried out. Six arrows in Fig.5 shows temperature anomalies along the open hole section of the production well measured at the moment of 10 hours after the start of injection from SKG-2 well. In the
same figure, the curves of spinner log with different cable speed are shown. The curve of a spinner log taken during the main circulation test, after an appropriate correction made by wellbore diameter variations according to a calliper log taken separately, permitted to estimate the shares of feed points: that a total production flow rate may be broken down into a 15%, 30% and 55% flow from at a depth of 1530m, an interval below 1530m to 1788m, and below 1788m down to 1800m respectively.

RESISTIVITY TOMOGRAPHY

Tomography surveys of resistivity were conducted two times, one before the stimulation test and the other after circulation test, by using the open hole intervals of both wells. And it was identified that low-resistivity zones reached the open hole section of HDR-1, one at around 1737m and the other at around 1793m, suggesting that two to four hydraulic communication channels are likely exist.

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4) New Energy and Industrial Technology Development Organization
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(a) the period of injection water from SKG-2 well

(b) the period starting after stop of the injection

Fig. 1 Histories of pressure, flow rate and temperature at the wellhead during the ressureizing test (1988)
Fig. 2 Hypocentral locations of micro-seismicity induced by the pressurizing test form SKG-2 well (1988)

Fig. 3 Histories of pressure, flow rate and temperature at production wellhead (HDR-1) during the circulation test (1988)
Fig. 4 Temperature, pressure and flow rate during one production cycle (1988)
Fig. 5 Spinner logs during circulation test and the temperature profile 10 hours after the start of minor flow test (1988)
MECHANISMS OF DISSOLUTION-PRECIPITATION PROCESSES INDUCED BY HOT WATER CIRCULATION IN A FRACTURED GRANITE.


M.-P. Turpault, G. Berger and A. Meunier

Fluid circulations in fractured rocks are known to produce zoned alteration (Bonorino, 1959; Hoton, 1985; Page and Wenk, 1979; Nuelle et al., 1985; Beaufort and Meunier, 1983; Parneix, 1987). Zonation is classically considered to be related to chemical or temperature gradients, the mechanisms of the zone growing are not known. Most of the studies describe secondary products in order to determine the physicochemical conditions prevailing during the alteration. Few is known concerning the dynamic of the processes from the opening to the sealing of a fracture.

The aims of this study is to determine these dynamical processes by quantifying, as far as it is possible, the dissolution-recrystallisation features. The calculation of bulk mass balance and the analysis of the secondary phases distribution allow to define the relationships between dissolution of primary phases and precipitation of secondary ones at different times.

I. GEOLOGY

This study required a fine grained, homogeneous granite with simple mineralogy and crosscutted by only one hydrothermal event.

The La Peyratte granite (Southeastern part of Armorican Massif, France) is a fine grained (grain size ranging from 100 to 150μm). The bulk rock composition is given in Table 1. The modal composition is: microcline (34.5%), oligoclase (31%), quartz (23%), biotite (10.5%) and accessory minerals (0.5%) (titanite, myrmekite and zircon). The average chemical compositions of major components are given in Table 2.

This granite is crosscutted by parallel veins whose alteration halos are evidenced by biotite decoloration.

II. PETROLOGY

II.1. Vein deposits

The composition of deposits depends on vein width:
- phengite ± fluorite ± pyrite (300μm < width < 200μm);
- orthoclase ± fluorite ± pyrite (200μm < width < 50μm);
heterogenous deposit depending on the fractured primary mineral (width < 20μm).

Two types of veins were studied:
- The phengite vein (300μm) is composed essentially of phengite (90%), with in the central part, fluorite (8%) and pyrite (2%). Phengite is the first mineral to precipitate. In the wall rock, all the primary minerals excepted microcline are dissolved. This induces variations of vein with from 400 to 200μm. Approximately 50% of vein volume is due to wall rock dissolution.
- The orthoclase vein (50μm) is composed of orthoclase (98%) and scarce fluorite and pyrite crystals (2%).

II.2. Wall rock zonations

The wall rock zonation is identical around phengite and orthoclase veins (Figure 1):
- In the nearest zone (0-4mm), the biotite is transformed into chlorite + leucoxene + phengite (phengite vein) or chlorite + leucoxene + titanite (orthoclase vein). Oligoclase is replaced by secondary albite, white micas (phengite along phengite vein and muscovite along orthoclase vein) and illite/smectite random mixed-layer (I/S R=0) from 55% to 70% of smectite (IS60S).
- In the farthest zone (4-16mm), oligoclase is transformed into I/S R=0 from 40% to 45% of smectite (IS40S). Phengite appears only along the phengite vein. Biotite does not react.

III. COMPOSITION OF SECONDARY PHASES

White micas are of polytype 2M1. Their chemical composition does not depend on the crystallization site (in vein PHV, in biotite PHB or in oligoclase PHF, Table 2). Interlayer charge is always up 0.9 per O(OH)2.

Orthoclase The secondary orthoclase is distinguished from microcline by its lower Na content (Table 2).

Albite contains calcium (0.08 per O, Table 2).

Chlorites The total octahedral cation content of chlorite increases versus distance from vein, while the aluminium in the octahedral sheet decreases according to the 2Al3+ =3(Fe+Mg) substitution.

Two average compositions were chosen for mass balance calculations (CHP= nearest chlorite and CHE= farthest chlorite, Table 2).

Illite/smectite mixed-layer The X-ray diffraction patterns of random illite/smectite mixed-layer show two characteristic reflections in the 17.0Å and 8.55Å reflections (Figure 2). The dissymetry of the (001) reflections (high saddle/peak ratio in the low-angle region) which decreases with distance from vein, and the shift of the (002) reflection towards higher angle, indicate that smectite in the mixed-layer increases towards the vein.
For mass balance calculations, two average chemical compositions were used (Table 2).

IV. QUANTIFICATION OF SECONDARY PHASES AND DISSOLUTION VOIDS

Chlorite and dissolution voids in biotite are deduced from bulk rock composition. The quantities of each secondary minerals and dissolution voids are measured by image processing.

Different images have been used:
- optical microscope photograph with few magnifications (70, 180, 300);
- scanning microscope photograph for dissolution voids.

IV.1. Phengite vein

* biotite

The phengite percentage (%PHB) decreases with distance from vein (Figure 3). The curve equation is expressed by log(%PHB)=4.38-1.97d with a correlation coefficient of -0.99.

* plagioclase

Outside the albitization front and random illite/smectite precipitation zone, a percentage of phengite (%PHF) and dissolution voids is calculated. The quantities of phengite which crystallize in plagioclases, vary with distance from vein according to a logarithmic law: log(%PHF)=2.17d-0.33 (correlation coefficient of -1.0, Figure 4). The dissolution voids distribution curve is more complex (Figure 4), but the sum of the phengite + dissolution voids is a logarithmic curve: log(%PLA)=2.95-0.17d (correlation coefficient of -0.99, Figure 4).

IV.2. Orthoclase vein

Quantitative determinations are made only for the percentage of dissolution voids (%VI) in plagioclase versus distance from vein (d). The curve equation is: log(%VI)=2.81-0.18d (correlation coefficient of -1.0, Figure 5).

V. CHEMICAL MASS BALANCE (for phengite vein)

V.1. Gresen method (1967)

Gresen derived a chemical mass balance equation based on composition-volume relationships. This requires that chemical compositions and specific gravities of altered and fresh rocks are known.

Here the volume factors \( f_v = 0 \) because the wall-rock volume does not change during alteration. The chemical mass balance calculations, which estimate the gains and losses of chemical constituents resulting from alteration, are listed in Table 3.
V.2. Reaction method

This method is based on the calculation of gains and losses of elements for each mineral reaction including the precipitation of phengite or orthoclase in the vein. The total mass balance is calculated for a volume of 0.16 x 0.50 x 0.05 cm, using the percentage of reactions measured by image processing. The "quantitative" reaction is established first in volume percentages and then calculated in mole percentages of each mineral. Results are given in Table 3.

V.3. The mass balance

The two methods of mass balance used here give similar results (Table 3), except for water because of large experimental error on ignition loss. In both cases Si, Al, K are leached from the altered wall rock. Phengite or orthoclase precipitation consumes the major part of Al and K. Only water with small amounts of F^- and S^{2-} must be added to the system.

VI. DISCUSSION-CONCLUSION

The calculation of the mass balance shows that the fluid which flows inside the fracture is a very diluted solution (mainly water with F^- and S^{2-}). This means that the chemical components conserved are by the crystallization of secondary phases originate from the primary mineral dissolution in the altered rock. Their migrations from the source region toward the fracture are controled by chemical diffusion processes (Korzhinskii, 1959; Joesen, 1977; Weare et al., 1976). The energy which entertain the migration is provided by chemical or temperature gradients in the steady diffusion state (Lasaga, 1984). However the logarithmic distribution of phengite and dissolution voids in plagioclases versus distance from vein, suggests that the system is not strictly stationary (Lichtner, 1988). This means that albite and chlorite crystallization is not dependant on the flow travelling in fracture. On the contrary, plagioclase dissolution and formation of phengite are governed by the concentrations of Si, Al and K in the solutions which circulate.

We can deduce from crosscutting relationships and from chemical mass balance, a schematic story for the phengite vein (Figure 6).

Stage 1. The hot fluid penetrates (water, F^-, S^{2-}) through the rock along the fracture.

Stage 2. The water invades the wall rock around the fracture, inducing dissolution-recrystallization processes which are interrelated and entertained by the growing of phengite into the vein.

Stage 3. The vein is sealed. The water inlet decreases rapidly, fluorite and pyrite precipitate. As no more
phengite crystallizes, dissolution of plagioclase and recrystallization of biotite stop.

Stage 4. Finally, the cooling of the wall rock induces illite/smectite mixed-layer precipitation inside the plagioclase voids.

REFERENCES


Three wall rock zones are distinguished with distance from vein (d):

- **1** - nearest zone (0 - 4 mm)
- **2** - farthest zone (4 - 16 mm)
- **3** - fresh rock

X-ray diffraction patterns, after ethylene glycol saturation, of random illite/smectite mixed-layer (17.10 ; 8.55A), with micas (10.07A) and chlorite (14.25 and 7.14A). The percentage of smectite in random illite/smectite mixed-layer decreases with distance from the vein(d).
FIGURE 3: Quantity of phengite in biotite (for phengite vein).

Percentage of phengite in biotite (%PHE) versus distance from vein (d).

FIGURE 4: Quantity of voids in plagioclase (for orthoclase vein).

Percentage of dissolution voids (%VI) in plagioclase versus distance from vein (d).

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Percentage of altered plagioclase (%PLA), outside the albitization front, versus distance from vein (d).

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Percentage of dissolution voids in plagioclase versus distance from vein.

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Percentage of phengite in plagioclase versus distance from vein.
The different stages of vein development are presented from fracturing to illite/smectite precipitation.
<table>
<thead>
<tr>
<th>ZONE</th>
<th>SiO2</th>
<th>Al2O3</th>
<th>Fe2O3</th>
<th>FeO</th>
<th>MgO</th>
<th>CaO</th>
<th>Na2O</th>
<th>K2O</th>
<th>TiO2</th>
<th>P2O5</th>
<th>CO2+H2O</th>
<th>TOTAL</th>
<th>SG</th>
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<td>3</td>
<td>67.63</td>
<td>15.74</td>
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<td>1.95</td>
<td>0.04</td>
<td>1.42</td>
<td>2.06</td>
<td>2.65</td>
<td>6.03</td>
<td>0.55</td>
<td>0.23</td>
<td>0.67</td>
<td>99.32</td>
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<td>15.62</td>
<td>0.39</td>
<td>1.91</td>
<td>0.04</td>
<td>1.45</td>
<td>1.95</td>
<td>2.63</td>
<td>6.07</td>
<td>0.51</td>
<td>0.21</td>
<td>0.83</td>
<td>99.26</td>
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<td>15.42</td>
<td>0.43</td>
<td>1.70</td>
<td>0.04</td>
<td>1.31</td>
<td>1.18</td>
<td>2.66</td>
<td>6.09</td>
<td>0.43</td>
<td>0.22</td>
<td>1.70</td>
<td>99.36</td>
</tr>
</tbody>
</table>

**TABLE 1:** Bulk rock compositions and specific gravities (SG) of three zones (for phengite vein):
- 1- nearest zone (0 - 4 mm)
- 2- farthest zone (4 - 16 mm)
- 3- fresh rock.

<table>
<thead>
<tr>
<th>WALL ROCK</th>
<th>VEIN</th>
<th>ROCK</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE 2</td>
<td>ZONE 1</td>
<td></td>
</tr>
<tr>
<td>GREESEN</td>
<td>REACTIONS</td>
<td>GREESEN</td>
</tr>
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<td>SiO2</td>
<td>-6.5</td>
<td>-5.8</td>
</tr>
<tr>
<td>Al2O3</td>
<td>-1.9</td>
<td>-1</td>
</tr>
<tr>
<td>FeO</td>
<td>-0.3</td>
<td>+0.2</td>
</tr>
<tr>
<td>MgO</td>
<td>+0.4</td>
<td>+0.3</td>
</tr>
<tr>
<td>CaO</td>
<td>-1.8</td>
<td>-0.9</td>
</tr>
<tr>
<td>Na2O</td>
<td>-0.5</td>
<td>-1.3</td>
</tr>
<tr>
<td>K2O</td>
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<td>+0.2</td>
</tr>
<tr>
<td>H2O</td>
<td>+6.6</td>
<td>+3.4</td>
</tr>
<tr>
<td>H+</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>e-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>F</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>S2</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**TABLE 3:** Results of chemical mass balance (in moles for total volume of 40dm³) for Gresens and reactions methods in wall rock, in vein and in rock.
| MINERAL | SiO2 | Al2O3 | FeO | MgO | TiO2 | MnO | Fe2O3 | CaO | Na2O | K2O | P2O5 | TOTAL | Vm | Dn | Si | Al | Fe | Mg | Ti | Mn | Ca | Na | K | O | H |
|---------|-----|------|-----|-----|------|-----|-------|-----|-----|-----|------|-------|----|-----|----|----|----|----|----|----|----|----|----|----|----|----|
| MICROCLINE | 64.08 | 18.46 | 0.06 | 0.03 | 0.15 | 0.04 | 0.04 | 0.84 | 15.31 | - | 99.01 | 106.87 | 2.59 | 2.98 | 1.01 | - | - | - | - | - | - | 0.08 | 0.91 | 8 | - | |
| OLIGOCLASE | 60.50 | 24.30 | 0.10 | - | 0.06 | 0.03 | 5.60 | 8.12 | 0.26 | - | 98.97 | 100.46 | 2.66 | 2.72 | 1.29 | - | - | - | - | - | - | 0.27 | 0.71 | 0.91 | 8 | - | |
| BIOTITE | 37.59 | 16.07 | 16.78 | 11.77 | 3.00 | 0.40 | 0.28 | - | 9.51 | - | 95.40 | 148.30 | 3.02 | 2.82 | 1.42 | 1.05 | 1.32 | 0.17 | 0.03 | - | - | 0.91 | - | |
| APATITE | - | - | - | - | - | - | 58 | - | - | - | 42 | 100 | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| PHENOCIVE V | 47.92 | 29.79 | 2.51 | 3.24 | 0.47 | 0.04 | 0.04 | - | 10.51 | - | 94.52 | 141.64 | 2.81 | 3.29 | 2.39 | 0.06 | 0.24 | - | - | - | - | - | - | 0.95 | 12 | 2 | |
| PHENOCIVE B | 47.41 | 29.60 | 2.32 | 3.27 | 0.45 | 0.13 | 0.12 | - | 10.17 | - | 93.47 | 141.58 | 2.81 | 3.29 | 2.40 | 0.06 | 0.24 | - | - | - | - | - | - | 0.93 | 12 | 2 | |
| MUSCovITE | 46.94 | 36.04 | 0.35 | 0.07 | 0.16 | 0.03 | 0.03 | 0.04 | - | 10.17 | - | 93.70 | 141.18 | 2.79 | 3.14 | 2.84 | 0.02 | 0.01 | - | - | - | - | - | - | 0.87 | 12 | 2 | |
| ORTHOCISE | 65.12 | 18.34 | 0.06 | - | 0.07 | 0.02 | - | 10.36 | 15.61 | - | 99.58 | 106.7 | 2.59 | 3.01 | 1.00 | - | - | - | - | - | - | - | 0.03 | 0.92 | 8 | - | |
| ALBITE | 65.60 | 21.47 | 0.07 | - | 0.01 | 0.07 | 1.75 | 10.90 | 0.13 | - | 100.0 | 104.9 | 2.63 | 2.89 | 1.11 | - | - | 0.06 | 0.93 | 0.01 | 8 | | |
| CHLORITE F | 26.46 | 19.98 | 15.63 | 0.11 | 0.54 | 0.08 | - | 0.03 | - | 86.82 | 210.65 | 2.95 | 2.77 | 2.53 | 2.09 | 2.49 | - | - | - | - | - | - | 18 | 8 | |
| CHLORITE E | 27.12 | 19.23 | 24.45 | 16.22 | 0.05 | 0.52 | 0.09 | - | 0.05 | - | 87.73 | 210.66 | 2.96 | 2.84 | 2.38 | 2.14 | 2.53 | - | - | - | - | - | - | 18 | 8 | |
| IGSOS | 48.66 | 21.43 | 3.18 | 1.40 | 0.11 | 0.03 | 0.49 | 0.20 | 4.10 | - | 79.50 | 182.40 | 2.30 | 3.76 | 1.91 | 0.22 | 0.14 | - | - | 0.04 | 0.03 | 0.37 | 14 | 6 | |
| IS4OS | 49.21 | 24.14 | 2.79 | 1.45 | 0.06 | 0.02 | 0.33 | 0.13 | 5.77 | - | 83.92 | 168.40 | 2.46 | 3.64 | 2.08 | 0.17 | 0.13 | - | - | 0.03 | 0.02 | 0.51 | 14 | 6 | |

**TABLE 2**: Average chemical compositions, molecular volumes (Vm) and specific gravities (Dn) of primary and secondary minerals.
MECHANISM OF DISSOLUTION–PRECIPITATION PROCESSES INDUCED BY HOT WATER CIRCULATION IN A FRACTURED GRANITE.

Part II: Modeling of water–rock interaction.

G. BERGER, M.-P. TURPEAULT and A. MEUNIER.

Little is known about the working process of hydrothermal fractures, in particular about the filling mechanism and its kinetics. In this investigation we are interested in this problem by applying two different approaches to the same geological object:

- Quantitative petrographical observations, carried out on hydrothermal alterations of the La Peyratte’s granite (France) provides precise data on temperatures, water–rock ratios (W/R), sequences of secondary phases and chemical budgets of the alteration (part I);
- Water–rock interaction simulations were performed with computer codes in order to ascertain the chemical composition of the fluid, compatible with this kind of alteration, and to evaluate step–working and the time evolution of these veins.

In this part, we present the calculations carried out with the EQ3/6 software package. The input constraints (temperature, starting solids, rate laws) were determined from petrographical and bibliographical data. The effect of the fluid composition on the secondary assemblage have been tested by changing the initial fluid composition.

I - Computer programs

The EQ3/6 computer software package was developed by WOLERY in the 1970's.
EQ3 computes the distribution of chemical species in an aqueous solution from input analytical data and calculates the concentration and activity of all dissolved species for which thermodynamic data are available.
EQ6 is capable of computing several types of mass transfer models. It utilizes the concept of approximation of irreversible chemical reactions by a series of infinitesimally small increments of reversible reactions. If the solution becomes saturated with one or more minerals at any stage of reaction progress, it simulates the precipitation of these phases.
The calculations presented here are "closed" system calculations; product phases remain in equilibrium with the fluid and can redissolve when the fluid ceases to be saturated with respect to them.
II - The input constraints

All the calculations presented here were made for a constant temperature of 300°C. We simulated the dissolution of an assemblage of quartz, microcline, oligoclase and biotite (respectively 22.4, 33.6, 33.5 and 10.5, by vol.). The surface of each mineral was fixed in regard to its volumetric proportion in the rock, and was held constant during all the runs.

The kinetic rate constants were determined from literature values, and were made independent of the fluid composition; no affinity corrections were taken into account. Whenever a mineral reached saturation in solution, its dissolution stopped, until it became undersaturated again.

The mineralogical composition and the kinetic data are reported in Table 1. We took also into account the fluor concentration of the La Peyratte's granite. In these calculations fluor was supposed associated with the mica and was added stoichiometrically with biotite.

Three compositions of solution were tested: pure water, 0.2M NaCl solution and 1% mol. CO₂ fluid. The composition of the last two fluids were chosen from the fluid inclusions study which indicated a salinity of the fluid ranging from .7 to 1.3 percent, and a carbon content less than 1 mol.% (detection limit by Raman microprobe). The pH of the starting solution was 5.56 for pure water and the NaCl solution (neutrality at 300°C), and 4.44 for the H₂O-CO₂ solution, assuming the dissociation of carbonic acid during the CO₂-H₂O mixing. The redox parameter was previously tested; from oxyding to reducing initial conditions, we did not observe any significant change in the secondary parageneses or the chemical composition of the solutions. The initial oxygen fugacity, for the calculations presented here, was 10⁻⁰.⁷, assuming infiltration of meteoric water in the vein.

Calculations are made for a closed system, with 1 kg of solution, and for water-rock ratios up to 0.01, for which almost all H₂O is incorporated in the secondary clays.

III - Results and discussion

Dissolution: The amount of each reactant dissolved, calculated by Eq6, has been transformed to thickness dissolved, versus time and W/R (mass of water / mass of rock which has effectively reacted). In all the runs, the dissolution proceeded by the same way. Figure 1 shows, as an example, the decrease of thickness of each primary phase by dissolution at the end of the "pure water" run. Biotite and oligoclase dissolved with time according to their rate constant; at the opposite, quartz dissolved very little and microcline not at all because the dissolution of these phases was controlled by their saturation in solution. The thickness dissolved of the
primary minerals reproduce the observed zoned alteration; they are not dependent on the chemical composition of the starting solution, but result from a self evolution of this system.

Secondary minerals: The main secondary phases are albite, Fe-Mg clays (saponite, nontronite and a small amount of minnesotaite), muscovite, microcline and small amount of Ca-phases (fluorite + prehnite or calcite, depending on the starting solution). Their volumetric proportions are reported vs W/R in Figure 2. They are very similar in all the runs for W/R < 100 or 10. For higher W/R, the differences mainly concern the concurrence between Na-silicate and K-silicate; in NaCl solution albite is favoured at the expense of microcline, while in the CO2-solution muscovite is favoured at the expends of albite. In pure water, at low W/R ratios, both muscovite and microcline are stable with albite.

Solutions: The dissolved cations are mainly Si, Na, Al (complexed as AlF3 and AlF5−) and K. Chemical composition of the solutions did not present important variations for a wide range of W/R. The only exception concerns the NaCl-run in which the dissolved salts (chloride) were strongly concentrated at the end of the simulation because 90% of H2O is incorporated in the secondary phases. The concentrations of the dissolved cations are more dependent on the starting fluid composition; with NaCl or CO2 they are one order of magnitude higher than for pure water. In fact, the extent of the exchanges between rock and solution is limited by the electroneutrality of both the solid and the fluid, and is more dependent of the ionic strength of the starting fluid.

In the same way, the redox potential and oxygen fugacity of the solution were buffered for all of the runs at low values around 10−31.

Silica, as opposed to the other dissolved cations, shows a very steady concentration, however are the W/R and the starting fluid composition. Its steady concentration in solution (quartz solubility) makes it a good geochemical indicator.

Filling of the vein: The alteration of the primary phases can be viewed as the albitionization of oligoclase, argilization of biotite, and precipitation of K-silicates and some Ca-phases, in a rock-dominated system. The secondary parageneses agree with the observed alteration, except for the Fe-Mg clays which were identified as chlorites rather than smectites. The precipitation of K-silicate phases are of primary interest in order to understand the evolution of the hydrothermal veins. In these simulations, muscovite and microcline (which were observed as fracture-filling phases) appear as major phases, throughout the runs. If these phases are not the last phases to precipitate, this implies that a permanent mass transfer exists from the dissolution interface, in the wall-rock, towards the nucleation sites of these
phases in the veins. Such a process may represent a time-limiting factor for the evolution of hydrothermal systems. In the case of the "phengite-vein", for example, we calculated from our simulations the W/R ratio for which the vein is filled by muscovite (or phengite), assuming that all muscovite, and only muscovite, precipitated in the vein (initial volume of the solution). We found that the vein must be plugged when 30 kg have reacted with 1 kg of solution (\( W/R = 0.0338 \)).

The process of mass transfer between the reactional interface in the whole rock towards the bulk solution in the vein is a fundamental aspect of the evolution of the veins. In order to understand this process, we used EQ3 to check the effect the variation of factors, like \( f(O_2) \), temperature and pH, on the stability of the secondary phases. From the steady concentration of the solutions, we calculated the saturation degree (\( Q/K \)) of secondary phases while changing one of these parameters. Variation of \( f(O_2) \) or temperature can not explain the observed mass transfer. On the contrary, the variation of pH affects more strongly the secondary parageneses. When pH increases, K-silicates, Mg-clays (mainly smectites) and anorthite are favoured. With lower pH, albite and Fe-clays (in particular chlorites) are the most stable phases, while muscovite and microcline are undersaturated. Thus, one can understand precipitation of chlorites in the whole rock rather than smectites, and early precipitation of phengite or orthoclase in the vein, together, assuming a pH gradient between the whole rock and the vein. Such a gradient can result either from the chemical reactions which occur in the micromedia near the dissolution interfaces, or from electrical effects due to the circulation of an electrolyte solution through the vein.

