

Deep Geothermal Review Study

Final Report

Department of Energy & Climate Change (DECC)

October 2013

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Document history

Job number: 5119440			Document ref: 5119440-RPT-004			
Revision	Purpose description	Originated	Checked	Reviewed	Authorised	Date
Rev 1.0	DRAFT Report	AN/IR	PT/NK/OM	DS/NA		05/07/13
Rev 2.0	Final Report	AN/IR	PT/OM	DS/NA		31/08/13
Rev 3.0	Re-drafted Final Report	DP	IR/MH	DS	DP	27/09/13
Rev 4.0	Re-drafted Final Report	DP	IR/MH	DS	DP	18/10/13
Rev 5.0	Corrected Final Report	DP	IR/MH	DS	DP	21/10/13

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Glossary of terms

Term	Meaning/Definition
Artesian	An artesian aquifer is a confined aquifer containing groundwater under positive pressure. This causes the water level in a well to rise to a point where hydrostatic equilibrium has been reached.
BHA	Bottom hole assembly
Binary cycle	'Secondary working' or 'binary cycle' with a fluid boiling point below that of water
Cap Ex	Capital Expenditure
CfD	Contract for Difference
CHP	Combined Heat and Power
DECC	Department of Energy and Climate Change
Deep Geothermal	A project that involves the exploration or use of geothermal heat generated within the earth.
Dm	Darcy metre
DHN	District Heating Network
DNO	Distribution Network Operator
EGS	Enhanced Geothermal System
EMR	Electricity Market Reform
ESP	Electric submersible pump
EM	Electromagnetic
FIT	Feed In Tariff
FMI	Formation Micro Imaging
Formation	Body or layer of rock in the ground
Geothermal reservoir	A heat reservoir in rocks from which the heat may be extracted for utilisation.
GIS	Geographical Information System
HCl	Hydrochloric acid
HDR	Hot Dry Rock
HSA	Hot Sedimentary Aquifer

Term	Meaning/Definition
HF	Hydrogen fluoride
HFR	Hot Fractured Rock
HTPF	Hydraulic Test in Pre-existing Fractures
Hydraulic conductivity (K)	Hydraulic conductivity is a property that describes the ease with which a fluid (usually water) can move through pore spaces or fractures in the ground, measured in m/d. See Permeability and Transmissivity.
Hydraulic stimulation	A technique involving the application of high fluid pressure on a reservoir (e.g. geological unit) to enhance the existing permeability and establish interwell connectivity by enhancing or opening sealed joints to allow fluid to move more freely through the formation.
ITT	Invitation to Tender
Kalina Cycle	A thermodynamic process for converting thermal energy into usable mechanical power
LCOE	Levelised Cost of Electricity
mD	Millidarcy
MT	Magnetotelluric EM method of geophysical survey
MWe	Megawatts electrical: units of electrical power
MWth	Megawatts thermal: units of thermal (i.e. heat) power
MWh	Megawatt hours: a measure of energy
NORM	Naturally Occurring Radioactive Materials
ORC	A thermodynamic process for converting thermal energy into usable mechanical power
Parasitic Power	The power required to operate a generating station
PDC	Polycrystalline diamond compacts
Permeability (k)	The ability of a material, and specifically rocks for this project, to transmit fluid; Measured in m ² or D (Darcy). See Transmissivity.
Petrophysics	The study of physical and chemical rock properties and their interactions with fluids
PI	Productivity Index

Term	Meaning/Definition
Proppant	Substance added at the end of the hydraulic stimulation to keep fractures open facilitating sustainable and long-term conductivity of fractures
Reserve (geothermal heat)	Geothermal heat which is likely to be recoverable given technological, economic and other constraints.
Resource (geothermal heat)	Geothermal heat that is technologically recoverable but for which there is significant uncertainty as to its recoverable potential owing to economic and other constraints.
RHI	Renewable Heat Incentive
ROC	Renewable Obligation Certificate
ROP	Rate of penetration
Stimulation	The enhancement of natural permeability. Stimulation is usually hydraulically achieved by injecting fluids (see Hydraulic stimulation above) or chemically by injecting acids or other chemicals.
Strike Price	The strike price of a CfD is the fixed price at which the owner of the option can sell an underlying security or commodity.
TCI	Tungsten Carbide Insert
Transmissivity (T)	The measure of how much water can be transmitted horizontally, such as to a pumping well. Measured in m ² /day, or Dm (Darcy metre). Transmissivity varies with aquifer thickness. See Permeability.
UBI	Ultrasonic Borehole Imaging
VSP	Vertical Seismic Profiling
WOB	Weight on bit

Executive Summary

Geothermal energy has the potential to provide a significant part of the world's energy needs in the form of low carbon renewable energy. This is most prominent in active tectonic zones such as Iceland, New Zealand, Italy, Turkey, Japan and parts of the USA, where significant geothermal energy is being generated currently at shallow depths. In these regions geothermal energy is widely exploited for power generation. However, these active zones only account for part of the global geothermal resource, with potential for generation in other less tectonically active areas.

Some locations with broadly similar thermal resource conditions and analogous geologies to the UK have an active Deep Geothermal industry. Australia has some very hot geothermal granites with small scale power plants (1MWe) being commissioned from 2013. Germany is a good example of the European context and has been included in the review through the experience of study partners Geowatt and IF Technology. Although generally for heat, small scale geothermal power production is underway in Germany with potential for expansion.

In non-volcanic regions, generating power from deep geothermal resource has typically centred on binary systems at lower temperatures or the development of Enhanced Geothermal System technologies (EGS) at higher temperatures. EGS may require the use of stimulation such as hydraulic fracturing to produce a subterranean reservoir to enable a sufficient flow of water. Binary systems are already established technologies. However, the technological challenges, risks and uncertainties surrounding deep geothermal EGS technologies mean that there has been only limited development to date. There are no deep geothermal power plants currently in the UK.

DECC's Energy Innovation Delivery Team has a remit to invest in technologies that will provide significant benefits to the UK in terms of the secure supply of renewable and low carbon energy. In order to prioritise investment, analysis has been undertaken to highlight where investment in certain energy and technology sectors will deliver benefit to the UK. As part of this process this study has been commissioned to consider the potential for deep geothermal power generation in the UK.

In addition to hot crystalline rocks such as radiothermal granites, there is also potential in the UK, albeit more limited, from geothermal heat present in deep sedimentary basins. Generally such sources are of lower thermal energy and therefore have potential for heat or combined heat and power rather than power generation exclusively. With innovations in the use of working fluids with lower boiling points these lower thermal energy resources may prove of increasing interest as a feasible power generating potential reserve. Recent reports suggest that in certain regions of the UK the particular granite geology would be less reliant on stimulation techniques as natural fissures and fractures potentially exist in the hot granite rock. These fractures could potentially be used, greatly reducing the risk of not being able to create a sufficiently permeable reservoir.

DECC wish to undertake further analyses to better understand the potential benefits and opportunities for power generation from deep geothermal technologies in the UK and to ensure that benefit is derived from any future investment decisions. This study is in response to DECC's wishes to further their understanding and focuses solely on geothermal energy for power generation, although includes heat re-use as a by-product. It is important to note from the outset that the remit for this study and report is focussed on power generation (i.e. the production of electricity), and not heat supply. However combined heat and power system schemes have been considered in order to provide a viable business case.

Atkins approach to the study reported here has comprised:

- A review of the work carried out in the area of deep geothermal to date.
- Assessment of the feasibility of geothermal exploration and exploitation for the electrical power market;
- Review of costs associated with exploration, exploitation and potential investment returns.
- Identification of opportunities for technological innovations and their potential impact on risk and cost reduction.
- Recommendations on next steps

There is currently uncertainty whether there is a viable resource which will not be overcome until deep boreholes are drilled into the potential host rocks to demonstrate both reserve extent and exploitability.

The lack of certainty of reserves and other factors leads to financial risk and uncertainty of viability. This financial risk is compounded by the uncertainty of the outturn costs and likely returns should the reserve be proven. In order to better quantify such financial uncertainty a series of case study scenarios have been developed.

The approach taken for selecting the case studies has employed two essential criteria:

- a temperature of >100 °C.
- at a depth less than 5km.

Using these criteria, a short list of three areas of the UK has been identified; the radiothermal granites of Cornwall; the radiothermal granites of Weardale in the North East stretching across towards the Lake District; and the sedimentary basin of Cheshire. Other areas may, of course, be suitable for heat only schemes.

Three case studies have been developed for illustrative purposes:

- A low permeability granite source in South West England;
- A high permeability granite source in Northern England; and
- A deep sedimentary basin low level heat source in Cheshire.

The two granite scenarios are interchangeable. Fractured granite has already been found in boreholes in the North West but could also be reasonably inferred as likely to be present in the South West as well. A sensitivity analysis of the costs has been carried out in order to provide context for investors on the potential financial risks.

It has been concluded that economic viability of all schemes is heavily reliant upon heat sales and this becomes a limiting factor, especially in more rural areas where the lower heat demand density makes district heating less economically viable.

Therefore it has been determined that the current potential in South West England is up to approximately 100 MWe. This could increase considerably as the sector matures, uncertainties are removed and costs reduce.

In Weardale and the Lake District very little heat demand exists locally due to the rural nature of the area. Hence the upper limit potential is currently suggested in the order of 70 MWe. This comes with the proviso that if heat could be piped to major conurbations this could rise to between 100 and 1000 MWe, although the economic viability of this level being achieved is highly unlikely.

The total resource in the Cheshire Basin is of a lesser extent and of lower temperature. Accordingly there is less potential for expanding the resource to cover a larger receiving community. Hence it is unlikely this resource would prove viable other than to provide for localised needs for heat and potentially power.

If uncertainties can be reduced and resources become proven reserves; capital costs reduce with scale; and experience and/or subsidy levels are altered such that expected rates of return based upon power generation alone become acceptable to investors, then more of the potential resource can be exploited and realised. Given the German context, where approximately 300MWe is planned by 2020 and the sector is more mature, 1 to 1.5 GWe might be a reasonable estimate for the UK in the longer term (2050).

This equates to about 4% of the annual average current UK electricity requirements. This is significantly lower than the c.20% of UK energy requirements presented in the forward to the SKM report (Ref. 61). Estimates are very difficult to substantiate owing to the current absence of reservoir characterisation. Longevity of schemes needs to be considered, with greater certainty needed with respect to total heat outputs and potential for heat degradation of the resource.

The scenarios demonstrate that with sufficient understanding of the resources and linkages to the final users there is potential for power generation from the granites. However, for commercial viability they will most

likely require not only power but also heat utilisation, at least until the perceived risks are reduced to permit “utility” type returns on investment to be acceptable. For the deep sedimentary sources the most likely use would be heat only, with a low probability of power generation potential. However, heat only or reliance on heat to make a scheme viable would be dependent on a local heating network to distribute the heat from the source to the user. Such heat networks would be more viable for new developments and potentially complicated and expensive where retrofitting to existing users.

A secondary part of this study involved stakeholder engagement via a questionnaire, stakeholder engagement day and limited interviews. This involved capturing key stakeholders’ views, especially regarding why investment has not occurred to date. These stakeholder views have been taken into consideration during this study and incorporated within the main body of the report where appropriate and substantiated by other sources of information.

To date no wells have been drilled in the UK to sufficient depth to measure or prove the resource for power generation. The cost of trial and exploratory wells is very high relative to the overall capital cost of the project. In order to limit the risks and make projects more investable, stakeholders consulted during this study suggested the following:

- Further research studies and investigations of the identified resource areas to improve the characterisation of the potential thermal reserve;
- Two or three test boreholes drilled in each location;
- Clear permitting and thermal rights of ownership clarified;
- Funding or insurance for early stage test boreholes put in place; and
- Adjustment of subsidy levels would promote investment. However the current large uncertainties surrounding the drilling to characterise the resource make initial investment decisions relatively insensitive to subsidies based upon operational revenues.

At present there is insufficient private sector appetite to de-risk the sector for power generation schemes. Steps to limit the risks, as set out above, would need to be led and funded by Government.

It is concluded in this study that deep geothermal energy production in the UK has potential to generate utility level returns for investors but not without significant risk and uncertainty. In order to reduce the risk and uncertainty economically exploitable resources need to be proven to the level at which investor confidence can be achieved. Developing confidence in reserve levels would need a programme, led and funded by Government, of test boreholes drilled to the depth required for production and testing of such wells to demonstrate reservoir properties and exploitability. Even with an increased level of confidence in reserves, the inherent risk profile of project development (in which full viability of any given scheme is not known until the project specific boreholes have been drilled) may continue to be an obstacle for private sector investment.

1 Introduction

1.1. Scope and Objectives

This study to investigate the potential and viability of generating power from Deep Geothermal energy resources in the UK has been commissioned by the Department of Energy and Climate Change (DECC). Power generation is the main focus of this study, however the combined use of heat with this power generation is also considered. This study currently excludes all low temperature resources from which only heat but not power could potentially be exploited using current technologies. However, the lower temperature threshold for power generation is likely to change owing to advances in power generation technologies using fluids that boil at a lower temperature than water. Therefore, some of the lower temperature resources currently identified might become economic reserves in the future due to the electricity conversion for the binary cycle¹ having a lower temperature cut-off for economic viability. Such conditions are considered in this study.

DECC has currently excluded “heat only” schemes from this study. Deep Geothermal heat only projects are already being developed in the UK – in Manchester and North Tyneside. There is increased confidence in the overall Deep Geothermal energy resource potential (and the geographical match with heat loads) and commercial backers are on board to support these developments. The only working Deep Geothermal scheme (at Southampton, though currently being refurbished) is a heat only scheme linking into a district heating network.

Although heat projects are being progressed, this is not the case with Deep Geothermal power projects where no projects are currently advancing. There are three potential power sites, two in Cornwall and one in the Weardale area of County Durham, which might be the first power projects. However, despite Government grant funding, these projects have failed to attract commercial interest given the uncertainty about the resource and the viability of establishing a power generation plant. DECC is testing whether there is a case for the Government to do more to prove the resource and power generation potential. It is important to note that all the proposed power projects would be CHP plants, so the heat element is an important consideration.

DECC has indicated that there has been interest at local authority level in generating power from hot sedimentary aquifers. Although it is likely that the temperatures involved do not make this a viable option, DECC is testing this proposition through this study.

This report sets out the background information that provides the rationale and conditions for favouring certain sites, and provides a methodology that will lead to case studies/‘scenario assessments’ for three illustrative sites.

This report covers the scope set out by the Invitation to Tender (ITT) (Ref. 13) issued by DECC in February 2013.

1.2. Background and Context

Geothermal energy, in the broadest sense, is the natural heat present within the earth's core, mantle and crust. The majority of the internal energy that was generated was caused by gravitational contraction of the planet as it was formed about 4.5 billion years ago (Ref. 7). Heat is also generated and maintained by radiogenic heat and which is continually generated by the decay of long lived radioactive isotopes of uranium, thorium and potassium within the earth's crust. The total heat content of the earth is in the order of 12.6×10^{24} MJ, of which 5.4×10^{24} MJ is contained within the earth's crust (Ref. 16).

Whilst this is an immense resource, currently there are limits to the economical viability of geothermal heat extraction. In continental areas, for example, the earth's crust is about 20-65km thick and currently only a small fraction of this potential resource is practically available for use.

¹ A binary cycle power plant is a type of geothermal power plant that allows cooler geothermal reservoirs to be used than with dry steam and flash steam plants using a second "working" or "binary" fluid with a lower boiling point, typically a butane or pentane hydrocarbon (see Section 2.1).

Deep Geothermal projects are usually executed in a phased process. The main phases for the development of the sub-surface elements of a geothermal scheme are as follows:

1. Preliminary survey
2. Exploration
3. Test drilling
4. Well testing and logging
5. Reservoir development
6. Production and reservoir monitoring

These aspects of a geothermal project are discussed in detail in Section 3 and Appendix A.

This study considers the UK geology up to depths of approximately 5,000m and investigates the potential for power generation by heat to electricity conversion from the geology at such depths and shallower.

1.2.1. Definitions

Definitions and interpretations of some of the key words and topics that were explored through this study are given below.

1.2.1.1. Geothermal systems

Geothermal systems vary according to their geological characteristics and the methods used to enhance the flow of fluids through the ground. This study considers the principal types of geothermal systems: crystalline rock and sedimentary aquifers.

Enhanced Geothermal Systems (EGS) were developed to enhance the initial permeability of crystalline rocks where natural fluid permeabilities are insufficient to facilitate economic flow rates (e.g. the granites at Rosemanowes, UK and Soultz-sous-Forêts, France). Many EGS techniques are also applicable to sedimentary aquifers.

1.2.1.2. Categories of geothermal resources and reserves

The Australian Geothermal Energy Group Reporting Code (Ref 63) uses the term 'Geothermal Play' as an informal qualitative descriptor for an accumulation of heat energy within the Earth's crust. For this (the Geothermal play) the Reporting Code provides a geothermal resources and reserves classification regime. The reporting code states it is important to understand the certainty (quality and quantity) of the information that is used to define the magnitude of resources and reserves. Table 1–1 has been reproduced from the Resources and Reserves summary provided in the Australian Reporting Code (Ref 63).

In the context of the UK situation there are no current proven reserves as resources have not been drilled to sufficient depth to prove temperatures suitable for energy generation, only heat reserves. To date, 2,000m deep boreholes at Rosemanowes in Cornwall with bottom temperatures of 79°C and temperature gradients of around 35 to 40°C per 1,000m (Ref. 19 and 4); and a 1,000m deep borehole at Eastgate and a 1,770m deep borehole at Newcastle with bottom temperatures of 46°C and 73°C respectively and temperature gradients of around 39°C per 1,000m (Ref. 70). This UK resource is further defined and discussed in this report (see Section 2.1 and Table 8-1).

Table 1–1 Summary of Resources and Reserves

	Geothermal Resource			Geothermal Reserve	
	Inferred	Indicated	Measured	Probable	Proven
Commerciality	Commerciality not yet established. Probably feasible with current or future technology, prevailing and/or more favourable market conditions.			Commercial. Feasible with existing technology and prevailing market conditions.	
Definition	The Recoverable Thermal Energy within an area/volume that has enough direct indicators of Geothermal Resource character or dimensions to provide a sound basis for assuming that a body of thermal energy exists, estimating temperature and having some indication of extent.	The Recoverable Thermal Energy within a more reliably characterised volume of rock than the Inferred Geothermal Resource. Sufficient indicators to characterise temperature and chemistry, although with few direct measures indicating extent.	The Recoverable Thermal Energy within a drilled and tested volume of rock within which well deliverability has been demonstrated, with sufficient indicators to characterise temperature and chemistry and with sufficient direct measurements to confirm the continuity of the reservoir.	That part of an Indicated Geothermal Resource for which commercial production for the assumed lifetime of the project can be forecast, or: That part of a Measured Geothermal Resource for which commercial production for the assumed lifetime of the project cannot be forecast with sufficient confidence to be considered a Proven Geothermal Reserve. The chance of occurrence is 'more likely than not'.	Applies directly to production satisfying all Modifying Factors. Directly related to that part of a Measured Geothermal Resource for which commercial production for the stated lifetime of the project can be forecast with a high degree of confidence.

From Australian Reporting Code (Ref 63)

This reporting code has been applied in the context of this report in relation to power generation and not heat only schemes.

1.3. Limitations

This study is limited to readily available information from literature review provided in the bibliography and references and experience provided by study partners, Geowatt and IF Technologies. Best endeavours have been made to provide a comprehensive review. However, as further research is undertaken, technology advances made and additional literature becomes available the findings of this study might need to be reviewed and re-evaluated. As such, where gaps in information have been identified, they are noted along with recommendations made for further study.

2 UK Geothermal Resource

2.1. History of Geothermal Energy Exploration in the UK

The UK has a number of areas identified that contain low to medium grade heat resources. However, to date no geothermal power only schemes have been developed and very few geothermal heat only schemes are in operation. Compared with other countries such as Iceland, New Zealand and Turkey, where active geological systems are present that generate large amounts of heat, the UK geothermal resource is largely undeveloped and the resource is considered to be lower grade.

2.1.1. Hot sedimentary aquifers

In the UK, the potential for exploiting geothermal energy was first examined by the Department of Energy in the wake of the 1973 oil crisis. This led to a research and development programme undertaken by the Department of Energy to examine the potential of geothermal energy utilization of geothermal aquifers. The project was abandoned leaving behind only the Southampton borehole and a geothermal 'heat only' energy scheme which forms part of the city centre district heating system drawing warm (76 °C) water from the Wessex Basin Hot Sedimentary Aquifer (HSA) at 1,800 metres depth.

2.1.2. Enhanced Geothermal Systems (EGS)

Excluding active hydrothermal fields, such as those in Iceland, most geothermal energy within reach of conventional techniques is in dry impermeable rocks. The United States pioneered the first effort to create an EGS - then termed HDR in the 1970s at Fenton Hill, New Mexico with a project run by the federal Los Alamos Laboratory.

Jointly funded by the Department of Energy and the European Commission in the late 1970s, geothermal energy research in extracting geothermal energy from hot dry rock was also conducted at the Rosemanowes Quarry, Cornwall and experience was gained on applying techniques of heat reservoir engineering (Ref. 54). As with Fenton Hill, the project was terminated; however, the site remained a research facility and its data provided were widely used and contributed to the 1.5MWe EGS demonstration project in Soultz-sous-Forêts, France for Deep Geothermal energy using permeability (fracture) enhancement (stimulation) techniques in crystalline rock.

2.2. UK Geothermal Resources

The principal exploratory technique for the identification and location of geothermal resources is the study of heat flow (or flux) as it permits the prediction of temperatures to depths below those reached by shallow drilling.

Although acquisition techniques for subsurface information, including seismic reflection surveys combined with improved interpretation techniques, have advanced significantly and new data have been taken into account in a hydro-geothermal study reported by Barker et al (2000) (Ref. 3), the British Geological Survey's (BGS) comprehensive work carried out between the mid-1970s and the mid-1980s and reported by Down & Gray (1986) is still the definitive reference to geothermal prospects in the UK, although supplemented by the more recent work by Busby (2010)(Ref. 9).

In his Geothermal Prospects in the United Kingdom document, Busby (2010)(Ref. 9) provided a flux map (see Figure 2-1) that was derived from 212 heat flow measurements supplemented by 504 heat flow estimates. Comparison of the locations of areas of relatively highest heat flow with a simple geological map (Figure 2-2) shows that these high flux areas are the radiothermal granites of South Western and Northern England.

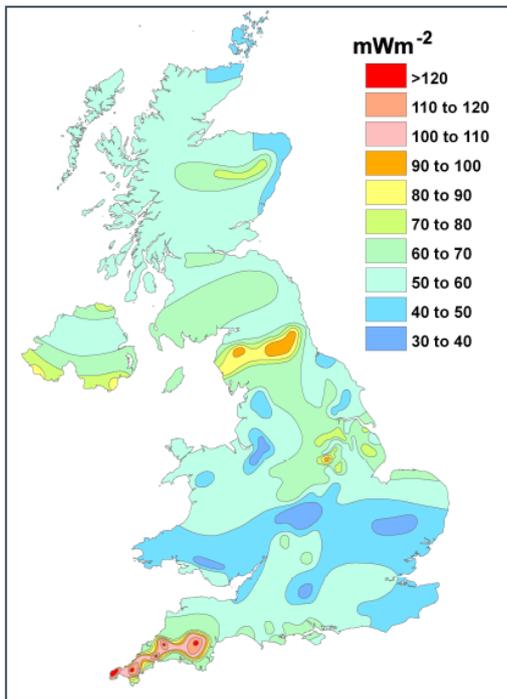


Figure 2-1 Heat flow map of the UK (Ref 9)

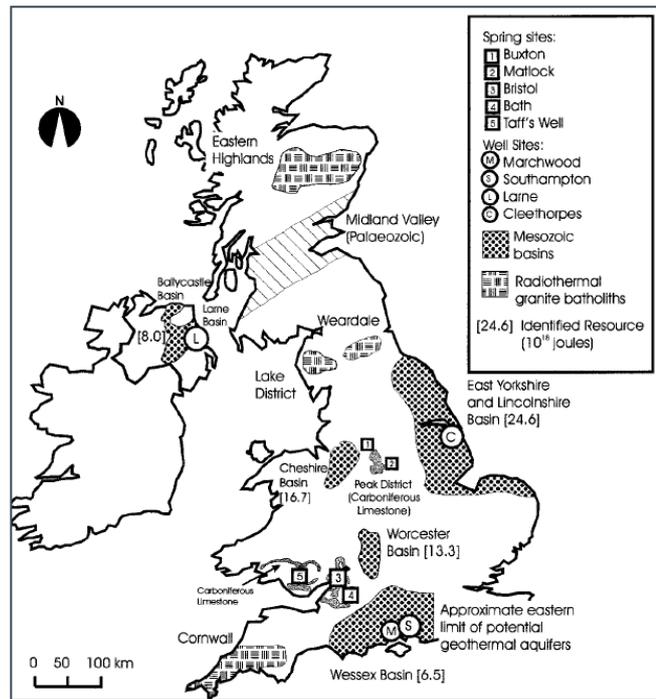


Figure 2-2 Location of sedimentary basins and major radiothermal granites (Ref. 3)

In a recent 2013 publication, Westaway and Younger (Ref. 67) concluded that the past failure to correct measured heat flow values for the residual effects of cooling during the last ice age has led to systematic underestimation of temperatures at depth in Britain and, thus, of the overall geothermal energy resource. This could have resulted in underestimates of previous temperature gradients of up approximately 6°C per 1,000m depths in some areas of the UK.

2.3. Major Radiothermal Granites

2.3.1. South West England

Temperatures

In the South West of England, areas of heat flow rates in excess of 120mW/m² (see Figure 2-3) coinciding with thermal gradients that exceed 35-40°C per 1,000m are suggested by the data given in Downing and Gray (Ref. 19) and Batchelor et al (Ref. 4). Drilling of boreholes to approximately 2,500m depth on the Rosemanowes Quarry site, which is in one of the 120mW/m² heat flow areas, confirmed the high thermal gradients anticipated (Ref. 54). Although there are variations on measured heat flow above the granite (shown as points with mW/m² values), there appears no compelling evidence for hot spot areas with respect to geothermal energy resource potential within this geology (see Figure 2-3). Based on near surface heat, Batchelor et al. (Ref. 4) and Downing and Gray (Ref. 19) state that temperatures in the order of 160 to 180°C and c. 200°C could be encountered at depths of 4 to 4.5 km and 5.4 km respectively.

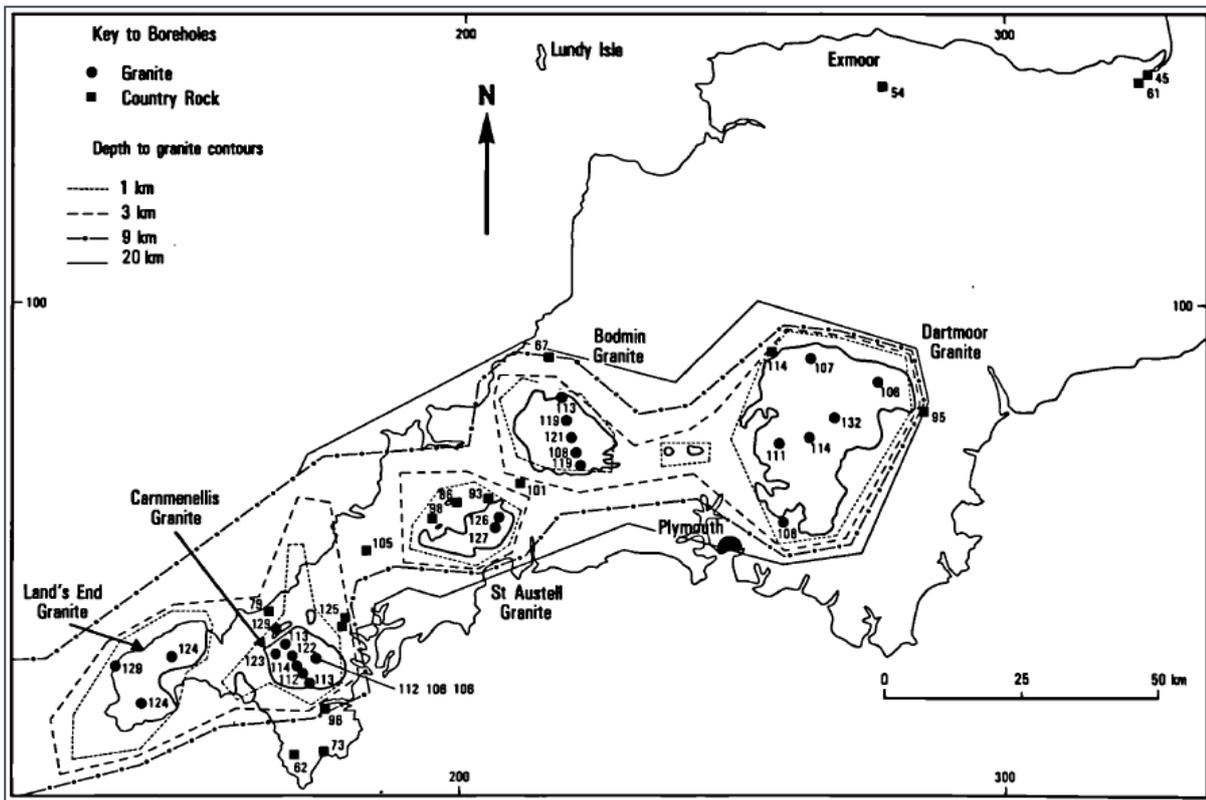


Figure 2-3 Distribution and values of heat flow measurements in South West England (Ref. 19) - Heat flow values in mW/m^2

Transmissivity

Currently, there is no evidence for the granite in the South West having transmissivity that would be sufficient for geothermal exploitation without stimulation of the geothermal reservoir rock. However, this lack of evidence is largely due to a lack of sub surface investigation of fault, fracture and weathered zones within which exploitable natural permeability might exist similar to those found in other granites, such as that in Northern England (see section 2.3.2 below).

2.3.2. Northern England: Weardale and the Lake District

Temperatures

High heat gradients are anticipated in the Weardale and Lake District granites (Refs 41, 60 and 70 – see below), albeit with lower values of flux measured near the ground surface than in South West England owing to the granites being buried by formations of lower thermal conductivity which insulate the granites.

Two boreholes, drilled to depths of approximately 1,000m and 1,800m, confirmed geothermal gradients in the order of 38 to 39°C per 1,000m for locations in Weardale (Eastgate) and Newcastle (Ref. 70).

Manning, Younger and Dufton (Ref. 50) conclude that a temperature of 160°C may be present in this area somewhere at depth as indicated by the highly mineralised chemistry of water samples obtained, which could only have equilibrated with the country rock at high temperatures and pressures.

Transmissivity

The Eastgate geothermal well, which was drilled into the Weardale granite in 2004, was targeted to intersect the Slitt Vein; a major, linear, sub-vertical and potentially permeable natural fracture-zone. The well was drilled to a depth of 995 m (723 m of which was within the granite) with a maximum bottom hole temperature of 46°C recorded. A highly permeable zone was encountered at a depth of 411 m within the Slitt Vein structure and a transmissivity of > 2,000 Dm was recorded. This is the highest value for any comparable interval of granite reported in literature reviewed by Younger and Manning (Ref. 69), in a naturally occurring permeable zone, and over 20 times greater than the maximum value derived from a compendium of data for granites and similar crystalline rocks in North America (Ref. 69).

Younger and Manning (Ref. 69) suggest that there is a minimal need of extensive fracture stimulation in this fractured zone of granite, which is encouraging for geothermal projects. Younger and Manning (Ref. 69) further suggest that water at temperatures in excess of 100°C would be expected in a borehole around 2 km deep, although this has yet to be proven. Although shallow data promotes optimism for good transmissivity and temperatures sufficient for power generation at depth, drilling a sufficiently deep borehole to prove such inferences would be needed to prove reserve in line with The Australian Geothermal Reporting Code (Ref. 63).

2.4. Hot Sedimentary Aquifers

For the UK as a whole, heat flux and geothermal gradients are generally lower for hot sedimentary aquifers than for radiothermal granites. Information given in Downing and Gray (Ref. 19) suggests an average gradient of 26°C per 1,000m depth. However, exceptions occur in areas where, although the heat flux values are relatively low, higher thermally conductive geological formations (e.g. Permo-Triassic sandstones) are overlain by formations (e.g. Mercia Mudstone) of lower thermal conductivity. For example, findings from boreholes drilled to c.1,700m depth in the Southampton area indicated thermal gradients of 38°C per 1,000m depth present in some areas of the Wessex Basin.

In the UK, temperature data are available only for sedimentary basins that are post-Carboniferous in age and the potential for geothermal power generation from such hot sedimentary aquifers is limited by the maximum depths of the aquifers. This limitation is a consequence of the cut-off temperature for economic viability of electricity conversion of a combined heat and power scheme being about 100°C (Note: this temperature cut-off depends on details of the scheme; the cut-off temperature required for the economic viability of power only schemes is usually greater).

The deepest post-Carboniferous sedimentary aquifers in the UK are within the Wessex and Cheshire Basins for which literature (Ref. 8 and Ref. 68) from the British Geological Survey (BGS) suggests bottom-depths of up to about 3,000m and 4,500m respectively (i.e. temperatures close to or above the 100°C cut-off for economic viability of electricity generation are expected only at maximum basin depths).

Sedimentary aquifers in other post Carboniferous age basins in England (the East Yorkshire, Lincolnshire and Worcester Basins) and Northern Ireland (the Larne, Rathlin, Lough Neigh and Northwest Basins) do not extend to depths significantly below 2,000m. On this basis, there is a low prospect of temperatures being encountered above the 100°C economic cut-off temperature in these shallower sedimentary basins.

Deep Carboniferous basins are present in the UK. However, as noted above, no data as to their likely geothermal potential have been identified during this study.

As a result of considerations of their likely temperature, only the Wessex and the Cheshire basins (both of Permo-Triassic, i.e. post-Carboniferous age) are considered in the assessments described below. This conclusion concurs with assessments made in SKM's 2012 report on Geothermal Energy Potential in the UK (Ref. 61). Geological descriptions including temperatures and fluid permeabilities of the Wessex and the Cheshire Basins are provided below.

2.4.1. Wessex Basin

Temperatures

The water temperatures over significant areas of the Wessex Basin are expected to be in the region of 40 to 60°C at depths greater than 1,000m in the centre of the Sherwood Sandstone Group. Thermal gradients of

about 36 to 38 °C per 1,000m depth are suggested by data reported by Down & Gray (Ref. 19) and pumping tests during the Southampton geothermal project. Temperatures during pumping tests from a c.1,700 metre deep borehole in Southampton were about 75°C, with the data reported by Down & Gray (Ref. 19) indicating the presence of up to 80°C at similar depths elsewhere in the Wessex Basin. A figure showing the estimated temperature distribution at the centre of the Sherwood Sandstone Group in the Wessex Basin (the exact depth is not well defined) is given below. For the same area, Rollin et al (Ref. 58) suggest 100°C at the base of the Wessex Basin (see Figure 2–5). However, at some places, the bottom of the Sherwood Sandstone Group is expected to reach depths of up to 3,000m. At such depths, temperatures are projected to be more than 100°C (i.e. greater than the cut-off value for geothermal power), but it should be noted that these temperatures are inferred rather than measured.

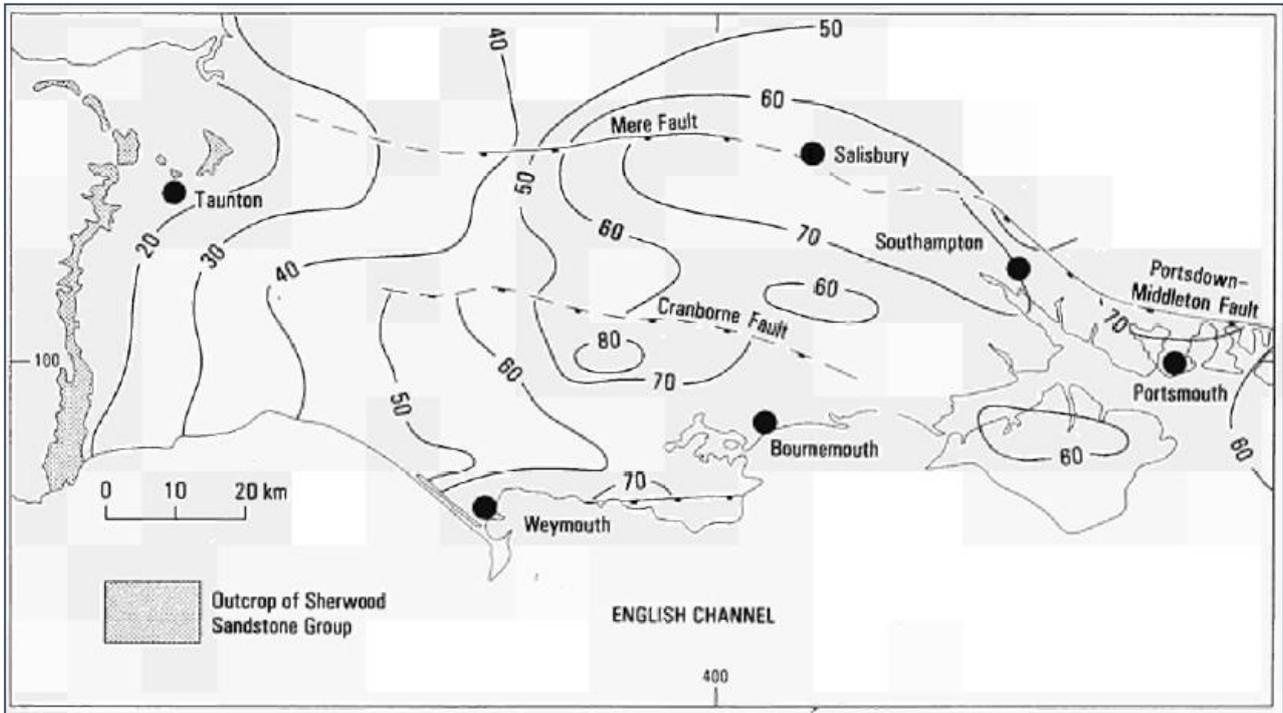


Figure 2–4 Estimated temperatures at the centre of the Sherwood Sandstone Group in the Wessex Basin (Ref. 19)

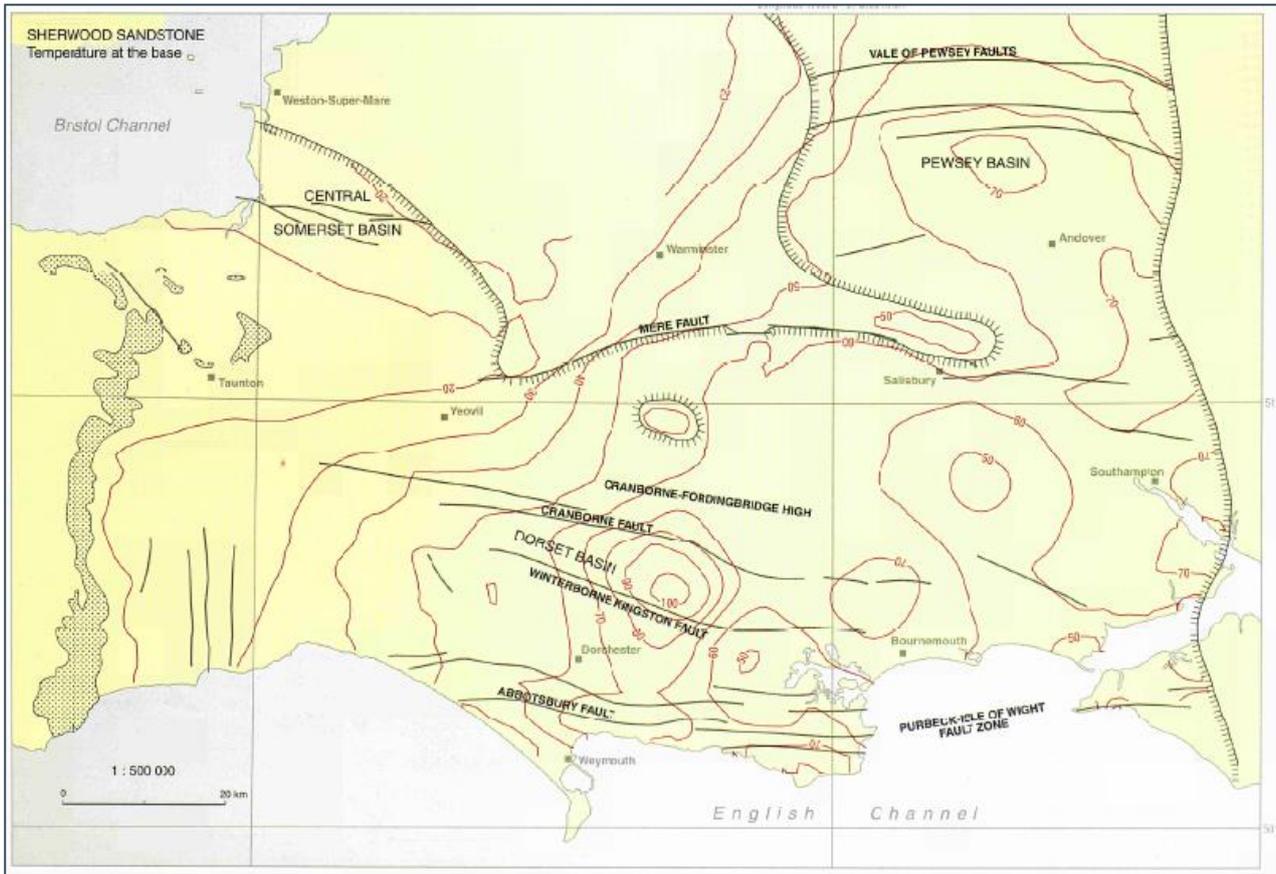


Figure 2–5 Estimated temperatures at the base of the Wessex Basin (Ref. 58)

These two figures appear inconsistent compared with the temperature identified in the Southampton borehole (75 °C at 1,800m depth). This illustrates the uncertainty in predicting temperatures at depth from inferred thermal gradients.

Transmissivity

Maximum transmissivities of Sherwood Sandstone are in the order of 10 to 20Dm. There are very few direct measurements of the Sherwood Sandstone transmissivity at depth in the Wessex Basin, and those that have been made are mainly confined to the Southampton area and to an area to the west of Bournemouth. The Sherwood Sandstone transmissivity near Southampton is about 5 Dm.

2.4.2. Cheshire Basin

Temperatures

The geothermal gradient within the Permo-Triassic Sandstones of the Cheshire Basin is low being about 20°C per 1,000m depth. Across the wider Cheshire basin, the temperature at the base of the basin is expected to be around 40 to 60°C (Ref. 3).

However, the Permo-Triassic sequence is expected to reach maximum depths of approximately 4 to 4.5km within the Cheshire Basin at its deepest point to the east of Crewe where Rollin et al (Ref. 58, see Figure 6) suggest 100°C at the base of the basin in this area.

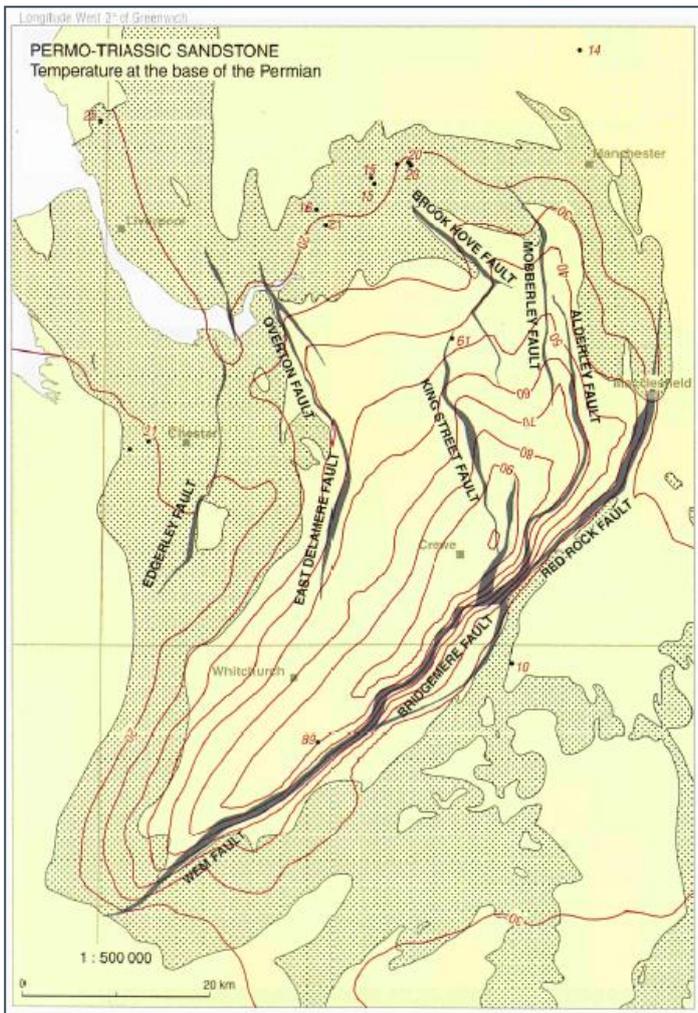


Figure 2–6 Temperatures at the base of the Permian in the Cheshire Basin (Ref. 51)

Transmissivity

The transmissivity, based upon geophysical investigations only, is believed to exceed 10 Dm (Ref. 3) and may be increased in areas of faulting, such as the Bridgemere Fault. However, this is based on the interpretation of geophysical logs and not direct test data (Ref. 3).