Decrease of volume and mass of the solution:
Dissolution-precipitation process leads to a slight increase of the solid phases volume, and the consumption of the initial water. The volume corresponding to the starting solution (vein + dissolution voids) will be filled by secondary minerals for a W/R ratio of \( 3.12 \times 10^{-3} \), while all the initial water will be used up when 115 kg of rock will be reacted with initially 1 kg of solution.

IV - Evolution of the hydrothermal veins of the La Peyratte's granite and concluding remarks.

These calculations give evidence for three kinds of limitations for the evolution of a vein:
- Precipitation of a phase into the fracture, resulting from a local mass transfer (\( W/R = 0.0338 \) in the case of muscovite, for which we have petrographic evidences of this process);
- Consumption of all the available water present initially in the fracture (\( W/R = 0.0087 \)). This process
implies a closed system;
- Filling all the voids of the system by increasing of the solid phases volume \((W/R= 3.12 \times 10^{-3})\). This process implies an open system.

Moreover, in the La Peyratte's granite, a correlation was found between the thickness of the zoned alteration and the thickness of the veins. In this representation, and assuming a closed system, a given \(W/R\) ratio is materialized by a straight line passing through the origin. The value of the \(W/R\) ratio is the slope of the line. Assuming that the vein represents the initial volume of the solution, and being ignorant of an eventual replacement of the solution, we compared the above limiting \(W/R\) ratios with the petrographic data (Figure 3). One can see that:
- None of the fractures reach the ultimate limit of the full filling of the system.
- The "water" limit fits the plots corresponding to the small fractures (less than .1 mm depth). This suggests that the alteration of the small veins i.) have been limited by the available amount of water and in the fractures and ii.) progressed in closed system, which supposes that small fractures are either not well connected or the fluid moves very slowly in such small thin spaces.
- The thicker fractures exhibit a trend towards the "muscovite filling limit", in agreement with the petrographic study.

From these correlations, we propose the following evolution for the hydrothermal veins of the La Peyratte's granite:
- Circulation of a hot solution in the fractures and growing of phengite on the wall on the veins.
- Vein filling by phengite occurs at first in the thin fractures. The alteration continues in closed system in the wall rock, because the system is heated by the neighboring thick fractures. The alteration stops in the small veins when all the water is consumed.
- At the opposite, the alteration of the large veins stops as soon as these fractures, which bring heat, are plugged.

The last point of the discussion concerns the time required for the process to occur. Most changes with time in the system are mainly in the amount of dissolved primary phases. Numerous studies have been devoted to the process of silicate dissolution; rate constants and activation energies have been determined for the first steps of dissolution, at conditions far from equilibrium and in surface-reaction controlled conditions. Now, caution should be exercised when predicting reaction rates at high temperatures at which transport of reactant in solution is likely a limiting step. The time scale we obtained should be considered more like a time indication rather than a true prediction.
Table 1 - starting mineral assemblage

<table>
<thead>
<tr>
<th>mineral</th>
<th>% vol.</th>
<th>mol/cm$^{-2}$s$^{-1}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>biotite (phlogopite + annite)</td>
<td>10.55</td>
<td>8.2 $10^{-13}$</td>
</tr>
<tr>
<td>quartz</td>
<td>22.40</td>
<td>1.3 $10^{-11}$</td>
</tr>
<tr>
<td>orthoclase</td>
<td>33.56</td>
<td>2.6 $10^{-13}$</td>
</tr>
<tr>
<td>oligoclase (albite + anorthite)</td>
<td>33.48</td>
<td>1.2 $10^{-12}$</td>
</tr>
</tbody>
</table>

Figure 1: dissolution of the primary phases
Figure 2: secondary mineral assemblage
Figure 3: correlations between W/R limits and petrographic data
SESSION 5B - RESERVOIR DEVELOPMENT
COOLING OF THE ROSEMANOWES HDR RESERVOIR

David A C Nicol
Camborne School of Mines Geothermal Energy Project, Rosemanowes Quarry, Herniss, Penryn, Cornwall, TR10 9DU.

ABSTRACT

The Hot Dry Rock geothermal reservoir created between wells RH12 and RH15 at Rosemanowes Quarry, Cornwall, UK has been significantly cooled over its lifetime. Simple lumped parameter models, which treat the reservoir as being in steady state, successfully describe the overall reservoir performance. Detailed description of the thermal performance is difficult because of lack of resolution in the available data. However, using the available thermal and flow logs, in conjunction with tracer data, it has been possible to identify the joint which produces the fluid with the lowest residence time. This joint also produces a lot of fluid with longer residence times, and thus the options in sealing cooling joints may be limited.

INTRODUCTION

Since 1980, the development of geothermal 'hot dry rock' systems has been investigated at Rosemanowes Quarry, Cornwall, UK. The concept involves first drilling a pair of wells into hot crystalline rock of low natural permeability and porosity. The existing joints in the inter-well region are stimulated to enhance their hydraulic characteristics. Water is then circulated between the wells to extract the heat from the rocks.

In 1985 the rock mass between the two wells RH12 and RH15 was stimulated by injecting 5500 m³ of a medium viscosity fluid (50 mPa s) at high pressures from the new RH15 well. This created the current experimental reservoir, the RH12/RH15 system. This reservoir has a gross rock volume of about five million cubic metres. Its size has been estimated from the locations of microseismic events generated during the stimulation.

The RH12/RH15 system was continuously circulated from August 1985 until February 1989 when the return well RH15 was subjected to a localised stimulation with a high viscosity gel containing proppant (Nazroo et al, 1989). Subsequent circulation indicated a major change in the reservoir flowpaths and temperatures. This paper will only consider the period up to the February 1989 stimulation. During that time there was an average fluid return of 14 kg/s of water through the well RH15, representing more than 75% of the water injected through well RH12. The mixed outlet temperature of the water, measured at the production well casing shoe, declined from 80°C to 55°C.
Nicol & Robinson (1989) examined the cooling of the reservoir and demonstrated a number of simple models which described its lumped thermal performance. Some of the models used tracer and seismic data to constrain the choice of free parameters. They showed that to model the thermal behaviour of the reservoir, it was appropriate to treat it as a fissured medium with parallel fractures at spacings of about 10 m to 20 m, which agreed with the borehole observations of the major flow paths into the well RH15. It was not appropriate to model the reservoir as a porous medium. For the general case of time-varying flow and varying inlet temperature, solutions to the fractured reservoir model must be obtained numerically. However, useful results were obtained with a constant-flow approximation. Flow proportions obtained with this model were comparable to those of the numerical solutions, but heat transfer areas were typically 25% smaller. In this paper, given the error bands surrounding flow rates derived from production logging, the simpler constant flow approximation has been used throughout.

There were some changes in the reservoir during the two and a half years of operation until January 1988 that Nicol and Robinson modelled. The tracer-determined fluid volume of the reservoir increased markedly, and there were changes in the flow logs of the production well. During that time, however, the overall thermal performance of the reservoir was adequately modelled by a steady state model.

The actual flow system contains a continuum of individual flow paths with different fluid velocities and residence times as seen in tracer-response curves. Some of these paths directly connect the wellbores, some take a more circuitous route from the inlet to outlet. For modelling purposes these many paths are lumped into a small number of individual flow paths (typically two to four).

All the models indicated the presence of certain flowpaths which collectively carried some 10% to 15% of the total flow and which had an extremely small heat transfer area. Earlier analysis (CSM, 1987) had described the reservoir in terms of two flow paths. One path containing 18% of the flow had a small heat transfer area, while a second path containing the bulk of the flow had a larger heat transfer area. The flowpath with the small area was labelled the 'thermal short circuit'. The thermal decline in the first year of operation was attributed to the cooling of the short circuit, and the continuing thermal decline thereafter to the cooling of the bulk of the reservoir. The results are reproduced as Figure 1, showing the measured data points and the model temperatures for each of the two flowpaths and the mixed outlet temperature. However, at that time a single cold entry into the well representing the short circuit had not been identified and it was concluded that the flow was well mixed before the water entered RH15.

FLOWPATH CHARACTERISATION EXPERIMENT

One of the Project's targets is to develop manipulation techniques to improve a reservoir's performance, such as to reduce near wellbore impedance or improve a reservoir's thermal productivity. To improve the detailed knowledge of the flow and thermal performance of the reservoir before any manipulation techniques were attempted, the
'Flowpath Characterisation Experiment' (Richards et al, 1989a) was conducted. This was a programme of inert tracer tests in which pulses of tracers were injected at one of two locations within the well RH12, and sampled at each of three locations within the production well RH15. The objectives of the tests were to determine the breakthrough times for each of the six possible flowpaths, to calculate the distribution of flow between the flowpaths and to calculate the residence time distribution for as many of the flowpaths as possible.

The flowpath characterisation tests were carried out between April and June 1988, during a period of relatively steady state in the reservoir. The results showed that out of the six arbitrarily defined flowpaths, the path through the reservoir with the shortest tracer breakthrough time was the path that left the reservoir near the bottom of well RH12, and entered the production well RH15 by the major flow entry between 2409 m MD (measured depth) and the casing shoe. This flowpath was of great interest, as during the period of the tests it carried half of the production flow and had a residence time distribution (RTD) which was more skewed towards short residence times than the bulk reservoir RTD. In addition the path could be correlated with a structure apparent in the microseismicity generated during manipulations of the rock mass before the current reservoir was created. Richards et al (1989a) concluded that this path had the characteristics of a thermal short circuit, although the 'short circuit' in thermal terms may only be part of the tracer defined path.
In conjunction with the flowpath characterisation experiment, average inlet temperatures were obtained for each of the three zones in the production well RH15. Zone 1 was from the casing shoe down to 2409 m MD (measured depth), Zone 2 was from 2409 m MD to 2464 m MD and Zone 3 was from 2464 m MD to the bottom of the well. The average inlet temperatures were estimated by carrying out a mass balance at the intervals between the zones. Uncertainties in the well bore diameter and the flow logs, and difficulties in picking appropriate points to measure the flows and temperatures are reflected in errors in estimates of both the flows and temperatures for each zone. In examining arbitrarily chosen zones, these uncertainties can be reduced by a careful choice of zone boundary. If individual joints are examined that freedom is not available, and the errors are larger. Thus initially the three zones were examined rather than individual joint behaviour.

The temperatures for each of the zones are plotted in Figure 2. Given the results of the flowpath characterisation experiment, it is at first sight surprising that the largest temperature drop is seen in Zone 2. These zone temperature profiles, and the mixed reservoir temperature were each analysed as discrete flowpaths. The mixed reservoir temperature could be described as two flow paths with the following areas as shown in Table 1.

<table>
<thead>
<tr>
<th>Flow Path</th>
<th>Surface Area (m²)</th>
<th>Fraction of total flow</th>
<th>Root mean square error</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>3400 ± 2000</td>
<td>0.18 ± 0.04</td>
<td>0.82 ± 0.04</td>
</tr>
<tr>
<td>b</td>
<td>114,000 ± 7000</td>
<td>0.82 ± 0.04</td>
<td>0.9°C</td>
</tr>
</tbody>
</table>

Figure 3 shows how these estimates of the areas have changed with time. The present results are within the bounds of the previous estimates. This justifies the use the approximation that the reservoir be treated as steady state to estimate when estimating its lumped performance.

Similar analyses were performed on the inlet temperatures to each of the three zones. The results are given in Table 2.

Throughout the experiment, between 65% and 90% of the flow entered Zone 1, with the average flow being 75%. The results for this zone are broadly comparable to the results for the entire reservoir. They show the presence of a significant minor flow path (Path 1a) with a small heat transfer area (ie a short circuit). They also show a major flow path with a large heat transfer area (Path 1b). Thus the short circuit appears within Zone 1, in agreement with the tracer results. The data fit obtained is not quite so good for this individual zone as for the whole reservoir.
Figure 2. Temperatures of the flowpath—characterisation zones

Figure 3. Estimates of area from constant flow model
TABLE 2: LUMPED ANALYSIS OF THE RESERVOIR BY ZONE

<table>
<thead>
<tr>
<th>Flow Path</th>
<th>Surface Area (m²)</th>
<th>Fraction of Zonal Flow</th>
<th>Fraction of total flow</th>
<th>Area massflow $10^{-6}$ m²s⁻¹</th>
<th>Root mean square error (by zone)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>2 800 ± 3 200</td>
<td>0.19 ± 0.10</td>
<td>0.14</td>
<td>1.4</td>
<td>1.5°C</td>
</tr>
<tr>
<td>1b</td>
<td>69 000 ± 4 000</td>
<td>0.81 ± 0.10</td>
<td>0.61</td>
<td>8.5</td>
<td></td>
</tr>
<tr>
<td>2a</td>
<td>800 ± 300</td>
<td>0.20 ± 0.07</td>
<td>0.03</td>
<td>1.9</td>
<td>2.1°C</td>
</tr>
<tr>
<td>2b</td>
<td>14 000 ± 1 000</td>
<td>0.80 ± 0.07</td>
<td>0.12</td>
<td>8.2</td>
<td></td>
</tr>
<tr>
<td>3a</td>
<td>600 ± 300</td>
<td>0.12 ± 0.03</td>
<td>0.01</td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>3b</td>
<td>23 000 ± 4 000</td>
<td>0.88 ± 0.03</td>
<td>0.09</td>
<td>18.2</td>
<td>4.0°C</td>
</tr>
</tbody>
</table>

The data fits for Zones 2 and 3 are considerably poorer. This is caused in part by the extremely variable flow into these zones and by the difficulties in accurately obtaining the thermal and flow data from the logs. For Zone 2, the flow varied between 3% and 19% of the total flow with a mean of 15%. For Zone 3, the flow varied between 5% and 17% of the total flow with a mean of 10%.

The main flow component in Zone 2 (Path 2b) has a smaller ratio of heat transfer area than the main flow component of Zone 1 (Path 1b). This is consistent with the larger long term cooling of Zone 2, noted in Figure 2. There are also some flows (Path 2a) with a relatively small ratio of heat transfer area to massflow, which although not quite as small as those of Zone 1 (Path 1a) might contribute to the short circuit. Zone 3 which cooled the least shows the highest relative values of heat transfer area.

JOINT ANALYSIS

To try to identify the short circuit more precisely, the four most productive joints were analysed to obtain the input temperatures. As noted above, the flow and thermal data are less reliable for individual joints than for the zones. Four joints at measured depths of 2374 m, 2394 m, 2420 m and 2490 m typically produced at least 10% of the flow into RH15. An estimate of their temperatures is plotted in Figure 4. Note that the top two joints at 2374 m and 2394 m are both in Zone 1, whilst the joint at 2490 m is in Zone 2, and the remaining joint at 2490 m is in Zone 3. One of the joints in Zone 1 at 2374 m and the joint in Zone 2 at 2420 m both show a temperature drop of between 40°C to 45°C, whilst the other two joints show a temperature drop of just over 25°C.

From the tracer results and the analysis above, the top joint at 2374 m is the candidate joint for containing the bulk of the short
Figure 4. Temperatures of individual joints, showing their depths and zones.

Figure 5. Drop in temperature for two of the joints.
circuit. However, the joint at 2420 m cools as much as the joint at 2374 m over the entire period. It is therefore necessary to examine the early cooling history to distinguish whether the joint at 2374 m wholly contained the short circuit.

Figure 1 shows that the dramatic cooling associated with the fast flow paths in the RH12/RH15 reservoir took place within the first 275 days of circulation. Figure 5 shows the cooling associated with the two joints at 2374 m and 2420 m over the first 500 days of circulation. In the first 275 days, the Zone 1 joint at 2374 m cooled twice as fast as the joint at 2420 m. This fast cooling indicates the presence of the short circuit. Examination of the flow logs shows that in that first 275 days the average flow into Zone 2 was only 9% of the total flow, rather than the 15% average over the whole flow history. Thus the low ratio of heat transfer area to massflow displayed in the Table 2 is misleadingly low, and the short circuit can be identified with the 2374 m joint.

Since over the first 275 days, the 2374 m joint only cooled by about 16°C rather than the 40°C predicted by the lumped two path model, a substantial amount of warmer water must have mixed with the colder water of the short circuit before the water was produced into the wellbore.

Over that first 275 days approximately 65% of the water in Zone 1 came from the joint at 2374 m. Table 3 shows a possible distribution of the flows in Zone 1. It assumes that all of Path 1a emerged in the 2374 m joint. Figure 1 shows that the short circuit (Path a) would have cooled by about 40°C, and that the main path (Path b) would have cooled by about 4°C. Applying these figures to the equivalent Paths for Zone 1, which as noted above behaves consistently with the whole of the reservoir, leads to the estimate that the 2374 m joint would cool by 15°C. This is in agreement with the observed figure of 16°C (Figure 5).

**TABLE 3: POSSIBLE DISTRIBUTION OF FLOWS IN ZONE 1 IN FIRST 275 DAYS**

<table>
<thead>
<tr>
<th></th>
<th>2374 m</th>
<th>Rest</th>
<th>Totals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Path 1a</td>
<td>19%</td>
<td>0%</td>
<td>19%</td>
</tr>
<tr>
<td>Path 1b</td>
<td>46%</td>
<td>34%</td>
<td>81%</td>
</tr>
<tr>
<td>Totals</td>
<td>65%</td>
<td>35%</td>
<td>100%</td>
</tr>
</tbody>
</table>

We thus note, that any successful reservoir manipulation which blocked the joint at 2374 m to block the short circuit, would also have blocked 45% of the flow into Zone 1, which forms one third of the total flow recovered. Operations to seal off the short circuit, thus risk closing off a substantial productive part of the reservoir as well as the unwanted flows paths.
TRACER ANALYSIS

In this paper the tracer data have not been used directly as part of the modelling process. However, Nicol & Robinson used tracer data to constrain flow path areas in proportion to the relative volume of fluid as estimated from the integral mean volume through the tracer tests. They suggested that the use of tracer data would be valuable in trying to predict the thermal production profile for a reservoir.

The interpretation of the flow path characterisation experiment presented by Richards et al (1989a) gives information about the flow distribution and residence time behaviour for six flow paths, three issuing from the main zone of the flow out of the injection well, and three issuing from the remaining flow. From the viewpoint of the thermal analysis by zones of flow, tracer data are required for the three paths linking the injection well as a whole to the tree zones of flow into the production well. The relevant data have been interpreted by Richards et al. (1989b). Table 4 gives the estimates of the volumetric characteristics of these three flow paths, as relative integral mean volumes. The results show that the apportionment of heat transfer area to volume is thus a fairly reasonable assumption in the absence of other data.

TABLE 4: COMPARISON OF RELATIVE THERMAL AREAS AND INTEGRAL MEAN VOLUMES

<table>
<thead>
<tr>
<th>Zone</th>
<th>Relative Area</th>
<th>Relative Integral Mean Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>65%</td>
<td>55% - 67%</td>
</tr>
<tr>
<td>2</td>
<td>13%</td>
<td>10% - 23%</td>
</tr>
<tr>
<td>3</td>
<td>21%</td>
<td>27% - 30%</td>
</tr>
</tbody>
</table>

We also note that Richards et al (1989a) identified that Zone 1 contained the short circuit through examination of the low breakthrough times for flow to Zone 1, and thus contained the most direct paths in the reservoir.

These results show the value of tracer data in examining the thermal performance of the reservoir.

CONCLUSIONS

Simple thermal analysis showed that treating the reservoir as being in steady state continued to be a good assumption for looking at the lumped thermal performance of the reservoir. The thermal areas and flow fractions obtained by this analysis were within the error bounds of previous analyses.

It is difficult to examine the thermal performance of individual joints and zones because of errors in flow measurement in the wellbore. The limit of resolution at looking at the reservoir in detail has probably been reached.
Nonetheless, the reservoir flowpaths with the smallest thermal area which substantially contributed to the cooling of the reservoir within the first three hundred days of operation were identified. They formed part of the flow of a joint at 2374 m in well RH15 within flow Zone 1 of the flowpath characterisation experiment. This result is in agreement with the analysis of the flowpath characterisation experiment.

Mixing of flowpaths before the water is produced into the well RH15 could make it difficult to undertake successful sealant operations to block off unwanted flowpaths.

Finally, a general agreement was noted between calculated thermal areas and volumes estimated by the flowpath characterisation experiment in agreement with previously made assumptions.

ACKNOWLEDGEMENTS

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REFERENCES


LIFETIME CALCULATIONS FOR MULTIPLE STIMULATED HDR RESERVOIRS

Derek Elsworth

ABSTRACT

A conceptual model is presented to describe thermal recovery from a candidate HDR geothermal energy scheme through a multiple arrangement of near spherical production zones. The arrangement facilitates advective drawdown within a series of well mixed and thermally equilibrated production zones and by conductive recharge from the geologic host. Dimensionless thermal drawdown $T_0$ with dimensionless time $t_0$ is controlled by the distribution of dimensionless flow rates ($Q_\alpha$), thermal porosity ($Q_{\alpha_0}$) of the k stimulated zones, and by the relative system geometry as expounded through the separation parameter $a/s_\eta$. Sensible agreement with previous models allowing for thermal disequilibrium is obtained and results from previous HDR experiments show encouraging agreement. Production histories are presented for colinear arrays of producing zones. The steady condition is a unique function of circulation rate $Q_\alpha$ and relative geometry $a/s_\eta$. For small circulation rate magnitudes ($Q_\alpha<10^3$), the steady production temperature is finite and may define considerable thermal potential not apparent from 'closed-system' analogues. The timing of conductive recharge may be sufficiently early to enhance the economics of HDR geothermal projects.

INTRODUCTION

Recent experiences with HDR stimulation have detected the development of discrete and tortuous flow paths within an otherwise impermeable geologic formation. It has been further hypothesized that the flow geometry results from the activation of relic jointing, at depth, with the disturbances consistent with changes in effective stresses and thermal contraction. This hypothesis is corroborated by the form of the passive microseismic record [Pine and Batchelor, 1984; Baria et al., 1987] with the activated fracture planes generally concordant with in situ features [Fehler, 1987]. Although representing an initially inefficient hydraulic system, the tortuous flow paths are commonly characterized by a decrease in impedance with time, primarily as a result of load shedding through thermal recovery. The discrete but dispersed flow arrangement presents a moderately efficient heat exchanger, of overall bulbous form, that may extract thermal energy both from the internal core and from the external geologic host. An appropriate theory is developed in the following to examine the productive influence of each of these thermal recovery mechanisms in a multiple stimulated HDR geometry and examine both magnitude and temporal distribution of the anticipated thermal yield.
CONCEPTUAL MODEL

A total of $k$ discrete production zones are considered as illustrated in Figure 1. The zones are of arbitrary radius, $a_i$, through which fluid at injection temperature $T_{il}$ is circulated at volumetric rate, $q_{Fi}$, to return at withdrawal temperature, $T_{ol}$. Thermal capacities of the stimulated zones and external geologic host are determined by the volume weighted averages of the rock and fluid components $\rho_s c_s$ and $\rho_F c_F$, respectively. Thermal transport within the stimulated zone is purely advective with thermal supply from the geologic host controlled by the constant thermal conductivity of magnitude $K_s$. The analysis is assumed linear with no changes in the material parameters with time. Additionally, the assumptions of full mixing and thermal equilibrium within the stimulated zone are mandated with conductive gradients permissible beyond the outer radius, $a_i$. The reasonableness of these assumptions will be demonstrated later.

GLOBAL EQUATIONS

A total of $k$ fully mixed spherical zones are considered within an infinite host medium through which fluid is circulated at rate $q_{Fi}$. The discrete energy balance relationship written in time, $t$, is

$$q_{li} = q_{ri} \rho_s c_{si} (T_{ol} - T_{li}) + \frac{4}{3} \pi a_i^3 \rho_s c_{si} \frac{\delta T_{ol}}{\delta t}$$

and may be assembled for each of the stimulated zones where $q_r$ is the conductive thermal flux supplied to the zone, $\rho_s c_s$ is the aggregated thermal capacity of fluid and rock within the zone and subscript $i$ refers to the $i$th zone. The energy equation balances the conductive flux generated from the geologic host with advective extraction from and thermal inertia of the stimulated zone. A suitable system of equations may be assembled provided the mutual conductive drawdown induced by multiple embedded zones may be determined, as embodied in $q_{ri}$. In generality, the temperature change $\langle T_i - T_o \rangle$ at location $i$ resulting from a total of $k$ stimulated zones may be defined through

$$\langle T_i - T_o \rangle = \frac{q_{ri}}{4\pi K_s a_i} A_j$$

where $A_j$ is a time dependent coefficient dependent upon the size and relative location of the producing zones together with the thermal diffusivity of the separating geologic host [Carslaw and Jaeger, 1959; Elsworth, 1989a]. In matrix notation, equation (2) is more conveniently represented as

$$\langle T_i - T_o \rangle = Aq_r$$
where \( \mathbf{q} \) is a vector of thermal discharges, \( \langle I_a - I_0 \rangle \) is a vector of temperature differentials and the coefficients of matrix \( A \) follow from equation (2) and are explicitly defined in Elsworth [1989b]. Duhamel's theorem may be applied to the time dependent nature of equation (3) to determine the thermal flux \( q_{tn} \) at time level \( t_n \) as

\[
q_{tn} = \int_0^{t_n} \frac{\partial}{\partial t} \Delta^{-1} \langle I_a - I_0 \rangle d\tau
\]

where \( \tau \) is the discrete parameter of time integration. The continuous derivative of equation (4) may be represented discretely for a constant initial in situ temperature \( I_a \) as

\[
q_{tn} = - \sum_{m=1}^{t_n} \Delta t_m \Delta \langle I_0 \rangle_{tm}
\]

where \( \sum \) is the sum of the terms.
where the components of $\Delta_{im}$ are appropriately modified. Thus, the thermal flux supplied to each of the stimulated zones may be incorporated into equation (1), represented in matrix form as

$$\alpha_{im} = B\langle I_o - I_i \rangle t_m + \frac{1}{\Delta t_m} C \Delta\langle I_o \rangle t_m$$

with $\Delta t_m = t_m - t_{m-1}$ and $\Delta\langle I_o \rangle t_m = \langle I_o \rangle t_m - \langle I_o \rangle t_{m-1}$, where the component diagonal matrices are $B_m = q_o \rho_s c_i$ and $C_m = \frac{4}{3} \pi \rho_s c_i$, with $B_q = C_q = 0$ for $i \neq j$. Substituting equation (5) directly into global equation (6) yields the incremental energy balance equation at time $t_m$ as

$$\left[ \Delta t_m^{-1} \alpha_m + B + \frac{1}{\Delta t_m} C \right] \langle I_o \rangle t_m = - \sum_{i=1}^{m-1} \Delta t_m^{-1} \Delta\langle I_o \rangle t_m + \left[ \Delta t_m^{-1} \alpha_m + \frac{1}{\Delta t_m} C \right] \langle I_o \rangle t_{m-1} + B \langle I_o \rangle$$

allowing direct solution for outlet temperatures $\langle I_o \rangle t_m$ at current time. However, results are more conveniently represented through use of appropriate dimensionless parameters. Dimensionless output temperatures are controlled by the relationship.

$$\langle T_o - T_i \rangle_{t_m} = \int \left[ \frac{q_o \rho_s c_i}{K_s a_j} ; \frac{K_s t_m}{\rho_s c_i a_j^2} ; \frac{\rho_s c_i}{\rho_s c_i} ; \frac{a_i}{s_y} \right]$$

where $j=1,k$ and no summation is implied. The separation between the central coordinates of two adjacent zones is given as $s_y$ where the dimensionless parameters are most conveniently referred to as

$$T_{0i} = \int \left[ Q_{0i} ; t_{0i} ; \phi_{0i} ; \frac{a_i}{s_y} \right]$$

where $T_{0i} =$ dimensionless production temperature, $Q_{0i} =$ dimensionless circulation rate, $t_{0i} =$ dimensionless time, $\phi_{0i} =$ dimensionless heat capacity or secondary porosity, and $a_i/s_y =$ zone separation ratio.

VALIDITY OF ASSUMPTIONS

The assumptions are made that both rock and percolating fluid remain in thermal equilibrium within the stimulated zone and that the equilibrium temperature is uniformly distributed. Thermal equilibrium is approached as fluid throughput rate ($q_o$) is reduced sufficiently that thermal gradients within the rock comprising the stimulated zone become insignificant. The maximum admissible magnitude of $Q_o$ that may be tolerated before this assumption is violated may be evaluated by
comparison with a thermal model that accounts for spatial disequilibrium. The parallel fracture model [Gringarten et al., 1975] may be redefined using the dimensionless parameters $T$, $Q$, and $t_0$ where the scaling length of reservoir radius, $a_0$, is replaced by reservoir volume, $V$, through $V = \frac{4}{3} \pi a^3$. Thus, the equivalent dimensionless parameters become [Elsworth, 1989b]

$$Q_0 = \frac{Q \rho C_p}{K_a} \left( \frac{4\pi}{3V} \right)^{1/3} ; \quad t_0 = \frac{K_t}{\rho C_p} \left( \frac{4\pi}{3V} \right)^{2/3}$$

with the additional reservoir 'shape' factor of $x_e/\sqrt{V}$ where $2x_e$ is the separation between adjacent parallel flow channels. The results of the parallel fracture model may be directly compared with those for a spherical zone where external heat supply is ignored.

Assuming that $x_e/\sqrt{V} \approx 10^{-1}$, as suggested by a spherical stimulated volume of $10^4$ m$^3$ and flow-path semi-spacing $x_e \approx 10$ m, allows thermal drawdown to be evaluated as illustrated in Figure 2 for the parallel flow model. The results for the spherical model with no external heat supply are superposed on the same figure. For small magnitudes of $Q_0$, the parallel fracture model duplicates the assumption...
of thermal equilibrium but is unable to allow for full mixing. For circulation rates \( Q_o \) lower than \( 1.6 \times 10^2 \) the spherical model is in reasonable agreement with the parallel fracture model where behaviour is bounded as \( Q_o \rightarrow 0 \). The inability of the spherical model to duplicate the data for all \( Q_o \leq 1.6 \times 10^2 \) results from the inability to accurately represent the inter-well thermal wave. However, from the results of Figure 2, reasonable bounds may be placed on the importance of this inadequacy.

**FENTON HILL 75 DAY DRAWDOWN**

The results of a 75-day thermal drawdown experiment run at the Fenton Hill Reservoir, and reported in Tester and Albright [1979] are used to further substantiate the proposed drawdown model. The data match illustrated in Figure 3 was obtained by direct fitting of the curves. Independently available from the results are the magnitude of dimensionless discharge rate as \( Q_o = 1.24 \times 10^3 \) and an estimate of the zone radius \( a = 20 \) m or volume \( v = 2.9 \times 10^4 \) m³. Clearly, the correspondence with the analytical circulation rate of \( Q_o = 10^3 \) is quite encouraging as is the zone radius magnitude, corresponding to the thermal drawdown zone located from post-experiment borehole temperature logs.

The correspondence with both the results of previous *in situ* experiments and the parallel fracture model suggest broad applicability of the proposed model. Of special importance are the ramifications of external heat supply from the external geologic host in prolonging reservoir life and increasing productive output.
PARAMETRIC EVALUATION

The thermal response to a variety of different production configurations may be determined through the dimensionless parameters above on direct application of equation (7). Of the 5k separate parameters, $\Phi_{ij}$ has minimal realistic range and little influence on the resulting temperature histories.

**Steady Behaviour**

In the long term as the steady condition is approached, equation (7) may be simplified as $\partial T_o/\partial t \rightarrow 0$ to give

$$\langle I_o - I_o \rangle = AB \langle I_o - I_o \rangle \quad (10)$$

where $A$ is appropriately determined for $t \rightarrow \infty$. This may be rearranged as

$$I_o + AB \langle I_o \rangle = \left[I + AB\right]^{-1} \langle I_o \rangle \quad (11)$$

where $I$ is the identity matrix or alternatively represented directly as dimensionless output temperatures through

$$\langle I_o - I_o \rangle = \left[I + AB\right] \langle I_o - I_o \rangle \quad (12)$$

Where the local geothermal gradient reduces to zero, for the sake of convenience or otherwise, dimensionless output temperature $T_{oi}$ is given by the sum of terms comprising the ith row of the matrix $\left[I + AB\right]^{-1}$. Of particular interest is the finite magnitude of long term withdrawal temperatures determined from equation (12) since the product $AB$ is directly proportional to $Q_0$. As reservoir circulation rate decreases, therefore, thermal drawdown in the reservoir is reduced. As individual throughputs, $Q_i$, become vanishingly small, conductive heat supply from the external geologic host is sufficient to maintain reservoir output at initial in situ temperatures.

Results may be specialized for a colinear arrangement of contacting production zones without hydraulic communication as illustrated in Figure 4. The average output temperature $\overline{T_o}$ decreases as the number of producing zones increases. The average steady production temperature is a unique function of geometry and circulation rate. Thus, for a ten-fold increase in total circulation rate, the steady return of thermal energy is increased less than ten-fold for intermediate magnitudes of circulation rate. Thermal recovery is most favourable for low dimensionless circulation rates corresponding to low flow rates or high thermal conductivities of the host rock. Although steady thermal yields at high dimensionless throughputs ($Q_o > 10^6$) increase near proportionately to the increase in number of producing zones, this behaviour is clearly far from optimum in all practicality due to the low specific recovery temperature.
As the number of zones in linear arrangement increases, the spread of production temperatures away from the mean value also increases. Production temperatures in the central region of the linear arrangement are always lowest with highest temperatures recorded at the extremities. The spread of these temperatures, available from equation (12), are illustrated by the bar of Figure 4. With the addition of more zones, the mean output temperature is predominantly influenced by the centrally located production zones. In the limit as the separation between adjacent zones is increased, and $\alpha/s_\theta \to 0$, the steady output temperature reduces to that for a single zone.

**Transient Behaviour**

Results for the transient drawdown of a single zone are illustrated in Figure 3. As noted previously [Elsworth, 1989a], bounding behaviours exist for extreme magnitudes of dimensionless throughput, $Q_0$. For very large throughput ($Q_0 > 10^9$), output temperatures are fixed in dimensionless time ($t_0 Q_0$) representing insignificant thermal recharge from the host. Conversely, for small circulation rates ($Q_0 < 10^{-4}$) the system suffers no thermal drawdown.
Where multiple extraction is considered, thermal histories will differ from those of the single case to a maximum offset when $a/s_q \rightarrow 1/2$ for equal sized zones. Results for a linear arrangement of fine zones are illustrated in Figure 5 where mean temperatures are volume averaged. Bounding behaviours are present for the same range of circulation rates, i.e., $10^4 \leq Q_o \leq 10^6$, as present for the single stimulated zone. At intermediate circulation rates, $10^4 \leq Q_o \leq 10^4$, the recovery temperatures are degraded over the single zone example at dimensionless time $t_o > 10$. This corresponds directly with the behaviour predicted for the steady case in Figure 4. With an increase in throughput, the degradation occurs at progressively later dimensionless time ($t_o Q_o$) or at earlier real times ($t$). The significance of this degradation, in reality, is conditioned by the anticipated useful lifetime of the system. The magnitude of the degradation is most pronounced for intermediate values of dimensionless throughput, $Q_o \approx 10^4$.

Doubling the number of producing zones to ten further degrades the mean output from the system. Transient results for this case, illustrated in Figure 6, indicate that the magnitude of degradation is only slightly accentuated over that for the fine colinear zones. Also illustrated is the spread of production temperatures from the innermost and outermost areas. The distinction between these two areas is only significant at intermediate circulation rates $10^4 \leq Q_o \leq 10^4$. Lowest temperatures are recovered from the centre and the highest from the extremeties. The distinction is only significant at dimensionless time $Q_o t_o \approx 10^4$. 
CONCLUSIONS

A conceptual model has been presented to describe thermal recovery from a geologic host through a multiple arrangement of artificially stimulated production zones. Significantly, the analysis predicts production temperatures considerably in excess of equivalent closed system models for sufficiently small fluid circulation rates, $Q_o$. Of further importance is that dimensionless circulation rates required to achieve this added thermal advantage are only slightly lower than those used to date in tests conducted at the Fenton Hill Reservoir. Dimensionless flow rates of $Q_o \leq 10^3$ maintain a finite thermal production steady state with previous circulation tests (Fenton Hill, Run Segments 2 and 5) estimated to be of the order $Q_o = 10^2$ to $10^3$.

The analysis further suggests an advantageous operating scenario of multiple colinear zones stimulated from a single injection-withdrawal well set where circulation rates in each zone are retained lower than would a single basal production zone. This arrangement offers the advantage of minimized external circulation losses and maximized thermal leverage from the external geologic host.

ACKNOWLEDGEMENTS

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Reservoir Water Loss Modeling and Measurements at Fenton Hill, New Mexico

Donald W. Brown
Earth and Environmental Sciences Division
Los Alamos National Laboratory, Los Alamos, NM 87545

Abstract

An extensive series of pressurized reservoir water loss experiments are presently being conducted in the deeper Phase II reservoir, at the Laboratory's Fenton Hill site in north-central New Mexico. The objectives of these experiments are:

1. To measure the boundary permeation loss rate at a number of equilibrium reservoir pressure levels, and as a function of time; and
2. with this pressure- and time-dependent water loss rate data, to determine the joint dilation (i.e., mean joint porosity) of the reservoir as a function of pressure up to about 23 MPa (as measured at the surface).

These experiments are being conducted in a sequence of pressure steps, with the recently completed production well (EE-2A) shut in, and with the reservoir initially in a fully vented-down condition. In this noncirculating and nonextending mode, all of the injected water must go either into inflating the reservoir or into boundary permeation flow out of the reservoir.

The permeability model of Gangi has been used to help explain the water loss rates as previously measured during two reservoir flow tests of 7 and 30 days duration. During the 30-day flow test, the model strongly suggests that the reservoir was actively growing, even at injection pressures as low as 27 MPa. Peripheral reservoir growth by fracture extension during the 30-day test is confirmed by seismic observations.

During the current series of pressurization experiments, the water loss rate due to permeation has thus far been measured at two reservoir pressure levels. For comparable times after the start of pumping, the permeation loss rates are 0.17 l/s and 0.51 l/s respectively, for reservoir pressure levels of 7.5 MPa and 15 MPa. These measured loss rates compare favorably with those predicted using the permeability model of Gangi.

Introduction

The Los Alamos National Laboratory is presently conducting an extensive series of pressurization tests on the deeper Phase II reservoir at Fenton Hill, New Mexico. These
tests, referred to collectively as Experiment 2077, began on 28 March and will continue through September 1989.

Four 3-week-long pressure plateaus have been planned during Experiment 2077 -- at 7.5, 15, 22.5, and 18.75 MPa -- to measure the peripheral reservoir water loss rate at each of these pressure levels, but only after the entire reservoir region has been inflated (or deflated) sequentially to each specified pressure. While the reservoir is being pressurized through the injection wellbore (EE-3A), the reservoir pressure is being monitored at the shut-in production wellbore (EE-2A).*

However, as of 28 June, we have only completed the first two pressure plateaus -- at 7.5 and 15 MPa, so we do not yet have a complete data set.

The Components of Reservoir Water Loss
The overall reservoir water loss rate is here defined simply as the difference between the injection and production flow rates. During the flow testing of a fractured hot dry rock (HDR) geothermal reservoir, this overall water loss rate is typically comprised of the following quantities:

1. Permeation losses to the far field from the periphery of the stimulated region,
2. Pressure-dependent storage within the stimulated joints comprising the HDR reservoir,
3. Pressure-dependent storage within the microcrack fabric of the crystalline rock interior to the reservoir region,
4. Fluid storage within newly stimulated regions at the boundaries of the existing HDR reservoir,
5. Density changes of the contained reservoir fluids.

Of the various water loss components listed above, the only true -- i.e., nonrecoverable -- water loss is that due to permeation flow outwards from the pressurized reservoir region (Item 1). All the other components represent recoverable water storage within existing or newly formed HDR reservoir regions.

The objective of Experiment 2077 is to pressurize the reservoir in such a way as to be able to measure the permeation loss and storage terms separately, over a range of reservoir pressures that precludes reservoir growth (Item 4).

Pressure-Dependent Permeability Model
As previously described (Brown and Fehler, 1989), the pressure-dependent permeability model being used for these reservoir water loss rate studies is the so-called "bed-of-nails" model originally proposed by Gangi (1978).

* All pressures and stresses given in this paper are as measured at the surface (i.e., above hydrostatic).
In this model, the permeability of jointed or microcracked rock is given by

\[ k(P) = k_0 [1 - (P/P_1)^m]^3 \]  

(1)

where \( P \) is the effective normal stress (total stress minus pore fluid pressure) across the joints or microcracks, \( k_0 \) is the zero-pressure (i.e., zero-effective-stress) permeability, \( P_1 \) is the normal stress at which the joints or microcracks are essentially closed, and \( m \) is a constant (0 < \( m \) < 1) which characterizes the asperity height distribution function. Limited field measurements during previous flow testing of our Phase II HDR reservoir at Fenton Hill suggest that the Gangi "bed-of-nails" model adequately represents the pressure-dependent permeability of the microcracked and naturally jointed crystalline reservoir rock, at least for effective stresses in the range of 0 to 30 MPa, the range typically associated with an HDR reservoir.

Predicted Reservoir Water Loss Rate vs. Pressure

For the long-term operation of a pressurized HDR geothermal reservoir, a very important parameter is the rate of water loss due to permeation at the boundaries of the pressure-dilated (i.e., stimulated) region. This water loss to the lower-pressure far-field region will most probably be through the interconnected microcrack fabric in the surrounding unstimulated rock. The fluid will permeate outwards, generally in a direction parallel to the least principal earth stress, and normal to the longer axes of the ellipsoidal-shaped reservoir region. Therefore, the permeable outflow will be controlled primarily by the intermediate earth stress. However, the unopened extensions of the stimulated joints comprising the HDR reservoir, if not completely filled with secondary mineralization, may afford additional paths for water loss to the far field.

Figure 1 shows the measured matrix permeability (heavy lines) as a function of effective confining stress (or pressure) for three representative core samples obtained from the Fenton Hill test site (Duffy, 1980). For initial analyses, the permeability curves of Fig. 1 have been averaged (the dashed curve) and then fitted with an equation of the form of Eq. 1

\[ k(P) = 1.6 \times 10^{-18} [1 - (P/117)^{-2.85}]^3 \]  

(2)

(The units of pressure and permeability for the above equation are MPa and \( m^2 \), not bars and nanodarcies as shown in Fig. 1.)

To illustrate the influence on reservoir water loss of the pressure-dependence of permeability, the Darcy flow equation in its steady-state form was used

\[ \dot{Q} = \frac{k A P}{\mu \Delta L} \]  

(3)
where $k$ is the mean permeability over the boundary pressure range, $A$ is the reservoir perimeter area (about \(2 \times 10^4 \text{ m}^2\)), $\mu$ is viscosity, and $\Delta P/\Delta L$ is the overall pressure gradient at the boundary of the reservoir.

Reasonable estimates for the mean peripheral reservoir permeability, for a range of HDR reservoir pressure levels, can be obtained from Eq. 2 by using the integral mean value theorem from calculus

$$E = \int_{P_2}^{P_1} k(P) \frac{dp}{(P_1 - P_2)}$$  \hspace{1cm} (4)

where $P_1$ and $P_2$ define the range of the effective earth stress variation at the boundary of the reservoir region. That is,

$$P_1 = \sigma_2$$

$$P_2 = \sigma_2 - P_r$$

where $\sigma_2$ is the far-field effective earth stress parallel to the strike of the reservoir region (and therefore normal to the permeating microcrack network off the "sides" of the reservoir), and $P$ is the specified HDR reservoir pressure level above hydrostatic. For the region surrounding the Phase II reservoir, $\sigma_2$ is about 35 MPa above hydrostatic, based on several indirect measurements. Figure 2 shows the calculated variation in reservoir water loss rate ($Q$ in Eq. 3) as a function of reservoir pressure, normalized to the water loss rate for a pressure of 24 MPa -- the mean reservoir pressure level for Experiment 2074 as discussed in the next section.

**Measured Water Loss Rates During Previous Reservoir Flow Testing**

During previous Phase II reservoir flow testing, the overall reservoir water loss rate has been determined in the usual way by differencing the injection and production flow rates. However, this approach has several serious drawbacks involving the accuracies of the separate flow meters and the state of the production fluid. Concerning the latter, the production fluid from an HDR reservoir typically contains dissolved gas (mainly CO$_2$) in varying concentrations which may partially come out of solution upstream of the discharge volumetric flow meter.

Notwithstanding the above limitations, the determination of the permeation water loss rate requires the multiple assumptions that the reservoir region (containing both joints and microcracks) is fully inflated but not extending, and that the gradient of pressure within the reservoir is but slowly varying (the so-called steady-state reservoir flow condition).

Figures 3 and 4 show the overall reservoir water loss rates as measured during two recent flow tests: Experiment 2074 in late 1987, and the Initial Closed-Loop Flow Test (ICFT) in mid 1986. Since the water loss rate
and associated microseismic data from these two flow tests have previously been discussed in considerable detail (Brown and Fehler, 1989), only a summary of the results will be presented here.

For Experiment 2074 as shown in Fig. 3, the water loss rate after only 7 days had declined to 1.4 l/s, and was still declining at a rate of 0.13 l/s/day. Since this flow test was essentially aseismic at a mean injection pressure of 24 MPa, one can conclude that the reservoir was not extending. However, from other analyses, it also appears that the Phase II reservoir region was less than half full (i.e., less than half inflated) at the end of this brief 7-day flow test. Therefore, the final overall water loss rate of 1.4 l/s still includes a considerable amount of fluid going into storage.

On the other hand, the ICFT was considerably longer and also highly seismic, particularly during the second flow-rate segment at a mean injection pressure of 31 MPa. The microseismic activity during the ICFT indicates that the reservoir was extending during most of this flow test, as verified by the considerably higher (than Experiment 2074) water loss rates shown in Fig. 4. Even at the end of the first 15-day flow rate segment, when the flow going into reservoir storage would have been considerably reduced, the overall water loss rate was still 2.3 l/s. This is considerably higher than the 1.6 l/s predicted from Fig. 2, suggesting that a significant amount of flow was going into new reservoir creation.

Experiment 2077 Results: First Pressure Plateau at 7.5 MPa
The first phase of Experiment 2077 was completed on 27 April 1989 after 30 days of continuous operation. During this time, a total of 1860 m³ of water was injected into the Phase II reservoir through the EE-3A wellbore using a combination of our two small piston pumps (0.5 l/s and 1.0 l/s). Even though Experiment 2077 was designed to maintain the Phase II reservoir at pressures below the fracture extension pressure (about 24 MPa), it is still necessary to differentiate between true water loss due to permeation outflow, and water going into storage as the reservoir inflates. From an analysis of the data measured during the first pressure plateau, it is apparent that the majority of the 1860 m³ of injected water went into reinflating the reservoir, rather than to permeation to the far field.

The first pressure plateau at 7.5 MPa was reached on 8 April, after 11 days of essentially continuous injection. It required over 1000 m³ to inflate the reservoir to 7.5 MPa (as measured at EE-2A) during this 11-day ramp-up in pressure. However, it quickly became apparent that the majority of the reservoir was not yet up to a pressure level of 7.5 MPa, but was still inflating beyond the central core representing the well-interconnected region between EE-3A and EE-2A. This suggests that access to the far reaches of this multiply jointed reservoir is highly impeded at a pressure of only 7.5 MPa.
Figure 5 shows the observed water loss rate during the 7.5 MPa pressure plateau. While maintaining this pressure level (as measured at the shutin EE-2A), the loss rate dropped from 0.8 l/s to 0.3 l/s in 19 days, far more rapidly than can be explained by the temporal variation of permeation outflow alone. A qualitative assessment of the variation of this water loss rate reveals several features. First, the total water loss rate appears to be declining towards a value less than 0.25 l/s. Second, the storage component of this overall water loss rate, after several months of pressurization, would be expected to contribute only a minor amount to the observed total water loss rate. It therefore appears that at least two-thirds of the early-time loss rate (0.8 l/s - 0.25 l/s) is going into pressurized storage, as would be anticipated.

From a conceptual point of view, the reservoir storage term, at a constant near-field pressure level, would be expected to decay exponentially to a vanishingly small value as the far reaches of the reservoir region fully inflate. Thus, the storage term, $Q_{stor}$, would be represented as

$$Q_{stor} = Ae^{-bt}$$

(5)

directly analogous to the Muskat model for extrapolating reservoir pressure to infinite time at a constant injection rate (for a non-pressure-dependent reservoir).

On the other hand, the reservoir permeation loss rate would be best represented by the nonlinear diffusion equation. Considering the shape of the Phase II reservoir, bounded by two large near-planar surfaces, a one-dimensional diffusion approximation appears appropriate. Further, since the driving pressure for diffusion (the reservoir pressure) and the sink pressure (the far-field pore pressure) are both essentially constant for the case being considered, the nonlinear diffusion equation with a pressure-dependent permeability, $k(P)$, can be solved by using Eq. 4.

Therefore, the similarity solution for the one-dimensional diffusion equation represents an adequate representation for the time-varying permeation loss, $Q_{perm}$. Thus, except for very early times

$$Q_{perm} = C - D\sqrt{t}$$

(6)

By fitting eqs. (5) and (6) to the composite water loss data shown in Fig. 5, the following flow rate equations obtain

$$Q_{stor} = 0.728e^{-0.066t}$$

(7)

$$Q_{perm} = 0.23 - 0.00776\sqrt{t}$$

(8)

where $t$ in both equations is elapsed time in days since 2 April (the mid-point of the initial pressure ramp to 7.5 MPa at EE-2A).
Table I compares the total measured water loss rates to the calculated values from Eqs. (7) and (8), and also the total predicted water loss rates, at four times taken from the curve fit to the data shown in Fig. 5. Table I also presents extrapolated total water loss rate values at 54 days and at one year.

Table I  
(All rates in l/s)

<table>
<thead>
<tr>
<th>Date</th>
<th>Elapsed time (days)</th>
<th>Measured Water Loss Rate</th>
<th>$Q_{st}$</th>
<th>$Q_{f}$</th>
<th>$Q_{s}$</th>
<th>Percent Error</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/8</td>
<td>6</td>
<td>0.700</td>
<td>0.490</td>
<td>0.210</td>
<td>0.700</td>
<td>0.0</td>
</tr>
<tr>
<td>4/16</td>
<td>14</td>
<td>0.483</td>
<td>0.288</td>
<td>0.201</td>
<td>0.489</td>
<td>+1.2</td>
</tr>
<tr>
<td>4/21</td>
<td>19</td>
<td>0.404</td>
<td>0.207</td>
<td>0.196</td>
<td>0.403</td>
<td>-0.3</td>
</tr>
<tr>
<td>4/26</td>
<td>24</td>
<td>0.341</td>
<td>0.149</td>
<td>0.192</td>
<td>0.341</td>
<td>0.0</td>
</tr>
<tr>
<td>Extrapolated:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5/26</td>
<td>54</td>
<td>—</td>
<td>0.020</td>
<td>0.172</td>
<td>0.192</td>
<td>—</td>
</tr>
<tr>
<td>4/2/90</td>
<td>365</td>
<td>—</td>
<td>0.000</td>
<td>0.081</td>
<td>0.081</td>
<td>—</td>
</tr>
</tbody>
</table>

From the above analyses, we can now determine the first data point for the effective pressure-dependent total porosity (both joints and microcracks) of the Phase II reservoir (i.e., fracture storage volume), for a reservoir pressure of 7.5 MPa. At the end of 30 days of reservoir pressurization, the total injected volume was 1863 m$^3$. By integrating Eq. (4) for the last 24 days of this 30-day period, the total permeation loss would be 424 m$^3$. Therefore, the total joint and microcrack storage term for 30 days would be 1439 m$^3$. The anticipated residual inflation volume -- i.e., additional storage -- at 7.5 MPa can be obtained by integrating Eq. (7) from 24 days to infinity. This residual storage volume is 195 m$^3$. Therefore, the total reservoir joint and microcrack porosity at 7.5 MPa is 1634 m$^3$ (above that at 0 MPa).