UK Geothermal Resource - Key Points

- Main resource for heat to power conversion are the radiothermal granites in the south west (Cornwall) and northern England (Lake District and Weardale).
- The Grampian granites (Scotland) have been considered as providing a potential resource, but the likelihood of geothermal temperatures sufficient to generate electricity is considered low. No suitable strata for geothermal power have been identified in Northern Ireland.
- The prospect for geothermal power generation appears highest in South West and Northern England due to the relatively high heat gradient (up to 38°C per 1,000m) suggesting temperatures of up to approximately 200°C at 5,000m depths.
- The potential for small scale geothermal power generation schemes within the deepest areas of the Cheshire and Wessex sedimentary basins are possible based on inferred geothermal temperatures of greater than 100°C. Other sedimentary basins of post-Carboniferous age in Britain are unsuitable for power generation due to their limited depths and relatively low heat gradients.
- There are uncertainties in inferring temperatures at depth based on thermal gradients.
- Carboniferous age basins could potentially enable heat abstraction from greater depths and higher temperatures beneath post-Carboniferous basins. However, these older basins have not been taken into account because insufficient information is available.

Table 2-1 Summary of UK geothermal resources potentially suitable for electrical power production

Type	Location	Thermal Gradient (measured) C / km	Inferred Temperature (Formation at depth) C	Estimated depth of reservoir (heat for power) km	Measured Transmissivity (Dm) or Permeability (mD)	Comments
Crystalline	South West England	35-40	160-200	4-4.5km	0.001 to 0.01 mD (minimum estimated as 1mD from similar granites at Soultz-soultz-Forets)	<p>Heat flow mapping, 40 observations indicate heat flow values of up to 136 mW/m² and heat gradient of 35 °C/km (Downing & Gray 1986, Busby 2010.)</p> <p>Rosemanowes, 3 boreholes drilled between 1980 and 1983 (MacDonald 1992 & Parker 1999) 80°C water produced from c.2,000m depth, but production temperature reduced to 55% over time.</p> <p>Note: boreholes deliberately drilled in areas with no major faulting to demonstrate EGS of fracture opening. Therefore hydraulic properties not necessarily representative of faulted granite in the region.</p>
Crystalline	Weardale & Lake District	38-39	160	c.2km	2000 Dm	<p>Temperature modelling on the basis of heat flow values logged at depths between approximately 300 m and 800 m, thermal gradients in the approximate range of 25°C and 35°C per km depth.</p> <p>Eastgate Geothermal Borehole, drilling down the axis of a vein structure (the Slitt Vein) down to 1,000m revealed a temperature of 46°C (Younger & Manning, 2010, Manning et al, undated).</p> <p>At 1,770m, a temperature of 73°C (Manning 2013) was found in a borehole drilled in Newcastle that is presumed to receive water from the granite suggesting gradient in excess of 35°C per km depth, with suitable temperatures for power generation estimated at c.2km.</p> <p>The base of the batholiths is estimated as 9 to 12 km (Kimbell <i>et al</i> 2010) from geophysics.</p>

Type	Location	Thermal Gradient (measured) C / km	Inferred Temperature (Formation at depth) C	Estimated depth of reservoir (heat for power) km	Measured Transmissivity (Dm) or Permeability (mD)	Comments
Sedimentary	Wessex Basin	36-38	100*	2-3km	10-20 Dm	Southampton, temperature in excess of 70°C found in borehole SU 3991 1118 (Geothermal Well at Southampton) measured 75°C at c.1,700m depth
Sedimentary	Cheshire Basin	23	100*	4-4.5	10 Dm	The Permo-Triassic sandstones that reach depths of 4,000m. Here temperatures exceed 60°C with maximum values of up to 100°C (Barker et al 2000). 100°C at 4,000m inferred from temp. gradients and geophysical measurements

* Marginal resource most likely suitable for heat only.

3 Phases of a Deep Geothermal Power Project

3.1. Introduction

A Deep Geothermal power scheme is a high cost project in terms of capital cost of investigating and developing the scheme and therefore it is critical to identify as early as possible the likelihood of success. A phased approach is undertaken, as for any costly infrastructure project, in order to manage risk and spend owing to the uncertainty and high costs in providing data to change the status of a resource to a reserve and managing technical and financial risks associated with reservoir and power plant development. Any full scale demonstrator project would involve all of the following phases as part of the scope requirements.

The aim of each phase is to reduce risk and uncertainty, but each subsequent phase has its own financial risk, with potential to identify a project as unlikely to be viable at each stage resulting in no return for the investment up to current phase. The phases are:

1. Preliminary survey
2. Exploration
3. Test drilling
4. Well testing and logging
5. Reservoir development
6. Production and reservoir monitoring

These phases of a geothermal project are discussed in detail in Appendix A and summarised as follows.

3.2. Preliminary Survey

The preliminary survey aims to assess the economic and technical feasibility of a project and to identify potential barriers for the development of a geothermal power plant. The area of investigation could be considered on a local, regional, national or international scale.

The topics for consideration and general order of progression are as follows:

- Literature review;
- Data collection, compilation and evaluation (e.g. geological, structural, petrophysical, thermal and geophysical data);
- Conceptual modelling;
- Numerical modelling;
- Potential study and resources assessment;
- Seismic risk evaluation;
- Environmental Impact Assessment (if required);
- Technical and economic feasibility; and
- Legal and societal aspects.

All of these topics need to be addressed in order to identify possible barriers and opportunities for the development of a geothermal project in the UK.

3.3. Exploration Phase

The aim of the exploration phase is to characterise the geological structure and the properties of the geothermal reservoir before proceeding with the first phase of drilling. Less costly and complex investigations are needed prior to drilling to limit the risks of abortive drilling costs. Surface geological surveys are a fundamental and cost effective way of investigating the subsurface. Field assessment can be carried out of geological outcrops, where the subsurface geology is exposed as an outcome of erosion and

weathering at the surface and also topographical variations, which often indicate the geology that is present at greater depths.

Exploration methods most commonly used are geophysical techniques (seismic, gravimetric, electrical and electromagnetic methods) and the drilling of shallow geothermal gradient boreholes. A summary of these methods along with their benefits and limitations are presented in Table 3-1.

Table 3-1 Geophysical methods

Method Description	Benefits	Limitations
2D Seismic: Traditional for oil and gas exploration.	<ul style="list-style-type: none"> Data are often already available for reinterpretation/reprocessing; Standard and commonly used method; and Deep investigation penetration 	<ul style="list-style-type: none"> Limited value in granite or basement rocks, as seismic velocity is relatively homogeneous in such rocks; Inability to detect vertical or very steep faults; limited ability to derive fault directions in three dimensions; Limited information about the hydrodynamic properties; and Not relevant for the thermal properties.
3D Seismic: Routinely used in Oil and Gas exploration and in the geothermal industry	<ul style="list-style-type: none"> Data are often already available for reinterpretation/reprocessing; Deep investigation penetration; A higher resolution of the underground structures; and The ability to derive fault directions in 3D. 	<ul style="list-style-type: none"> Limited value in granite or basement rocks, as seismic velocity is relatively homogeneous in such rocks; Higher costs than 2D; Difficult to deploy in an urban environment; Requires a larger survey area than 2D; Limited information about the hydrodynamic properties; and Not relevant for the thermal properties.
Gravimetry: Provides information about the geological structure at depth and on a local scale, when correlated with other kinds of data, e.g. 3D geological models.	<ul style="list-style-type: none"> Delineation of vertical or sub vertical structures; and Most useful for identifying hydrothermal areas and large igneous intrusions. 	<ul style="list-style-type: none"> Only effective for structures with good density contrast; and Would ideally require a 3D geological model for comparison between modelled and measured anomaly distribution.
Electrical and Electromagnetic: Electrical resistivity is affected by properties such as temperature, porosity, permeability, fluid salinity, partial melt fraction and viscosity.	<ul style="list-style-type: none"> Identification of weak zones; and Phase changes from liquid to gas can be clearly visualised. 	<ul style="list-style-type: none"> Low geometrical resolution at higher depth; and Non-unique explanation for low-resistivity zones.

The drilling of shallow geothermal gradient boreholes is carried out to enable extrapolation of heat changes with depth from shallower elevations to those of the deep reservoir. A summary of the benefits and limitations of such investigation is summarised in Table 3-2.

Table 3-2 Geothermal gradient boreholes

Method Description	Benefits	Limitations
Geothermal Gradient Borehole: Analysis of terrestrial heat flow density (or terrestrial heat flow). It is expressed as the product of the thermal conductivity of rocks and the temperature gradient. The temperature gradient is the rate of increase of temperature with depth.	<ul style="list-style-type: none"> • Identification of geothermal active area. 	<ul style="list-style-type: none"> • Only suitable where geothermal anomalies occur.

Geochemistry can also be used in the exploration phase and encompasses a wide range of methods. Examples of these methods are listed below, with each one fulfilling a different objective.

- Chemical geothermometers - aim to estimate the fluid temperature at a depth to provide better understanding of the flow systems.
- Electrical conductivity measurements - performed on rock samples in the laboratory to characterize the thermal characteristics of the different rock type.
- Other hydrochemical fluid parameters - provide relevant information for the understanding of deep flow systems and include parameters such as pH, Eh, cation and anion concentrations.
- Gas content - obtained at the surface or in natural springs or water wells, includes parameters such as radon and CO₂ and may give important information on subsurface structures.

3.4. Test Drilling

Boreholes (or 'wells') are needed to access geothermal reservoirs for energy exploitation. The drilling phase is probably the most important phase of the overall project, as it typically accounts for more than half of the overall budget. Therefore, detailed planning of the drilling is required.

The aspects that need to be considered as part of the drilling phase are as follows:

1. Choosing an appropriate drilling rig (one of the most important decisions in well planning) and drilling process:
 - Rotation of the drilling bit;
 - Ensure circulation of the drilling mud; and
 - Provide traction power for the drill string to be pulled out of the well and to control the weight on the drill bit during drilling.
2. The design of the geothermal wells. The well diameter and corresponding diameters of injection and production strings are larger than hydrocarbon wells due to the high production rates.

The drilling techniques applied in geothermal reservoir exploration do not differ fundamentally from those applied in drilling oil and gas wells. Particular attention should be paid to the large diameter of geothermal wells, directional drilling and techniques that avoid damaging the ground from which heat may be extracted at depth. This has implications not only on drilling costs, but also for the borehole wall. The drilling bit generally has to be chosen according to the drilled geological formation.

Technical matters that may need to be addressed during the drilling process include; reducing or increasing drilling rate; mud invasion into the surrounding formation from injection into the well bore; clay mineral mobilisation; thermally induced stress on the casing during hot water production; and fluid circulation behind the casing.

A sidetrack is a secondary well drilled from the original well as an offshoot. Sidetracks might be used, for example, to bypass an unusable section of the original wellbore or explore a geologic feature nearby.

3.5. Well Testing, Tracer Testing and Logging

The well testing, tracer testing and logging phase aims at characterizing the properties of the well and of the geothermal reservoir.

Well testing comprises water or air pumping or injection in order to evaluate the quantity of water/gas/oil that can be extracted/injected from/to the reservoir.

- Tracer testing consists of injecting solute compounds directly into the reservoir formation. The behaviour of the solute compounds provides information about the hydrodynamic properties of the reservoir; and
- Well logging describes all the technologies that are aimed at determining the properties of the well and the rock at or close to the well's wall. Technologies include downhole geophysics, stress measurements using over coring and hydraulic fracturing.

This well testing phase usually commences directly after the achievement of the first exploration well although for some tests at least one pair of wells, an abstraction and an injection well, will be required. Dependent on the overall strategy and its suitability for abstraction versus injection, the first exploration well will become the abstraction or injection well of the final scheme. Usually, the overall strategy will be finalised when all wells are complete and have been tested. Normally, the final geothermal power/energy scheme will comprise a well doublet system with one abstraction and one injection well as a minimum. A single well/standing column wells ("coaxial tube") system is an exception. The concept of single well/standing column wells ("coaxial tube") systems are outlined in Appendix B.

3.6. Reservoir Development

The knowledge of the in-situ stress field within a geothermal reservoir is fundamental for the design of the stimulation tests. Hydraulic stimulation can be used as a method of increasing the fluid permeability; it consists of large volumes of water injected at a high flow rate and at a pressure close to the breakdown pressure.

Two mechanisms should be distinguished:

- Shearing and opening of natural fractures through shear failure, at low pressures. The shearing of fracture planes induces seismicity; and
- Creation of artificial fractures (Hydraulic fracturing) at high pressures (tensile fracturing).

Knowledge about the stress regime is of great importance to understand or even to predict the hydraulic fracturing process. The response of the rock mass to hydraulic stimulation (fracturing / stimulation) can be predicted with geomechanical analysis, and thus prior to the water injection.

Chemical stimulation consists of acid injection into the open hole at pressures low enough to avoid formation fracturing. Three sequences are needed for the treatment of a classic geothermal reservoir:

- Preflush – performed most often with an HCl solution, first to displace the formation brines;
- Main flush – used to remove fine materials such as drill mud and residual broken rock created during the drilling process with potential to block fluid pathways. This flush is most often a mixture of HF and HCl or organic acids pumped into the well; and
- Overflush - displaces the non-reacted mud acid into the formation and the mud acid reaction products away from the well bore.

3.7. Production and Reservoir Monitoring

There is no standard procedure for monitoring of geothermal fields and their production. However, the process generally comprises monitoring factors such as reservoir pressure and temperature and geothermal fluid chemistry alongside the observation of seismic activities. An adequate monitoring program helps to avoid overexploitation of the geothermal reservoir that would lead to unstable rates of production.

3.7.1. Production Pump

Self-flow of the well could occur due to artesian or thermosyphon effects. When self-flow is not sufficient to guarantee the economic viability of the power plant, the installation of a production pump is necessary. Depending on the setting depth and water temperature different types of pumps could be used. They include line shaft pumps and submersible pumps for example (Ref. 42).

3.7.2. Injection Pump

To minimize environmental impact and enhance fluid recharge into the geothermal system under operational conditions, reinjection of waste water becomes a model feature of all geothermal developments. In some cases the use of reinjection pumps become necessary and part of the production facilities, although, where practicable, gravitational recharge is preferred.

3.7.3. Corrosion and Scaling

Effective protection from corrosion and scaling of wells is required. This can be achieved by injecting inhibitors based on quaternary amines into the fluid, whose filming capacity ensures an optimum protection of the casing.

3.7.4. Reservoir Management and Monitoring

The purpose, goals and design of a geothermal monitoring program mainly depend on the local geological environment and production conditions. Parameters that might need to be monitored include; production temperatures and flow rates; pressure and temperature of the reservoir; fluid chemistry; seismicity; gravity; and the electrical potential of the fluids. Schemes with non closed cycle heat to power conversion systems may also require monitoring for microbiological organisms to prevent the risk from biological clogging.

An adequate monitoring program combined with methods of reservoir modelling leads to a better understanding of the geothermal system and helps to avoid overexploitation of the geothermal reservoir.

3.8. Phases of Deep Geothermal Power Project Cost and Risk Profile

As discussed above, each phase of a Deep Geothermal project, much like an oil and gas or mineral exploration project, has associated costs and financial risk profiles, with the aim of each phase to reduce overall uncertainty and risk of the ultimate project. A summary of the phases with approximate magnitude of cost for each is provided in Figure 3-1. The costs are in rough orders of magnitude and presented as a percentage of total outturn cost.

The risk profile decreases with time and expenditure as additional data are gathered. However, many of the project costs are up front and therefore the early levels of risks are extremely high, with a large chance of scheme failure after spend of c.60% of overall scheme budget. This makes early scheme investment unacceptable to investors owing to the high risks for limited return on investment. These risks and the investor view of them are summarised in Figure 3-2.

The stakeholder engagement carried out as part of this study involved capturing key stakeholders' views, especially regarding why investment has not occurred to date. The conclusion drawn was that Deep Geothermal in the UK for power generation is currently un-investable as the resource remains to be fully identified and characterised and therefore falls within the research phase. As demonstrated by Figure 3-2, the state of UK geothermal is in the upper risk bracket of the research phase as no potential production wells have been drilled into the resources to prove reserves. Until such time as this has been carried out and the risk profile moves towards development phase, the financial institutions will remain of the opinion that such projects are not investable.

Elsewhere in the world there is more appetite for investment. For example Geodynamics and TATA are currently investing in a 1MW power plant in the Cooper Basin in South Australia (Ref. 23). However, this is an area which has been sufficiently drilled and tested in order to move the project into development and towards the construction phase.

In Chile, in order to move through the development phase and appeal to investors the government are considering drilling insurance (Ref. 18). Such insurance should manage the risk of failed drilling such that geothermal energy schemes are more appealing to investors.

Figure 3-1 Approximate Spend Profile for Phases of a Geothermal Project

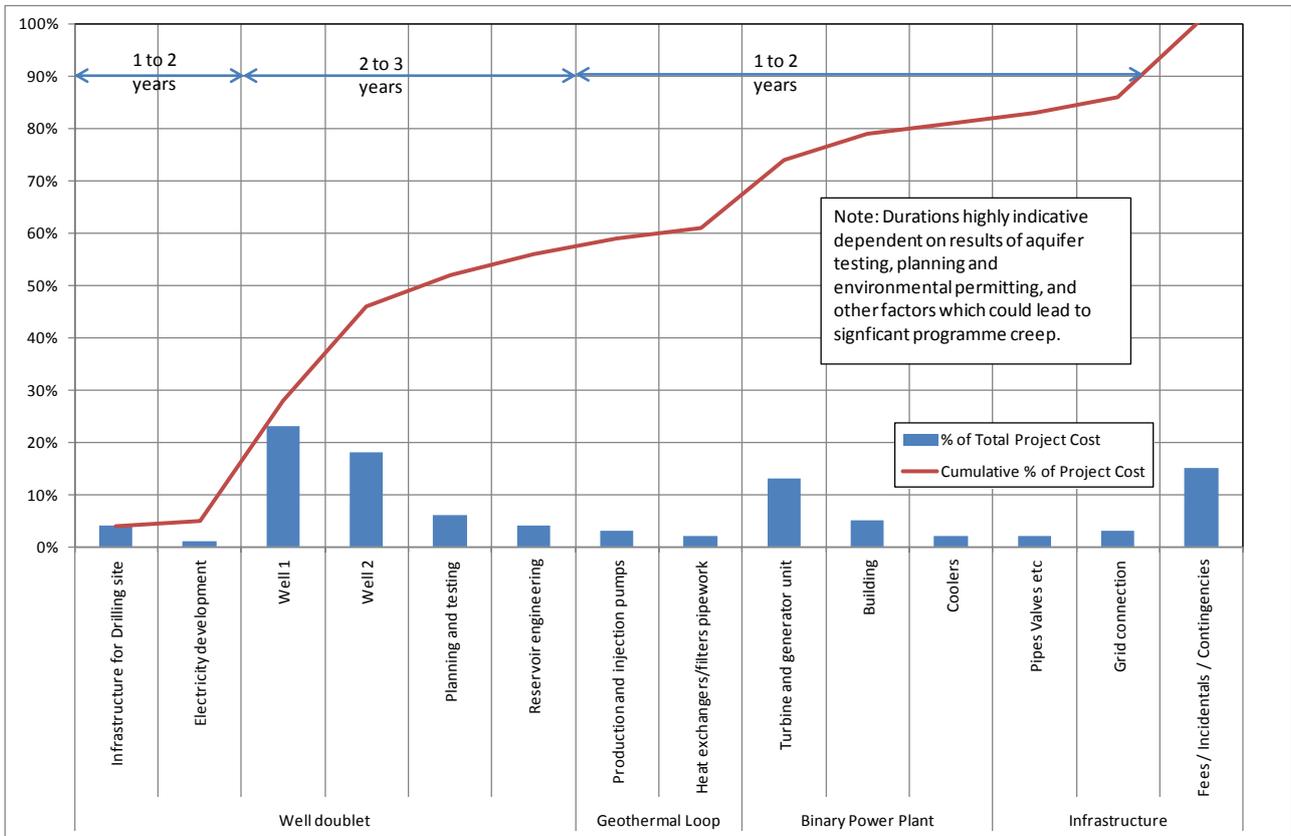
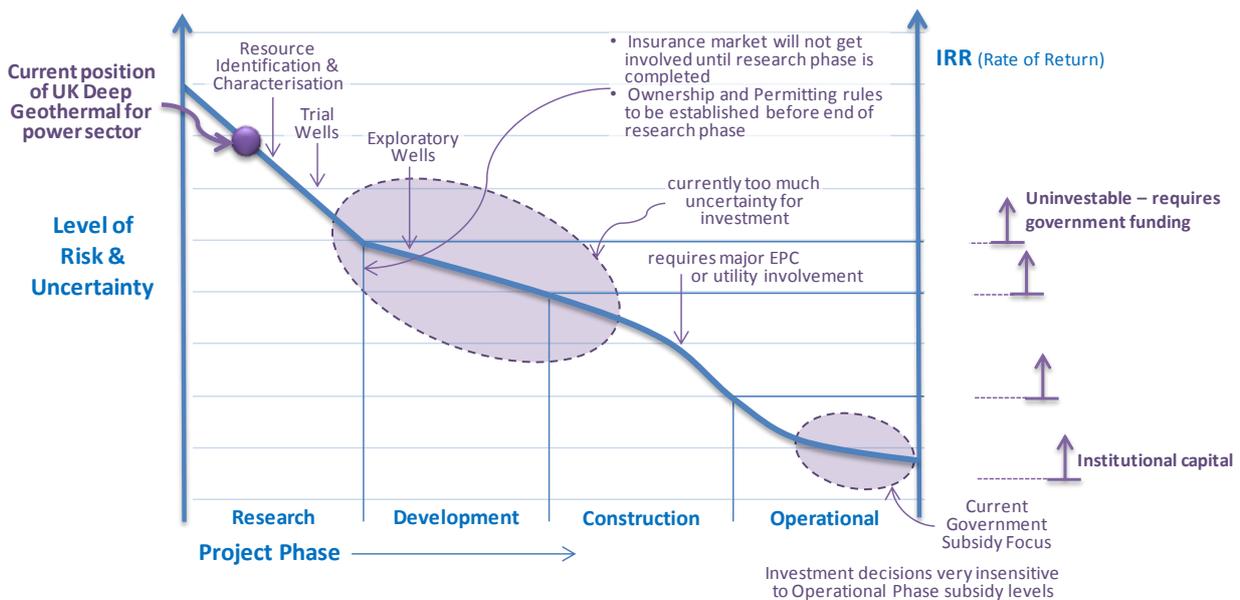


Figure 3-2 Stakeholder Engagement Investor View



Conclusion

Deep Geothermal for power is at the research phase = unproven = uninvestable

NOTE: IRR levels, funding types and boundaries are for broad illustrative purposes and should not be considered as exactly defined.