Experiment 2077 Results: 2nd Pressure Plateau at 15 MPa
The 15-MPa pressure plateau was completed on 28 June 1989. The duration of this 2nd pressure plateau was 32 days, with reservoir pressure (as measured at the shut-in production wellbore) being maintained by cyclic pumping into the injection wellbore as before.

The overall reservoir water loss rate profile measured during the 15-MPa pressure plateau is shown in Fig. 6. By comparing this profile to the one measured during the 7.5 MPa plateau shown in Fig. 5, two significant features can be recognized. First, the initial decay in overall water loss rate occurs much faster during the 15-MPa pressure plateau, indicating that the main interconnecting reservoir flow passages are more open at this higher pressure. Second, even though the initial pressure decay
occurs more rapidly, the residual -- i.e., permeation --
water loss is significantly higher at a reservoir pressure
level of 15 MPa. It would appear that the overall water
loss rate has asymptoted to a value of about 0.51 l/s,
representing the permeation-only loss rate.

From an examination of the normalized permeation water
loss rate versus reservoir pressure curve given in Fig. 2,
the loss rate at 15 MPa is predicted to be 2.84 times that
at 7.5 MPa. Using the 54-day permeation loss rate value
from Table I of 0.172 l/s at 7.5 MPa, the Gangi model
would predict a permeation water loss of 0.49 l/s at 15
MPa. This predicted value is quite close to the measured
permeation loss rate of 0.51 l/s obtained from Fig. 6 for
June 29, 52 days following the mid-point of the pressure
rise to 15 MPa.

However, this comparison is very preliminary. When
Experiment 2077 is finally completed in September, with
permeation water loss rate data for additional reservoir
pressure levels of 22.5 MPa and 18.75 MPa, and using
transient nonlinear permeation flow modeling, a much
better comparison will obtain.

Conclusions
Although, the stepwise pressurization of the Phase II
reservoir will not be completed for at least two more
months, several conclusions can already be reached.
1. The permeation water loss rate from this deep, hot
HDR reservoir, with a stimulated volume of at
least 0.3 cubic km, is quite small.
2. However, the pressurized water storage in this
reservoir is quite large -- over 1600 m$^3$ at 7.5
MPa.
3. The pressure-dependent permeability model of Gangi
has been experimentally verified, albeit only in a
preliminary sense as yet.

Acknowledgements
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around-the-clock 3-month (so far) pumping test.

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Figure 1. Measured Permeabilities for three Granitic Core Samples from Fenton Hill. After Duffy (1980).

Figure 2. Predicted Reservoir Water Loss.
Figure 3. Experiment 2074 Injection Flow and Water Loss Rates.

Figure 4. ICFT Injection Pressure and Water Loss Rate.
Figure 5. Observed Water Loss Rate at a Reservoir Pressure of 7.5 MPa

Figure 6. Observed Water Loss Rate at a Reservoir Pressure of 15 MPa
THE USE OF VSP AND CROSS-HOLE SEISMIC SURVEYS IN THE DEVELOPMENT OF HDR RESERVOIRS

R.C. Stewart, R.H. Jones; Camborne School of Mines Geothermal Energy Project

ABSTRACT

A number of active seismic surveys have been carried out at the Camborne School of Mines hot dry rock geothermal energy project since 1982. The purpose of these has been to detect any changes in the geothermal reservoir caused by stimulation of the reservoir or by the long-term circulation of water.

Cross-hole seismic surveys reveal large changes during long-term water circulation and clearly have potential for mapping fractured regions that have contracted due to cooling and thus contain a high proportion of water. Vertical seismic profiles (VSP's) are also sensitive to such regions. However VSP's are most useful in assessing the effects of stimulations: the analysis of tube waves seen in VSP surveys provides a means of mapping sizeable fractures that are intersected by a borehole.

1 INTRODUCTION

This paper describes the results of vertical seismic profile (VSP) and cross-hole seismic surveys performed at the Camborne School of Mines (CSM) hot dry rock (HDR) geothermal energy project in November and December 1988 and compares them with surveys in 1985 and 1986.

VSP and cross-hole surveys were carried out in 1985 and 1986 before and after a major viscous stimulation (Baria and Green, 1986) of the production well between depths of 2225m and 2397m measured depth (MD). The purpose of these was to observe any changes induced in the rockmass by the stimulation. Since 1986 the reservoir has undergone long-term water circulation with the injection flow rate varying between 17 and 40 l/s. The temperature of the production water has steadily declined from 65° in December 1985 to 50° in December 1988. In late 1988, further VSP and cross-hole surveys were carried out to determine the effects of the long-term circulation.

In both the cross-hole and VSP surveys two parameters will be investigated: the velocity of propagation of seismic waves and the attenuation of their amplitudes. The reservoir is composed of fractured homogeneous granite: changes in these parameters are predominantly a result of changes in joint and crack apertures and therefore the amount of water within the reservoir. The VSP surveys can also provide information on the permeability of joints that
intersect the wells from analysis of the tube waves that are generated at the intersection. The higher the permeability of the joint, the larger the amplitude of the tube wave (Hsui et al. 1985).

2 CROSS-HOLE SEISMIC SURVEYS

In December 1988 a cross-hole survey was carried out between the three wells in the reservoir. This was a repeat of the survey carried out in November and December 1985 following the viscous stimulation. The post-stimulation survey had shown only small changes compared to the pre-stimulation survey (CSM, 1988a).

![Figure 1: Shot and Receiver Positions for Cross-Hole Surveys](image)

Figure 1 shows the shot and receiver positions used in the surveys. A detonator tool, holding 11 custom-built detonators, was repeatedly deployed in the production well, RH15, and 59 shots were fired at various intervals along its length. Seismic signals generated by these shots were detected on down-hole hydrophones. A string of three hydrophones with 90m and 102m intervals was deployed in RH11, the observation well, and this was left stationary during the survey. A single hydrophone was deployed in the injection well, RH12, and for most of the survey this remained at the lowest position shown in the figure. For the last 9 shots, however, it was pulled up together with the detonator tool to perform a horizontal scan.

To reduce background seismic noise in the wells whilst maintaining the reservoir in a pressurised state, the pumps were stopped and all three wells shut in approximately 30 minutes before the start of each run of the detonator tool. Despite this, seismic noise in the 1988 survey was still a serious problem. The mean RMS noise level was up by a factor of 10 compared to 1985 and signals could not be seen over many raypaths.
Figures 2 and 3 each show two seismic sections: these consist of the seismograms recorded during the 1985 post-stimulation survey and the 1988 survey. Figure 2 shows the data recorded on hydrophone 3 (the lowest element of the string in RH11) and Figure 3 shows that recorded on hydrophone 4 in RH12 – the shot number increases upwards from the bottom of each plot. The amplitude of each trace in a section has been normalised to allow arrivals to be clearly seen.
The large difference in signal-to-noise ratios between the surveys is immediately apparent. It is so poor in the 1988 survey that in many places no arrivals can be seen (the sections from hydrophones 1 and 2 are worse than those illustrated). The arrival time, amplitude and period of each visible P arrival was measured and the seismic velocity for each raypath was then calculated.

Absolute values of velocity are difficult to interpret because errors in source or receiver location introduce bias. For example, an incorrect well trajectory giving an error of 10m in the position of a shot could introduce up to a 7.5% error in the estimate of velocity on the shortest raypath in the survey, and up to 1.5% for the longest raypath. The use of relative values, ie a comparison of velocities determined in the 1988 survey with those in the 1985 post-stimulation survey, removes such uncertainties. Location errors are now restricted to the accuracy with which a tool can be repositioned in a well: the errors in velocity estimates are less than 1% in this case. The use of relative values for the amplitude and period data removes any need to correct the data for radiation patterns that may be imposed by the tools or the boreholes.

2.2 Results and discussion

Figure 4 shows plots of the P-wave amplitude ratio against the source depth at each of the four hydrophones. The figure also includes RH15 temperature and flow logs taken on 25 October 1988. It is clear that amplitudes are greatly reduced since the last survey: a factor of 2.1 was measured. There is however a large scatter in the data, and no systematic variations in amplitude drop with depth can be discerned.

The ratio of the period of the first arrivals at the four hydrophones exhibits similar changes. Again, the scatter is large and no systematic variations can be seen. However there is a general increase in period (reduction in frequency) by a factor of 1.3 on average.
A reduction in both the amplitude and frequency of a seismic signal is indicative of an increase in anelastic attenuation, where the energy lost by a seismic wave travelling through an absorbing medium increases with frequency and/or an increase in the amount of wave scattering within the rock. Both are consistent with an increase in the extent of water-filled cracks in the rock (Green et al, 1989).

Figure 5 shows the ratios of the velocities calculated in the two surveys for the four hydrophones. As with the amplitude and period data there have been changes since 1985, with a mean drop in velocity of 1.8%. In contrast to that data, the velocity ratio shows distinct spatial variation, from little or none on paths from deep in RH15 to hydrophone 4, to regions where the velocity drop is as large as 3%.

Changes in velocity of a few percent are very significant. In the comparison between the 1985 pre-stimulation and post-stimulation surveys, velocity drops of 0.5% were deemed significant (CSM, 1988a, Green et al, 1989).

However, the significance of these large changes has to be qualified by stating that the quality of the data in some places is poor. This includes almost all the data recorded on hydrophones 1 and 2: the two distinct trends seen in the velocities for hydrophone 2 may be due to the second cycle of the arrival being picked by mistake on some traces. Therefore, the velocity drop in this region, and others where a large scatter is seen, may well be overestimated.

The results in Figure 5 show two distinct regions: from shots above and below the major flowing zones (these can be seen from the temperature and flow logs). Below the flowing zones there is little or no change and above the zones the changes are of the order of 2-3%.

The decrease in signal-to-noise ratio between the surveys has created raypaths over which no signals can be seen. One region with no data may actually be strongly attenuating. This is the gap in the data
recorded on hydrophone 3 from shots at depths between 2390m and 2500m MD in RH15. The amplitudes observed from shots at these depths in the 1985 survey are no smaller than those on some of the paths from the bottom of RH15 in the same survey. Thus it seems reasonable to propose that this zone is now strongly attenuating. This is supported by the RH15 VSP data discussed below where the lowest amplitudes are recorded for hydrophone positions between 2400m and 2450m MD.

Changes in velocity, amplitude and period in the HDR reservoir have in the past been ascribed to a change in the water storage of the rock, eg from new fractures opened by a stimulation. It seems reasonable to similarly ascribe these recent changes to an increase in water content, but caused by an increase in fracture aperture since no new fractures should have been caused during reservoir circulation. The observation that the drop in velocity is spatially varying points to localised cooling and contraction of the rock mass.

To understand the significance of the velocity changes it is important to realise that while changes to the amplitude of a signal can come about by changes in the rock over very small distances (a disturbed zone only 1 metre thick can reduce amplitudes significantly), velocity changes require large volumetric changes. The two surveys being compared were carried out with similar reservoir pressures and the most significant change between them is the large drop in temperature of the production water. This cooling of the reservoir would affect a large volume of rock and be effective between the flow exits from RH12 and the flow entries into RH15, which is where the velocity changes are observed.

It is possible to use the velocity reduction to estimate the change in fracture aperture. Using Wyllie et al's (1958) time-average equation for porous media and assuming the velocity of uncracked granite as 5.8 km/s, gives an increase in porosity from 0.25% to 1.25% in the region of high (2.8%) velocity drops. Using O'Connell and Budiansky's (1974, 1977) relationship for a cracked solid gives an increase in the crack density parameter by a factor of 5. A simple calculation of linear rock contraction based on the observed production-temperature drop over the three year period gives an estimate of 0.4mm per metre of rock; consistent with the cross-hole results if initial fractures widths were less than 1mm and the average fracture spacing was 5 to 10m. It is interesting to note that estimates of reservoir volume from chemical tracer data have increased over the period between the two surveys. The estimate of the integral mean volume increased by a factor of about 4 between November 1985 and May 1988.

The observation that the velocity changes, and the inferred cooling, only occur above the lowest flow entry in the production well (RH15) indicates that flow does not access depths deeper than the lowest flow zone in RH15.

3 VSP SURVEYS

A series of VSP surveys have been conducted at the project since 1985. The geometry for all these surveys is essentially the same. A single hydrophone was deployed at a series of depths in RH15 or RH12 and repeated shots of 125g of high-explosive used as a source. The explosive shots were detonated in the same position in a local flooded quarry at an offset of about 1.7km. The receiver spacing in the wells
was either 1.25m or 2.5m. All three wells were shut in during the survey to reduce noise on the hydrophones. Only the data collected in RH15 is presented here.

Two aspects of the VSP data acquired at the project are of particular interest, these are:

(1) The analysis of tube waves to identify permeable features within the rock which intersect the wells. In most oil field applications tube waves are regarded as noise and efforts are made to suppress them, although their ability to detect permeable zones in the study of nuclear waste disposal sites has been investigated (Huang and Hunter, 1981).

(2) The analysis of the first arrival waveforms to determine the areas of enhanced permeability.

3.1 Tube waves

Tube waves are large-amplitude, low-velocity surface waves which travel along the wellbore. They have waveforms and frequency contents which are closely related to the waves which generate them. Tube waves can be generated by four distinct sources: a source within the borehole, a surface wave impinging on the top of the borehole, a seismic wave incident upon a change in the borehole diameter, or a seismic wave incident upon a permeable zone which intersects the borehole. Only the latter two sources are considered to operate in the VSP data acquired by the project.

In order to understand the 1988 VSP survey of RH15 it is necessary to discuss the surveys performed in 1985 and 1986. These surveys were carried out before and after the viscous stimulation of RH15. The VSP sections from the two surveys are shown in Figure 6. The main feature of the pre-stimulation survey is the dominant tube wave emanating from the bottom of the borehole. There are also weak tube waves emanating from depths of 2570m MD and from the casing shoe at 2225m MD. The results from the post-stimulation survey show considerable changes. The most striking change is the strong tube wave emanating from 2390m MD. This corresponds to the major flow entry point which was established by the viscous stimulation. The tube wave at 2570m MD has also been enhanced and new tube waves appear at 2630m and 2770m MD. The tube wave originating from the bottom of the well now terminates at the depth of the enhanced tube wave at 2570m MD, thus giving further evidence that a change took place at the borehole wall at this depth during the stimulation, although this part of the well was sanded off. For this to be the case this portion of the well could not have been entirely independent of the pressure changes caused by the stimulation.

The recent survey of RH15 was carried out in December 1988. The seismic section from this is also shown in Figure 6. The main changes between this survey and the post-stimulation survey is the appearance of a new tube wave originating at a depth of 2740m MD. There also appears to be an increase in the number of minor tube waves generated from the lower portion of the well.
3.2 First arrival data

In an attempt to quantify changes to the rock mass three aspects of the first arrival data were examined: velocity, amplitude and frequency. The velocity was obtained from the first arrival time which was picked manually. Because of the large amounts of data the first arrival amplitude and frequency were determined automatically. The amplitude is taken as the first peak of the envelope function after the application of a 80 to 250Hz bandpass filter. The frequency is the average of 5 measurements of instantaneous frequency taken at the position of the amplitude measurement.
Figure 7 shows the frequency, velocity and amplitude of the first arrival in the 1988 RH15 survey plotted with the RH15 temperature and flow logs. The frequency and velocity profiles are featureless apart from some low-velocity measurements at depths of 2400 to 2450m MD. These are not believed to be genuine but are caused by the low signal-to-noise ratio in this region making it difficult to pick the arrival time accurately.

The amplitude profile can be divided into 5 zones:

1. 2790m to 2625m MD. Considerable scatter in amplitude caused by the large number of tube waves originating from this interval.

2. 2625m to 2575m MD. Large first-arrival amplitudes indicate the presence of a zone of large amplitude tube waves.

3. 2575m to 2400m MD. The amplitudes are small and consistent. This is a zone from which few tube waves originate.

4. 2400m to 2350m MD. Large amplitude first arrivals similar to (2) above. This is the zone containing the major flowing joints.

5. 2350m to 2300m MD. Low consistent amplitudes in a region without tube waves.

Figure 8 shows the ratio of the first arrival measurements from the 1986 post-stimulation survey and the recent survey. Apart from a reduction in the frequency in the bottom 60m of the well there are no significant changes in the frequency and velocity measurements. The amplitude shows a reduction on average with the largest changes in the bottom 100m of the well. The cause of these may be linked to the increase in the number and amplitude of the tube wave in this portion of the well.
3.3 Discussion

The increase in tube waves originating near the bottom of RH15 has been progressive. The 1986 survey showed an increase in the amplitude of the tube wave originating at 2570m MD and new tube waves at 2390m, 2630m and 2770m MD over the 1985 survey. The 1988 survey shows an additional tube wave originating at 2740m MD not present in 1986. These changes indicate an increase in the permeability in the joints and fractures that intersect the well in this zone. This is unexpected since during the viscous stimulation of RH15 in 1985 this portion of the well was sanded off. Also no significant flow has been observed from this zone; the deepest significant flow entry in RH15 is at least 50m shallower. The changes in the VSP's are clear and unambiguous and require reassessment of the viscous stimulation.

Examination of the viscous-stimulation microseismicity (Baria and Green, 1986) shows that it forms a vertical tube from the bottom of RH12 towards RH15 at a depth of about 2600m MD, although it does not intersect RH15. It was originally thought that the tube waves originating at 2570m and 2630m MD in RH15 were different permeable structures to that indicated by the microseismic cloud, although possibly providing a means of connection between it and RH15. It is now hypothesised that the two are the same structure and that this has been a conduit for much of the 25% water loss over the last few years. That the water loss is downwards is supported by the microseismicity detected beneath this zone at depths of 3 to 3.5 km.

4 CONCLUSIONS

Comparison of the recent VSP and cross-hole seismic surveys with surveys of 1985/1986 show significant changes in the geothermal reservoir.

(1) The large reduction in velocity detected in the cross-hole surveys for shots shallower than the deepest significant flow entry into RH15 suggests an increase in joint apertures due to rockmass cooling. This indicates that the production flow in RH15 has not accessed depths deeper than the deepest point of flow entry.

(2) The decrease in velocity implies a porosity increase by a factor of 5, consistent with the change expected due to thermal contraction.

(3) There has been an increase in the number and amplitude of the tube waves originating from the bottom 225m of RH15. These indicate an increase in the permeable features intersecting the borehole. It is believed that these permeable features represent an extension of the zone stimulated in 1985 as represented by the microseismicity induced during the stimulation (CSM, 1988b)
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THE POTENTIAL OF ELECTRICAL RESISTIVITY METHODS TO DETECT HYDRAULICALLY CONNECTED FRACKURES

P.D. Jackson, J.P. Busby, M. Rainsbury, G. Reece, & P. Mooney

ABSTRACT

Electrical resistivity modelling has been used to assess the contribution electrical resistivity methods could make to fracture mapping and circulation assessment within an Hot Dry Rock (HDR) reservoir. It is shown that enhanced resolution arrays could provide additional information on the near borehole zone which provides the majority of resistance to flow, and that cross-hole arrays can provide information on the interborehole structure. The results can be dramatically enhanced if conductive fluid is injected in one borehole enabling hydraulic connections to be identified as changes in cross borehole electrical impedance. Impedances can be monitored immediately after tracer injection and a scheme is proposed to infer the tracer movement prior to breakthrough in the recovery well.

1. INTRODUCTION

The identification of hydraulically conductive fractures in a rock mass by electrical resistivity techniques has been assessed by the BGS for the Camborne School of Mines HDR Project. This project is funded by the U.K. Department of Energy through the Energy Technology Support Unit (ETSU). The aim is to develop a means of detecting fractures which carry a substantial portion of the hydraulic flow. These major pathways have been identified by the Camborne School of Mines Geothermal Project (CSM) as having a poor thermal connection to the reservoir due to their discrete nature and low specific surface area, and as a result lower the extraction temperature due to local cooling.

The resistivity of unfractured granite is likely to be in the range $10^5$ to $10^7\text{ohm}\cdot\text{m}$ for the existing wells. Therefore fluid filled cracks will present paths of low electrical impedance and thus carry a substantial proportion of the electrical current. In such a case then it is possible that electrical resistivity techniques may be developed to detect these hydraulically connected fractures.

Single hole electrical logs could be used to assess the fracture geometry in the near borehole zone, as this would provide an independent evaluation of the portion of the reservoir where the highest resistances are expected.

A variety of cross-hole resistivity measurements would be undertaken to assess the disposition of fractures. Cross-hole impedance measurements appear attractive as one may be able to take the lowest electrical impedances to indicate the best hydraulic connection. In practice this would be a four terminal measurement but conceptually it can be

* British Geological Survey, Regional Geophysics Group
* Bristol University, Dept. Engineering Mathematics
regarded as a source and sink.

A problem remains in that, although the flows of electric current and fluids are both governed by similar differential equations, there is a frictional term in the fluid flow case. This term results in the hydraulic impedance being controlled by the surface roughness, average size of the pore channels and the flow regime, in addition to the cross-sectional area available for flow.

Electric and fluid flow cannot be directly related unless information is available to separate the cases of many small fractures compared to one large one where the porosity $n$ is the same but the average cross-sectional area $a_{eff}$ of the cracks are different. Both these cases above would present the same electrical resistance to flow, but only one may be hydraulically conductive. In order to separate them the device of injecting small amounts of conductive tracer has been considered. Here the hydraulically conductive cracks would be made electrically more conductive than the smaller width cracks that collectively previously may have had a similar electrical resistance. It would be possible to gather additional information on changes in electrical properties as the conductive front passes through the reservoir.

Assessments of the interborehole resistivity distribution would make it feasible to monitor the progress of a tracer through the reservoir. This information would be useful in predicting areas where flows are restricted.

2. DEFINING THE NUMERICAL MODELS

2.1 The resistivity is-situ

The resistivity of the CSM reservoir is controlled by fracturing and jointing as the granite matrix is thought to have a resistivity greater than 100,000 ohm-m. The following factors are known to control the electrical resistivity of granites and other similar crystalline rocks (Brace et al, 1965; Parkhomenko and Bondarenko, 1963; Skagius and Neretnieks, 1986; Evans, 1980).

1. Pore fluid resistivity
2. Surface conduction
3. Connected or effective porosity
4. Tortuosity of the pore channels
5. Temperature
6. Frequency of alternating current flow

Laboratory measurements of electrical resistance of granite core plugs will be degraded by the alteration caused by the sampling process, and it will be difficult to predict in-situ values from laboratory measurements. Also the porosity will be difficult to assess as the effective porosity is likely to be very much smaller than total porosity (Evans, 1980).

Thus one would hope that unfractured resistivities could be assessed in situ, however at present there are difficulties due to:

1. Large volumes of investigation that will contain some fractures
2. Disturbance of the rock mass by the drill hole resulting in a de-stressed zone of disturbance near the borehole.
3. Most proven commercial equipment is not capable of measuring the very high resistivities expected in-situ.
An appraisal of both laboratory and in-situ measurements was made in order to provide a best estimate of the in-situ resistivity of the unfractured granite.

Laboratory and field measurements deal with a disturbed portion of the rock mass. The disturbance in both cases is likely to promote the growth of connected fractures and thus reduce the measured resistances. The best estimate is likely to be an in-situ value derived from measurements which are not degraded by the disturbed zone. The resistance of the disturbed zone could be assessed separately and used to correct the deeper investigating arrays. If this is not done then any disturbed zone would have an exaggerated contribution as a consequence of the high current densities in the near borehole region.

Deep resistivity logs such as the LL7 may have reached their upper limit in regions free of obvious fractures and so underestimate the in-situ resistivity. The maximum value of 70,000 ohm-m in RH15 is rather low given a likely porosity of 0.1% and a pore-water resistivity of 20 ohm-m. The resistivity is likely to be in the range 100,000 to 10,000,000 ohm-m.

While the uncertainty in the in-situ resistivity poses a problem it should be noted that a significant portion of the potential drop will be in the near borehole zone. The effects of this zone will degrade cross-hole measurements and will have to be accounted for. An assessment of crack geometries is thus very important to any cross-hole resistivity investigations. Focussed electric tools of high resolution and variable depths of investigation would be capable of such surveys. An example is given in figure 1 where an improvement in both resolution and maximum measured value can be seen for a LL13 compared to a LL7. The LL13 has extra controlling systems to isolate the central portion of the LL7 current beam.

2.2 The Theoretical Models

There are a number of techniques available for solving 2 and 3-D electrical resistivity problems namely finite element, finite difference, integral equation and alpha centres. We shall describe work using both finite element and finite difference formulations.

3-D resistor network

Finite difference methods have tended to concentrate on modelling 3-D arbitrary resistivity structures (Scriba, 1981; Dey and Morrison, 1979; Mufti, 1978) which use various methods to solve Poisson's equation. They require the solution of large matrix equations or the iterative solution of the finite difference equations. Other means have been attempted to solve similar FD problems such as summary representation (Santos et al 1972) or the application of the Tri-diagonal Matrix Algorithm (TDMA eg Reece, 1986). We have applied the TDMA algorithm to the finite difference solution scheme and replaced Poisson's equation with Ohm's law and Kirchoff's law for current flow in a resistor network rather than in a continuum.

The resistor network is shown in figure 2 where the boreholes and the notation are displayed. The 3-D problem has been transformed into two dimensions by considering lumped resistances connecting the two boreholes which would approximate the current flow in-situ. The lumped
resistances simulated radial current flow close to the boreholes and parallel flow in the central region. These resistances accurately represent the borehole and the effect of enhanced fracturing in the near-borehole zone. Current flow was limited to a 300m x 150m zone of elliptical section in the xy plane.
The scheme used is a 3-D implementation where the cross-section is shown in figure 2. Although this carries a small computational overhead it provides a system that can be expanded to 3-D networks, as might be useful for modelling the response of resistivity sondes (see also Zemanian and Anderson 1987).

The starting point for the numerical modelling was to construct a network representing anisotropic electrical flow in the rock mass, due to a 10m cubic joint set, and a low resistance path in the boreholes. Enlarged cracks were simulated in the near borehole zone which, if not present, would infer the borehole was a very much better conductor than the reservoir. The anisotropic nature is incorporated by simulating alternating layers of fractures and matrix, with crack resistances 40% lower than the rock matrix. Thus one can see it is within the capabilities of the model to represent the cubic crack structure which includes the best estimates of crack widths in each orthogonal direction.

2-D Finite element model

Examples using finite element and integral equation methods have made it clear that a conductive body between two boreholes can be detected by galvanic resistivity methods (Barnett, 1972; Daniels, 1977). Conductive zones have also been modelled by surface and volume integral equation methods (Yang and Ward, 1985; Beasley and Ward, 1986).

These models have not approached the problem of a very thin tabular or ellipsoidal body intersecting boreholes. A method which will allow borehole intersections with thin bodies is the two dimensional finite element method. A model of any complexity can be created because the whole of the half space is discretised (Rijo, 1977).

For downhole modelling the mesh must be fine in both the x and z dimensions since the electrodes are implanted in the half space. The thinnest fracture that is possible in the mesh is 0.2 m. To reproduce the resistance of a real crack of thickness 400 microns the resistivity of the model crack was increased to 10,000 ohm-m, assuming fluid in the crack to have a resistivity of 20 ohm-m. Due to the two dimensional nature of the program the effect of the borehole has not been modelled and the fractures extend to infinity in the y (strike) direction. The resistivity of the host medium (granite) has been set at 100,000 ohm-m.

3. CRACK RESPONSES & SIMULATED TRACER EXPERIMENT

3.1 2-D FE modelling of fracture response

The 2-D finite element models are shown as sub-meshes in figure 3. The fractures are coloured black and the boreholes are shown by the finer x axis mesh. The array that has been used is the mobile dipole-dipole array. Both the transmitter and receiver dipoles are of length one meter and are moved simultaneously in both boreholes and are hence at the same depth. Apparent resistivities were calculated every 0.5 m and the results are presented as $r_a/r_i \times 100$ where $r_i$ is the resistivity of the granite. Figure 3 shows the results for a crack of length 79.4 m and resistivity 10,000 ohm meters, which intersects both boreholes. At the depth of the crack, 127 m, a large reduction in $r_a$ occurs In order to examine the possibility of detecting crack structure between the boreholes the crack was given a vertical deviation. In the calculated
profile, shown in figure 3, both horizontal crack elements are clearly distinguished and the shape of the anomaly profile is influenced by the diagonal elements.

3.2 3-D Tracer Test Modelling

While one can detect low resistivity zones they cannot be directly related to hydraulic conductivity as different processes control the flow. If a conductive tracer were introduced this would change the formation resistivity only through hydraulically connected fractures.
FIG. 4  CONDUCTIVE CRACKS INTERSECTING THE TWO BOREHOLES

The resistor network model was set up as shown in figure 4 where there was a single large fracture in the injection well (Bhl) and four smaller fractures in the production well (Bh2). It was postulated that only one of the fractures was hydraulically connected and that the electrical connection was that of the background joint and granite matrix in the central inter-borehole region (figure 4a).

Cross-hole impedance modelling was chosen as being sensitive to fracture resistance and has been calculated in a way similar to cross-hole seismic tomography, and displayed as a borehole space plot as seen in the work by Masne and Poirmeur (1988).

All possible combinations of impedance were calculated as the source and sink are moved independently in each borehole. The spacing for the movement was taken as 2 or 4 nodes or 10 - 20m with the source being placed opposite a model crack. Thus if there were 10 sample points in each borehole there would be a 10 x 10 grid plotted as borehole 1 against borehole 2.

This exercise was repeated for the case where the tracer had been
FIG. 5 BOREHOLE SPACE PLOTS OF CROSS BOREHOLE RESISTANCE

Imp Map: No tracer present

Imp Map: Tracer present
FIG. 6  THE CONNECTING CONDUCTIVE TRACER RESPONSE
injected into the formation and was now forming a good electrical connection between the hydraulically connected fractures. The borehole space plots can be seen in figure 5 before and after the addition of the tracer. Each fracture produces a lower value of impedance when one measuring point is opposite it, and a substantially lower value when both measurements are made at fracture inter-sections. Thus the response of a single fracture intersecting both boreholes would be a "cross" where the intersection is the fracture location in both boreholes. The response in figure 5a shows three "cross" features where two have produced a merged anomaly due to the interval of computation and not the resolution of the method.

The effect of the introduction of the tracer can be seen in figure 5b where the resistance of the topmost anomaly (Bh1=26, Bh2=38) is now lower than before.

The change in the interborehole resistance has been enhanced by taking the residual of the two images in figure 5 and is shown in figure 6. The response in figure 6 has been interpreted in terms of the large anomaly (Bh1=26, Bh2=38) representing a resistivity low in the interborehole zone. The response is more sensitive to changes in position in Bh2 than Bh1 which reflecting the relative position of the conductive anomaly (i.e. it is closer to Bh2 than Bh1). A prediction of the position and the orientation of the conductive zone is also given in figure 6 assuming no other information than the borehole space plots of figures 5 & 6.

4. CONCLUSIONS

There is some uncertainty in the value of the resistivity of unfractured granite in-situ; it is likely that presently accepted values are underestimates principally due to borehole disturbance and limitations of standard resistivity logging.

Modelling has shown that substantial anomalies are caused by electric current flow in the fluid filled fractures, and that when using cross-hole arrays the boreholes do not form dominant low resistance paths. Where a cross-hole current source and sink have been used the electric current flow and cross-hole impedance are strongly dependent on the position of the current electrodes even when there is free flow in the boreholes.

Cross-hole dipole dipole arrays have responded to off hole fractures which do not intersect the borehole, which suggests that they may be suitable for fracture mapping.

Cross-hole impedance logs are sensitive to changes in crack impedance in the central zone away from the boreholes. Borehole-space impedance plots can be used to highlight the response of conductive cracks over the whole inter-borehole section, and is particularly effective when residuals can be computed to highlight changes in the interborehole zone.

The near borehole zone should investigated during any assessment of the connecting impedance between any two fractures. In a practical situation this data could be acquired by a dual focussed device where this zone would be assessed with each tool acting independently as a
conventional single-hole tool.

Electrical impedance cannot be related to hydraulic impedance without some additional knowledge of the flow paths. If one knew only a single path existed, then it could be done. The introduction of a conductive tracer can be used as a means of identifying major hydraulically conductive fractures. The effects of such a tracer could be measured before entry into the production well, and monitoring of the electrical impedance, described above, as the tracer progresses through the rock mass is seen as a possibility that should lead to further information on the location and magnitude of the zones of high hydraulic impedance. A first attempt has been made to do this numerically but further work is required.

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A Study of the Applicability of Geotomography to Rock Investigations

H. Saito and H. Shima, OYO Corp., Japan

Summary

To study the applicability of geotomography to rock investigation, experiments using seismic tomography and resistivity tomography were conducted at a dam site.

Prior to the experiments, numerical experiments of both tomographic methods were conducted to demonstrate the appropriateness of a reconstruction algorithm developed by the authors, expecting that it will be effective in rock investigation.

The geological background of the site is known that the ground consists mainly of granodiorite, with a complex pattern of weathering and fault zones. From the result of seismic tomography, weathered layers and fault zones were identified as low velocity zones, and from the result of resistivity tomography, a weathered layer near the surface or deeply located fresh rock were identified as high resistivity zones and fault zones could be identified as low resistivity zones. Thus through the interpretation of results from both tomographic methods, more objective evaluation of ground condition was found feasible. Beside these experiments, before and after the injection test by salt water, resistivity tomography was carried out. The results showed that resistivity tomography is effective in evaluating the continuity of fault zones.

The authors believe seismic tomography can be used not only for mapping of fault and fracture zones within geothermal zones, but also to provide valuable information for improving accuracy with which the source of seismic events can be located. Resistivity tomography can also be quite an effective method for evaluating fault and fracture zones by combining tracer injection test.

Introduction

Geotomography uses measurements obtained by geophysical technique as projection data to reconstruct a profile image of the objective underground distribution of physical properties. Various geotomography techniques can be classified according to the physical phenomenon or physical properties used. Of these, the authors have continued to conduct research and development on two different techniques, seismic tomography and resistivity tomography, applying the techniques to civil engineering ground investigation. Each of these techniques determines the distribution of different physical properties. By
using a combination of the two, more detailed information about the underground can be obtained. The authors have conducted experiments involving rock investigations at a dam site. Prior to these experiments, numerical experiments were conducted, with the objective of developing a reliable method.

Reconstruction Algorithm
The following are outlines of the reconstruction algorithms for the two types of geotomography used in the experiments.

(1) Seismic Tomography
The first arrival travel times of the elastic waves penetrating the ground are used as projection data to reconstruct a profile of the distribution of velocities in the ground. It was practical to use the iterative method, as shown in Fig.1, for reconstruction. The initial model in this flow chart was constructed by the back projection technique (BPT), assuming straight ray pass. Cell ray tracing, which is an improved version of the approximate path calculation method (Itoh et. al., 1983), was used to take ray bending into account in the step of calculation of theoretical travel time. In this way, the first arrival travel times and their respective ray paths for the model were calculated. The velocity model was corrected to minimize residuals between calculated travel times and observed travel times. The damped least squares technique was used to determine the correction quantities for this purpose (Saito and Ohtomo, 1988).

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**Figure 1** Flow chart of seismic tomography
Electric potentials are used as projection data to reconstruct a profile of the distribution of resistivity in the ground. For reconstruction, the iterative method as shown in Fig. 2 was used. Though the outline of the analysis flow was similar to the flow of seismic tomography, details were modified to deal with potential fields. At first, topographic compensation was conducted to reduce the topographic effect. The resistivity back projection technique (RBPT) proposed by the authors (Shima, 1987), was used to construct initial model. In the step of calculation of the theoretical electric potential, the alpha centers method was used (Sakayama and Shima, 1986). Because the calculation is much faster than other methods such as FEM, this method is practical when a large volume of data is used. The model modification method used was the non-linear least squares method, which used the singular value decomposition method to evaluate the independence of the solution.

Numerical Experiments
Before field experiments, numerical experiments were conducted to verify the propriety of the analysis methods of above-mentioned tomography and to study the applicability of the methods to rock investigations (Saito and Shima, 1988). Fig. 3 shows the model used in the numerical
This model postulates an area of rock, having a weathered layer near the ground surface and faults in the lower region. In the numerical model, the weathered layer has low velocity and high resistivity, while the fault zone has low velocity and low resistivity.

Fig. 3 shows the experiment model. Fig. 4 shows the observation points and observation pattern. In the figure, the combination of source and receiver is shown by connecting straight lines. In this experiment, observation points were postulated on the ground surface and in boreholes to the left and right of the area of exploration. Accuracy of the analysis can be improved by placing observation points at the bottom of the exploration area as well. However, since such placement would be difficult in an actual investigation, no observation point was located at the bottom. Experiments conducted heretofore have demonstrated that artifacts end to occur at the bottom (Shima, 1987, Saito and Shima, 1988). In the seismic tomography, the cell ray tracing method mentioned above was used to calculate the theoretical travel times of the model. These were used as the input data for the numerical experiment, and 614 data were used. For resistivity tomography, FEM was used to calculate the theoretical potentials of the model. Here, 608 data were used. Both experiments do not postulate noise.

Fig. 5 shows reconstruction profiles for each of the tomography methods. In these, the low velocity zone and high resistivity zone, which correspond to weathered layer, were reconstructed with good accuracy. The reason for this is that projection data are obtained from many directions. In each case, reconstructed image of fault that has low velocity and low resistivity, is generally good, but the distribution pattern take different forms in each case. The differences may be considered to be due to the fact that the two tomography techniques are different in nature, that is, concerning the handling of projection data. In seismic tomography, projection data is handled so as to reflect distribution of velocity values along ray paths, while in resistivity tomography, projection data is handled so as to reflect the
resistivity distribution of the entire space. Therefore, in resistivity tomography, it is difficult to reconstruct sharp changes in resistivity, but a reconstruction image with good continuity is obtainable. On the other hand, in seismic tomography, because ray paths are taken into account, sharp changes in velocity can be reconstructed to a certain degree, but, since spatial continuity is not taken into account, small artifacts tend to occur in reconstructed images. In this way, in seismic tomography and resistivity tomography, the projection data are not only reflecting different ground characteristics, but also the handling of the projection data differ as well. These differences make for different characteristics of reconstruction, and therefore, it is necessary to understand them, when we interpret reconstructed images.

**FIGURE 4** Observation pattern  
(a) seismic tomography, (b) resistivity tomography

**FIGURE 5** Reconstructed images  
(a) seismic tomography, (b) resistivity tomography
FIGURE 6 Experiment results
(a), (b), and (c) are models for stage-1, -2, and -3 respectively; (d), (e), and (f) are reconstructed images of stage-1, -2, and -3 respectively; (g) and (h) are difference distributions from stage-1 to stage-2 and from stage-1 to stage-3 respectively.
The authors have also tried combining a low resistivity tracer (salt water) with resistivity tomography (Shima, 1988). In this method, the low resistivity tracer is injected into a fault confirmed by test drilling, and changes in resistivity are monitored by resistivity tomography to determine continuity and permeability of the fault. By this technique, it becomes feasible for the first time to explore thin faults or fractures. In this paper, the effectiveness of this method for the detection and evaluation of faults are also examined by numerical experiments. The structure of the experimental model is the same as above, but it is postulated that the resistivity of the fault is different, due to introduction of the salt water. The model shown in Fig. 6-a is the state prior to injection of the tracer (stage 1). It is the same as Fig. 3. Fig 6-b is stage 2, where the tracer has penetrated one-third through the fault, which intersects the exploration area. Resistivity following penetration is taken as 25 ohm-meters. Fig 6-c is stage 3, in which the tracer has penetrated to just opposite the borehole. Observation pattern is the same as Fig. 4-b.

The analysis results before injection of the tracer is the same as in Fig. 5-b, but it is given in Fig. 6-d. Analysis results after injection of tracer are shown in Fig. 6-e and -f. From these results, it can be seen that resistivity values progressively decrease from the upper area of the fault to the lower area. To clarify changes in resistivity distribution, the change ratio at each stage is graphed. This ratio is calculated using the logarithms of resistivity values, according to the following equation:

\[
\text{Change ratio} = \frac{\log \rho' - \log \rho}{\log \rho} \times 100 \% 
\]

where \(\rho\) is resistivity before penetration and \(\rho'\) is resistivity after penetration. This processing clearly delineates the changing states as the tracer penetrates. Maximum change ratio between Stage 1 and Steage 2 is 8% (Fig. 6-g). Between Stage 1 and Stage 3, it reaches 16% (Fig. 6-h). The high resistivity artifacts strongly appearing at the bottom right in Figs. 6-d, -e, and -f, are cancelled out when the change ratio is calculated.

In field investigations, the fact that resistivity decreases with penetration of the tracer means that the fault has continuity, from the standpoint of water flow. This movement also provides information on permeability.

Examples of Applications to Rock Investigation

Outline of Topology and Geology of Investigation Area

Fig. 7-a and -b show vertical and horizontal profiles, giving rock classifications and the geology of the site where geotomography was conducted. Generally, in rock classification, B- and Cn-classes correspond to relatively fresh rock, on the other hand, Ct- and
D-classes correspond to weathered rock. The site where the investigation was conducted was the left bank of a dam site. As shown in Fig.7-a, it had a very sharp incline, of 40-50 deg. Geotomography was conducted by using boreholes and an adit excavated from this incline.

The geology of this site consists mainly of granodiorite, with areas of diorite and aplite. As main faults, F-1 and F-2 have a strike running NE to SE, with a dip of 60 deg. They run nearly parallel to a mountain slope in the exploration objective area. Also, Fault F-3 runs with more gentle dip, and is crossed by F-2. Almost all of the joint and fissures run in about the same direction as these main faults. A very few intersect them. In the shallow areas, this site consists of surface soil or strongly weathered D-class rock. Below this area, in order, C₁-, C₂- and C₃-class rock.

In this way, investigations previously conducted at the site have provided a rough picture of its geology and rock classification. The authors conducted geotomography
by using boreholes and the adit to obtain a detailed picture of the distribution of physical properties of the rock.

**Measurement Methods**

(1) Seismic Tomography

As shown in Fig 8, the seismic sources and receiving points are placed in the boreholes in the objective profile (B-1 to B-4), in the investigation adit (TL-1) and on the mountain slope. Both the sources and receivers are placed at 2-6 m intervals. By lining up the sources and receivers alternately in the adit and on the ground surface, it was made possible to acquire data from many directions effectively. There are 59 seismic sources and 60 receiving points. In measurement, three sets of OYO Corporation's McSeis 1500 digital data processing system (12 channels) were hooked up together for simultaneous measurement on 36 channels. Of the measured data, the first arrival travel times were read out from 1542 data having a good S/N ratio for use as input data for analysis.

(2) Resistivity Tomography

As shown in Fig 9, resistivity tomography was conducted over a triangular area surrounded by borehole B-1, adit TL-1 and the mountain slope. Electrodes were placed at 2 m intervals. Two remote electrodes each were placed about 2 km away from the site, and measurement by the pole-pole array method was conducted. From the 98 electrodes, 450 potential data were measured, covering the area uniformly.

The salt water tracer was injected into borehole B-1 from an altitude of 320 to 321.24 m to investigate the underground water flow. In order to detect changes in resistivity due to tracer penetration, resistivity tomography was conducted before the injection, one day and six days after the injection, three times in total. As shown in Fig.10, an injection method using a double packer was adopted. 8 m³ of salt water was injected over
about a four hour period. Injection pressure was 4.5 to 5 kgf/cm². Concentration of the salt water was about 5%, and Resistivity values were 0.193 to 0.195 ohm-meters.

Results and Interpretation

(1) Seismic Tomography

First, Fig.11 shows the velocity distribution profile obtained by seismic tomography. Analysis was conducted after dividing the profile into 2 m square cells. A contour diagram was prepared by placing the velocity value of each cell in its center. The dark zones represent high velocities, and bright zones low velocities. From the profile, it can be seen that the triangular area surrounded by adit TL-1, borehole B-1 and the mountain slope has lower velocity values than other parts. Comparing these results with those obtained in previously conducted geological investigations, it can be seen that the velocity distribution within this area well reflects such conditions as the relatively widely distributed C₄ to D-type rocks and relatively complex geological conditions such as the faults and fractures that exist closely together. Of these conditions, areas showing low velocity values of 1.0 km/s or less are concentrated along the mountain slope vicinity and in borehole B-1 at an altitude of around 310 m. Comparing with results from geological investigations, this low velocity zone may be interpreted as corresponding to the weathered layer comprising the ground surface and faults. The area from the top of borehole B-2 to the vicinity of adit TL-1, which was heretofore interpreted from previous investigation results as mainly consisting
of C\textsubscript{4}-class rock, is inferred from the tomography results to consist of highly weathered rock (C\textsubscript{L}-class), due to the fact that it consists largely of velocity values of 2.0 km/s or less. There are few areas showing low velocities on the mountainside of borehole B-1. Near the ground surface, there is a layer having velocities of 2.0 to 2.5 km/s and a thickness of 20 to 25 m distributed uniformly. Below this layer, high velocity zone of 3.5 to 5.0 km/s is distributed. These distribution of velocities correspond to results from geological investigation. On the valley side of borehole B-1, this high velocity layer is distributed only at lower altitudes from adit TL-1. However, at the lower part of adit TL-1, as can be seen from the observation pattern (Fig. 8), there are few data. In addition, ray path directions are mostly horizontal. Therefore, changes in velocity values cannot be detected in the horizontal direction, and the overall uniform velocity distribution may be regarded as having been determined.

![FIGURE 11 Reconstructed image of seismic tomography](image)

(2) Resistivity Tomography

Next, the resistivity distribution profile obtained before injection of the salt water by resistivity tomography is shown in Fig. 12-a. The dark parts represent high resistivity, and the bright parts low resistivity. Most notable is that, in addition to covering the ground surface, the high resistivity zone extends from an altitude of 320 to 330 m in the vicinity of borehole B-1 to the lower right and above adit TL-1. Also, in the
vicinity of altitude 290 to 300 m around borehole B-1, a somewhat high resistivity zone can be seen. In between, a complex low resistivity zone is present. Comparing with the results from previous investigations, and taking into account the general relation between resistivity and the state of the rock, this resistivity distribution may be interpreted as follows. The high resistivity zone in the vicinity of the ground surface is considered to correspond to the weathered zone of the mountain slope, having low water content. The high resistivity zone directly above adit TL-1 is interpreted as being relatively hard rock (C<sub>n</sub>-class). The high resistivity zone extending from borehole B-1 at altitude 320 to 330 m to the lower right corresponding to the area of low water content resulting from weathering. The high resistivity zone at an altitude of 290 to 300 m in the vicinity of borehole B-1 is considered to correspond to an area of relatively fresh rock. The low resistivity zones found in between are considered to be a high water content zone or faults including clay or some other fine material.

Next, Fig.12-b and -c show analysis results from resistivity tomography after injection of the tracer. Examination of resistivity distribution one day after injection of the tracer shows further lowering of resistivity in the low resistivity zone (below the altitude of tracer injection), indicating that the tracer has penetrated to this zone. Resistivity distribution after 6 days shows that resistivity values have begun to recover.

![Resistivity Tomography Images](image)

**FIGURE 12** Reconstructed images of resistivity tomography
(a) before injection, (b) one day after injection, (c) six days after injection

Figs.13-a, -b, -c show resistivity variation ratios before and after injection of the tracer. In the figures, a and b are directly obtained from measurement results. c is the distribution of ratios extrapolated for after nine days. Examination of the variation ratio for the first
day after injection shows a great decrease in resistivity in the low resistivity zone. The change reaches a maximum of 16% or more, indicating that this zone is a predominant permeability zone. Distribution of variation ratios six days after injection has begun to recover since the state one day after injection. In the area around where this recovery of resistivity has occurred, an area of decreased resistivity has appeared. This signifies that penetration of the tracer is continuing. Examination of the variation ratio distribution nine days after injection shows a partial decrease, but resistivity distribution has generally recovered to the state before injection.

![Figure 13](image_url)

**FIGURE 13** Difference distributions
(a) one day after, (b) six days after, (c) nine days after

(3) Interpretation
Greater reliability should be obtainable by combining and interpreting results from seismic tomography and resistivity tomography. By combining the two methods and interpreting, the following can be said of the area surrounded by adit TL-1, borehole B-1 and the mountain slope. The area along the mountain alope is considered to consist of surface soil and D-class rock ranging in thickness from several to under 20 m and having low velocity and high resistivity, i.e., low water content. Below this area, from an altitude of 330 m in borehole B-1 to adit TL-1, there is a zone of somewhat low velocity and low resistivity. This zone is considered to correspond to the previously mentioned faults F-1, F-2 and their surrounding area. Velocities increase gradually in the area of relatively high resistivity at 310 to 290 m in the vicinity of borehole B-1, and corresponds to C_r-class rock.

Combining the use of a salt water tracer with resistivity tomography has made it possible to identify the distribution of high permeability zones, which was not possible by previous exploration methods. As a result, it
was considered that faults F-1, 2, and 3 have good permeability and that inter-continuity between them exists.

**Conclusion**

This paper has presented the results of numerical and field experiments conducted by the authors in seismic tomography and resistivity tomography. The results from the field experiments showed relatively good correspondence with the actual geology and state of the rock at the dam site. Thus, it has become possible to use tomography to describe a detailed objective distribution of physical properties in a way heretofore impossible. Hereafter, this technique promises to become practical and effective for this purpose. In addition, this technique promises to provide much information useful, for example, for the development of techniques for the determination of the sources of seismic events.

Moreover, using a salt water tracer to artificially change the resistivity of permeability zones and tracing the progress over time of change in resistivity, make it possible to clearly identify distribution of permeability zones, i.e., faults and fractures. This, too, was heretofore impossible. Technique for monitoring of dynamic changes in resistivity of rock promises to become an effective tool in rock investigation for evaluating faults and fracture zones.

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SESSION 5C – RESERVOIR DEVELOPMENT
Introduction

This paper presents a study conducted by Ecole des Mines de Paris and supported by Agence Francaise pour la Maitrise de l'Energy. Its purpose is to interpret thermal logs as flowmeter logs. It is shown how the flow rate of each producing zone of a well under production can be determined.