Phases of Geothermal Power Project Development - Key Points

- A preliminary survey will assess the economic and technical feasibility of a project and to identify potential opportunities, barriers and constraints.
- The survey will comprise a study of the geology. This could involve geophysical methods of exploration prior to the drilling of boreholes (wells).
- The level of resource testing and understanding will be dependent on the number of wells drilled, i.e. only limited testing can be carried out with a single well but better data gathered and understanding gained from double or multiple well testing.
- Hydraulic stimulation can be used as a method to develop the reservoir / increase the reservoir fluid permeability, thereby facilitating increased flow rates required for the geothermal power project.
- In order to safeguard its sustainable utilisation, the reservoir should be monitored for induced seismicity and changes in temperature, flow rates, pressure etc.
- An adequate monitoring programme combined with methods of reservoir modelling leads to a better understanding of the geothermal system and helps to manage risks of overexploitation of the geothermal reservoir.
- Initial costs to prove reserves are high and the risks make the project unpalatable to investors currently owing to limited return on investment.

4 Geothermal Power Generation Systems

4.1. Overview

Geothermal power production relies on extraction of heat from the ground at sufficiently high temperature and volume to drive a turbine and associated electrical generator. The below ground temperature dictates the method of heat extraction and subsequent power generation and the thermal conductivity and hydraulic conductivity dictates the rate of heat transfer to the geothermal fluid and fluid transfer and volume through the reservoir.

There are locations around the world where steam is directly emitted from geothermal locations and power plants are constructed to utilise this (Dry Steam Plant). Such sites are extremely limited and most of the operational geothermal power stations use geothermal heat to generate steam directly from below ground directly to drive a turbine and generate electricity (Flash Power Plant). Steam from underground can also be used indirectly via a heat exchanger. Condensate water is normally returned to the underground thermal reservoir.

Where temperatures are insufficient to directly generate steam a binary system approach is used. Binary plants typically use an Organic Rankine Cycle (ORC) system. This uses hot water to boil off a secondary working fluid which has a lower boiling point than water. The resulting vapour expands and is used to drive a turbine in a similar approach to a conventional steam turbine. The two fluids are kept entirely separate. Modified ORC systems have also been developed utilising mixed working fluids such as water and ammonia in the Kalina cycle. This allows generation from lower temperature heat sources and can operate with marginally higher efficiencies than a conventional ORC system.

Some plants utilise a hybrid of Flash Power and a Binary Cycle.

4.2. Technologies

4.2.1. Flash Power Plant

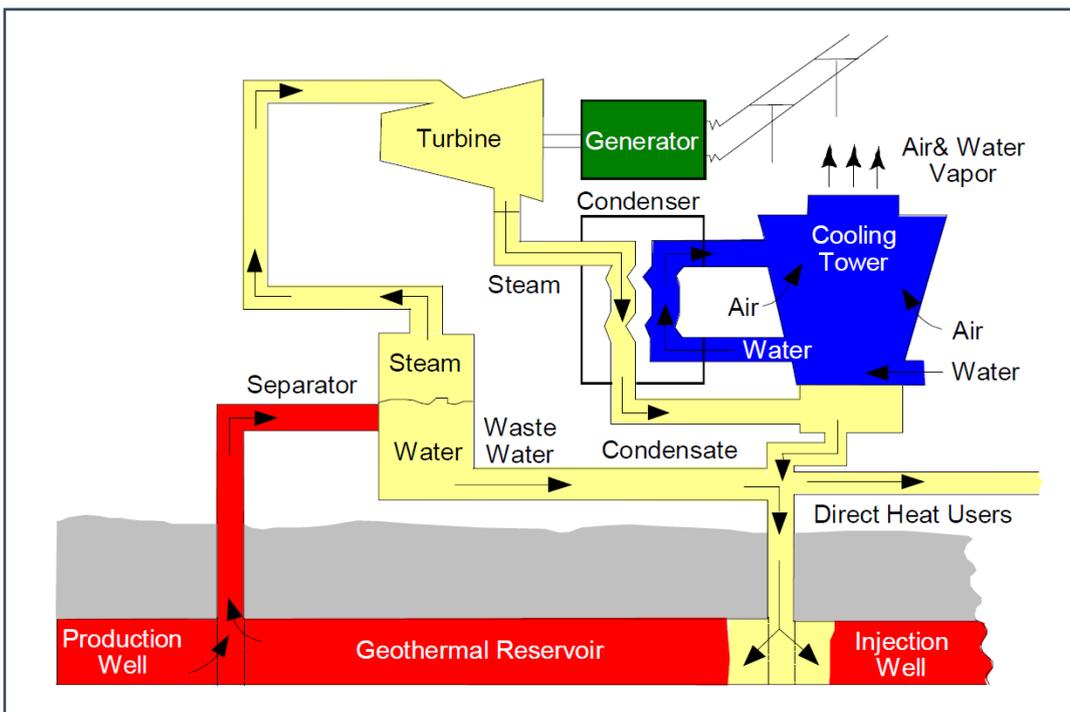


Figure 4-1 Flash Power Plant (Source: Geo-Heat Center)

The Flash Power Plant design (Figure 4–1) is used extensively throughout the world. However, it typically requires geothermal temperatures in excess of 180°C and is therefore unlikely to have application for geothermal generation within the UK. Most Flash Power Plants utilise cooling towers in the condensing process which leads to a water consumption of between 6,500 to 15,000 l/MWh of generation. Air cooling can be used but is less efficient and can be problematic in summer.

4.2.2. Binary Power Plant

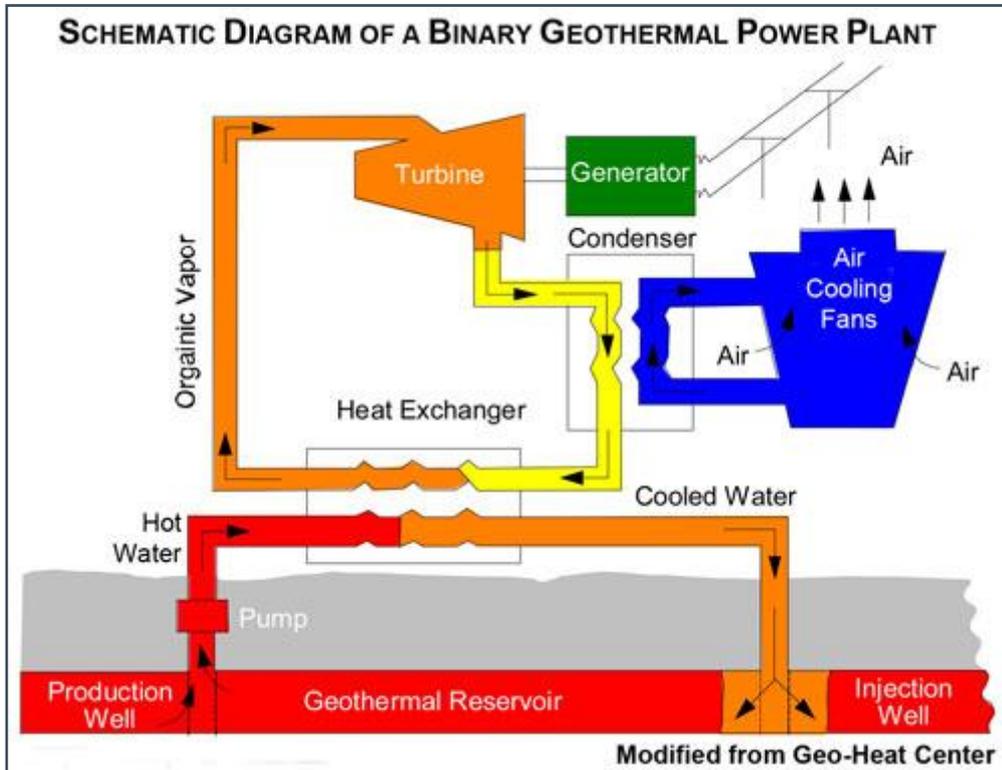


Figure 4–2 Binary Power Plant (Source: Geo-Heat Center)

The Binary Geothermal Power Plant (Figure 4–2) is commonly used for power generation and it is estimated that around 15% of plants use this system. It can operate with resource temperatures as low as 74 °C and up to 180 °C. Water is extracted from the production well and the reservoir is replenished through the injection well. At lower temperatures the transmissivity of the reservoir is very important because if it is too low, the power required for pumping the water between injection and abstraction wells will outweigh the power generated. These plants operate as a closed loop system with the above ground water being pumped through a heat exchanger, where it heats the working fluid and is then returned to the injection well. The working fluid, which is vaporised by the heat exchanger, drives the turbine and is then condensed back to a liquid. Where sufficient temperature remains and there is a suitable heat source, the cooled water may be used for low grade heating prior to returning it to the injection well. In these cases as the useful output is power and heat, they are referred to as Combined Heat and Power (CHP).

The typical efficiency of a binary power plant is in the range 10 – 13% with the higher end of this efficiency range being achievable where higher temperatures (circa 180°C) are available. The lower the temperature the lower the efficiency.

Kalina Cycle

The Kalina Cycle is an improvement in thermal power plant design over that of the Rankine Cycle binary plants. This is due to the Kalina Cycle utilising an ammonia-water mixture as a working fluid to improve system efficiency and provide more flexibility in various operating conditions.

A number of projects have recently been developed in Europe which utilise the Kalina cycle. Here, the working fluid utilises a mixture of ammonia and water, which boils over a range of temperatures and has a good temperature profile match with the heat profile of the heat exchanger. This enables higher transfer

efficiencies over a range of temperatures. Also, through varying the ratio of ammonia to water (typically 70:30), some control over the properties of the fluid can be achieved enabling a system to be optimised for a varying heat source. A consequence of using an ammonia-water based fluid rather than conventional ORC fluid (e.g. pentafluoropropane) is that a larger heat exchanger is required and the system is more complex.

Power Output

In all but the flash steam cycle plants the gross power produced is significantly reduced by the power required to operate the abstraction and return pumps and other station auxiliary plant. The greater the requirement for such pumping powers the lower the net efficiency and economic return of the plant.

District Heating

Whilst District Heating Networks (DHN) are not presently common in the UK, it is recognised as an important part of the movement towards a low carbon economy. DHN aggregate a number of heat loads into a common single supply circuit, the heat is then provided by one or more centralised energy sources of which geothermal is considered suitable. Several major UK cities such as Sheffield operate DHN and a number of other UK cities are currently making plans to introduce them.

Where such a DHN network is in close proximity to a geothermal project, it provides an ideal opportunity to maximise the heat available from the geothermal scheme, this can be both a geothermal heat only scheme and Geothermal CHP schemes. The viability of introducing a new or connecting to an existing DHN will be dependent on the distance from the geothermal scheme, the total heat load and the number / size of the individual heat loads – with increasing distance and a higher number of smaller loads the costs associated with the DHN are likely to increase along with the system losses of transporting the heat.

4.3. Existing Generating Plant Examples – ORC & Kalina Cycle

There are a number of existing geothermal power plants based on ORC and Kalina cycle technology currently in operation. A summary of these existing plants is summarised in Table 4-1 and further detail where available provided below.

Table 4-1 Summary of Existing ORC and Kalina based Generating Plants

Name	Location	Operation Date	Technology Type	Electrical Power (MW)*	Thermal Power (MW)
Unterhaching Power Plant	Germany	2009	Kalina	3.4	30
Landau Power Plant	Germany	2009	ORC	3.0	3.5
Husavik facility	Iceland	1999	Kalina	2.0	20
Bruchsal facility	Germany	2009	Kalina	0.58	Unknown
Matsunoyama Onsen hot spring	Japan	2011	Kalina	0.05	Unknown

*There is a lack of clarity as to whether the publically available data is reporting Net or Gross electrical power.

Unterhaching Power Plant, Germany (Kalina)

Commissioned in April 2009 the Unterhaching Power Plant was the first of its kind in the low enthalpy region of southern Germany. This plant produces 3.4MW of electric power and 30MW of heating for the local township of Unterhaching. Up to 150 litres per second of water at more than 120°C are extracted from a depth of over 3,300m.

Landau Power Plant, Germany (ORC)

The facility in Landau is rated 3MW electrical and 3.5MW thermal. The plant exploits thermal water of 155°C from a depth of 3,000 metres. The high temperature water is used to generate electricity. Once it leaves the generating plant the residual heat from the water at a temperature of 72°C is used in a district heating system. Then, the water at a temperature 50°C is injected back under the surface via a 3,170 metre deep injection well. The electricity generating system uses an ORC.

Husavik facility, Iceland (Kalina)

Husavik facility in Iceland is rated with 2MW electric power output and 20MW thermal. It should be noted that plant this is in a geothermally active region and therefore might not be applicable to the UK situation.

Bruchsal facility, Germany (Kalina)

Commissioned in December 2009, the Bruchsal facility produces 580kW of electricity.

Matsunoyama Onsen hot spring, Japan (Kalina)

The first ever 50kW EcoGen unit was installed at Tokamachi, Niigata in Japan in 2011. The EcoGen units are based on the miniaturization of the Kalina cycle and designed for the Japanese hot spring market and other low enthalpy geothermal markets.

4.4. Case Study – Pump & Well Operation

As discussed previously, pump selection is important because the power used to drive production and injection pumps reduces the net efficiency of the power plant and, as a worst case, can render the project uneconomical. Pump performance can vary not only between types of pump, but also at different temperatures and pressures within the borehole or well. An example of how the efficiency of a pump can vary from the EGS Soultz Geothermal Project is presented in Table 4–2 which shows the difference of power consumption and efficiency with depth of the same pump.

Table 4–2 EGS Soultz Geothermal Project (France): Line Shaft Pump (LSP) performance at two different depths in GPK2 well

Depth	07 August 08	09 April 09
Pump Depth	350 m	250 m
Flow Rate	24.1 l/s	20 l/s
Production temperature	165°C	162°C
Back pressure	54 bars	44 bars
Intake pressure	36.6 bars	33.72 bars
Total dynamic head	17.4 bars	10.28 bars
Hydraulic drawdown	80 m	10 m
Hydraulic power P1	43.1 kW	20.56 kW
Hydraulic power P2	64 kW	37.87 kW
Global recover (P1/P2)	67%	54%

Pump efficiency curves often drop dramatically as the duty point moves away from the Best Efficiency Point (BEP) and the results of poor matching of the pump to the duty point can be seen in the table. With multi-stage line shaft pumps each stage will increase the head without any increase in flow capacity. It may be possible to remove stages from existing pumps to match a reduced change in duty to achieve the best efficiency. Therefore care is needed with pump design to ensure that parasitic power losses from inefficient pump provision is minimised.

4.5. Case Study – The German Situation

In Germany, the first power production commenced at a small geothermal plant at Newstadt Glewe using both geothermal and fossil energy to provide district heating. Although this plant is essentially for heat production (~7 MWth from geothermal) for a district heating scheme, some electricity is produced (230 kWe) in the summer months only, when the heating demand is low.

In 2004, the advantageous feed in tariff was increased, including support for geothermal power production, and by 2009 the overall installed electrical capacity had increased to 6.61 MWe with the construction of the CHP plants at Landau and Unterhaching.

In 2010, the installed capacity represented around 0.021% (10 MWe) of the total installed electricity generation capacity from renewable energies (53,944MW). Renewable energy sources supplied approximately 17% of the electricity demand in Germany (485,000 GWh). Geothermal in 2010 provided 27 GWh of electricity or 0.006% of total demand.

By 2013, there is now 12.3 MWe installed, a further 48 MWe under construction and an additional 90 MWe in the planning stage. Heat production from CHP and heat only plants is currently at 223 MWth.

The German national plan projects rates of installed capacities from geothermal to increase to ~300 MWe and ~1700 GWh respectively by 2020 (Ref. 30). This geothermal energy will be approximately 0.3% of the national generation from renewable resources. By then, 35% of the electricity demand is to be supplied from renewable resources and geothermal would contribute around 1.2% of annual consumption.

Geothermal Power Generation Systems - Key Points

- Flash Power Plants are unsuitable for the UK geothermal situation owing to the high geothermal temperatures needed (in excess of 180 °C), which are not readily available in the UK.
- ORC, Kalina or CHP plants are more applicable (operating temperatures potentially as low as c.100°C), with efficiency and economic sustainability likely to need a heat element as well as a power element of the power plant.
- Managing and maintaining pump efficiency is essential to limit net loss of power through the system and maximise profitability of the plant.
- Power can be produced with temperatures generally over 100°C and the higher the temperature the more efficient the power production from a given quantity of hot water.
- CHP applications increase the utilisation of heat extracted, particularly where low grade heat can be used.

5 Lessons Learned From Past Projects

5.1. General Considerations

Lessons learned and experiences gained from geothermal projects in Europe and elsewhere are invaluable in gaining an understanding of the risks associated with geothermal power exploration and exploitation in the UK. The questions to be answered are:

- What failed/succeeded in these projects?
- What are the reasons of failure/success?
- Could it be done differently?

The following sections focus on stimulation (EGS) technologies applied to crystalline rocks. They can also be applied to sedimentary aquifers where enhancement of the rock permeability may be required.

The Rhine Valley is currently the main area for EGS projects in predominantly crystalline rocks, albeit with overlying sedimentary rocks, and provides an initial focus for many lessons learned. An overview of other EGS projects is also provided together with lessons learned in sedimentary aquifers. A summary of the lessons learnt as relevant to the UK and described in the following sections is provided in Table 5–1.

5.2. Rhine Valley

From a geological perspective, the Rhine Valley is a rift zone characterized by a strike-slip to normal faulting stress regime. It is the most important region for geothermal projects in crystalline rock in Europe. Several geothermal power plants are currently active in the Rhine Valley:

- The Soultz-sous-Forêts EGS site (France) is a R&D EU-financed pilot project active since 1986. The current installed capacity is 1 MWe. Three deep wells were drilled to 5 km depth in granite. Methods of stimulation enhancements (EGS) to create the geothermal reservoir were carried out within the granite.
- The Landau power plant (Germany) has been in operation since 2007. Two 3 km wells were drilled; the open sections of the wells are located in the Buntsandstein and in the top of an igneous intrusion. These open sections target regional faults. One of the two wells was found sufficiently productive without stimulation. For the second well stimulation, comprising hydraulic fracturing and acidizing, was undertaken, presumably targeting both the Buntsandstein and the igneous intrusion. The installed capacity is 3.6 MWe.
- The Insheim power plant (Germany) has a drilling target the same as in Landau (fault zones at the top of the igneous intrusion and within the Buntsandstein). Since 2008, two wells with depths of 3500m have been drilled. The installed capacity is 4 MWe. A sidetrack was successfully drilled from the first well, because of a poor well production in comparison with the second well.
- The Rittershoffen project (France) had its first successful borehole drilled in 2012. Start of operation is planned in 2014. This project also targets faults zones at the top of the granite.
- The Basel site (Switzerland) is located in the southern boundary of the Rhine Graben. One 5 km borehole was drilled in 2006 into the basement. Seismic events of 3.4 on the Richter scale occurred during stimulation, which led to the cessation of the overall project (Ref. 17).

The major findings of the Rhine Valley projects can be summarized as follows:

5.2.1. Exploration and drilling target

Geologically the Rhine Valley is situated in a rift zone (a linear zone where the Earth's crust and lithosphere are being pulled apart) in the centre of which a linear feature comprising a down faulted depression, called a graben, was formed within geological timescales. Granites and gneiss forming the bedrock had been formed by volcanic activity during the Palaeozoic era and are now covered by layers of red sandstone, shell limestone and Keuper Marl (Mercia Mudstone Group).

In Soultz-sous-Forêts and in Basel the top of the granite is always much more fractured and permeable than the deeper granite. Consequently, the target of the more recent project was the fault zones located in the top crystalline and the bottom of the sediments. These fault zones appear to be very efficient for geothermal exploitation (see for example Landau, Insheim and Rittershoffen).

Vertical seismic profiles (VSP) were performed in Soultz. These seismic techniques appeared to be relatively cost intensive and results were disappointing in the granite environment.

5.2.2. Drilling

The open-hole section should be drilled under balanced conditions, i.e. with a density of the drilling mud selected to minimize drilling mud and cuttings entering the formation during the drilling.

The drilling well's orientation should be chosen according to stress field orientation. Stimulation pressures directed into the direction of minimum horizontal stresses are more likely to open fractures with a higher success rate in increasing the transmissivity.

Well alignment should be parallel to maximum horizontal stress in order to allow the best hydraulic connection between wells, whilst minimising the risk of short circuiting the geothermal reservoir.

5.2.3. Testing and stimulation

Different stimulation concepts have been applied to enhance the productivity of geothermal wells as reported in Huenges 2010 on Enhancing Geothermal Reservoirs (Ref 42). Stimulation techniques can be subdivided with respect to their radius of influence.

Techniques to improve the near-wellbore region up to a distance of few tens of metres are chemical treatments, and thermal fracturing.

The only approved stimulation method with the potential to improve the connectivity within the geothermal field for greater distances, up to several hundreds of metres away from the borehole, is hydraulic fracturing.

The wells must be cleaned (cuttings removed) before hydraulic stimulation can take place. The original concept in Soultz-sous-Forêts was to perform hydraulic stimulation without cleaning the well first (i.e. with cuttings still present). The aim was to use the cuttings as a natural proppant in order to keep the sheared fractures open. Following hydraulic stimulation it appeared that the cuttings plugged the fractures and also damaged the production pumps afterwards, which is still an issue currently.

There is evidence in Basel and Landau that the increase in fluid permeability due to hydraulic stimulation was within close vicinity of the well only, a distance of around 10 to 50 m. It is not known whether this was a result of local well conditions limiting the extent of hydraulic stimulation or owing to the use of other, near well stimulation techniques such as chemical or thermal stimulation. However, if the former, this study highlights the risk of potential limited stimulation which might limit the fluid movement and thermal recovery within a well field.

It is understood that the first well Landau was very productive and did not require stimulation. However, the second well required was not so productive and required both "massive hydraulic stimulation and acidizing" [DiPippo 2012 (Ref. 17) and personal conversations with D Baumgaertner during the geothermal workshop in June 2013]. As a result, it is possible that, whilst the overall permeability of reservoir unit was good, the open section of the second well was unluckily placed in a local zone with low permeability only. Therefore, it is possible that a short distance was all that was required and the stimulation was never planned to increase the permeability further afield (as this may not have been necessary).