Measurements

Measurements that is talken about here have been performed in Le Mayet de Montagne experimental field where a research programm on methods for extracting heat from impervious deep rock formations has been undertaken for many years (Cornet et all 1987). Major experiments have been run during 1987 and main results are derived from forced fluid circulating tests between two 800m deep boreholes, 100m apart.

These forced fluid circulating tests have been carried out in successive phases corresponding to different improvements of the reservoir development. (respectively 15, 21 and 65 days in duration April-August 1987).

Various techniques were utilized to locate the most important hydraulic conductive zones. Induced microseismic activity was assumed to be significant from identifying flow zones away from the wells. Spinner and thermal logs were prefered to geophysical logs for locating injected and productive fractures in both wells. This choice may appear reasonable when considering that these logs only deal with fractures really connected to a network that accepts fluid.

After the last attempt to develop our reservoir by stimulating and propping preexisting fractures at the bottom part of the production well, a long test was planned in order to precise the hydro-thermal characteristics of the heat exchanger that has been develop during the preceding phases. Injection borehole was INAG III.9 and producing borehole was INAG III.8.

Since it has been observed that thermal logs were
very sensitive for identifying water producing fractures, a continuous survey of the open-hole section of III.8 was organized. This survey involved periodic time spaced thermal logging operations in order to provide a quantitative distribution of the outflows and any disturbance of this breakdown in time.

The thermometer tool used a platinum resistance (such sensor has a fast response) and temperature profiles were analogically recorded. The velocity of the probe during logging was equal to 3 m/min.

During the 66 days of duration of this circulating test, 19 logs were run between 410m and 765m, while the production flow rate was ranging from 4.5 l/s to 9.3 l/s. Corresponding injected flow rate was varying between 7.5 l/s to 21.0 l/s. At least four days were necessary to reach a new quite steady state situation at the production borehole when increasing injected flowrate from a designated value to another enlarged one. It is to be noticed that same flow rates do not provide same hydraulic recovery factors after some ten thousands meter cubed of fluid have circulated through the reservoir.

![Graph](image.png)

**Figure 1** Injection and production flow rates (m3/h) versus time(days) for the third circulating phase

Figure 1 shows an overall view of injection and production flow rates for the total duration of this third circulation experiment. It includes the dates of the logs and corresponding data such as the recovery factor and the global impedance.

Some of the whole set of 19 logs are shown figure 2.
Eleven productive fractures are outlined at the depths of 438m, 471m, 632m, 639m, 644m, 649m, 661m, 674m, 713m, 754m and 764m. Three of them were not observed on previous logs and are considered to have been stimulated during previous experiments (649m, 661m and 713m).

**Figure 2: Some logs observed in III.8**

A strong warming effect is noticed between 661m and the bottom of III.8 well. This behavior is relevant from the first circulating phase (April 87), when III.8 was used as the injection borehole of the doublet. Injection took place under an inflatable packer set at 710m and the bottom part has then been cooled for 15 days at the rate of 8.3 l/s of 12°C water. As it has been concluded from others measurements, most of the injected water had been drained back to ground surface by some major subvertical fractures in the very near vicinity of the well. It is suggested here
that those short-circuits were connected to fractures intercepting III.8 at the depths of 661m and 674m since no cooling effect is noticed above.

**Numerical modelling**

This analysis deals with boreholes under production and all the producing levels are assumed to be located. The open hole part of the well can then be divided into impervious sections where heat exchange with the formation may occur, separated by inflow levels where both flow rates coming from below and from the fracture are instantaneously mixed.

Because various experiments have been run in the well, temperatures of the entering partial flow rate can't be derived in a simple way from the knowledge of the temperature gradient away from the well. They will be considered as parameters while the partial flow rates are the unknowns.

**Equations**

Flow in each interval is constant and supposed to be turbulent. Since borehole radius is small, the change in radial direction may be neglected. Moreover conduction of heat in the fluid is also negligible compared to axial convection (axial=along the borehole). The temperature of the water, denoted $T_w$, is then a function of depth $z$. As a consequence of the turbulent heat transport of the water, it is assumed that there is a temperature difference between the flowing water and the borehole wall which is equal to $(T_w(z) - T_p(z))$.

Under these circumstances, the heat conservation equation for the water is equation [1] which do not take transient effects of heat storage into account.

$$4Nu(T_f - T_p) + Re PD \frac{\partial T_f}{\partial z} = 0$$

$Nu$ denotes the Nusselt number of the fluid, $Re$ is the Reynolds number and $P$ is the Prandtl number. $D'$ denotes the borehole diameter. (All $Nu$, $Re$ and $P$ are dimensionless).

For turbulent flow $Nu$ is related to $Re$ and $P$ by relation [4]

$$Nu = 0,024Re^{0,8}P^{0,5}$$
Concerning the surrounding granitic formation, the heat conservation equation can be simplified into (2) when neglecting axial heat conduction. The variable \( k_m \) denotes the thermal diffusivity of the rock (subscript \( m \) denotes rock matrix).

\[
\frac{\partial T_m}{\partial t} = k_m (\frac{\partial^2 T_m}{\partial r^2} + \frac{1}{r} \frac{\partial T_m}{\partial r})
\]

(2)

The boundary condition that couples equation (1) and (2) is prescribed by equation (3) which deals with heat flux exchange at the borehole wall.

\[
K_m \frac{\partial T_m}{\partial t} (r = R) = \frac{K f}{D} N u (T_p - T_f)
\]

(3)

The last condition is the temperature at which water enters the bottom of each impervious section. This is obtained when considering that an instantaneous mixing occurs at each producing level.

More precisely, the flow corresponding to the lower productive levels \( Q \) is mixed with an additional flow rate \( dQ \) entering the system with temperature \( T_{frac} \). The temperature of the resulting total flow rate \( Q + dQ \) is drawn from relation (5) and provide the needed condition for solving the set of equations (1), (2) and (3).

\[
Q \cdot T_{inf} + dQ \cdot T_{frac} = (Q + dQ) \cdot T_{mélange}
\]

(5)

Boundary and initial prescribed conditions

- Far from the well, the temperature is supposed to be undisturbed. Since the total duration of the circulating tests is less than three months and since the thermal diffusivity of the granite is about 1.5 \( 10^{-6} \) m\(^2\)/s, "far" means roughly some meters: we have choosen to set this limit at a radius of 10 meters.

- The temperature of the fluid entering at the bottom of the well is prescribed at its measured value.

- The total flow rate at the top of the open-hole section is also prescribed at the measured value.

Initial temperature field is derived from the temperature gradient. Disturbances induced by phase 1 of the experiments is taken into account. (analytical solution for the previous cooling effect, Berest et all 1987)
Numerical solving process

The numerical model uses an implicit finite difference technique, which solves for the temperature changes in the formation and temperature change for the water at each depth of a discretized space grid. Computing begins at the bottom of the well where axis z is originated.

Such an algorithm provide at every time step a water temperature profile corresponding to a given set of partial flow rates accompanied from a distribution of entering temperature. This numerical profile has to be compared to the real observed one and the fitting of both curves leads out the sought flow rates.

Following required parameters are regarded as data

- natural geothermal gradient C: 0.032 K/m
- thermal diffusivity of the water kf: 1.45 e-7 m2/s
- thermal conductivity of the water Kf: 0.6 W/m/K
- thermal diffusivity of the granite km: 1.40 e-6 m2/s
- thermal conductivity of the granite Km: 3.30 W/m/K
- water cinematic viscosity at 30°C nu: 0.83 e-6 m2/s

RESULTS

Results are presented in figure 3 in which each column corresponds to a thermal log. In each column each producing fracture is represented by a segment the length of which is proportional to the flow rate and normalized with respect to the total production rate measured at surface.

The depth of each producing zone is indicated in the legend.
According to these results, three fractures (471m, 713m and 754m) provide the major part of the total production rate. A significant part (43%) is relevant from the bottom part of this well.

Since the distribution of partial flows do not show significant change in time whilst injection rate varies from 7.5 l/s to 21.0 l/s (9.0 to 12.5 MPa), it is suggested that mechanical effects due to elevated fluid injection pressure are located in the vicinity of the injection borehole where they have been observed through spinner logs.

**Figure 3: Flow rates of the various producing fractures ( % of the total production rate)**
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FLOWPATH CHARACTERISATION OF THE ROSEMANOWES HDR RESERVOIR USING INERT TRACERS

H G Richards1, K A Kwakwa2, G P Osiku1, 3

1 Camborne School of Mines Geothermal Energy Project, Penryn, Cornwall, TR10 9DU, UK.
2 GeoScience Ltd, Falmouth Business Park, Bickland Water Road, Falmouth, Cornwall, TR11 4SZ, UK.
3 Present address: Robertson Group PLC, Units 5 and 6, Wellheads Crescent Trading Estate, Dyce, Aberdeen, AB2 0GA, UK.

ABSTRACT

The experimental HDR geothermal reservoir at Rosemanowes links Wells RH12 (injector) and RH15 (producer). During circulation, the production temperature declined in a way that indicated the existence of a thermal short circuit. A programme of inert tracer tests was performed, in order to characterise the flow distribution in the interwell region, and hence to identify the flowpath or paths most likely to be associated with the short circuit. The reservoir was considered as consisting of six possible flowpaths, linking two inlet zones of flow in the injection well with three outlet zones in the production well. Pulses of tracer were injected downhole above each inlet, whilst sampling downhole above each outlet.

Four of the six possible flowpaths were found to be carrying 10% or more of the production flow. One flowpath was carrying about 60% of the production flow and had the shortest fluid residence times. About a quarter of the flow in this hydraulic short circuit path was responsible for the thermal short circuit. It was also found that this path correlated with a geological structure identified from microseismic events created during earlier hydraulic injections, before the creation of the RH12/RH15 reservoir. This adds weight to the idea that short circuits in HDR reservoirs are likely to be controlled by natural geological structures.
INTRODUCTION

The current experimental HDR reservoir at Rosemanowes was created in 1985. The connection between the injection well (RH12) and the production well (RH15) was established by the viscous stimulation of RH15 (Pine et al., 1987) and was circulated continuously from August 1985 until February 1989, when RH15 was subjected to a proppant treatment. The performance of the reservoir after the viscous stimulation was monitored using hydraulic measurements, production logging, microseismics and tracer tests (Pine et al., 1987; Parker, 1989a).

In the first two years of the circulation, the mixed outlet fluid temperature of the reservoir declined from 80 to 60°C. Modelling of the thermal behaviour suggested that the cooling was due to an initial rapid effect of a thermal "short circuit", followed by general cooling of the main reservoir (Nicol and Robinson, 1989). However, there was no obvious effect of a short circuit in the results of repeated temperature logs of the production well (Nicol, 1989).

During this period, inert tracer testing was used routinely to determine changes in the residence time distribution (RTD) of the system, from which changes in volumetric characteristics could be obtained (Kwakwa, 1988). The flowpath characterisation experiment (FCE) described here was a programme of tracer tests designed to resolve the composite RTD of the reservoir into several components, in order to obtain more detailed information about the distribution of flow in the inter-well region.

On the basis of flow logs, it was decided to divide the flow out of the injection well into two zones and the flow into the production well into three zones, thus defining six theoretically possible flowpaths through the reservoir (Figure 1). The FCE consisted of tracer tests in which a pulse of tracer was released immediately above one of the zones of flow out of the injection well whilst sampling immediately above one of the zones of flow into the production well (Figure 1). In all, six tracer results were required to characterise the six possible flowpaths.

The objectives of the FCE were:

1. To determine the breakthrough times of as many as possible of the six flowpaths shown schematically in Figure 1.

2. To calculate the distribution of flow between the flowpaths, using the masses of tracer recovered through each flowpath.

3. To calculate the RTD of as many flowpaths as practicable, for comparison with the bulk system RTD.

THEORY

Inert tracer definitions

The RTD is defined as a probability distribution function E(t) for the time spent by water molecules in a single pass through the reservoir. The RTD may most accurately be determined by the injection of an
instantaneous pulse of a known mass of inert tracer into the injection stream during steady state circulation:

\[ E(t) = \frac{Q_{in} C(t)}{M_{in}} \]  

Various parameters may be derived from the RTD. Several of those used in this paper have been defined by Robinson and Tester (1984; 1986), namely breakthrough time, breakthrough volume, modal volume \( V \), median volume \([V]\) and integral mean volume. The width at half-height, \( t_{1/2} \), is defined here as the width (in terms of time) between the two points on either side of the peak of the RTD for which the tracer response is half its peak value.

**General assumptions for the FCE**

In order to interpret the results of the FCE, it was necessary to assume that the flow rates and RTD's of the bulk reservoir and individual flowpaths were constant throughout the FCE and that the bulk reservoir and individual flowpaths behaved as linear systems (ie the outlet concentration-time response, \( C(t) \), for a pulse injection containing \( N \) mass units of inert tracer was equivalent to \( N \) times that of a pulse injection containing 1 mass unit of tracer).

**Calculation of distribution of flow between flowpaths**

A general flowpath \( a-i \) through the reservoir has the flow zone \( a \) out of the injection well as its inlet and the flow zone \( i \) into the production well as its outlet. In order to calculate the distribution of flow between all flowpaths, it is necessary to perform tracer tests in which all possible combinations of tracer injection and sampling locations are used. The tracer injection location \( a \) is defined as being the depth in the injection well corresponding to the top of flow zone \( a \) and the sampling location \( i \) is defined as being the depth in the production well corresponding to the top of flow zone \( i \).

For the FCE, there were two flow zones out of the injection well (A and B) and three flow zones into the production well (1, 2 and 3). The six possible flowpaths may therefore be labelled A-1, B-1, A-2, B-2, A-3 and B-3, and are shown schematically in Figure 1.

The function \( M_{a_1}(t) \) is the mass of tracer that has passed location \( i \) in the production well up to time \( t \) in response to injection of a pulse of tracer at location \( a \):

\[ M_{a_1}(t) = Q_{i} \int_{0}^{t} C_{a_1}(t) dt \]  

If it is assumed that the water entering the production well is entirely derived from the injection well, then for a pulse of tracer (of mass \( M_{in} \)) injected at location A, the mass of tracer eventually recovered at location i for a tracer test of quasi-infinite duration \( (t = t_{\infty}) \) is given by:

\[ M_{A_1}(t_{\infty}) = \frac{Q_{i} M_{in}}{Q_{A}} \]
The flow rate in a given flowpath \(q_{a_i}(t)\), may be calculated from the mass of tracer \(m_{a_i}(t_\infty)\) that would pass through the flowpath in response to injection of a pulse of tracer (of mass \(M_{in}\)) at location A:

\[
q_{a_i} = \frac{Q_A m_{a_i}(t_\infty)}{M_{a_i}(t_\infty)} = \frac{Q_A m_{a_i}(t_\infty)}{M_{in}} \quad (4)
\]

If the same mass \(M_{in}\) is injected at the general location \(a\) in the injection well, then:

\[
m_{a_i}(t_\infty) = \frac{Q_A m_{a_i}(t_\infty)}{Q_A} \quad (5)
\]

where \(m_{a_i}(t_\infty)\) is the mass of tracer transmitted through flowpath \(a-i\) in response to an injection of a tracer pulse of mass \(M_{in}\) at \(a\). Provided that the same mass of tracer \(M_{in}\) is used for each test, the values of \(m_{a_i}(t_\infty)\) are calculable from a set of six equations:

\[
m_{B3}(t_\infty) = M_{B3}(t_\infty) \quad (6)
\]

\[
m_{B2}(t_\infty) = M_{B2}(t_\infty) - m_{B3}(t_\infty) \quad (7)
\]

\[
m_{B1}(t_\infty) = M_{B1}(t_\infty) - m_{B2}(t_\infty) - m_{B3}(t_\infty) \quad (8)
\]

\[
m_{A3}(t_\infty) = M_{A3}(t_\infty) - \frac{Q_B M_{B3}(t_\infty)}{Q_A} \quad (9)
\]

\[
m_{A2}(t_\infty) = M_{A2}(t_\infty) - \frac{Q_B M_{B2}(t_\infty)}{Q_A} - m_{A3}(t_\infty) \quad (10)
\]

\[
m_{A1}(t_\infty) = M_{A1}(t_\infty) - \frac{Q_B M_{B1}(t_\infty)}{Q_A} - m_{A2}(t_\infty) - m_{A3}(t_\infty) \quad (11)
\]

Calculation of RTD's of flowpaths

It is shown below (Table 3B) that the flow rates of only three flowpaths could be calculated accurately enough for their RTD's to be determined. These are the paths issuing from flow Zone B in the injection well. The general equation for the RTD's of these flowpaths is:

\[
E_{B1}(t) = \frac{q_{B1} G_{B1}(t)}{m_{B1}(t_\infty)} \quad (12)
\]

The function \(G_{B1}(t)\) is the concentration-time response that would be observed at the outlet of the path connecting Zones B and i (in isolation from other paths whose outlets are i) for an injection of tracer above Zone B.

The \(G_{B1}(t)\)'s are derived from the observed concentration-time responses of individual experiments using the following equations:
where \( t_{32}, t_{21}, t_{31} \) are plug-flow wellbore transit times between the sampling locations.

**Working approximation**

In practice, the condition expressed by Equation (3) was never realised. That is, the elapsed time at the end of the test was less than \( t_{\infty} \), and the concentration of tracer in the production stream did not decline below the pre-test background (Figure 2). A variety of methods can be used to relate the value of the function \( Q_i(t) \) at the end of the test (or at some other value of elapsed time) to the required parameter \( M_{i1}(t_{\infty}) \), including various arbitrary mathematical extrapolations. In this paper, an implicit extrapolation method has been used that takes advantage of the similarity of the experimental tracer curves when plotted with respect to appropriately scaled axes. This type of approach has also been suggested by Robinson and Tester (1988).

The experimental concentration-time responses of the six tests (Figure 2) are shown plotted with respect to dimensionless axes of concentration divided by the peak concentration and elapsed time since breakthrough divided by \( t_{1/2} \) (Figure 3). The resulting curves are very similar in shape. If the shapes of the curves in Figure 3 were identical both within and beyond the limits of the experimental data, then:

\[
\frac{M_{a1}(nt_{1/2})}{M_{a1}(t_{\infty})} = \frac{M_{a1}(nt_{1/2})}{M_{a1}(t_{\infty})}
\]  

(16)

where \( nt_{1/2} \) is the elapsed time since breakthrough in terms of multiples of \( t_{1/2} \). All the tracer tests were run up to or beyond \( 2t_{1/2} \). In order to proceed with the calculation of the flow distribution, it has been assumed that Equation (16) is approximately true for \( n=2 \).

Inherent in Equation (16) is the assumption that for all tracer tests, the ratio of \( M_{a1}(2t_{1/2}) \) to \( M_{a1}(t_{\infty}) \) was the same. Using data from injections of tracer above Zone A, it was found that the ratio of \( M_{a1}(2t_{1/2}) \) to \( M_{a1}(t_{\infty}) \) in fact varied from 0.42 to 0.59, being smallest for the experiment involving sampling above Zone 3 and largest for sampling above Zone 1. In the calculations reported below, the largest value (0.59) was used, so that the relative errors in the calculated flow rates of the flowpaths contributing to the major flow zone (Zone 1) would be less than in the minor flowpaths contributing to Zones 2 and 3.
Since Equation (4) does not use the data from the production well flow logs, a check on the errors introduced by using Equation (16) may be made by comparing the sum of the $q_{ai}$'s for a given value of $i$ with $Q_i$, the flow log-indicated flow rate from Zone $i$.

**METHODS**

The FCE took place in April-June 1988 in the middle of a 10 month period of circulation at a constant injection flow rate averaging 21.6 l/s. To avoid reinjecting the tracer, the system was operated on open-loop (continuous injection of fresh water while discharging the production water). Flow logs were run in both injection and production wells before and after the FCE (January and August 1988). The logging tool was a spinner device which measured flow rates relative to the total flow rate in the cased wellbore.

Sodium fluorescein dye had been used in previous tracer tests, and had been shown in laboratory and field tests to have the necessary inert properties in the Rosemanowes HDR reservoir. A purpose-built downhole tracer injector tool was used to transport a 10 litre solution containing 1.00 kg of fluorescein to a selected depth in the injection well, where the solution was released by remote control at the required time.

The production well was sampled continuously using the open end of a string of 4" (OD) drill-pipe. A small drilling rig was used to handle the pipe. The flow rate in the drill-pipe was kept constant at 1.5 l/s throughout the FCE. This ensured that the overall flow rate produced from the drill-pipe was always less than the total flow entering the production well below the bottom of the drillpipe, to avoid water being drawn from above the sampling depth. For the flow conditions in the various parts of the open holes, drill-pipe and production well annulus, the Reynolds Numbers were in the range 40000-174000, implying turbulent plug flow. Thus measurements made at surface could be corrected for wellbore or drill-pipe transit times using plug flow velocities.

A purpose-built automated flow-through fluorimeter was used throughout the FCE to determine the tracer concentrations in water from the production well annulus and drillpipe.

**RESULTS**

**Reservoir flow conditions during the FCE**

During the FCE, the injection flow rate was held constant at an average of 21.6 l/s and the total production flow rate dropped slightly from 14.1 to 13.7 l/s. For calculation purposes, a constant total production flow rate of 14.0 l/s has been assumed. The results of the flow logs run before and after the FCE are given in Table 1. As on previous occasions, there was little change in the distribution of relative flow rates (% of total). The logs shown in Figure 1 are those made before the FCE. The ranges given for the relative flow rates in Table 1 indicate the uncertainties in the flow logs. The "values used for FCE" are the ranges of flow rates in the wellbores used for calculating the results reported below.
TABLE 1  FLOW RATES IN THE WELLS

<table>
<thead>
<tr>
<th>WELL</th>
<th>TOP OF ZONE</th>
<th>DEPTH (m)</th>
<th>JANUARY 1988 (% of total)</th>
<th>AUGUST 1988 (% of total)</th>
<th>VALUES USED FOR FCE (l/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection Well RH12</td>
<td>A</td>
<td>1790</td>
<td>100</td>
<td>100</td>
<td>21.6</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>2170</td>
<td>69-72</td>
<td>70-74</td>
<td>15.1-16.0</td>
</tr>
<tr>
<td>Production Well RH15</td>
<td>1</td>
<td>2218</td>
<td>100</td>
<td>100</td>
<td>14.0</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>2409</td>
<td>32-34</td>
<td>28-31</td>
<td>3.9-4.3</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2464</td>
<td>17-18</td>
<td>15-17</td>
<td>2.1-2.4</td>
</tr>
</tbody>
</table>

Characteristic parameters of experimental tracer curves

The observed concentration-time responses are shown in Figure 2. Various parameters can be obtained from each curve. These are given in Table 2. All volumetric parameters have been calculated with wellbore volumes subtracted, and breakthrough times ($t_b$) are corrected for wellbore and/or drill-pipe transit times. Median volumes could not be defined for injections of tracer above Zone B.

TABLE 2  PARAMETERS OBTAINED FROM EXPERIMENTAL TRACER CURVES

<table>
<thead>
<tr>
<th>INJECTION LOCATION</th>
<th>SAMPLING LOCATION</th>
<th>$t_b$ (hr)</th>
<th>$t_{1/2}$ (hr)</th>
<th>$V$ (m$^3$)</th>
<th>$[V]$ (m$^3$)</th>
<th>$M_b \sqrt{(2t_{1/2})}$ (kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>1</td>
<td>1.5 ± 0.1</td>
<td>30</td>
<td>550</td>
<td>2050</td>
<td>0.382 ± 0.019</td>
</tr>
<tr>
<td>B</td>
<td>1</td>
<td>1.2 ± 0.1</td>
<td>27</td>
<td>550</td>
<td>2050</td>
<td>0.436 ± 0.022</td>
</tr>
<tr>
<td>A</td>
<td>2</td>
<td>4.7 ± 0.3</td>
<td>33</td>
<td>240</td>
<td>1150</td>
<td>0.092 ± 0.009</td>
</tr>
<tr>
<td>B</td>
<td>2</td>
<td>4.2 ± 0.2</td>
<td>31</td>
<td>240</td>
<td>1150</td>
<td>0.110 ± 0.010</td>
</tr>
<tr>
<td>A</td>
<td>3</td>
<td>5.6 ± 0.3</td>
<td>43</td>
<td>210</td>
<td>1100</td>
<td>0.043 ± 0.005</td>
</tr>
<tr>
<td>B</td>
<td>3</td>
<td>5.4 ± 0.3</td>
<td>38</td>
<td>170</td>
<td>1100</td>
<td>0.047 ± 0.0055</td>
</tr>
</tbody>
</table>

The transit time between the tracer injection locations A and B was 0.35 hour. If this is added to the breakthrough times for injections above Zone B, the two breakthrough times at each sampling depth are seen to be indistinguishable. Thus the only flowpath breakthrough times that can be given absolute values are those for the flowpaths originating at Zone B (B-1, B-2, B-3), with breakthrough times of 1.2, 4.2 and 5.4 hours, respectively. For injections above Zone A, breakthrough probably took place through paths originating from Zone B. Flowpath B-1 contained the most direct route in the reservoir between the injection and production wells.

Calculated flow distribution models

The masses of tracer recovered up to $2t_{1/2}$ ($M_b \sqrt{(2t_{1/2})}$'s) are also given in Table 2. These values were used to calculate the flow distribution model given in Table 3A, using average values for the flow rates in
the wells. The uncertainties associated with the $M_{i}(2t_{1/2})$'s in Table 2 are those due to uncertainties in the production flow logs and the analytical uncertainty of about ±5%. Allowing for these uncertainties and the uncertainty in the injection well flow logs, a range of flow distribution models has been derived (Table 3B). For flow Zones 1 and 2, there is good agreement between the sum of the model flow rates entering the zone and the actual inflow indicated by the flow logs. The agreement is less good for Zone 3, but not so bad as to invalidate the approximating assumption inherent in using Equation (16).