Geomechanical analysis prior to the stimulation enables a proper design of the stimulation scheme. This is essential as hydraulic stimulation has to be carried out with care, to avoid seismic events (risk mitigation). Seismic events felt by the population can halt a project (see Ref. 17). The risk of producing significant seismic events increases with injection time. This was experienced during hydraulic stimulation in Soultz and Basel for example. During all stimulation, the largest events occurred at the end of the injection or during shut-in of the well. As a consequence, short-term stimulation, using high flow-rates and high pressure, give best results in terms of stimulation efficiency. It offers the advantage of limiting the risk of significant seismic events (i.e. those noticeable to the population). For further discussion on seismicity see Sections 6.3.1 and 8.4.5.1.

Reservoir tomography (seismic velocity distribution) appears to be a highly beneficial tool to monitor the reservoir during stimulation. Tomography studies used in Soultz showed that some seismic slips could occur in the reservoir (creating permeability without associated acoustic emission).

Methods have been recently developed in order to understand and predict micro-seismicity during hydraulic stimulation in geothermal reservoirs (Ref. 5).

5.2.4. Production

Seismic events could occur also during production/operation of the reservoir (as was the case in Landau) as well as during reservoir stimulation. Consequently, the best option to minimize the influence of the geothermal exploitation on the reservoir is to use the most productive borehole for injection and the least productive one for production. Thus, the overpressure induced by injection is minimized.

In Soultz, deposits and scaling minerals collected in the pipes, filters and heat exchangers were radioactive. Naturally Occurring Radioactive Material NORM deposits have to be treated with appropriate care and under supervision of the adequate authority similar to the descaling of gas pipelines for example, where NORM materials also accumulate.

5.2.5. Monitoring

Geophysical monitoring using seismic techniques may be done using an existing regional or national seismic grid, where there are seismic stations of the grid in the vicinity of the EGS development site, or by installing a dedicated seismic monitoring system which can be tailored to the site-specific conditions and particular stimulation parameters (Ref. 17).

For example in Soultz, a downhole seismic network of six stations registered the micro-seismic events occurring during stimulation, while a surface seismic network was also available and well adapted for the micro-seismic event determination (Ref. 42). These micro-seismic events can be used to geophysically map the reservoir in order to provide a better understanding of where stimulation is occurring, the fracture and therefore flow network and other geophysical properties of the area being exploited.

In Soultz and in Basel it has been shown that the accuracy of the seismic monitoring network is of key importance, as the quality of the seismic information gathered during reservoir stimulation and operation could definitely help with the understanding of processes occurring in the geothermal reservoir.

5.3. Experience from Other EGS Sites

A brief overview of lessons learned in other EGS sites worldwide is presented below. More details concerning most of these sites can be found in Tester, J.W. et al., 2006 (Ref. 62).

5.3.1. Fenton Hill, New Mexico, USA

The Fenton Hill project in New Mexico was the first EGS project. It was the first attempt to develop a deep, full-scale HDR reservoir. It started in 1974 and ended in 1993. This project proved that it was possible to connect two boreholes with an artificially created fracture(s).

The major findings of the project can be summarized as follows:

- The proof of concept was established (drilling and artificial connection between wells was possible);
- Fractures could be artificially created by hydraulically stimulating wells drilled in hot, deep, intrusive rock;
- The stress field may vary with depth;
- The second well should be drilled after the first one has been stimulated, in order to target the best newly created features;
- Directional drilling control was possible in hard crystalline rock;
- Acoustic emission (seismicity) and tracer tests could help mapping the reservoir; and
- It was not possible to create a closed reservoir, as water losses between the wells were important at the high pressures needed for operation.

5.3.2. Rosemanowes Quarry, UK

The Rosemanowes project started in 1977 and ended in 1992. It is located near Penryn in Cornwall. Three wells were drilled and several stimulation/circulation experiments were undertaken.

The major findings of the project can be summarized as follows:

- It was clearly shown for the first time that permeability enhancement achieved through hydraulic stimulation was due to shearing of pre-existing fractures and not by tensile fracturing of unknown rock (hydrofrac);
- This shearing is linked to the fact that the stress field is anisotropic in basement rocks, implying that the natural fractures fail in shear, long before the opening of fractures (jacking) occurs, or before new fractures are created;
- The hydraulic conductivity of the reservoir could not reach a commercial level; pumping costs were always too high; and
- Direct connections could be established between wells. It was clearly shown that cold injected fluids could find some short pathways through the reservoir, resulting in a lower production temperature.

5.3.3. Hijori and Ogachi, Japan

Two EGS projects were carried out in Japan in the 1980s-90s in Hijori and Ogachi.

The major findings of both projects can be summarized as follows:

- The well locally influences the stress field, as the growth direction of the seismic cloud changes at a certain distance of the well.
- Seismic events were produced during the production/circulation phase.
- Injections on short term at high pressures could improve the well's injectivity.
- Long term injections and circulation at lower pressures had an even more beneficial effect. This is because the reservoir grew and connectivity improved more during circulation tests than during efforts to stimulate at high pressures.
- Thermal short-circuits occurred. This is why well spacing should be carefully considered owing to short-circuits being more likely to occur with narrow spacing. However, the fluid connection between the abstraction and injection zone is more difficult to establish with a wider spacing.

5.3.4. Cooper Basin, Australia

The Cooper Basin was known from oil exploration drilling to have temperatures of c.250°C at c.4,000m depth.

Six wells are known to have been drilled (maximum depth 4,900 m) at the time of writing. This Cooper Basin geothermal site is characterized by an overthrust faulting mechanism. Although the altered granite was relatively easy to drill, some drilling problems occurred. Equipment was lost in a hole and the drilling of a sidetrack was necessary as the fractured unstable rock meant that balancing drilling fluids was critical to successful drilling.

Although such drilling issues were encountered, the basin reserves and the ability to exploit them were confirmed sufficient to move from the research to the development phase. Geodynamics and TATA power have commissioned a 1MW plant, as reported in June 2013, after which it is anticipated that significant further development of power generation in the basin will be carried out (Ref. 23).

5.3.5. The Geysers, USA

The experience of the Geysers field, USA, with 22 power plants and a cumulative capacity of 1,531 MW shows the importance of a common monitoring and management plan for nearby wells, which might be utilized by different users. The objective is to maintain a sustainable production of the geothermal fields. The importance of re-injecting produced fluids in the geothermal field has been emphasised.

The over exploitation of the geothermal field (steam production) during the 80's led to a drastic pressure drop in the field. This pressure drop resulted in a decline of the production of all the power plants. The pressure

drawdown due to overexploitation of the Geysers geothermal field has been notably reduced since the water reinjection programme started in 1992.

5.3.6. Groß Schönebeck, Germany

A geothermal research project has been set up at Groß Schönebeck, Germany, designed to deliver an improved understanding of the long-term reservoir characteristics during geothermal power production.

One of the aims of this project is to investigate whether the geothermal fluid temperature will be maintained over a minimum of 20 to 30 years (only over such time periods are geothermal power stations commercially valid).

The location of this geothermal power plant is representative of areas in Germany that are underlain by sedimentary aquifers. If it is possible to construct a plant in these areas, economically generating electricity from geothermal power, then it should be possible in many other areas and geothermal power could purportedly provide at least 5% of heat energy and power demand in Germany (Ref. 40).

5.3.7. Experience from Hot Sedimentary Basins

The following experience from geothermal projects in hot sedimentary aquifers can also be used for EGS projects in the UK:

- Scaling problems can be solved with inhibitors. In the Paris Basin, where about 30 doublets target the Dogger aquifer for heating purpose, scaling and mineral deposits in the wells could lead to the abandonment of a well after a few years of exploitation only. Therefore, scaling inhibitors, injected in the production well using a downhole pipe were successfully developed and applied in the 1980s;
- The logging campaigns of the cased sections of the well should not be neglected. For example, realising an imaging log such as a UBI or a FMI in cased sections (realised before installing the casing) can help identify large scale structures, which could eventually be targeted by a sidetrack later on if the first well is not productive. This scenario was observed in Blumau (Austria);and
- 3D seismic techniques can bring a decisive advantage to a geothermal project (at least in deep sediments), as it allows an optimal targeting of the well. Kirchweidach, Germany (Ref. 45) is an example where a successful sidetrack was planned based on 3D seismic attributes analysis from a non-productive borehole.

Table 5–1 Summary of lessons learnt from Non-EGS and EGS Projects in Crystalline Rock and Hot Sedimentary Rock Geothermal Projects

Region	Geology	Lessons Learnt
Rhine Valley <ul style="list-style-type: none"> • Soultz-sous-Forêts (EGS site) (France) • Landau power plant (Germany) • Insheim power plant (Germany) • Rittershoffen project (France) • Basel site (Switzerland) 	<ul style="list-style-type: none"> • Granite • Sedimentary and Igneous rock • Igneous rock • Granite • Not stated. 	<ul style="list-style-type: none"> • Exploration and Drilling Target. <ul style="list-style-type: none"> - Fractured region in the top of granite appears to be very efficient for geothermal exploitation. More permeable than deeper in the granite. - Vertical seismic profiles (VSP) were performed in Soultz. It appeared to be relatively cost intensive and results were disappointing in the granite environment. • Drilling <ul style="list-style-type: none"> - Open hole section should be drilled under balanced conditions in order to minimize drilling mud and cuttings invasion into the formation. - Drilling orientation should be chosen according to stress field orientation, increases chance of high overall transmissivity. - Well alignment should be parallel to maximum horizontal stress, in order to allow the best hydraulic connection between wells. • Testing and Stimulation <ul style="list-style-type: none"> - Wells must be sufficiently cleaned before hydraulic stimulation can take place to reduce the risk of plugging fractures and also damage of the production pump. - Increase fluid permeability due to enhancement of permeability of the well. - Hydraulic stimulation has to be realised with care, to avoid significant seismic events (risk mitigation). - Geomechanical analysis prior to the stimulation allows a proper design of the stimulation scheme. - Short-term stimulation, using high flow-rates and high pressure give best results in terms of stimulation efficiency, and offers the advantage of limiting the risk of significant seismic events. - The ability to improve the rock mass permeability through stimulation appears to be limited (max 1 l/s/bar). - Tomography studies are a good method of monitoring the reservoir during stimulation. - Recent methods have been developed in order to understand and predict micro-seismicity. • Production <ul style="list-style-type: none"> - Significant seismic events could occur during production/operation of the reservoir as well as during stimulation. - Best option to minimize the influence of the geothermal exploitation on the reservoir is to use the most productive borehole for injection and the less productive one for production. - NORM deposits may be encountered and must be treated with appropriate care and supervision. • Monitoring <ul style="list-style-type: none"> - Accuracy of the geophysical seismic monitoring network is of key importance in understanding processes occurring within geothermal reservoir.

Region	Geology	Lessons Learnt
Fenton Hill, US (EGS, HDR Site)	<ul style="list-style-type: none"> Igneous rock 	<ul style="list-style-type: none"> Fractures could be artificially created by hydraulically stimulating wells drilled in hot, deep, intrusive rock. The stress field may vary with depth. The second well should be drilled after the first one has been stimulated, in order to target at best the newly created features. Directional drilling control was possible in hard crystalline rock. Acoustic emission (seismicity) and tracer tests could help mapping the reservoir. It was not possible to create a closed reservoir, as water losses between the wells were important at high pressures needed for operation.
Rosemanowes Quarry, UK	<ul style="list-style-type: none"> Igneous rock 	<ul style="list-style-type: none"> Permeability enhancement achieved through hydraulic stimulation was due to shearing of pre-existing fractures and not by tensile fracturing. Linked to the fact that the stress field is anisotropic in basement rocks. The hydraulic conductivity of the reservoir could not reach a commercial level; pumping efforts were always too high. Direct short connections could be established between wells, resulting in a lower production temperature. The consequences of reservoir pressurization are irreversible.
Japan	<ul style="list-style-type: none"> Igneous rock 	<ul style="list-style-type: none"> The well locally influences the stress field. Seismic events were also produced during production/circulation phase. Injections on short term at high pressures could improve the well's injectivity. Long term injections have a positive effect on the reservoir, due to thermal effects (in the well vicinity and in the rock mass).
Cooper Basin, Australia	<ul style="list-style-type: none"> Granite 	<ul style="list-style-type: none"> Because the granite was hydrothermally altered, it was relatively easy to drill. Waterbased overpressure is a surprise, but it assists with stimulation and convective inflow. It is difficult to drill multiply fractured zones without underbalanced drilling. Subhorizontal fracture zones are present in the granitic basement (either thrust faults or opened unloading features). Overthrust stress environments are ideal for stimulation, leading to development of horizontal reservoirs Scale up to multiwell systems on a large scale seems feasible, because of the horizontal reservoir development. Scaleup should reduce cost to levels that will compete with other baseload technologies.
The Geysers, USA	<ul style="list-style-type: none"> Igneous rock source 	<ul style="list-style-type: none"> A common monitoring and management plan for nearby wells is necessary to monitor changes in the reservoir that might affect production. Reinjecting produced fluids in the geothermal field is needed to maintain water temperatures and pressures and avoid over exploitation
Groß Schönebeck, Germany	<ul style="list-style-type: none"> Sandstone 	<ul style="list-style-type: none"> By means of well-known reservoir geometry, structure geology, hydrothermal conditions and the occurring coupled processes, the change of geothermal reservoir conditions can be simulated to help with forward planning.
Paris Basin, France	<ul style="list-style-type: none"> Sedimentary Basin 	<ul style="list-style-type: none"> Scaling problems can be solved with inhibitors.

Region	Geology	Lessons Learnt
Blumau, Austria	<ul style="list-style-type: none">• Sedimentary Basin	<ul style="list-style-type: none">• Realising an imaging log like a UBI or a FMI in cased sections (realised before installing the casing) can help identify large scale structures.
Kirchweidach, Germany	<ul style="list-style-type: none">• Sedimentary Basin	<ul style="list-style-type: none">• 3D seismic can bring a decisive advantage to a geothermal project (at least in deep sediments), as it allows an optimal targeting of the well.

6 Environmental, Regulatory & Other Considerations

6.1. Environmental Considerations

6.1.1. Introduction

The potential environmental issues caused by the development of geothermal projects in the UK are discussed within this chapter. There is a potential for environmental issues to arise both by the construction and operational phases of the project. It is noted that the construction phase potential issues are short-term only and should be viewed within this context.

6.1.2. Water Use

The volume of water required during fracture stimulation is likely to be large; the Rosemanowes geothermal project, Cornwall required 8,640 m³/d. This volume of water could detrimentally impact upon groundwater/surface water reserves and resources, and hence dependent wildlife and ecological habitat.

During the operational phase there is expected to be very little water lost from the reservoir, so water requirements should be very low. At this stage, it is not known if the power plant will be air or water-cooled; if it is to be water cooled, additional water would be required and such requirements would need careful consideration as to their environmental impact and implications.

6.1.3. Water Pollution

Well drilling, fracture stimulation and geothermal operational fluids could potentially contaminate groundwater and/or surface water, and hence, detrimentally impact ecology and water resources.

Fractures induced by investigation, aquifer stimulation and the associated micro seismicity could provide a pathway to overlying aquifers or surface waters; the fluid injected during fracture stimulation or operation could migrate along this pathway and, potentially, contaminate water bodies. The fracture lengths induced by Deep Geothermal projects are small, in the order of tens to hundreds of metres (Ref. 2). Therefore, although considering the zone of fracture propagation is likely to be in the order of 4 to 5 km below ground level could generally be considered as an insignificant risk, it will be necessary to evaluate such risk taking into account the rock mechanics and stress fields identified at initial investigation stage and drilling stage as part of the project planning process.

If best practice guidance regarding the handling and storage of potentially contaminated materials is adhered to then spills or leaks and potential for contamination should be very low in probability. However, all will need to be assessed both for planning and as part of the application for the likely requirement of an Environmental Permit. Additionally an RSR (Radioactive Substances Regulations) permit might be needed where NORM (Naturally Occurring Radioactive Material) is encountered, which is particularly likely in radiothermal granites where minerals containing uranium and other elements with potentially radioactive isotopes can be present.

The wells will be cased with at least one layer of steel during drilling, and subsequently sealed with a cement grout, inhibiting contact with any surrounding groundwater, and preventing any contamination. This should also be geophysically surveyed using a cement bond log to quality assure the seal.

It should be noted that the potential for pollution of water from geothermal exploration and exploitation is lower than other similar deep resource exploration and exploitation such as for unconventional gas. There is some similarity to the processes used in oil and gas; however there are significant differences as shown in Ref. 29. The key differences are, unlike shale gas, EGS can use water extracted in situ and does not require a large amount of external water. Furthermore, it does not produce wastewater as a by-product (Ref. 29), and the fluids are re-circulated in the reservoir. Where potentially contaminative fluids are introduced, they are in relatively small amounts solely for the chemical stimulation of the reservoir during the development phase or for removal of drilling fluids. No further chemicals should be introduced during the operation of the plant apart from potentially scaling and biological inhibitors where fouling could be an issue.

If the power plant is cooled by water, which is subsequently discharged to surface water or groundwater, then there is the possibility of thermal pollution during power plant operation. This will need to be assessed fully as part of planning and environmental permitting as appropriate.

6.1.4. Gas Emissions

Geothermal fluids will contain dissolved gasses such as CO₂, H₂S, NH₃ etc. However, during electricity generation process the geothermal fluid will not come into contact with the atmosphere. Therefore, there is no opportunity for the gas to discharge to the atmosphere. The risk of discharge into the atmosphere will need to be assessed fully as part of planning and environmental permitting as appropriate.

6.1.5. Solids Emissions

The wells are anticipated to be drilled to a depth of 4 to 5 km; at this depth there is the possibility of increased radioactivity. Appropriate management, testing, handling and disposal of this waste stream will ensure that the impact from this material on the environment is negligible. This will need to be assessed fully as part of planning and environmental permitting as appropriate.

6.1.6. Noise and Visual Impact

Drill rigs required to drill the geothermal wells will be in the order of 40 to 50 m high, with drilling maintained 24 hours a day. The noise and light associated with the well drilling and power plant construction could be potentially disruptive to sensitive wildlife communities. Mitigation measures, such as noise abatement measures could be implemented to reduce any impact.

Once operational the geothermal power plant should be designed such that it has minimal noise and visual impact in accordance with likely planning conditions.

6.1.7. Land Take/Habitat Removal

The land take for a geothermal power plant is significantly less than other forms of electricity generation, on an electricity per unit basis. Habitat studies and/or relocation projects could be carried out to ensure the disturbance is minimised.

6.2. Regulatory

The requirements for Environmental Impact Assessment (EIA) and the circumstances in which one should be undertaken are established by the European Directive on 'the assessment of the effects of certain public and private projects on the environment' Directive 85/337/EEC (as amended by the Directive 97/11/EEC and 2003/35/EC). The European Directive has been transposed into U.K. legislation by the Town and Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 (EIA Regulations).

These Regulations contain two lists of development projects. Schedule 1 identifies all the types of developments for which an Environmental Impact Assessment (EIA) is mandatory irrespective of their location. Schedule 2 identifies the types of developments where an EIA must be carried out if the development if any part of the development is to be carried out in a 'sensitive area'. The EIA Regulations define 'sensitive areas' as including nature conservation sites with national or higher level designations (e.g. Sites of Special Scientific Interest, Special Protection Areas, Special Areas of Conservation and Ramsar sites), Areas of Outstanding Natural Beauty, National Parks, World Heritage Sites and Scheduled Ancient Monuments.

Schedule 2 developments must also be assessed based on the likelihood to have a significant impact on the environment by virtue of its nature, size or location. Regulation 4(5) advises that, where a decision as to whether Schedule 2 development is an EIA development, an account should be taken of the selection criteria as set out in Schedule 3 of the EIA Regulations. These criteria relate to the characteristics of the development, the location of the development and the characteristics of the potential impact as listed below.

During the desktop stage it will be necessary to seek a "screening opinion" from the local authority. This will require a brief letter of request as to whether the proposed development will require an EIA. It will include a basic description of the scheme and of the existing site, a comment about the screening criteria and a preliminary listing of possible effects on the environment.

Cornwall County Council is the only Local Authority which appears to have a policy regarding Deep Geothermal energy installations (Ref. 11). They detail their position within Renewable Energy Planning Guidance Note 8: The Development of Deep Geothermal, Draft (July 2012), which states:

“Planning consent will normally be required for the development of a Deep Geothermal energy facility. For some Deep Geothermal energy proposals an Environmental Impact Assessment (EIA) may also be required”.

The need for an EIA will be dependent upon the outcome of a Screening Opinion. Further guidance regarding the decision process is highlighted within this Cornwall County Council document.

The Environment Agency details their official position on groundwater related subjects, as well as a summary of the regulatory regime, in Groundwater protection: Principles and practice (Ref. 27). This states that:

“some deep geothermal schemes operate by the injection of water that is subsequently re-abstracted from a depth considerably below the active Hydrogeological zone as there is negligible natural groundwater at this depth. These types of schemes do not require a GIC [groundwater investigation consent] or abstraction licence to re-abstract this water from depth as there is no abstraction from a source of supply. Discharges at this depth do not require environmental permit again if there is negligible groundwater and therefore not considered by us to be a groundwater activity.... Abstraction of shallow groundwater or surface water to fill these schemes will require licensing where abstraction volumes are greater than 20 m³ per day”.

Further details on abstraction requirement including a position statement of the Environment Agency on Deep Geothermal energy can also be found in Ref. 26.

Where NORM is anticipated an RSR permit will be needed to ensure such materials are managed in a controlled manner. This would also be the case where radioactive sources might be used in the equipment used to carry out geophysical assessments, such as gamma logging equipment.

6.3. Other Considerations

6.3.1. Induced Micro-Seismicity

Fractures in the host rock are required to allow the geothermal fluid to be transmitted, heating the fluid as it passes. Geothermal projects can require fractures to be created or ‘stimulated’. Micro-seismicity or micro-earthquakes can be caused by the stimulation of fractures and the injection of fluid under high pressures during operation.

Micro-seismic events are normally caused by changes in natural in situ stresses that exist in the Earth, due to pressurised fluid injection. In general, the micro-seismic events associated with geothermal power production are too small to be felt. They routinely occur during mining activities, oil and gas abstraction and storage, carbon capture and sequestration, geothermal power production and stimulation as well as any other activities where liquids are injected or abstracted at significant depths.

The size of a micro-earthquake event (given by its magnitude at the source) and the surface acceleration (how the event is measured at the surface) are influenced by local geology. It is a general rule that a Deep Geothermal project cannot cause an event larger than that which would have occurred naturally at some time. In the UK, the geology is relatively stable. Micro-earthquakes caused by Deep Geothermal projects are believed to be small and very unlikely to cause damage.

However, natural earthquakes do occur and will occur in the future. A Deep Geothermal project will cause earthquakes and could potentially cause an event that would be felt at the surface. The sudden fracturing of rock caused by the injection of water into the reservoir zone is the cause of the earthquakes. This was the case during the Rosemanowes project (see Section 5.3.2). The Rosemanowes project caused thousands of micro-seismic events but only 2 were felt and no damage was caused (Ref. 2).

However, there have been notable exceptions such as in Basel, Switzerland 2006 (Ref. 17) where a Deep Geothermal project caused a magnitude 3.4 event resulting in minor damage to buildings. The Deep Geothermal project was stopped. It was predicted at the time that the Basel event would halt Deep

Geothermal development in Switzerland. Instead, the Swiss decided that the best approach would be to develop an inclusive policy and involve and inform the local population. The involvement of the local community has led to a number of new Deep Geothermal projects now being developed (Ref. 2).

In the UK, micro-seismicity in association with shale gas extraction has raised public and governmental awareness of the issue in recent years. The micro-seismicity has caused both media reaction and severe delays to the shale gas project near Blackpool recently in the UK.

Monitoring and interpretation of micro-seismic events is an essential tool used to understand the development and extent of a reservoir. On the other hand, public perception and, in rare cases, actual minor damage resulting from earthquakes could potentially cause public alarm that would require authorities to limit development of Deep Geothermal projects. Therefore, it would be sensible to start thinking about public consultation at an early stage of the project.

It should be noted that, unlike shale gas extraction, for geothermal exploitation the hydraulic fracturing is short term for reservoir development. After reservoir development the only fluids circulated within the geothermal reservoir are recirculated hydrothermal fluids rather than continued frac fluid and proppants, which are needed in shale gas to continually develop the resource. The water usage and treatment facilities are significantly lower as a result with respect to geothermal operations compared with shale gas.

Other significant differences in hydraulic stimulation between shale gas and geothermal reservoir development are the generation of multiple vertical fracs from horizontal wells in shale gas exploitation, compared with opening of existing fractures and development of shear planes to increase permeability between generally vertical wells in geothermal networks.

Environmental, Regulatory and Other Considerations - Key Points

- Short term construction phase issues are much more significant than the longer term operational issues.
- Water use during the construction may be significant with associated implications for environmental issues.
- Ground water contamination risks should be manageable but require consideration. This will include during hydraulic stimulation.
- A Radioactive permit is likely to be required for handling Naturally Occurring Radioactive Material associated with the radiothermal granites.
- Risks are assessed as lower and short term for deep geothermal stimulation and exploration as compared to unconventional gas.
- Land take for geothermal projects is significantly less than for other forms of electricity generation.
- There is an established regulatory regime that can be applied to geothermal projects plus some local authorities may have individual planning guidelines.
- Micro seismic events can be produced during reservoir stimulation but are likely to be too small to be felt although exceptions have occurred. Consequentially public perception and consultation is important.

7 Revenue and Subsidy /Funding Mechanisms

7.1. Sources of Revenue for Deep Geothermal

Sale of electricity is the main revenue stream for a Deep Geothermal power project with sales of heat complementing the power sales in a geothermal CHP project. Additionally there are incentive schemes from the government which supplement the sales revenues. These revenue streams can be described as follows:

- **Power Export:** The net power generation from a geothermal combined heat and power station is the power that is available to be sold either directly via a private wire to a local consumer (should sufficient demand be available) or exported to the local distribution network. It is expected that a geothermal power station would operate base load i.e. continuously at a steady output, and would enter into a long term power purchase agreement with a licensed electricity supply company. If a local consumer could be directly connected then this would attract a higher tariff and improve the economic returns of the project despite the additional cost of installing the direct electrical connection.
- **ROC's / FIT's and CfD:** Up until the 1st April 2017, under the Renewables Obligation (RO), accredited renewable generating stations are eligible to claim Renewable Obligation Certificates (ROC) based on the volume of gross power generated. Power generated from geothermal is currently supported at 2 ROC's / MWh and the value of each ROC can vary. The April 2013 ROC price was approximately £44. Post 1st April 2017 no accreditation will be available under the RO for new renewable generating stations.

Under the Energy Bill 2012 and Electricity Market Reform (EMR) a Contract for Difference (CfD) Feed in Tariff (FiT) will be open from 2014/15 which aims to encourage investment in low carbon generation and reduce an investor's exposure to changes in wholesale energy prices. Under the CfD FiT scheme a generator will receive the usual electricity market price plus a top up to a pre-agreed Strike Price (SP). The draft SP for Geothermal (with or without CHP) in 2014/15 is £125/MWh.

Between 2014/15 and 1st April 2017 there will be a transitional period and both the RO and CfD FiT support schemes will co-exist. Investors will have a one off opportunity to choose between the RO and the CfD FiT regimes. Further clarification is required on how the value of the ROC will be supported post 2017.

- We have based our financial analysis on the RO ROC scheme and assumed that the ROC price will not devalue below April's 2013 price of £44/MWh.
- **Heat Export:** The usable heat that is available for sale (subject to suitable heat loads nearby) can be sold on a price per metered kW sold. The rate at which the heat can be sold at will be dependent upon the cost of other primary fuel sources such as gas. Heat would need to be priced so that it is competitive with existing fossil fuel costs as is currently being done at a growing number of district heating schemes in the UK. The sale price may also reflect a premium as it is from a low carbon source and therefore avoids various carbon costs, depending on the circumstances in which it is used.
- **RHI:** As the heat generated from a geothermal source is renewable, it is eligible for the Renewable Heat Incentive (RHI). Deep Geothermal heat supplied by a plant over 100kW currently qualifies for a rate of 3.5 p/kWh. There is a consultation underway at present (2013) which could potentially increase the RHI for Deep Geothermal heat to 5.0 p/kWh.

7.2. Grants

From time to time there are funding streams from UK or EU targeted at specific technologies or activities that may be used to incentivise the development, uptake or deployment of low carbon technologies. There can be technology specific funding or 'technology agnostic' funding aimed more generally at carbon reduction measures or delivery partners (e.g. Higher Education or local government). These funds can be for capital

plant or technological support such as consultancy support or R&D. This is a rapidly changing scene but there are no specific measures currently available to target Deep Geothermal projects.

7.3. Commercial Models/ Routes and Types of Investment

There is no specific single route or commercial model which applies to Deep Geothermal projects. In general the scheme will be promoted by a specialised Deep Geothermal development company either working independently or in agreement with a potential host site. The project will be developed to a position where the costs and potential returns are reasonably well understood. At this point discussions can commence with potential investors to explore the availability and cost of funding the project. It is at this point, that in recent years in the UK, projects have stalled due to an unfavourable risk/reward proposition for private funding to be accessed.

Revenue and subsidy/ funding mechanisms - Key Points

- The main revenue stream is from electricity sales, either to the grid or local clients.
- Support for renewable electricity sales from deep geothermal power is currently 2 ROCs/MWh.
- The current market value of ROCs is £44 per ROC.
- Under the EMR, CfDs are planned to come into operation in 2014/15 and there will be transitional arrangements from ROCs to CfDs.
- The currently proposed CfD strike price for geothermal is similar to the current value of the ROC support.
- Heat sales can compliment electricity sales if local customers require heat.
- The RHI currently supports geothermal heat sales with a supplement worth 3.5p/kWh for plants of over 100kW. It is currently proposed that the RHI is increased to 5.0p/kWh in the near future.
- There are currently no direct grants for deep geothermal energy in the UK.

8 Geothermal Power Schemes Feasibility Analysis

8.1. Introduction

In order to illustrate the potential opportunities and risks associated with Deep Geothermal energy exploration and exploitation in the UK, it was decided to develop a number of generic case studies so that specific costs and revenues can be discussed without reference to the unique and potentially confidential numbers associated with potential 'live' projects. To develop these case studies a number of factors were considered as screening criteria to derive three relevant case studies to analyse. The case studies include a number of defining characteristics which suit the geology such as drilling depth, abstraction and return temperatures and fluid permeability which then enable estimates of abstraction flow rate and thus the power and heat outputs to be derived. These factors also enable capital costs and revenues to be estimated and financial returns to be calculated.

Obviously, for such generic plants, none of these figures will be accurate but by using sensitivity analysis on various elements enables upper and lower extremes of potential investor returns, and hence financial viability, to be assessed.

It should also be noted that until the resources are drilled to the depths necessary to supply the heat required for power generation the thermal energy, fluid permeability of the rock and other geophysical parameters are indicative only and therefore the actual reserve once proven could vary from the illustrative scenarios. For example, the Weardale granite could be less transmissive and the Cornubian granite more transmissive, therefore the two scenarios could apply similarly to either region, as could many others. However, these scenarios are considered adequate to illustrate the points made.

8.2. Geology

A geothermal resource defines itself by the temperature of the ground or geological formation. In this respect a geothermal resource is present where heat is present at temperatures that can be utilised for geothermal power generation. However, for geothermal resource to be utilisable it also needs to be technically accessible. The technical accessibility of the resource for geothermal power generation is satisfied if the following conditions are present:

- The well production temperature is high enough to allow the thermal energy to be converted to electrical energy using currently available technologies;
- The resource is not beyond depths of current drilling operations; and
- Means of temperature transfer exists to extract the geothermal energy, for example via the flow of a geothermal fluid.

In the UK the geology that might provide each of these conditions at depths that are currently technically achievable is limited.

Only a proportion of the resource that is technically accessible can be regarded as a reserve. The likelihood of a geothermal resource to be classified as a reserve depends on a number of technological, economical, legal, environmental, land access, social and governmental factors.

The Australian Reporting Code defines a regime of classifying geothermal resources and reserves depending on the economic feasibility of a project, as defined in Section 1.2.1.2. The geology of the UK meeting the requirements of a resource or reserve is discussed in the following sections.

8.3. Resource and Reserves

The assessment of the geothermal power generation is based on the heat in place concept, which is an approach similar to that applied to other below ground non-renewable (e.g. oil and gas) energy sources.

Below ground energy sources, including geothermal energy is classified as resources and reserves, as supported by the Australian Geothermal Reporting Code (Ref. 54).

In broad terms related to geothermal energy, the geothermal resource is an estimate based on both direct measurements and inferences from the geology of how much geothermal energy is actually in the ground. However the geothermal reserves of any particular area are defined as the amount of measured geothermal resource that could be expected to be economically extracted using current commercial technology and current economic conditions. Therefore geothermal reserves represent a small and changeable percentage of geothermal resources, which can change based on the technology used to extract it, and the value of the thermal energy which is currently directly linked to fossil fuel prices for heat only and power prices where a geothermal reserve is used for power or CHP production.

Both resources and reserves are further subdivided into a number of categories.

Resources can be subdivided into Inferred, Indicated and Measured resources and are outlined below in order of reducing risk:

- Inferred – The geothermal resource based on an assumed geological structure.
- Indicated – The geothermal resource based on a combination of direct measurement and reasonable geological assumptions made with high confidence.
- Measured – The geothermal resource based on direct measurements to gain high accuracy and would often include flow and production temperatures.

Geothermal Resource estimates should clearly identify any known potential technical risks, including geological factors such as faults which could prejudice production or sources of cool fluid intrusion which could degrade the resource.

Reserves can be subdivided into Proven and Probable. Only Proven and Probable Reserves should be used when considering the economic feasibility of a project. Definitions of each reserve term are outlined below:

- Probable – The geothermal reserve which has been both demonstrated and also deemed to be economically and technologically usable at any given time.
- Proven – The geothermal reserve that might reasonably be expected to be extracted and used. This is sometimes also called the recoverable reserve and a 'recoverability' factor is often applied dependent upon a number of factors such as well flows and temperatures.

The process of conducting a feasibility study should refine the assessment of Reserves using more project-specific technical, environmental, regulatory and commercial criteria.

An illustration of the geothermal resources and reserves in the context of depths that are likely to be found in the UK is shown in Figure 8–1.

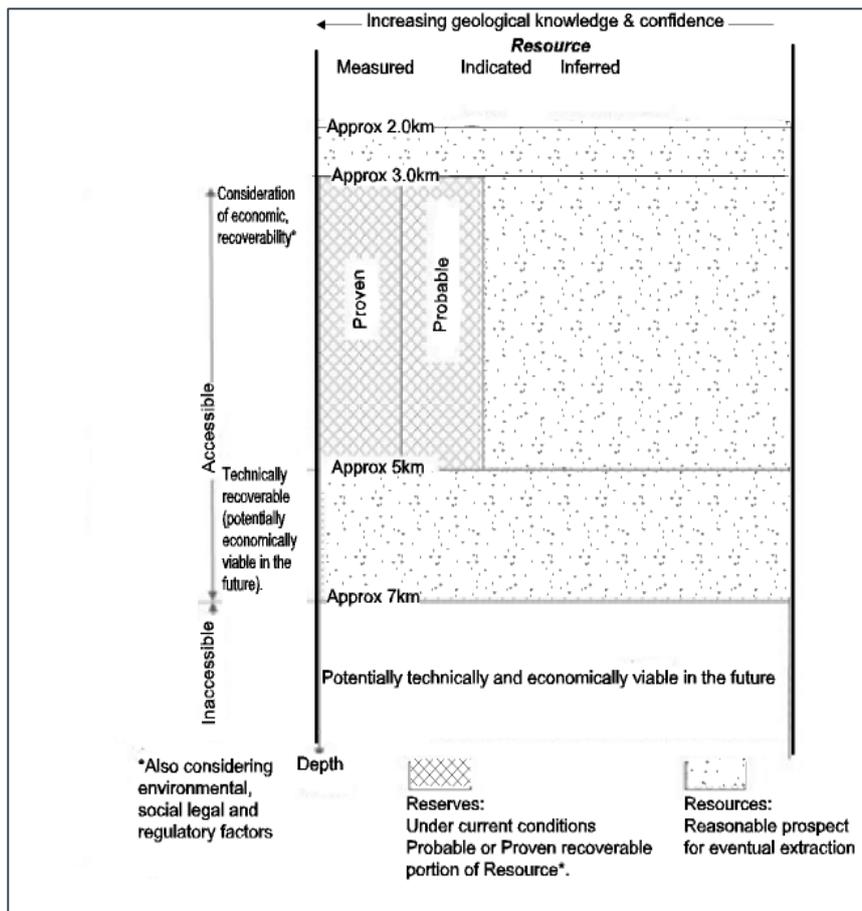


Figure 8-1 Resources and reserves in the context of depths that are likely to be found in the UK (Ref. 53)

8.4. Screening for Geothermal Reserves in the UK

8.4.1. Reserves

In the UK, currently, there are no geothermal power schemes in operation and as yet, no drilling work to depths with temperatures in excess of 100°C have been undertaken. As a result, geothermal energy to provide a source for geothermal power generation is not proven and therefore there are no reserves as defined by the Australian code (Ref. 63).

8.4.2. Resources

Largely based on work performed by Downing & Gray (Ref. 19), areas with a high geothermal inferred reservoir are present within the 'South West Cornubian Batholith', the Weardale and the Lake District granites at approximately 3 to 5 km depths, as indicated by temperature gradient evidence from Rosemanowes and Eastgate respectively (see Section 2.3).

In addition, under natural conditions, it is unlikely the permeability in most of these areas will support flow rates sufficient for a commercial power plant without stimulation. State of the art stimulation techniques require targeting features (e.g. geological faults) with higher permeabilities from the outset.

Therefore, it is presumed that reserve areas exist within the 'South West Cornubian Batholith', the Weardale and the Lake District granites which are characterised by favourable conditions for stimulation. A number of further factors need to be considered when determining areas that constitute probable reserves (e.g. legal, environmental, land access, social and regulatory). However, as no boreholes have been drilled to depths sufficient to prove the required minimum temperatures for power generation, these strata cannot be considered as reserves for power generation under the Australian code definitions (Ref. 63).

Due to their anticipated lower reservoir temperatures (~100°C) and transmissivity ($\leq 10\text{Dm}$) the likelihood of the base of Wessex and Cheshire sedimentary aquifers to serve as reserves for geothermal power generation is also assessed as probable, albeit at the lower heat end suggesting that heat generation is more likely to be viable than electrical power generation. However, again, as no boreholes have proven the required temperatures the aquifers can only be considered indicated resources rather than reserves.

A summary of UK geothermal resources and reserves that might be suitable for power generation is presented in Table 8-1.

Table 8-1 Summary of assessment of resource and reserve areas in the UK (using definitions from the Australian code)

Plays	Resources			Reserves		Reference information	Temperature measured and extrapolated at depths (gradient)
	Inferred	Indicated	Measured	Probable	Proven		
S.W. Cornubian Batholith		√				Heat flow mapping, 40 observations indicate heat flow values of up to 136 mW/m ² and heat gradient of 35 °C/km (Downing & Gray 1986, Busby 2010.) Rosemanowes, 2 boreholes drilled between 1980 and 1983 (MacDonald 1992 & Parker 1999)	79°C measured at 2,000m depths (34°C/km)
Lake District & Weardale Granite		√				Temperature modelling on the basis of heat flow values logged at depths between approximately 300 m and 800 m, thermal gradients in the approximate range of 25°C and 35°C per km depth. Eastgate Geothermal Borehole, drilling down the axis of a vein structure (the Slitt Vein) down to 1,000m revealed a temperature of 46°C (Younger & Manning, 2010, Manning et al, undated). At 1,770m, a temperature of 73°C (Manning 2013) was found in a borehole drilled in Newcastle that is presumed to receive water from the granite suggesting gradient in excess of 35°C per km depth.	46°C measured at 1,000m, 73°C measured at 1,770m depths (>35°C/km)
Cheshire Basin	√					The Permo-Triassic sandstones that reach depths of 4,000m. Here temperatures exceed 60°C with maximum values of up to 100°C (Barker et al 2000).	100°C at 4,000m inferred from temp. gradients and geophysical measurements (23°C/km)
Wessex Basin		√				Southampton, temperature in excess of 70°C found in borehole SU 3991 1118 (Geothermal Well at Southampton)	~75°C at 1,700m depth (37°C/km)

Note: No reserves measured or proven. No resources identified in Scotland or Northern Ireland currently suitable for geothermal electrical power generation.

8.4.3. Areas not currently assessed as reserves

Falling into this category are all other areas that are not assessed to fall within the above indicated resources areas with respect to power generation. This includes the East Grampian Batholith of Scotland granites with only moderate geothermal gradients (Ref. 19).

This category comprises all other areas for which temperature gradients ($\leq 20^{\circ}\text{C}$ per 1,000m) or for which required drilling and EGS creation depths ($>5,000\text{m}$) are likely to render potential geothermal scheme as economically unviable. However, this is dependent on state of the art technologies and technical advancement, for example in drilling techniques, may supersede this presumption in the future.

8.4.4. Spatial Constraints

8.4.4.1. Land take

In addition to the geology beneath a site with prospects for geothermal power generation, the land-take for the above ground power generation facilities will need to be considered. Such land-take not only comprises the footprint of power and pumping stations next to geothermal abstraction and injection boreholes but the network of pipes for the geothermal power scheme.

Whilst the land take can hamper the construction of geothermal power schemes in urban areas, the extent of pipes networks can be reduced by means of directional drilling. This drilling technique ensures sufficient reservoir abstraction and injection zones spacing with short distance between abstraction and injection wells at surface. An example of a borehole arrangement by directional drilling is illustrated in Figure 8–2 below showing the borehole triplet scheme at Soultz-sous-Forêts.

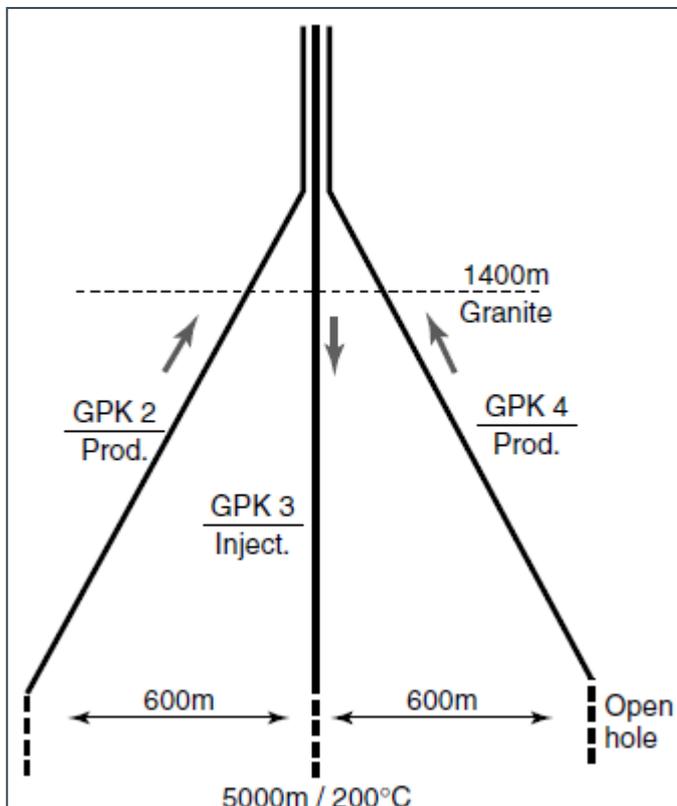


Figure 8–2 Scheme of the borehole triplet at Soultz-sous-Forêts

8.4.4.2. Zones of fluid permeability

Radiogenic granites

It is likely that, fluid permeability enhancement (i.e. stimulation) technologies will generally be necessary for the majority of the radiogenic granites to be sufficiently permeable for economic power generation from granites at 3000 - 5000 m depths to be feasible. In discussions about fluid permeability enhancement technologies [i.e. Enhanced Geothermal Systems (EGS)], much emphasis is given on the importance of identifying areas with increased permeability and associated fault zones. This means that EGS technologies are more likely to be applied to a proportion of the granite exhibiting the thermal properties required.

Deep sedimentary aquifers

Compared to granites (with matrix permeabilities in the order of 1mD), sedimentary aquifers are generally characterised by significantly higher matrix permeabilities. However, for sandstones at depths within the Cheshire and Wessex Basin, maximum formation transmissivities of around 10 Dm and 20 Dm have been reported. For the utilisation of a power generation scheme to be economically feasible, Paschen et al (Ref. 55, see also Section 8.2) suggest a minimum reservoir transmissivity of approximately 5 Dm.

Whilst, permeabilities tend to decrease with increased depth, it may be possible for zones of higher permeabilities to be present in deeper fault zones. Alternatively, in the presence of zones of increased porosity, stimulation may lead to permeability enhancements as per experience from the Groß Schönebeck research project (Ref. 42). In the case study for power generation utilising heat from a deep sedimentary basin (Cheshire basin) reported below (see Section 0) stimulation to increase the reservoir permeability has not been considered.