**TABLE 3** MODEL FLOW RATES IN THE VARIOUS FLOWPATHS (1/s)

**A** Example calculation using average values for flow rates and values of $M_{i}(2t_{1/2})$ from Table 2

<table>
<thead>
<tr>
<th>INLET ZONE (RW12)</th>
<th>A</th>
<th>B</th>
<th>TOTAL (model)</th>
<th>ACTUAL (log)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OUTLET 1</td>
<td>2.0</td>
<td>8.6</td>
<td>10.6</td>
<td>9.9</td>
</tr>
<tr>
<td>ZONE 2</td>
<td>0.15</td>
<td>1.65</td>
<td>1.8</td>
<td>1.85</td>
</tr>
<tr>
<td>(RW1)</td>
<td>0.35</td>
<td>1.25</td>
<td>1.55</td>
<td>2.25</td>
</tr>
<tr>
<td>RECOVERY (model)</td>
<td>2.5</td>
<td>11.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>INJECTION (log)</td>
<td>6.05</td>
<td>15.55</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LOST FLOW</td>
<td>3.55</td>
<td>4.05</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**B** Ranges of values taking flow log and analytical uncertainties into account

<table>
<thead>
<tr>
<th>INLET ZONE (RW12)</th>
<th>A</th>
<th>B</th>
<th>TOTAL (model)</th>
<th>ACTUAL (log)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OUTLET 1</td>
<td>1.4 - 2.8</td>
<td>7.8 - 9.4</td>
<td>9.2 - 12.2</td>
<td>9.7 - 10.1</td>
</tr>
<tr>
<td>ZONE 2</td>
<td>0 - 0.5</td>
<td>1.4 - 2.0</td>
<td>1.4 - 2.5</td>
<td>1.5 - 2.2</td>
</tr>
<tr>
<td>(RW1)</td>
<td>0.1 - 0.5</td>
<td>1.1 - 1.4</td>
<td>1.2 - 1.9</td>
<td>2.1 - 2.4</td>
</tr>
<tr>
<td>RECOVERY (model)</td>
<td>1.5 - 3.8</td>
<td>10.3 - 12.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>INJECTION (log)</td>
<td>5.6 - 6.5</td>
<td>15.1 - 16.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LOST FLOW</td>
<td>1.8 - 5.0</td>
<td>2.3 - 5.7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 3B shows that well-constrained flow rates (better than ±20%) could be calculated for Paths B-1, B-2 and B-3. Path B-1 clearly dominated the system, carrying 55% to 67% of the total production flow, while three other paths were each carrying between 8% and 20% of the flow (A-1, B-2 and B-3).
Calculated RTD's of paths issuing from Zone B

The RTD's of the flowpaths issuing from Zone B, for which well-constrained flow rates have been calculated, were calculated using the values of the model flow rates in Table 3A, and are shown in Figure 4. Figure 4 also shows the full system RTD, which is the flow-weighted sum of the RTD's of all six theoretical flowpaths, including those for which RTD functions could not be calculated accurately. The modal volumes of Paths B-1, B-2 and B-3 were 130-155, 60-90 and 85-110 m³, respectively (using the ranges of flowpath flow rates given in Table 3B). These values are all smaller than the total system modal volume of 550 m³ (taking the second peak of the full system RTD as the mode).

DISCUSSION

Identification of the thermal short circuit

One of the objectives of the FCE was to identify the flowpath(s) containing the thermal short circuit. Not surprisingly, it turned out that the Flowpath B-1 linking the main zone of flow out of the injection well with the main zone of flow into the production well had the highest flow rate and lowest fluid residence times. However, Flowpath B-1 and the thermal short circuit were not synonymous. The flow rate in the thermal short circuit was 18 ± 4% of the total production flow according to Nicol (1989), as against about 60% in Flowpath B-1. Nicol (1989) also estimated that about 20% of the flow from Zone 1 was associated with the short circuit. Path B-1 was carrying about 80-90% of the total flow entering Zone 1 (Table 3B), and if it is assumed that Path A-1 was carrying no short circuit flow, then about 22-25% of the flow in Path B-1 was associated with the thermal short circuit.

Interpretation of the RTD's

The RTD of Flowpath B-1 was almost unimodal, with only a slight shoulder corresponding to the position of the second (main) peak of the full system RTD. This suggests that the second peak of the full system RTD (Figure 4) was at least partly caused by the longer residence time RTD's of the flowpaths entering the production well via Zones 2 and 3. The slight bimodality apparent in the RTD of Path B-1 may reflect the fact that flow Zone 1 in the production well included two major flowing joints at 2374 m and 2394 m (Nicol, 1989).

Structural control of the short circuit

Figure 5 (View 1) shows the locations of the earliest microseismic events generated during the major hydraulic stimulation from Well RH12 in 1982. This stimulation was during an earlier phase of HDR research at Rosemanowes, when an unsuccessful attempt was made to establish a good connection between well RH12 and another 2 km deep well, RH1 (Batchelor, 1983). There is a clear alignment of events in this microseismicity. The group of events defining the alignment is seen to form a somewhat flattened tube in other views. Such a feature in the microseismicity is interpreted as being due to the transmission of high pressures through a permeable structure during the stimulation. Figure 5 (View 2) shows that this structure almost exactly corresponds
to the shortest route from the main flowing joint in Zone B (RH12) to the two main flowing joints in Zone 1 (RH15). The spatial correlation with the positions of the inlet and outlet of Path B-1 suggests that the short circuit was developed within this structure.

The geological control of the location of the hydraulic short circuit at Rosemanowes may prove to be a typical feature of HDR reservoirs, and this must be taken into account in stimulation design.

Distribution of water losses

Table 3B gives the total model water recoveries from Zones A and B in RH12 and the injection flow rates into Zones A and B. This allows calculation of the apparent distribution of water losses between Zones A and B. It appears that the absolute losses from Zones A and B were about the same (2 to 5 l/s each).

Other uses of the tracer data

The interpretation of the tracer tests presented here is not unique. For the purposes of interpreting the thermal drawdown, radon release and geochemical behaviour of the three defined zones of flow into RH15, only the tests involving injection above Zone A are relevant, and the reservoir may be considered as consisting of three flowpaths, each linking the entire openhole of RH12 to one of the flow zones in RH15. The RTD and various tracer-determined parameters for each of these flowpaths have been calculated by Richards et al (HDR Geochemistry Group, 1989). Nicol (1989) has noted that there is a correlation between the partial integral mean volumes of the three flowpaths and the associated effective heat transfer areas. This supports the contention of Robinson and Tester (1984; 1988) that inert tracer results may be useful for rough prediction of the thermal performance of an HDR reservoir before thermal breakthrough occurs.

Implications for the future programme

One of the objectives of Phase 3A of the current UK HDR research programme is to demonstrate that it is possible to identify and seal unwanted short circuits in HDR reservoirs (Parker, 1989b). The FCE has shown that a hydraulic short circuit flowpath in an HDR reservoir is likely to carry substantially more flow than the flow associated with a thermal short circuit. This is an important consideration when planning a short circuit sealant treatment.

The results of the FCE serve as a benchmark study with which to compare the results of further downhole tracer tests to be performed after the 1989 proppant placement and sealant treatment. In these later tests, a downhole fluorimeter (not available at the time of the FCE) is to be used in place of the drill-pipe and rig to obtain downhole tracer data. This will cut down costs and improve access to the production well while the tracer programmes are in progress.

CONCLUSIONS

The flowpath characterisation experiment (FCE) showed that in mid-1988, out of six arbitrarily defined flowpaths, one path was carrying about 60% of the production flow and had the characteristics of a hydraulic short circuit. Its inlet was the major flow zone near
the bottom of the injection well (>2170 m MD) and its outlet into the production well was the major flow zone between 2409 m MD and the casing shoe. The residence time distribution function (RTD) of this path was skewed much more towards short residence times than the bulk reservoir RTD and was bi-modal, probably because the outlet consisted of two discrete flowing joints. About a quarter of the flow in this path was identified as being through routes responsible for the thermal short circuit indicated by thermal modelling.

Only three out of the five other flowpaths investigated were found to be carrying about 10% or more of the production flow. Two of these paths (like the path containing the short circuit) were ones originating from the major flow exit near the bottom of the injection well. It was also shown that the water losses from the two zones of flow out of the injection well were roughly equal, even though the flow rate from the lower zone was twice that from the upper one.

The FCE has shown both the usefulness and the limitations of downhole tracer techniques in the identification of a thermal short circuit in an HDR reservoir and in determining the flow distribution in the interwell region.

**NOMENCLATURE**

- $C_{a_i}(t)$ = Tracer concentration-time response in the production stream above Zone $i$ in response to tracer injection above Zone $a$. $t$ is time since tracer injection.
- $G_{a_i}(t)$ = Tracer concentration-time response in the flowpath $a-i$ in response to injection of tracer above Zone $a$. $t$ is time since tracer injection.
- $E(t)$ = The RTD function (units of reciprocal time). $t$ is time since tracer injection.
- $a$ = Zone of flow out of injection well ($a = A$ or $B$).
- $i$ = Zone of flow into production well ($i = 1, 2$ or $3$).
- $a-i$ = The flowpath connecting flow Zone $a$ to flow Zone $i$.
- $M_{in}$ = Mass of tracer injected.
- $M_{a_i}(t)$ = Mass of tracer recovered above Zone $i$ up to time $t$ in response to injection of tracer above Zone $a$. $t$ is time since tracer breakthrough.
- $m_{a_i}(t)$ = Mass of tracer transmitted through flowpath $a-i$ up to time $t$ in response to injection of tracer above Zone $a$. $t$ is time since tracer breakthrough.
- $m'_{a_i}(t)$ = Mass of tracer transmitted through flowpath $i-j$ up to time $t$ in response to injection of tracer above Zone $A$. $t$ is time since tracer breakthrough.
- $Q_a$ = Flow rate in injection well above flow Zone $a$.
- $Q_i$ = Flow rate in production well above flow Zone $i$. 
Flow rate in production well above flow Zone j (Equation 13).

Total injection flow rate (= Q_A).

Flow rate in the flowpath linking flow Zone a to flow Zone i.

Breakthrough time (since tracer injection).

Width of RTD function at half-height.

Elapsed time since tracer breakthrough at which all the recoverable tracer has been returned.

Modal volume.

Median volume.

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FIGURE 1 FLOW LOGS, TRACER INJECTOR AND SAMPLING LOCATIONS, FLOW ZONES AND POSSIBLE FLOWPATHS FOR THE FLOWPATH CHARACTERISATION EXPERIMENT. ARROWS DENOTE MAJOR FLOWING JOINTS
FIGURE 2  TRACER CONCENTRATION–TIME RESPONSE CURVES FOR INDIVIDUAL TRACER TESTS, CORRECTED FOR WELL–BORE TRANSIT TIMES
**Figure 3** Normalised tracer response curves for individual tracer tests.
FIGURE 4  RESIDENCE TIME DISTRIBUTION FUNCTIONS FOR FLOWPATHS ISSUING FROM ZONE B IN RH12, WITH FULL RH12/15 SYSTEM RTD
APPLICATION OF TRACERS TO THE DETERMINATION OF THE GEOMETRY OF THE MAYET DE MONTAGNE HEAT EXCHANGER

CORDIER E.*, GOBLET P.*, BIGOT S.**, CHUPEAU J.**, TOULHOAT P.***, TREUIL M.**

(**) Laboratoire de Géochimie Comparée et Systématique, Université Paris VI.
(***) CEA/DERDCA/DCAEA/SEA/Section d’Études et d’Analyses Isotopiques et Nucléaires, CEN Saclay.

Abstract: tracer tests are used to estimate the exchange surface of a geothermal doublet in fractured rock. Several tracers are used simultaneously for three different measurement campaigns. From the non-sorbed or weakly sorbed tracer curves, a picture of the reservoir consisting of at least two independent major conductive zones is evidenced. The flow rates in each channel are in good agreement with independent estimations. Values of the surface of an equivalent parallel single fracture are obtained for each channel.

The central point in dimensioning a geothermal doublet is the prevision of its lifetime. For this purpose, the contact surface between water and rock has to be assessed, since water withdraws heat from the medium through this surface. Several techniques may be used to try and evaluate this surface:

- Measurement of microseismic events related to the fracturing of the medium provide a mean to describe the reservoir geometry, but do not indicate which fractures effectively carry water and which do not.

- The results of a large scale heat extraction experiment provide the necessary information about the lifetime, but are impractical on the scale of a real geothermal doublet, because the involved duration would be of the order of several years (the actual expected duration of the doublet).

- Chemical tracers constitute an attractive option to investigate the geometry of the exchanger, since the time needed to go from the reinjection to the
production well is typically of the order of a few days to a few weeks.

The purpose of this paper is to present the results of a series of tracer tests performed on the Mayet-de-Montagne site (France), as well as an interpretation of these tests. A complete presentation of this work may be found in ref. [1].

1) DESCRIPTION OF THE EXPERIMENT

The tracer tests were performed on the Mayet-de-Montagne site, near Vichy (Alliers, France). The site is in a granitic rock mass and has been submitted to an extensive program of investigation for several years (see ref. [2]). Two main boreholes were used for the present tests (III.8 and III.9), respectively 782.7 m and 839.5 m deep. The distance between these boreholes is of the order of 103 m on the ground surface and of 93 m at a 750 m depth. Simultaneously, a third borehole (III.3), 192 m deep and 10 m apart from III.8, was used for control measurements (see fig. 1).

From the injection tests performed on the site, it has been deduced that three major fracture families transport most of the water between boreholes III.8 and III.9, one between 440 and 470 m below ground surface, one between 620 and 660 m, and one between 660 and 764 m.

Three tracer test campaigns were performed in 1987. The tests may be described by the following characteristics:

- flow direction,
- position of packers in the boreholes,
- injected and produced flow rates,
- type and quantities of tracers used,
- measured recovery curves.

All these characteristics are presented in table 1 and figure 2.
2) QUALITATIVE ANALYSIS OF THE RESULTS

The objective of our interpretation was to find consistent features between the various tests. For this reason, in this first analysis, we excluded the tests performed with the water flowing from III.8 to III.9.

Due to the hydraulic fracturing performed between the tests, the exchanger geometry evolved, and the comparison between results of different tests was complicated. However, the site modifications were restricted to its deepest part, the shallowest fracture zones remaining unmodified.

The arrival curve for Iodine during test 2 is shown on figure 3. Due to the position of the packer, this curve is probably representative of a transfer through the deepest zone. This zone was later refractured, and therefore the corresponding curve cannot be quantitatively compared to the results of the following campaign. On the opposite, the Iodine coming out of the shallow borehole III.3 with a maximum concentration around 50 hours was interpreted as having travelled through the highest fracture zone from III.9 to III.8, then along the tubing of III.8, and finally through a highly conductive shallow zone at a depth of 150 m from III.8 to III.3. Since the shallowest fracture zone was not modified between tests 2 and 3, it was considered to be a permanent feature of these tests.
Figure 2. Tracer test characteristics

The curves measured during the third test (fig. 4 and 5) show a very fast channel (8 hours travel time), probably created by the fracturing of the deep reservoir. The tail of the Iodine curve indicates a possible second channel with a travel time around 30-40 hours. This may be related to the highest channel identified during the second experiment.
Figure 3. Recovery curves for Iodine - Test 2

Figure 4. Recovery curves in III.8 - Test 3

The comparison of the Iodine and Dysprosium curves suggest that the former is retarded by some interaction mechanism, and that the Dysprosium should be considered the best tracer for this experiment. However, since the available mea-
surements for Dysprosium span only 25 hours, we had to use the Iodine curve to describe the late behaviour of the reservoir.

With these observations in mind, we interpreted essentially the last tracer test, and tried then to substantiate its results by those of the second test.

3) MODELLING OF THE TESTS

The Iodine results for test 3 give the longest recovery curve concerning the present state of the reservoir. However, its interpretation is made difficult by the retardation mechanisms. The Dysprosium curve was therefore interpreted first to give the hydrodispersive properties of the fastest channel (deep reservoir). These properties were then considered valid for Iodine as well, and a retardation model was identified by comparison of the purely hydrodispersive recovery curve (obtained by numerical prevision) and the measured curve. The global model for Iodine (advection-dispersion-retardation) was then used to identify longer channels.
3.1) Modelling of the Dysprosium curve

A first interpretation of this curve was done, based on a type-curve published by L.Gelhar (ref. [3]). Under the hypotheses of an infinite medium, of equal flow rates in the injection and production boreholes and of zero transverse dispersion, this model gives a first estimate of longitudinal dispersivity (10 m), and of the flow rate per unit thickness of fracture.

The ratio between the recovered mass of tracer (assuming a total recovery, by extrapolation of the measured curve) and the injected mass is equal to the ratio of the flow rate along the fastest channel to the total injected flow rate, if we assume a perfect mixing of the tracer in the injection borehole. The aperture of an equivalent parallel fracture can then be calculated.

From the recovery curve, we can deduce a "spreading function" which gives, for a given fraction of the flow rate in a channel, the volume swept by the fastest flow tubes up to this fraction:

\[ W(\phi) = \int_0^\phi V(\psi) \, d\psi \]

Where:

- \( V(\psi) \) is the cumulated volume of the fastest flow tubes carrying a fraction \( \psi \) of the total flow rate.

This volume tends towards the total volume of the channel when the recovery rate \( \phi \) approaches 100% (ref. [5]).

The estimation of the volume obtained by this procedure is of 38 \( m^3 \) for 85% of the flow rate. This gives us an equivalent parallel fracture of area 16000 \( m^2 \). The total volume is of course greater than this value.

This first evaluation was used as input for a numerical model, which represents better the limited extent of the fracture. The METIS code, developed by P.Goblet at the Centre d'Informatique Géologique under contract with the Commissariat à l'Energie Atomique, solves the equations of flow and mass transport using the method of Finite Elements (ref. [4]).

In our model, the reservoir was modelled as a rectangular zone of constant aperture. The shape of the recovery curve depends of three main parameters:

- aspect ratio of the fracture,
- longitudinal dispersivity (the transverse dispersivity was taken to be ten times smaller than the longitudinal one),
- flow rate per unit thickness of fracture.
These parameters were adjusted by trial and error, giving the following set of values:

- fracture area = 35000 m²
- longitudinal dispersivity = 10 m
- flow rate/unit thickness = 1150 m²/h

From a refined estimation of the flow rate inside the fracture, we obtain a final estimate of the fracture aperture:

\[ Q = 5.3 \, m^3/h \]
\[ H = 4.6 \times 10^{-3} \, m \]

3.2) Modelling of the Iodine curve

3.2.1) Modelling of the fastest channel

Taking into account only the hydrodispersive transport, the recovery curve of Iodine would be the same as the Dysprosium curve (up to a scaling factor due to a different mass). The discrepancy between the curve predicted for Iodine on the basis of the hydrodispersive model and the real curve will be interpreted by a retardation mechanism.

One of the most frequently mentioned mechanisms for retardation of a tracer in a granitic fractured medium is diffusion into the impervious rock, known as "matrix diffusion" (see for instance ref. [6]).

This phenomenon can be simulated by the METIS code. It depends of three main parameters: the diffusion constant in the rock matrix, the porosity and the thickness of the zone available for diffusion (neglecting any other retardation mechanism).

We investigated a wide range of values for these parameters: from \(10^{-8} \, m^2/s\) to \(10^{-3} \, m^2/s\) for the diffusion coefficient, and from a few millimeters to infinity for the invaded zone. This range of values did not permit to reproduce the shape of the Iodine curve. Matrix diffusion does not seem to be a major mechanism for the rather short travel times considered here.
We selected therefore a simple, first order interaction model with first order kinetics, represented by the following set of equations:

- Mass balance inside the mobile water:

\[
\text{div}(D \nabla C - UC) = \varepsilon \frac{\partial C}{\partial t} + \mu \psi
\]

where:

- \(D\) is the dispersion tensor.
- \(C\) is concentration in the mobile water.
- \(U\) is Darcy velocity.
- \(\varepsilon\) is kinematic porosity (1 for an open fracture).
- \(\mu\) is the contact surface between mobile and immobile phase per unit volume of fracture. It is related to the fracture aperture: \(\mu = 2/\varepsilon\).
- \(\psi\) is the mass flux between mobile and immobile phases.

- Mass balance inside the immobile phase:

\[
\frac{dF}{dt} = \psi
\]

where:

- \(F\) is the sorbed fraction.

- Flux between the phases:

\[
\psi = K_1 \left( C - \frac{F}{K_a} \right)
\]

where:

- \(K_1\) is the kinetic constant.
- \(K_a\) is the coefficient of surfacial sorption.

Application of this model to the Iodine measurements gives the following values:

\[
K_1 = 10^{-7} \text{ m/s}.
\]
\[
K_a = 3,4 \times 10^{-3} \text{ m}.
\]
To obtain a satisfactory fit, the flow rate through the fracture must be adjusted to a value of 7.8 m³/h. This result is in contradiction with the value obtained from the Dysprosium curve. We propose two tentative explanations for this discrepancy:

- Part of the Dysprosium could be lost during injection. A weak recovery rate would then lead to an underestimation of the flow rate.
- The flow path used by Iodine is effectively larger, due for instance to the large size of the Dysprosium-EDTA complex.

We consider that the flow rate given by the Iodine is closer to the value relevant for heat transfer. The parameters characterizing the fast channel can therefore be summarized as follows:

- Equivalent parallel fracture area = 35000 m².
- Fracture thickness = 8 mm.
- Flow rate through the fracture = 7.8 m³/h.
- $K_1 = 10^{-7}$ m/s.
- $K_w = 3.4 \times 10^{-3}$ m.

### 3.2.2) Modelling of the slowest channel

Applying a relation of perfect mixing to the concentration coming out of the fastest channel and of a second channel, the flux-weighted concentration is:

$$C_{\text{measured}} = \frac{Q_1 C_1 + Q_2 C_2}{Q_1 + Q_2}$$

A concentration in the second channel is thus calculated, and the characteristics of this channel are identified as before:

- Equivalent parallel fracture area = 40000 m².
- Fracture thickness = 1.9 cm.
- Flow rate through the fracture = 5.3 m³/h.
- Same interaction parameters as for the first channel.

The rather high value of thickness suggests that this “second” channel might indeed be a superposition of several paths, which is indicated as well by the very irregular shape of this part of the Iodine curve.
4) DISCUSSION AND CONCLUSION

The main objective of this work was to estimate the thermal exchange area of the reservoir. Interpretation of two non- or weakly adsorbed tracer curves shows that two major flow paths may transport tracers (or heat).

Table II summarizes the characteristics of the two flow paths identified from the third series of tracer tests.

Figure 6 shows a comparison between the measured and the simulated breakthrough curves for Iodine.

\[ 
\begin{array}{c}
\text{Time (hours)} \\
\hline
0 & 24 & 48 & 72 & 96 & 120 & 144 & 168 & 192 & 216 \\
0 & 500 & 1000 & 1500 & 2000 \\
\end{array}
\]

![Image of Figure 6](image)

**Figure 6.** Modelling of the Iodine recovery curve - Test 3

The first channel is probably the deep zone developed by hydraulic fracturing, while the second one would be the superposition of several conducting zones situated at an approximate depth of 440 to 470 m.

The area identified for each channel is consistent when several interpretations exist. However, it must be emphasized that this parameter has a rather small influence on the shape of the recovery curve. The values given should be considered rather as lower limits.
The flow rate in channel 1 differs, depending on the tracer used for its calculation. The values of flow rate obtained from the Iodine curve give the following repartition:

- Flow rate in channel 1 = 43% of total flow rate
- Flow rate in channel 2 = 29% of total flow rate

Two remarks may be done:
- This repartition is in very good agreement with the repartition obtained from independent measurements (injection tests), giving 42% – 30%.
- These two channels do not carry all the flow rate. One may therefore expect that even slower channels contribute to a larger value of the exchange area.

The fracture area obtained with these two channels is of the order of 75000 m², giving a heat exchange area of 150000 m², if each channel were a single fracture. However, the high values of aperture obtained suggest that each “fracture” might be indeed a set of fractures. This would increase dramatically the contact area, provided these fractures are not to close to each other.
REFERENCES


<table>
<thead>
<tr>
<th>PHASE</th>
<th>Direction of circulation</th>
<th>Injection flow rate</th>
<th>Production flow rate</th>
<th>Tracer used</th>
<th>Moles injected</th>
<th>Moles recovered</th>
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<tr>
<td>PHASE I</td>
<td>III.8—III.9</td>
<td>30 m³/h</td>
<td>in III.9</td>
<td>Iodine</td>
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<td>in III.9</td>
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<td>5 m³/h</td>
<td>in III.9</td>
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<td>PHASE II</td>
<td>III.9—III.8</td>
<td>30 m³/h</td>
<td>10 m³/h</td>
<td>Iodine</td>
<td>30</td>
<td>in III.8</td>
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<td>6.5 m³/h</td>
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<td>in III.8</td>
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<td>June 15 - August 14</td>
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<td>in III.9</td>
<td>Samarium</td>
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<td>18.2 m³/h</td>
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<td>Iodine</td>
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Table I: Characteristics of the tracer tests

<table>
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<th>FAST CHANNEL</th>
<th>SLOW CHANNEL</th>
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<tr>
<td>Tracer</td>
<td>Iodine</td>
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<td>Fracture area</td>
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<tr>
<td>Flow rate</td>
<td>7.5 m³/h</td>
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<tr>
<td>Fracture thickness</td>
<td>8.1 mm</td>
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<tr>
<td>Sorption Parameters</td>
<td>$K_1 = 10^{-7}$ m/s</td>
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<tr>
<td></td>
<td>$K_s = 3.4 \times 10^{-7}$ m</td>
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</tbody>
</table>

Table II: Characteristics of the channels
RESERVES
The stresses in the Earth's crust produce a compressive stress concentration on the wall of a vertical borehole which is greatest at the azimuth parallel to the least compressive regional horizontal stress (Sh, Figure 1), and least at the azimuth perpendicular to Sh.