8.4.5. Environmental and Social Impacts

Geothermal plants are far less environmentally intrusive than conventional plants (e.g. coal fired power stations) in several respects, including due to the absence of carbon dioxide (CO₂), nitrogen oxide (NO_x) and sulphur oxide (SO_x) emissions, which is valid where geothermal fluids are returned into the geological heat reservoir within an enclosed cycle (Ref. 17). Given the relatively low temperatures available in the UK, enclosed Binary Cycle power stations are the system of choice.

Apart from specific risks such as subsidence and induced micro-seismicity, other potential impacts of geothermal power stations under operational conditions are comparable with those of conventional power stations and comprise:

- Water pollution;
- Solids (fugitive dust) emission to the surface and the atmosphere;
- Potentially radiological impact if naturally occurring radioactive materials (NORM) are present in host rock;
- Noise pollution;
- Land use;
- Water use;
- Disturbance of wildlife habitat and vegetation;
- Alteration of natural vistas; and
- Health and safety risks.

Such impacts of a geothermal power station or elements of a geothermal scheme will be regulated as discussed in Section 6.2.

8.4.5.1. Induced micro-seismicity

As discussed previously, the effects of induced micro-seismicity need to be taken into account, as described in detail in Section 6.3.1.

8.4.5.2. Subsidence

It is difficult to draw generalisations about subsidence because of the wide range of experiences among geothermal fields. However, the operation of a number of large schemes (≥500MW) is not reported to have resulted in significant subsidence. Problems with subsidence have not been generally reported for schemes where most of the water is returned (Ref. 17). In the case studies discussed in this report, where the geothermal fluid is returned to the geothermal reservoir, the probability of subsidence is considered very low.

8.4.6. Summary of Steps Facilitating Geothermal Power Utilisation

A number of steps are required to facilitate geothermal power utilisation. These steps improve data and understanding of the risks, constraints and opportunities with the project and can be summarised as follows. It should be noted that the terminology used is not currently industry standard, but based on experience in other areas and the information gained as part of this study as to likely elements of each stage. A summary of these phases and decisions made during the process up to the end of the definitive feasibility study are as follows.

8.4.6.1. Scoping

The scoping stage of the project would comprise a high level review of information on a site and economical appraisal of the proposed project. The key aim of this stage is to identify risks and uncertainties associated with development of a particular resource/reserve in terms of both the surface and underground facilities.

Site screening and selection, potentially including scoping for planning, would be carried out as part of this stage in order to ensure that there are no significant constraints on surface development prior to expenditure on costly investigation.

Economic appraisal would include high level cost assessment and analysis of likely return on investment based on market analysis.

8.4.6.2. Pre-feasibility

Pre-feasibility studies might include more detailed data assessment and review and some non-intrusive investigations such as surface geophysics. Where significant constraints for surface facilities have been identified then additional data gathering and assessment might be undertaken to characterise these constraints and identify whether they are likely to be critical to achieving project objectives.

The economic appraisal would be updated at this stage to identify any significant changes.

8.4.6.3. Feasibility and investigation

The feasibility stage would include investigation to prove reserve and is the costliest part of the project, hence the earlier stages would be critical in identifying any critical constraints prior to commencement of drilling.

Drilling and testing would be carried out to characterise the reserve, the data from which would be used to firm up the financial model.

During this phase of works outline front end engineering design would be carried out, subject to the findings of the investigation, and planning permission would be sought in order to resolve key constraints prior to the next stage.

8.4.6.4. Definitive feasibility study

Once the reserve is proven and planning permission obtained, a definitive feasibility study (DFS) would be carried out. This is the final stage of feasibility where the project costs are defined through detailed front end engineering design in order to identify costs to within a reasonable percentage of final outturn costs (e.g. plus or minus 10 to 15%). This stage should provide sufficient confidence for investment for the final build funding.

8.4.6.5. Build and commissioning

On completion of the DFS and once investor funding has been secured based on a sound business case, the final scheme as designed at DFS stage would be built and commissioned.

8.4.7. Financial Modelling

Having established screening criteria to select case studies, a high level techno-economic model was prepared to evaluate the expected financial returns over a range of plant locations and sizes from now to 2050. The general inputs to this model are discussed below. The case specific assumptions are included later in the report with reference to the case being considered.

Where Internal Rate of Return (IRR) figures are quoted they are based on equity investment excluding any tax considerations. As they can be affected by many variables, these figures should not be taken to be the actual rates of return that an investor might achieve but they do allow for comparison of the cases and sensitivities produced from the modelling done for this report.

Capital Costs

Capital, operating costs and revenues have been developed to analyse the possible range of financial returns. Geothermal energy development costs can vary widely between different geologies and approaches and therefore it is not easy to generalise. Comparing a number of sources from developers and previous reports a range of costs for a plant of <10 MWe are suggested from £2 – 10m / MWe. Scale of plant and number of wells has a large bearing on this cost. A mid-point of £6m/MWe (net) has been used for the base case analysis and then sensitivities applied to show the effect of that variable. At the base figure £6M per MWe the cost of a 2.5MWe plant as shown in our case study of £15M (although it should not assume that a specific plant of this size could be built for this cost). Whilst this cost may seem low for that particular example, it also gives a value of £60M for a 10MWe scheme, which is consistent with other data.

The reason for using this approach is that the modelling is intended to reflect the situations that may be expected to occur, for a whole range of plant sizes which may be considered between now and 2050. Any potential comparison with current projects in the planning stage has been intentionally avoided to prevent any inference of project returns for those specific projects which would be outside the competence of a generalised report such as this.

There is a certain minimum cost for drilling the first pair of wells, and this is not directly proportional to the energy extraction capability which is dependent on the ground permeability, abstraction rate and temperature, and power conversion technology. Whilst the use of a cost per MWe figure can therefore get distorted, the chosen baseline, with sensitivity the range of analysis applied, gives a reasonable expected range of capital costs for plants of over 2MW that would be expected to be developed in the UK in various types, locations, geologies and numbers of boreholes over the long term.

Where the cost per MWe approach is not applicable is in the case study for the Cheshire basin (Crewe). Here the abstracted water temperature is significantly lower than the other two cases and hence the electrical output is significantly reduced so the baseline cost/MWe approach above would result in a capital cost of under £2 M which is too low considering the similar drilling costs to the other two case studies. For this example the baseline capital cost has been set at £15M (similar to case study for Cornwall) and similar sensitivity percentage adjustments applied to this figure as used for the other two cases.

Capital costs are expected to reduce over time if the technology becomes more commonly deployed. This will be due to increased business efficiencies from competition entering the market and the increased volume of production, and supply of capital plant, also reducing costs. Some work undertaken as input to a recent DTI study into the deep geothermal industry suggested that a 15 to 19% reduction by 2050 could be expected, with the majority of that (11 to 16%) occurring by 2025 and reduction tailing off thereafter.

The 2012 Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewable Obligation Order 2012 (Ref. 37), in Annex D, "Capital and Operating Cost Assumptions used in Banding Review Analysis for Selected Years" shows an expected fall in the Cap Ex of Deep Geothermal of 25% from 2010 to 2015 and a 2-3% reduction per five year period thereafter until 2030. The ranges shown there are approximately £2.7M – 8.0M /MW in 2010 reducing to £1.9M – 5.5M /MW by 2030. These are broadly consistent with those used in the modelling for this report.

The high level split of capital cost items for a geothermal combined heat and power station can be summarised into the following key areas:

- **Geothermal well:** The costs associated with the exploration and drilling of the production and depending on the scheme, the re-injection well(s). These costs would include all associated site preparation and infrastructure such as access roads etc to reach the well site. The Geothermal well capital costs will be very much dependent on the location of the site, the depth and the geological structure. The costs may also be dependent upon the oil price as this has an impact on the availability of drilling rigs.
- **Geothermal fluid transportation:** The costs associated with harnessing the geothermal fluid from the well head to the power generating station e.g. flow and return pipework to/from the well and associated pumps for extraction and re-injection. Depending on the location it may not be possible to site the power station directly at the well head or there may be multiple wells at different locations feeding a single power station. The capital costs associated with transporting the geothermal fluid from the geothermal well will be directly proportional to the distance to/from the power generating station.
- **Power Generating Station:** The conversion technology may vary e.g. ORC or Kalina cycle, but will include a prime mover, generator, electrical transformers / switchgear, condenser cooler e.g. water / air type radiator, associated control systems and buildings / structures for housing the power generating station. The power generating station would also include the capital costs of the electrical connection to the district network operator (DNO) so that surplus power can be exported. The capital costs of the power generating station will be largely dependent on the installed MW capacity, but also the specific technology / conversion type used.
- **District Heating:** As district heating is an important part of the government's strategy for renewable heat it is envisaged that district heating will become a more widely spread technology over the coming years. It is therefore assumed for the purpose of this report that if there is a reliable constant source of low carbon heat available from Deep Geothermal in an area where there is a sufficient heat demand currently being met by fossil fuel, investment will come in from other sources to construct the heating network. These costs have not therefore been included in this report. The costs that would need to be met by others would include: the piping network; pumps heat substations; and energy meters. The capital costs associated with a district heating circuit will be dependent on the length and complexity of the pipework route, its capacity and the number and size of the connected heat loads. It should be emphasised that the cost of installing a DHN is not inconsiderable and is greater in a retrofit situation than if there is an opportunity to include it in a 'new build' situation (i.e. a new residential or commercial development). The cost of including a DHN solely to increase the utilisation of a Deep Geothermal project may therefore outweigh the financial benefits to the project. In new build situations, not only are the installation costs of DHN lower than in a retrofit situation, but there are other costs of providing the low carbon solutions which are required to meet planning obligations which will be offset by the provision of heat from a low carbon source.

Capital cost breakdown

The high level cost breakdown for a typical double well geothermal power plant is given in Table 8–2 below:

Table 8–2 Typical capital cost breakdown

Category	Sub-Category	%
Well doublet	Infrastructure for Drilling site	4%
	Electricity development	<1%
	Well 1	23%
	Well 2	18%
	Planning and testing	6%
	Reservoir engineering	4%
	Sub-total	55%
Geothermal Loop	Production and injection pumps	3%
	Heat exchangers/filters pipework	2%
	Sub-total	5%
Binary Power Plant	Turbine and generator unit	13%
	Building	5%
	Coolers	2%
	Sub-total	20%
Infrastructure	Pipes Valves etc	<2%
	Grid connection	<3%
	Sub-total	5%
	Fees / Incidentals / Contingencies	15%
	TOTAL	100%

Operational Costs

The high level operational costs for a geothermal combined heat and power station can be summarised as follows:

- **Personnel costs:** The cost of human time to operate the station. Due to the nature of a geothermal CHP system, once operational it requires relatively little human interaction except to perform routine checks and inspections, some of which could be performed remotely. The most human interaction would be required for regular routine inspections, at start-up / shutdown of the plant and during maintenance periods.
- **Routine maintenance costs:** All the equipment associated with the geothermal CHP station such as valves, pumps, the generator, switchgear etc will have required maintenance works to maintain its performance and life.
- **Consumables:** The cost of consumables is considered to be items such as filters, oil and chemicals, which will have a relatively low overall operational cost. However, depending upon the geothermal site / system, water and dosing chemicals may be required on an ongoing basis especially if water is not all re-injected / recovered from the well.

It is unlikely that a geothermal well will have sufficient natural pressure gradient to produce a flow of geothermal fluid and for this reason a lift pump and possibly a re-injection pump are required. These electric pumps would require power to drive them. It has been assumed that for the majority of the time (except during plant start-up and shutdown) the pumps would be powered by the output of the generating station therefore reducing the net power available for export (i.e. a reduction in revenue rather than an increased cost payable to others). For this reason the pumps parasitic power usage is not considered as an operational cost, but instead seen as reduced revenue. The parasitic pump load will vary from site to site and depend on the lift head required and the permeability of the geo-structure.

Plant Degradation

The base case financial modelling that has been carried out for this study assumes there is no degradation of the thermal abstraction temperature with time. If a reduction in the abstraction temperature did occur, this would result in a lower power output from the project and hence reduced revenues. The heat produced by the well has been assumed in the base case to remain constant over the life of the project. There is some evidence that there is potentially an annual degradation in available temperatures and therefore the power production and the potential effect of this has been considered in the sensitivity analysis.

Availability

In estimating the annual energy volumes and hence revenues produced by the installation, a capacity factor of 90% has been assumed for all plants. This capacity factor takes into account both the performance and availability of the installation.

Power & Heat Sales Prices

To calculate the potential revenue from the energy volumes, it has been assumed that the base load power price is £45.00/MWh (a realistic price for baseload power at the time of writing, 2013) and that each MWh of generation is eligible for 2 ROC's at a price of £44.00/ROC (based on the April 2103 auction price). Deep Geothermal is currently supported at 2 ROC's/MWh and this has been used in the base case. For heat, Deep Geothermal is currently supported at £35.00/MWh and in the base case we have also assumed that heat can be sold at £25.00/MWh. As noted above the potential heat sales will be dependent upon suitable heat load customers that can be connected to the station via a district heating network.

First Year Output

For calculating the timing of project revenues it has been assumed that the plant output in the first full year of operation after construction would be 50% of the final anticipated full load output. This is due to ramping up of the production well and other factors involved with the operation of a new plant.

Energy Price Escalation

For calculating the NPV a discount rate of 10% has been assumed as the base case and that electricity prices will increase at a rate of 3.8% per annum which is a figure from the published National Grid, UK Energy Price Scenarios report of September 2012 using the "Gone Green" scenario. Gas prices (and therefore the equivalent heat sale prices for CHP plant) have been assumed to increase at 1.2% per annum, an average figure between now and 2030, taken from the DECC Fossil Fuel Price Projections report of July 2013. (NB. The equivalent gas price increase from the National Grid report used for electricity predicts a gas price growth of 2.3% per annum). The base case assumptions are summarised in Table 8–3 below. Prices for electricity have been based on the current market prices at the time of writing this report.

It should be noted that a lower discount rate will affect the NPV, however it will not impact the IRR.

Table 8–3 Base Case Modelling Assumptions

Term	Assumption
Capacity factor	90%
Capital Cost	£6m per MW net
Opex cost (year 1)	£200k per MW net
Discount Rate	10%
Heat Sale Price	£25.00 /MWh
RHI Value	£35.00 /MWh
Power Sale Price	£45.00 / MWh
ROC Value	£88.00/ MWh (ie 2 ROCs / MWh @ £44.00 /ROC)
Rate of Inflation	2% per annum

Term	Assumption
Electricity Cost Increase	3.8% per annum
Gas (therefore heat) price increase	1.2% per annum
Construction Period	3 years
First year output	50% of anticipated full output
Assessment Period	25 years

Site requirements assumptions for financial model

For all the case studies the power generation facility would normally be expected to comprise a compound or building depending on the nature of the surrounding area. The plot required for this size of plant would typically be approximately 100m x 50m and would comprise:

- The well head(s);
- One or multiple single storey buildings housing;
 - Power generator
 - Electrical switchgear and transformers
 - Pumps for circulation, cooling and district heating where appropriate
 - Heat exchangers
 - Filters
 - Metering and control equipment
 - Office, welfare and stores
- Areas for;
 - Vehicle parking
 - Spares
 - Mud lagoon / waste areas
 - Dump Coolers

The financial cost model has been based on these site requirements to develop the capital cost.

8.5. Scenario Analysis for Case Studies

8.5.1. Screening Criteria for Geothermal Power Plants

Three case studies have been produced for scenario analysis based on the following key screening criteria:

- Temperatures >100°C
- Heat gradients \geq UK average (20°C per 1000m) - allowing the geothermal reservoirs to be created at economical drilling depth of 5000m
- Heat reservoir permeability $\geq 5 \times 10^{-12} \text{ m}^3$ (~5mD)

Radiogenic granites of Cornwall, Weardale and the Lakes District are being suggested as probable reserves for geothermal heat generation and therefore have been used in two of these examples. However, it should be noted that the current status of these granites is inferred resource owing to the lack of characterisation.

However, projects utilising geothermal energy from temperatures (~100°C) at the base of the Wessex and Cheshire sedimentary aquifers may also have potential and therefore an example describing such a project has also been included. Current technology conversion efficiency from thermal energy to electrical energy is directly linked to the production temperature that is supplied. A lower production temperature reduces the conversion efficiency and 100°C is currently considered the minimum temperature that can be used to make a project economical. A feasibility study for geothermal power generation in Germany has been carried out by Paschen et al (Ref.46) which suggests specific parameters for a heat reservoir to be economically feasible and is summarised in Table 8–4. Paschen et al also suggest 1 to 2 km distance between the abstraction and injection wells for doublet systems as being suitable to utilise geothermal energy. These suggested parameters have been taken into account in the case studies.

Table 8–4 Minimum parameter geothermal scheme suggested by Paschen et al (Ref. 48)

Parameter		Value
Minimum reservoir temperature	T_{MIN}	100°C
Minimum production temperature	T_{MIN}	100°C
(Geothermal fluid) return/injection temperature (power only schemes)	T_{IN}	70°C
(Geothermal fluid) return/injection temperature (combined heat & power / without heat pump)	T_{IN}	50°C
(Geothermal fluid) return/injection temperature (combined heat & power / with heat pump)	T_{IN}	30°C
Minimum flow rate	Q_{min}	50m ³ /h (14*10 ⁻³ m ³ /s)
Maximum pressure difference	Δp_{max}	80bar (8MPa)
Minimum transmissivity	T_{MIN}	$2 * 10^{-12} \text{ m}^3$ (2 Dm) ⁺

⁺ Paschen et al (Ref. 55) indicates this value is relatively low, making reference to another literature source suggesting a minimum transmissivity value of $5 * 10^{-12} \text{ m}^3$ (5 Dm).

8.6. Electrical Grid Connections

Every geothermal power plant would need an electrical connection and the cost of this would be dependent on location and proximity to existing supplies but also on the current loading and electrical configuration of those supplies. Some general considerations are considered below.

Smaller plants (2 – 10 MWe) would be connected into the distribution network at either 11kV or 33kV. Ideally the connection would be directly into a primary (33/11kV) substation or a grid supply point (132/33kV) substation. However the distance to these sites may not be economically viable.

Alternatively the connection could be made by a ‘T’ connection into an existing cable or overhead line passing near to the generator either directly or by establishing a switching point. Suitability of the existing

cable or overhead line would need to be carefully assessed to ensure voltage stability; circuit rating and protection clearance times are not exceeded.

In some parts of the distribution network, generation levels may exceed demand and this could cause reverse power flow in the transformers from the lower to higher voltage level. If this occurrence exists, transformer investigations would be required to ensure the transformer reverse power flow capabilities are not exceeded. This may well be the case in regions which have traditionally not had much generation but are now handling growing amounts of wind power.

Connection of larger multiple plants (10 – 50+ MWe) would necessitate a connection into either the 132kV or 400kV networks. If the connection was into the 132kV network the connection maximum capacity would be approximately 200 - 250MW. Exceeding this level would require a 400kV connection.

Establishing this size of connection would require clustering multiple generation plants into a 132/33kV or 275/33kV or 400/33kV node point and then clustering the node points into a single substation connected to either the DNO or National Grid Transmission networks. In creating the generator plant clusters the network would operate at distribution voltage levels. In doing so this could facilitate the creation of a new Independent Distribution Network Operator (IDNO). The benefit of a new IDNO would be dependent on the number of geothermal schemes within a close proximity, the capacity of the existing electricity network and / or the costs of upgrading the existing electricity network compared to a new IDNO. Ofgem has currently issued six distribution licences to IDNOs.

Detailed studies would be required for each scenario to ensure the distribution or transmission networks are capable of connecting the generation. The studies would include voltage stability, fault level, reverse power flow, protection clearance times, telecommunication systems and network capability.

8.7. Summary of Risks Involved in Developing Deep Geothermal Projects

There are a number of risk areas which need to be considered when considering the development of a Deep Geothermal power project. Table 8-5 Summary of Risks Involved in Developing Deep Geothermal Projects identifies the main risks, the risk group (e.g. technical, economical etc), the consequences and the potential risk mitigation measures. The risk mitigation measures are somewhat subjective, dependent on the readers position e.g. investor / developer or government trying to develop/establish an industry. Each risk has been scored on a scale of 1 to 5 for both likelihood and severity and then the score summed together to give an idea of the overall risk.

Table 8-5 Summary of Risks Involved in Developing Deep Geothermal Projects

Risk	Category	Description of Risk	Consequences	Likelihood	Severity	Overall Score	Risk Mitigation
Power Price	Economic	The power price can decrease both in the long and short term depending on market conditions	A fall in the power price would increase the payback period of a project.	5	5	10	Forward fix power prices and volume to gain budget certainty
ROC Price	Economic	The ROC price can change depending on the market surplus / shortfall.	A fall in the ROC price would increase the payback period of a project.	3	5	8	Continue to monitor the market. Contract forward if possible and monitor the market
ROC Support Level	Economic / Policy	The ROC support level for Geothermal Power is currently set at 2 ROC's / MWh. The current level of support is set to drop to 1.8 ROC's / MWh in 2017,	A lower ROC support level would reduce the revenue to a project and hence reduce the payback.	3	5	8	It is likely that a developed or granted project would continue to receive grandfathered ROCs. Continue to monitor the market
RHI Rate	Economic / Policy	Deep Geothermal heat currently qualifies for the renewable heat incentive at a rate of 3.5p/kWh. There is a risk that this level of support could reduce in the future.	A lower RHI rate would reduce the revenue to a project and hence reduce the payback.	1	5	6	It is likely that a developed or granted project would continue to receive grandfathered FITs. Continue to monitor the market
Other Natural Resources	Economic / Policy / Regulatory	The geothermal development area may have other more profitable or conflicting resources / minerals, for example shale gas. There may also be cases where wells from different companies are using the same aquifer and hence the production and / or resources may be reduced.	Potential geothermal sites are not developed as there are economically attractive options. Development of geothermal energy becomes limited.	3	4	7	Ensure that the appropriate economic, regulatory and policy are put in place to make geothermal energy attractive.