Zones of failure and spalling ("breakouts") at the former azimuth may cause the borehole diameter to enlarge, whereas at the latter azimuth fluid pressure in the borehole may cause vertical hydraulic fractures to form. In this paper we use logs of the four-arm caliper tool and the ultrasonic borehole televiewer to identify these features and use them to interpret the stress orientation in the vicinity of the Soultz borehole.

Caliper logs between 1400 m and 2000 m depth were examined for breakout intervals using the following criteria: (1) the caliper tool (which normally rotates due to cable torque) must stop rotating, (2) one of the two measured borehole diameters must be larger than bit size, and (3) one diameter must be equal to bit size. No intervals were identified which satisfied all of these criteria. Using televiewer logs provided by the Westfälische Berggewerkschaftskasse (WBK), televiewer data were reprocessed to produce borehole cross sections and three-dimensional information on borehole geometry. Televiewer logs between 1420 m and 2000 m depth showed several places in which the borehole shape was slightly oval, but in cross sections of these intervals the borehole wall was smooth, not spalled, suggesting that the ovalization was caused by tool gouge rather than by stress-induced failure.
In the televiewer logs between 1400 m and 2000 m depth, at least 135 m contain vertical fractures which bisect the borehole and follow the borehole axis for up to a few tens of meters. These fractures are generally not present in the core at corresponding depth intervals, suggesting that they are induced by fluid pressure in the hole during drilling. They are therefore inferred to have formed parallel to SH. The orientations of these features have an average of 169° east of True North and a standard deviation of 7°. This is slightly more north-south than the orientation of SH determined from other stress indicators in this region (Figure 2). It is possible that a more north-south orientation of the most compressive stress in the Soultz area is due to its location near the west side of the Rhinegraben. An east-west tension associated with the down-warping of the down-dropped block within the Rhinegraben could, when superimposed on a NE-SW regional orientation of SH, rotate the local SH to a more north-south direction.

Acknowledgements:

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DEVELOPMENT OF A NEW HYDRAULIC FRACTURING METHOD
(CASING REAMER AND SAND PLUG METHOD)

H. Kaieda, S. Hibino

Abstract
We developed a new hydraulic fracturing method by which a multi-stage fracture could be created in a well without using open-hole packers. Applying the method to a well of 400 m depth drilled into Tertiary lapilli tuff, fractures were created at 3 different depths. These fractures were observed by bore hole TV scanner (BTVS) survey, permeability measurement and acoustic emission (AE) observation.

Introduction
Conventionally it has been considered that the hydraulic fracturing method with using open-hole packers was most effective to create man-made fractures in rock for the HDR development. However we have been facing such severe problems at deep wells as packer failure by high temperature and as wall collapse in open-hole region by high geopressure. In order to avoid these problems, we have devised a new hydraulic fracturing method by which multi-stage fractures can be created in rock from a well without using any packers.

Conception of the new hydraulic fracturing method (Fig.1)
This method is briefly described as follows. First of all a well drilled into rock is completed with casing cemented-in from the surface to the bottom of the well. The bottom of the well is then drilled additionally to make an open-hole region. When water is injected into the well, hydraulic pressure applies all over the well wall. But fractures progress into rock only at the open-hole region in the bottom. This operation is the first-stage fracturing.

Next at a given depth the casing pipe cemented-in in the well is machine-cut by casing reamer to produce a new open-hole region. Casing reamer is a tool for repairing well wall. In order to control the lost circulation into the first-stage fracture, sand is emplaced below this open-hole region. Water is again injected into the well. This time fractures progress into rock only from the new open-hole region. This operation is the second-stage fracturing. The third-stage fracturing is also conducted by machine-cutting the casing pipe and injecting water. Repeating this operation several times, multi-stage fractures can be created from a well in rock.

According to the result of the room test using 3-inch casing pipe and sand composed same particle size distribution as that used in the Los Alamos hydraulic fracturing experiment[1], the water leakage through the 10 m length sand plug was estimated less than 1 l/min at a water pressure of 300 kgf/cm².
After all fracturing operation, the sand in the well is easily removed by water circulation with using drill-pipe in the well. Then water is injected simultaneously into all the fractures which were created individually, thereby it is enable to largely expand the heat extraction area in rock. We call the method 'Casing Reamer Sand Plug Method, abbreviated as CRSP Method'.

Demonstration Experiment of the Method at Akinomiya, Japan.
Akinomiya in Akita prefecture, northern Japan, is a hot spring resort. Its neighborhood has many promising places for geothermal resources. In 1986 Akinomiya was selected as a site for HDR development experiment and a well was drilled for hydraulic fracturing. The well was drilled down to 390 m with 125 mm of diameter in Tertiary lapilli tuff. Geophysical loggings (electric, temperature, sonic) and BTVS survey were conducted in the well to observe crack distribution and to determine the fracturing depth in the well. Then 3-inch casing pipes were inserted to the bottom in the well and fixed by cement. The well was drilled again down to 400 m with 76 mm in diameter. The temperature of the rock at 400 m depth was around 60°C.

No crack was observed by BTVS survey in the layer of 10 m at the bottom (390 m to 400 m depth). This open-hole region was taken as the first-stage fracturing. Flow rate and wellhead pressure history at the beginning of the fracturing was shown in the upper of Fig.2. In this fracturing a small breakdown was observed in which the wellhead pressure decreased from 164 kgf/cm² to 110 kgf/cm². However, after the breakdown the wellhead pressure increased again and the maximum wellhead pressure was measured to reach at 287 kgf/cm² at 50 l/min of flow rate. This pressure was much higher than the the tensile strength of 26 kgf/cm² determined by Brazilian test with the core specimens taken from the well. Total volume of water, about 46 m³ was injected in about 12 hours.

In the region between 371.5 and 373.5 m depth (2 m interval) no crack was observed by the geophysical loggings and the BTVS survey, so this region was selected for the second-stage fracturing. Before machine-cutting the casing pipe, sand was emplaced below the region. The length of the sand plug from the first-stage open-hole region to the second-stage was about 17 m. During pressurizing experiment the flow rate of the circulation lost through the sand plug was measured less than 1 l/min at a wellhead pressure of 262 kgf/cm². The casing pipe in the region were machine-cut by the casing reamer to make an open-hole region. Flow rate and wellhead pressure history at the beginning of the fracturing was shown in the middle Fig.2. In this fracturing about 81 m³ of water in total volume was injected in about 6 hours. A clear breakdown was observed. The wellhead pressure in the breakdown decreased from 190 to 110 kgf/cm² at 30 l/min of injection flow rate.

In the third-stage fracturing the 2 m region (359.7 to 361.7 m depth) was selected for fracturing, though several cracks were observed in the region. The purpose of this fracturing was to check the application of the CRSP method in cracky zone. Flow rate and well-
head pressure history at the beginning of the fracturing was shown in the bottom of Fig.2. A total volume of water, about 85 m³ was injected in 17 hours. The maximum wellhead pressure was 193 kgf/cm² at 70 l/min of injection flow rate.

**Fracture observation**

After the first-stage fracturing a new fracture was detected in the open-hole region by BTVS survey conducted before and after the fracturing. The strike of this fracture at the well wall was N 50° W, its dip was almost vertical, its length was about 90 cm and its aperture was about 2 mm in average (see Fig.3). Permeability of the rock in the well was measured by Lugeon Test before and after the fracturing. The permeability of the rock was measured less than $10^{-7}$ cm/sec before the fracturing, but it increased more than 300 times after the fracturing.

In the second-stage fracturing the BTVS allowed to confirm that three fractures were created. The fracture observation by the BTVS survey at the well wall was as follows: the strikes were N 45°E, N 20°W, N 60°E, the dips were 30°N.W., 70°N.E., 30°N.W. respectively, and the apertures were on the order of 2 mm in average for all the three (Fig.4). Before the fracturing the permeability of the rock was measured less than $10^{-7}$ cm/sec, but it increased more than 500 times after the fracturing. Further the AE observed during the fracturing led to an estimation based on the distribution of hypocenters that the fractures were progressing toward N 45°E in strike, about 45° N.W. in dip with progressing direction toward the depth.

In the third-stage the BTVS revealed no fracture newly generated, but permeability of the rock was measured to increase more than 500 times after the fracturing. The existing cracks were therefore estimated to be enlarged by fracturing.

After preparing the three-stage fractures, on the basis of the distribution of the positions of AE hypocenters another well was drilled down to 430 m depth at a distance about 40 m from the fracturing well in order to observe the state of progress of the fractures in rock. As a result of water injection into the fracturing well, water was recovered from the observation well and it was thus revealed that through the fractures the two wells were in water connection with each other. However because of the weak connection between the two wells, flow rate of the recovered water (0.5 l/min) was much small compared to the flow rate of the injected water (400 l/min). (see Fig.5)

**Future plan**

A long-term water circulation experiment will be conducted between the two wells through the fractures. To enhance the recovery flow rate of circulating water, the flow impedance in the fractures should be reduced. The state of fracture progression in rock between the two wells will be investigated by means of temperature measurement, electric logging and BTVS in the two wells before, during and after water circulation. Data from the water circulation experiment will be
used to construct a model of artificial reservoir.

An experiment is planned to confirm the practicability of the CRSP method in the hot dry rock of 1000 m depth and 200°C in 1989 to 1993.

Conclusion
A new hydraulic fracturing technology was devised. As a result of hydraulic fracturing conducted by using this new method in a well of 400 m depth, fractures were successfully created at three different depths in a well. From the BTVS observation before and after the hydraulic fracturing, it could be measured the strike of the fracture, its dip and aperture at the well wall. Based on the AE hypocenter distribution map, another well was drilled. Communication of water between the two wells through the fracture was achieved successfully.

From the above, it has turned out that the new hydraulic fracturing method allows to construct multi-stage fractures in a well.

References


Third Fracture (359.7~361.7m)

Second Fracture (371.5~373.5m)

First Fracture (390~400m)

**FIGURE 1.** CONCEPTION OF THE NEW HYDRAULIC FRACTURING METHOD.
FIGURE 2. PRESSURE/FLOW RATE HISTORY DURING FRACTURING OPERATIONS.
FIGURE 3. FRACTURE OBSERVED BY THE BTVS SURVEY IN THE FIRST-STAGE.
FIGURE 4. FRACTURES OBSERVED BY THE BTVS SURVEY IN THE SECOND-STAGE.
Flow rate of Circulated Water from Exploration Well

FIGURE 5. FLOW RATE HISTORY OF INJECTED WATER AND RECOVERD WATER.
The Hot Dry Rock (HDR) concept had modest origins. The concept is simple and can be described in a few words. The approach is to drill a hole into hot competent rock, create a man-made fracture system to support large energy extraction and then drill a second hole to complete the fluid loop. Initially industry was convinced it could conduct the necessary HDR operations and provide the necessary services under the anticipated conditions. As the early experiments were evolving none of us fully appreciated the challenges of implementing the HDR concept.

In the US, the geothermal resource is the largest resource within our total domestic resource base. This makes it potentially very attractive for diversifying our electrical production capacity. In addition, high quality resources are widely distributed throughout the western US enhancing its attractiveness. Operating geothermal power plants have demonstrated a high availability factor. This industry experience has increased the confidence of investors and financial organizations in the reliability of geothermal energy for base load and load following applications.

Geothermal energy is environmentally benign, producing only a negligible contribution to the greenhouse effect. Small amounts of CO₂ may be produced from steam resources while if properly separated and reinjected none are produced from other resources.

Numerous estimates of HDR electricity costs have been made over the years. Several countries, including the Japan, UK and US and have evaluated the economics of HDR systems and found them to be attractive. In the US the implementation of geothermal power plants has reached a point where an ongoing industry has developed to support the construction and operation of about 3000 MWe of electrical power production capacity. This positive experience has contributed to the acceptability of geothermal power already on-line. This will provide a substantial industry base on which HDR technology can build. Developing the multi-disciplinary knowledge necessary for implementing the concept will give the participating companies a competitive edge.

Direct measurements of the underground system can only be made within the borehole and only indirect measurements can be made of the surrounding rock. Therefore theories explaining the system operation beyond the borehole must be developed, tested and verified. This is a multi-disciplinary problem, requiring expertise in geology, chemistry, physics and supporting skills such as mechanical and electrical techniques. It will be a challenge to identify the limitations of the data gathered and its extrapolation. Many countries have been involved in HDR projects including the US, UK, Japan, West Germany and France. Because of the diversity of areas required to solve the technical issues, it is important that the researchers from the many
countries remain current on the accomplishments of each other. The future worldwide looks good.

Finally, the challenge to the technical community is to recognize that "A man's real limitations are not the things he wants to do but cannot; they are the things he ought to do, but does not".
VIEWGRAPHS FROM CLOSING ADDRESS

Viewgraphs used in my Closing Address at the
INTERNATIONAL SYMPOSIUM ON HOT DRY ROCK GEOTHERMAL ENERGY
On June 30 1989
Redruth, England

1 Time sheet
2 The beginning is the most important part of the work - Plato
3 Picture; Hot Dry Rock concept - Brown, Smith and Potter 1970
4 Industry Approach
5 None of us fully appreciated the challenges of implementing the HDR concept
6 Contour Map of the US showing Geothermal Gradients
7 Availability factors of Energy
8 CO₂ from Geothermal
9 Estimates of Hot Dry Rock Electricity costs
10 Geothermal Power on line (Based on EPRI Survey)
11 Recognize Opportunities - Develop Theories - Validate Hypothesis - Implementation
12 Knowledge is Power - Francis Bacon
13 Window on the World - 9 3/8 borehole - direct - indirect
14 Many Disciplines - Geology - Chemistry - Physic - Mechanical - Electrical - Supporting Skills
15 International HDR Projects - United States, United Kingdom, Japan, West Germany, France
16 Daily News - HOT DRY ROCK SAVES WORLD
17 A man's real limitations are not the things he wants to do but cannot; they are the things he ought to do, but does not.
CONFERENCE PARTICIPANTS

ASHWORTH J.
School of Earth Science
University of Birmingham
P.O. Box 363, Birmingham, B15 2TT
England
Tel:

BARIA R.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel:0209 860141

BAUMGERTNER J.*
Ksy GmbH
Heesmannstr. 49
D-4630 Bochum 1,
Germany
Tel:234 5431

BEAUFORT B.D.*
University of Poitiers
40, Avenue du Recteur Pineau
Batiment G.O.N., 86022 Poitiers Cedex,
France
Tel:49 46 26 30 ex 734

BENNETT T.S.
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel:0209 860141

BESWICK A.J.*
Kenting Drilling Services Ltd
Trent Lane
Castle Donington, Derby, DE7 2NP
England
Tel:0332 850060

BROWITT C.W.A.
British Geological Survey
Murchison House
West Mains Road, Edinburgh, EH9 3LA
Scotland
Tel:031 6671000

BALDWIN R.P.
Geothermal Resources International Inc
1825 South Grant St., Suite 900
San Mateo, California 94402,
U.S.A.
Tel:0101 415 349 3232

BATCHelor A.S.*
GeoScience Limited
Falmouth Business Park, Bickland Water Road
Falmouth, Cornwall, TR11 4SZ
England
Tel:0326 211070

BEAUCE A.B.*
B.R.G.H./I.H.R.G.
BP 6009
45060 Orleans, Cedex 2,
France
Tel:0033 38 64 36 92

BECQIEY H.
Institut Francais du Petrole
1 et 4 Avenue de Bois Preau, BP 311
92506 Rueil Malmaison, Cedex,
France
Tel:47 52 63 78

BERGER G.*
CNRS-UPS
Laboratoire Geochimie
38 Rue des 36 Ponts, 31400 Toulouse,
France
Tel:61556611 ex 7484

BLANCK D.
Siemens AG, UB KMU/UB 312
Hammerbacherstrasse 12 + 14
8520 Erlangen,
Germany
Tel:09131/18-3175

BROWN D.*
Los Alamos National Laboratory
P.O. Box 1663
Los Alamos, New Mexico 87545,
U.S.A.
Tel:505 667 4318

* Presenter
BRUEL D.B.*
Armines, Ecole des Mines de Paris
35 rue St Honore
77300 Fontainebleau, ,
France
Tel:64 22 48 21

CARELLA R.*
AGIP S.p.A.
Plaza Varnoni 1-20097
S Donato Milanese, Milan,
Italy
Tel:2 - 520 - 4174

CLARKE J.H.
Energy Technology Support Unit
Harwell Laboratory, Building 156.7
Didcot, Oxfordshire, OX11 ORA
England
Tel:0235 24161 ex 3487

COCKERHAM J.A.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss Longdowns, Cornwoll,
England
Tel:0209 860141

COMBS J.B.
Geothermal Resources International
Inc
1825 South Grant Street, Suite 900
San Mateo, California 94402,
U.S.A.
Tel:0101 415 349 3232

CORLETT D.K.
R.T.Z. Ltd
Bos Elvan, Penhalvean
Redruth, Cornwall,
England
Tel:0209 860663/860141

DESROCHES J.*
Institut de Physique du Globe de
Paris
Tour 14/24, Place Jussieu
75252 Paris, Cedex 05,
France
Tel:(1) 43 54 90 52

DOHERTY P.
Sunderland Polytechnic
Priestman Building, Green Terrace
Sunderland, Tyne & Wear,
England
Tel:515 2846/7

DYKE C.G.
B.P. Research
Sunbury Research Centre, Chertsey
Road
Sunbury-on-Thames, Middlesex, TW16
7LN
England
Tel:0932 762069

ELIASSON T.M.*
Dept of Geology
Chalmers University of Technology
S-412 96 Gothenburg, ,
Sweden
Tel:4631722097

ELSWORTH D.*
University of Waterloo
Waterloo Centre for Groundwater
Research
Waterloo, Ontario N2L 3G1,
Canada
Tel:519 885 1211 ex 6395

FOUILLAC C.*
B.R.G.H./I.H.R.G.
B.P. 6009
45060 Orleans, Cedex 02,
France
Tel:33 38 64 36 90

GELBKE H.C.
WSK
Westfalische Berggewerkschaftskasse
Hernestrasse 45, Bochum 1, D-4630
West Germany
Tel:0234 625 483

GERARD A.G.
B.R.G.H./I.M.R.G
B.P. 6009
45060 Orleans, Cedex 02,
France
Tel:33 38.64.30.51

* Presenter
GREEN A.S.P.*
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

HACKETT P.
Camborne School of Mines
Pool
Redruth, Cornwall, TR15 3SE
Tel:

HALLIDAY N.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

HARRISON R.*
Sunderland Polytechnic
Priestman Building, Green Terrace
Sunderland, Tyne & Wear, England
Tel:515 2846/7

HAYASHI K.*
Institute of High Speed Mechanics
Tohoku University
2-1-1 Katahira, Sendai 980, Japan
Tel:022 227 6200 ex 3341

KICKS T.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

HIRAKAWA S*
University of Tokyo
2-37-4 Kitazawa
Setagaya-Ku, Tokyo, Japan
Tel:03 640 1429

Hughes J.F.
RTZ Consultants Ltd.
Castlemead, Lower Castle St
Bristol, Avon, England
Tel:0272 276407

HIRSCH P.*
Armines, Ecole des Mines de Paris
35 Rue St. Honore
77300 Fontainebleuf, France
Tel:64 22 48 21

JACKSON P.D.*
British Geological Survey
Nicker Hill, Keyworth
Nottingham, Notts, NG12 5GG
England
Tel:06077 6111

HICKS T.
C.S.H. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

JACQUES P.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

JONES R.H.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdouns, Cornwall, England
Tel:0209 860141

KAPPELMEYER O.*
Geothermik Consult
Kapppelheimer GmbH
Nikolastrasse 18, D-8390 Passau, Germany
Tel:0851 72260

* : Presenter
MINETT S.T.
Sheffield City Polytechnic
School of Urban & Regional Studies
Pond St, Sheffield, South Yorkshire,
S1 1WB
England
Tel: 0742 720911 ex 2328

MORTIMER N.D.*
Sheffield City Polytechnic
School of Urban & Regional Studies
Pond St, Sheffield, South Yorkshire,
S1 1WB
England
Tel: 0742 720911 ex 2339

NAZROO M.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel: 0209 860141

NICHOLLS J.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss Longdowns, Cornwall,
England
Tel: 0209 860141

NICOL D.A.C.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel: 0209 860141

NUFER G.C.
Noasco Well Service (U.K.) Ltd
2nd Floor, National House
60-66 Wardour St, London, W1V 3HP
England
Tel: 01 736 2944

O'NEILL M.S.D.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdowns, Cornwall,
England
Tel: 0209 860141

PAIGE R.W.
B.P. Research Centre
Chertsey Road
Sunbury-on-Thames, Middlesex, TW16
7LH
England
Tel: 0932 763739

PARKER R.H.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel: 0209 860141

PAUELLE
B.R.G.M./I.M.R.G.
BP 6009
45060 Orleans, Cedex 02,
France
Tel:

PYE J.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss Longdowns, Cornwall,
England
Tel: 0209 860141

RAE J.*
Department of Energy
Thames House South
London, , SU1
England
Tel:

RANDALL M.W.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel: 0209 860141

RANNELS J.E.*
U.S. Department of Energy
1000 Independence Avenue
Washington, D.C. 20585,
U.S.A.
Tel: 202 586 8070

* = Presenter
RICHARDS S.
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss Longdowns, Cornwall,
England
Tel:0209 860141

RICHARDS K.G.*
C.S.M. Geothermal Project
Rosemanowes Quarry,
Herniss, Longdowns, Cornwall,
England
Tel:0209 860141

ROBINSON B.A.*
Los Alamos National Laboratory
Mail Stop D443
Los Alamos, New Mexico 87545,
U.S.A.
Tel:505 667-4318

SATOH Y.*
Nat Res Inst for Pollution & Resources
Onogawa 16-3
Tsukuba, Ibaraki, 305,
Japan
Tel:0298 54 3067

SAVAGE D.*
British Geological Survey
Nicker Hill
Keyworth, Notts, NG12 5G
England
Tel:06077 6111

SCHELLSCHMIDT R.*
Niedersaechsisches Landesamt fuer Bodenforschung, Stilleweg 2
D-3000, Hannover 51,
Germany
Tel:0511-643540

SHIMA H.*
Geotechnical Institute, Oyo Corporation
2-2-19 Daitakubu, Urawa
Saitama 336, ,
Japan
Tel:81 48 882 5374

SHOJI T.*
Tohoku University
Res.Inst. for Strength & Fracture of Mats.
Faculty of Engineering, Sendai/980,
Japan
Tel:022 222 1800

SMITH H.O.
RTZ Consultants Ltd.
P.O. Box 50, Castlemead, Lower Castle St
Bristol, Avon, BS99 7YR
England
Tel:0272 276407

SMITH I.K.*
The City University
Northampton Square
London, , EC1V 0HB
England
Tel:01 2534399 ex 4233

SHOLKA K.*
Geothermik Consult Kappelmeyer GmbH
Nikolastrasse 18
D-8390, Passau,
Germany
Tel:0851 72260

STEWART R.C.*
C.S.M. Geothermal Project
Rosemanowes Quarry
Herniss, Longdowns, Cornwall,
England
Tel:0209 860141

SUETO SHI.
NEDO
Sunshine 60, 1-1, 3-Chome
Higashi Ikebukuro, Toshima-ku,
Tokyo,
Japan
Tel:03-987-9301

SUNDQUIST U.
Dept of Geology
Chalmers University of Technology
S-41296 Goteborg, ,
Sweden
Tel:4631 722047

* Presenter
SYMONS G.D.
Energy Technology Support Unit
Harwell Laboratory, Building 156
Didcot, Oxfordshire, OX11 ORA
England
Tel:0235 24141 ex 3487

TAYLOR R.J.N
Energy Technology Support Unit
Harwell Laboratory
Didcot, Oxfordshire, OX11 ORA
England
Tel:0235 24141

TENZER H.A.*
Stadwerke Bad Urach
Rathaus, Postfach 1240
D 7432 Bad Urach, Germany
Tel:0 7125 156 237

WALKER A.B.
British Geological Survey
Murchison House
West Mains Road, Edinburgh, EH9 3LA
Scotland
Tel:031 667 1000

WILLIS-RICHARDS J.*
C.S.M. Geothermal Project
Rosemanoues Quarry
Herniss Longdouns, Cornwall, England
Tel:0209 860141

YAMAGUCHI T.
Nat Res Inst for Pollution & Resources
Onogawa 16-3, Tsukuba
Yatabe, Ibaraki, 305,
Japan
Tel:0298 54 3066

YAMAMOTO K.
M.I.T.I.
1-3-1, Kasumigaseki
Chiyoda-Ku, Tokyo, Japan
Tel:03 501 9279

YAMASAKI, M.
Japan Metals & Chemicals Co Ltd
24 Ukal
Takizawa-Mura, Iwate 020-01,
Japan
Tel:0196 84 4112

YOSHIKAI M.Y.
Japan Metal Centre
Chancery House
53 Chancery Lane, London, WC2A 10X
England
Tel:01 405 7301

* Presenter