Risk	Category	Description of Risk	Consequences	Likelihood	Severity	Overall Score	Risk Mitigation
Skills and Resources	Economic / Policy / Regulatory	The appropriate skills and resources are not available to develop geothermal energy in the UK	Development of geothermal energy becomes limited or costs increase as the skills / resource is needed from overseas	3	3	6	Although geothermal energy is relatively new in the UK, when split into its individual component parts, the skills and resources could be established from other industries such as oil & gas and power generation.
Planning Permission	Regulatory	Planning permission is rejected or takes a long time due to lack of awareness / public misconceptions	A project is delayed or does not proceed at all. Can potentially also add additional costs to a project	4	4	8	Planning permission can be determined upfront in the early development stages of the project to help reduce the risk of unknown costs.
Easements and wayleaves	Regulatory	Where the geothermal production and return pipe and / or power cables cross other owners land, easements and wayleaves will need to be established	Easements and wayleaves may not be agreed / granted for the most economic route. Alternative routes may be needed increasing the cost of the project	2	3	5	Easements and wayleaves can be established at the development stage of the project so that the costs are known and risks reduced
Licensing	Regulatory	Licensing and the legal ownership of geothermal resources in the UK is currently not clear	Could lead to large areas of debate; this is a significant risk for geothermal energy development.	4	5	9	Put appropriate licensing in place so that ownership is defined.
Changes to laws / regulations (EA) / permits	Regulatory	Laws and regulations are currently established; however there could be changes or new laws / regulations in the future	Any negative changes in law or regulations could put off potential developers and investors.	4	4	8	Continue to monitor
Access	Regulatory	Access to the drilling site will be required	If the required access cannot be achieved then an alternative site or access may be required potentially increasing the cost. A project may not proceed.	1	5	5	Permission and cost can be determined upfront in the early development stages of the project and hence significantly reduce the risk of unknown costs.

Risk	Category	Description of Risk	Consequences	Likelihood	Severity	Overall Score	Risk Mitigation
Available resource	Technical	The exact geothermal resource available can only be established at the later stages of the project cycle.	As the resource determines the volume of energy available, it is a large contributing factor to the overall revenue the project will generate and hence the economics. Considerable upfront capital required to determine the resource	4	4	8	Carry out detailed modelling and test wells to establish the resource as far as possible
Exploration / drilling risk	Technical	There are various risks associated with drilling such as encountering unexpected strata and these will not be fully known until the drilling progresses.	A well is unproductive or has to be abandoned	3	5	8	Carry out exploration studies as far as possible to help gain certainty
Availability / cost of rigs for drilling	Economic	The availability and cost of a drilling rig is linked to the oil price,	A higher oil price makes it more attractive to develop more expensive oil fields and hence there is competition to secure an appropriate drilling rig. This could either delay the program until a rig is available or increase the cost of drilling. A fall in the oil price would provide the opposite scenario.	3	5	8	Arrange a drilling rig in advance to achieve favourable pricing
Water	Technical	A water resource may be required to provide the geothermal fluid.	Could increase the cost of a geothermal project and also has environmental considerations.	2	3	5	The availability of water resources can be established at the development stages of a project and a good idea of costs established.

Risk	Category	Description of Risk	Consequences	Likelihood	Severity	Overall Score	Risk Mitigation
Grid connection proximity and cost	Technical	If a geothermal CHP plant is to export the surplus power generated then it will need a connection to the local distribution network.	The availability and proximity of a suitable grid connection can add considerable cost to the project	3	3	6	The feasibility and cost of the connection can be determined upfront in the early development stages of the project and hence significantly reduce the risk of unknown costs.
Well degradation	Technical	A wells production temperature could reduce over time or reduce quicker than expected.	A reduction in the energy available and hence the revenue for the same or increased production costs.	3	5	8	Carry out detailed testing and logging of the well to establish its viability before continuing development.
Heat load proximity and cost	Economic / Technical	To develop a CHP system, there needs to be a suitable heat load(s) within a reasonable proximity to the power generating station.	If there are no head loads then CHP will not be possible and this will reduce the economics. If potential heat loads are a long distance away, this will increase the costs of distribution and hence reduce the project economics	2	4	6	An estimate of the heat demand in the area can be established in the early feasibility stages; however the exact heat demand would need to be firmed up during the development phase of the project and commitments agreed with the heat load owners.
Performance and availability	Technical	The revenue modelling of a geothermal energy project is based on the overall performance and availability of the geothermal system.	If the performance or availability is less than expected then the project revenue would be reduced.	1	4	5	The techno-economic model should be an ongoing process incorporating new / gained information and hence increasing certainty
Operating costs	Economic	Operating costs are higher than estimated / budgeted.	Higher operating costs would reduce the project economics	1	4	5	There will always be some unplanned operational events and these will need to be covered as contingency in the operational budget.

9 Case Studies

9.1. Rationale

9.1.1. Scenario rationale

For a geothermal power plant to be economically feasible a good flow of heat is required. Power generation rates depend on the flow rate of geothermal fluid and its temperature. Flow rates are governed by the hydraulic characteristics of the rock and need careful consideration. The three case study schemes reflect a mixture of scenarios applicable to the UK situation and the main performance parameters are based on the following assumptions:

Cornwall Scheme

Representative of granites where permeability restricts flow rates and stimulation is required. Note zones of faulting and features in this area can be reasonably expected to be present as per the Weardale scheme below but this is as yet unproven.

- Reflects the experience derived from the testing of boreholes at Rosemanowes. Permeabilities of the granite to some depths have been investigated and reported. However, Rosemanowes was chosen for its absence of geological features. As a result, the permeability values found are only representative for the much lower matrix permeability that cannot be relied upon when creating a geothermal reservoir.
- The granites in the Upper Rhine Graben are an analogous area where the following can be inferred:
 - Based on the reservoir index of the reservoir constructed in a fault zone at Soultz-soultz-Forets, a conservative pre-stimulation permeability of approximately 1 mD can be assumed.
 - Stimulation is presumed to enhance the permeability by a factor of 19 as per experience from the Soultz-soultz-Forets site.
 - The application of a pressure of 60bar is considered reasonable to overcome the reservoirs resistance to flow, its thickness and fluid viscosity. A post stimulation flow rate of 40 l/s was calculated.
- It is possible similar features (as per the Weardale Granite) facilitating higher flow rates exists in the Cornish Granites, however, this scenario tests a case where such features are absent.
- If absent, 'geological disturbances' generated by faulting can provide higher permeabilities.
- Dependent on a number of plant specific parameters (e.g. return temperature and conversion efficiency) the 190°C hot fluid (indicated at depths between 4,500 and 5,000m) flowing at a rate of 40l/s after stimulation results in a gross electricity generation rate of about 3.1MW.

Weardale Scheme

Representative of granites with features where the permeability is not limiting flow rates. The presence of such features has been reported by the Eastgate studies.

- The presence of a geological feature (Slitt Vein) in the granite suggests unusually high permeability.
- Provided such permeabilities persist to the base of the reservoir (estimated at c.4,500m), then large technically and economically feasible flow rates may be possible. Based on geothermal power plant sites where high permeabilities are not the limiting factor for flow, a rate of 80l/s has been used for this scenario.
- Dependent on a number of plant specific parameters (e.g. return temperature and conversion efficiency) the 160°C hot fluid flowing at a rate of 80l/s results in a gross electricity generation rate of about 4.5MW.

Crewe Scheme

Representative of a deep sedimentary aquifer.

- Although based on an interpretation of geophysical logs and not direct test data, Barker et al 2000 (Ref. 3) suggests that the transmissivity in the sandstone is likely to exceed 10 Dm. No information is given as to what depth range the transmissivity applies to. However, permeability and transmissivity, as a product of permeability and aquifer thickness, decrease with depths. Therefore, a 10 Dm transmissivity has been used when calculating flow rates for this scenario.
- A pressure of 80bar is considered technically feasible however, to overcome the reservoirs resistance to flow and has been applied to the scenario together with the reservoir permeability and thickness, and the fluids viscosity, to calculate a flow rate of 40l/s.
- Dependent on a number of plant specific parameters (e.g. return temperature and conversion efficiency) the 100°C hot fluid (inferred at depths between approximately 3,650 m and 4,250 m) flowing at a rate of 40l/s results in a gross electricity generation rate of about 0.7 MW. The moderate gross electricity generation rate, the majority of which would be taken up by parasitic loads, is low due to the relatively low temperatures anticipated (100°C).

9.1.2. Recovery factor for scenario analysis

The recovery factor is reflective of the fracture distribution of the geological unit the heat is abstracted from. If, for example, the geological heat reservoir relies on a small number of large fractures, rather than a vast network of small fractures, then the recovery factor is low. In this instance, for a given heat extraction rate to be feasible, the volume of the geological reservoir has to be greater.

Recovery factors are used when calculating the overall potential of generating electricity from source rocks on a regional rather than scheme specific scale, following the heat in place concept. A low recovery factor determines the maximum rate of energy that can be extracted from a single scheme to a lesser extent than it puts limitations on the overall rate that can be abstracted from an entire region (e.g. the granites of South West England).

Whilst the heat recovery factors for naturally fractured geothermal systems generally lie between 5 % and 15 % (Ref. 38). Because of the difficulty in emulating naturally fractured systems, the heat recovery factors for an EGS system is expected to be lower. Grant & Garg 2012 (Ref. 38) suggest a recovery factor of 2% for reservoirs engineered in the granites of the Cooper Basin.

For the scenario development a variety of recovery factors has been used for illustrative purposes; a low 2% for an EGS system in granite; a higher 10% for naturally permeable fractured granite and a high 20% for a fractured sedimentary aquifer with additional intergranular porosity. In reality, the recovery factors will be variable in the host rock as a result of differences in natural fracturing, with areas of higher and lower recovery in all systems. However, by providing varied factors in the scenarios the effect of such variation can be demonstrated.

9.2. Enhanced Geothermal System (EGS): Cornwall

9.2.1. Heat reservoir conceptual model

A potential scheme utilising heat from the radiogenic granite is illustrated in **Figure 9–1** below.

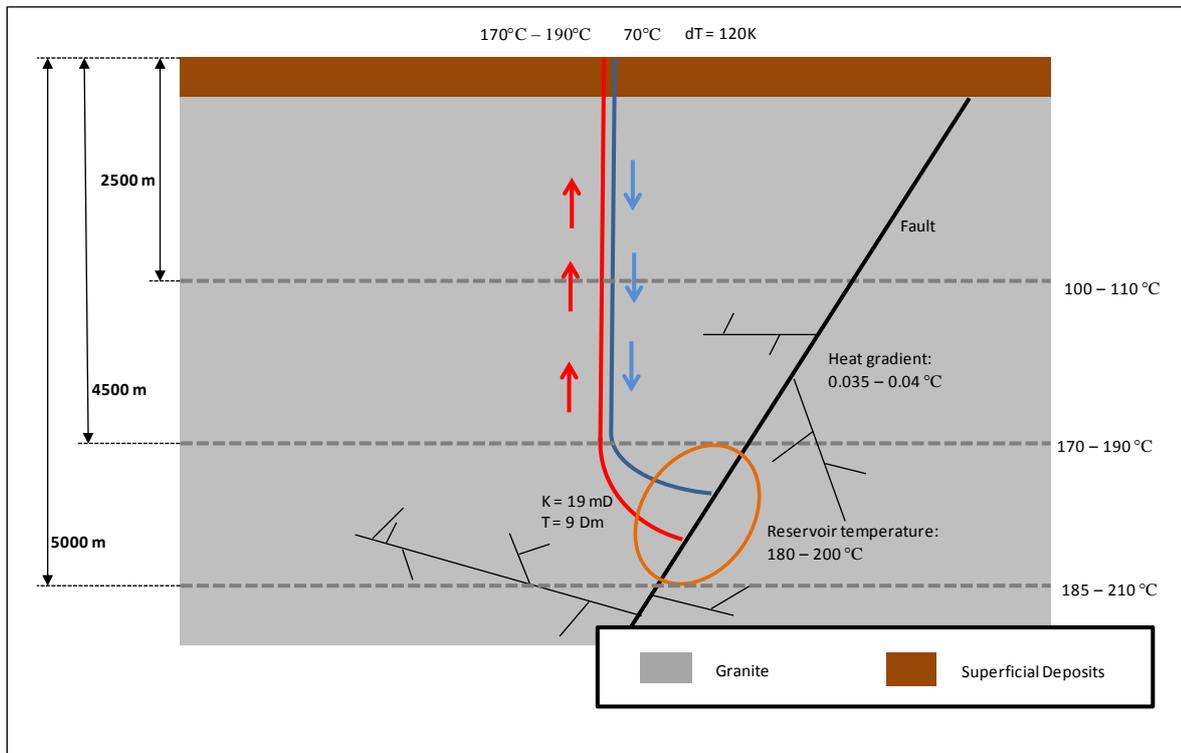


Figure 9–1 Cornwall geothermal power conceptual model

The heat reservoir in this scenario is created within faults zones at depths between 4500 m and 5000 m. The presumed permeability (1mD) of the granite in this scenario is increased by means of stimulation (EGS). At the depth of the reservoir, depending on detailed design, the abstraction and injection zones are approximately 1000 to 2000 m distant from each other. The granite at the fault zone is presumed to exhibit an initial permeability and porosity of $9.9 \times 10^{-16} \text{ m}^2$ (1 mD) and 15% respectively. In this scenario, stimulation by means of hydraulic fracturing is estimated to result in a permeability improvement 19 times the original value. This compares with the result at Soultz-sous-Forêts (Ref. 42), and post the stimulation the reservoir shows average permeability and transmissivity values of $1.9 \times 10^{-14} \text{ m}^2$ (19 mD) and $9.4 \times 10^{-12} \text{ m}^3$ (9 Dm) respectively.

Depending on local heat gradients (the anticipated range varies between 35 °C per 1,000m and 40 °C per 1,000m the average reservoir temperature anticipated is between 180 °C and 200 °C. Parameters, specific for the reservoir presumed in the scenario are summarised in Table 9–1 below.

Table 9–1 Cornwall scenario geothermal reservoir parameter

Parameter	Value
Stratigraphy	Granite
Thermal gradient	35 – 40 °C per 1,000m
Depths (reservoir thickness)	4500 m – 5000 m (500m)
Reservoir Temperature	180 – 200 °C
Geothermal (reservoir) fluid type	Brine
Geothermal (reservoir) fluid density	1200kg/m ³
Geothermal (reservoir) fluid viscosity	0.0007 Pa s

Parameter	Value
Permeability(prior to stimulation)	$9.9 * 10^{-16} \text{ m}^2$ (1 mD)
Permeability (post stimulation)	$1.9 * 10^{-14} \text{ m}^2$ (19 mD)
Transmissivity (post stimulation)	$9.4 * 10^{-12} \text{ m}^3$ (9 Dm)
Reservoir index (productivity / injectivity)	0.7 l/s/bar (24 m ³ /h/MPa)
Injection pressure	6 MPa (60 bar)
Flow rate	0.040 m ³ /s (40l/s, 144m ³ /h)
Volumetric heat capacity (Granite)	2.4MJ m ⁻³ K ⁻¹
Recovery factor	2%
Conversion coefficient	13%
Economic life of project	25 years
Heat reservoir volume	1.4 km ³
Power generation (gross)	3.0 MW
Parasitic load (pump for pressure difference)	0.5 MW
Power generation (net)	2.5 MW

9.2.2. Outline discussion on sensitive parameters

Reservoir temperature

With the presumed heat gradient of 0.035 – 0.04 °C/m, it is assumed that average reservoir temperatures in the order of 180 - 200 °C will be encountered at depths of 4500 m to 5000 m) suggested by the equation below.

$$R (\text{°C}) = 0.035 - 0.04 \frac{\text{°C}}{\text{m}} * d(\text{m}) + 12\text{°C} \quad \text{Equation 1: Reservoir temperature}$$

With $R (\text{°C})$ = reservoir temperature, $0.0035 - 0.04 \text{ °C/m}$ = thermal gradient; $d (\text{m})$ reservoir depth and 12 °C subsurface temperature

Reservoir permeability

The granite at the fault zone is presumed to exhibit an initial permeability and porosity of $9.9 * 10^{-16} \text{ m}^2$ (1 mD) and 15% respectively. In this scenario, stimulation by means of hydraulic fracturing results in a permeability improvement 19 times the original value.

Based on these assumed parameters and with the presumed fluid viscosity and injection pressure (pressure difference), the flow rate is calculated to equate to 0.04 m³/s (40 l/s or 144 m³/h).

$$Q_f = \frac{T * \Delta p}{2 * \mu} = \frac{9.4 * 10^{-12} \text{ m}^3 * 6 * 10^6 \text{ Pa}}{2 * 0.0007 \text{ Pa} * \text{s}} \quad \text{Equation 2: Geothermal fluid flow rate}$$

9.2.3. Financial Modelling - Cornwall

Base case assumptions and model

Based on the reservoir conceptual model heat flow for Cornwall, it has been assumed that the heat can be converted to electricity at a conversion efficiency of 13% which gives a gross electrical capacity of 3.0MW. The pump power required to circulate the geothermal fluid through the reservoir and the relatively minor (by comparison) power loads to operate the generating station has been estimated at 500kW. This is the parasitic load for the overall installation and therefore the resulting net power output is 2.5MW, i.e. the power output available for sale or other uses.

It is assumed that geothermal fluid after the binary cycle power plant could be used for district heating purposes with an assumed minimum re-injection temperature of 45°C, although the minimum return

temperature will be determined from the specific chemistry of the water in each case as crystallisation of any salts needs to be avoided. In this case the available heat output rate available is up to 5 MW. It should be noted that this is the maximum heat output rate and the volume of usable heat would be dependent on the connected thermal loads. Although not assumed possible in this case study, if the low grade heat (circa 20 – 45°C) could be used from the power plant condenser (which is separate to the well circuit and would otherwise be dissipated) , then significantly larger quantities of heat could be available. Based on the installed capacity, for the base case we have assumed a capital cost of £15 M and annual operational cost of £500k. The capital costs include all costs associated with the geothermal well, electrical generation station, grid connection and associated pipe work and auxiliary equipment. All the base case assumptions are summarised in Table 8–3, with specific assumptions summarised in Table 9–2.

Table 9–2 Cornwall: Specific modelling assumptions

Term	Assumption (Base Case)
Electrical efficiency	13%
Gross Capacity	3.0 MW
Net Capacity	2.5 MW
Usable Heat Output	5 MW
Capital Cost	£15.0 M
Opex cost (year 1)	£500,000 pa

With the base case assumptions set as per Table 8–3, a sensitivity analysis has been carried out on the volume of heat sales and the effect on the project NPV and IRR. The ability to use and sell the heat would be dependent upon one large heat user or a number of smaller users connected to a heating network. The costs associated with delivering the heat to the user(s) would be very much dependent upon the distance from the geothermal wells along with the size and number of heat customers to be connected. A single heat load customer taking all the heat available within close proximity to the geothermal well is likely to provide the most economic option compared with a small number of heat loads a long distance away from the geothermal well being the least or uneconomic option.

For this reason the heat volume sale sensitivity analysis has been carried out assuming zero cost for delivering the heat to the customer. Dependent upon the distance, number and size of the heat loads, the cost for delivering the heat would increase and hence reduce the economic case.

The results of the sensitivity analysis without including costs for delivering the heat are shown in Table 9–3. It can be seen initially with the base case of zero heat sales that the NPV is low. However as an increasing volume of heat sales will increase the revenue to the project, it can be seen that when 75% of the potential heat volume is sold the IRR reaches approximately 17%.

Table 9–3 Cornwall: Heat sale sensitivity

% Heat sold	Heat sold (MWh)	NPV £	IRR %
0%	-	£1,439,070	10.9%
25%	9,844	£5,108,305	13.1%
50%	19,688	£8,777,540	15.1%
75%	29,532	£12,446,775	16.9%
100%	39,376	£16,116,010	18.6%

District heating is normally considered to be viable in areas with a high heat density with some good base loads which are both large and constant (often referred to as anchor loads). Having availability of space for routing underground heat distribution pipework is also beneficial to district heating. This is not typically how one would describe the situations in small Cornish towns. However, as the benefits of the low carbon of district heating become more widely understood we may move away from the traditional ‘norms’ just described.

In order to put the heat loads potentially available from geothermal energy into context with the area, the online DECC heat mapping tools have been used to estimate the heat requirements. If our sample case study plant was situated at Redruth in Cornwall, then the map below (**Figure 9–2**) shows the heat loads within a 1km radius as indicated by the small blue/purple circle.

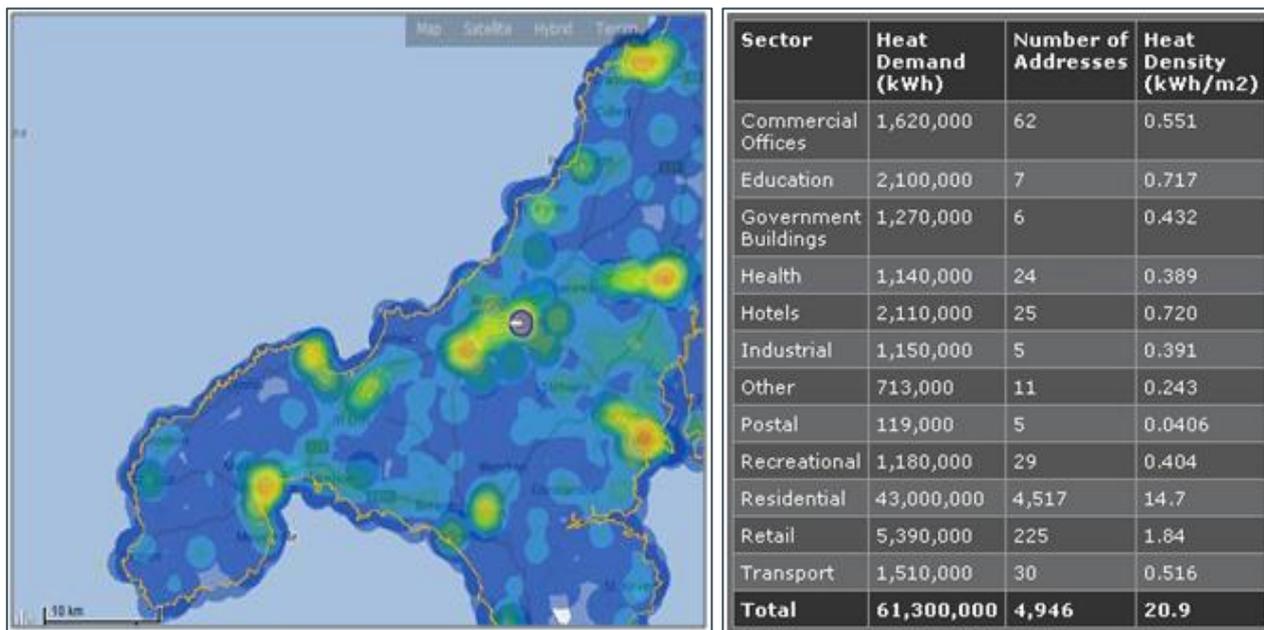


Figure 9–2 Heat Load Mapping around Redruth

Sector loads typically suited to district heating systems are:

- Education
- Government
- Health
- Hotels
- Residential

This tool suggests that these sectors have an annual thermal demand for approximately 50,000 GWh in that area with 43,000 GWh being domestic load. Comparing this to an existing city centre district heating scheme in Sheffield, the online mapping suggests that within the same 1km radius of the city centre the matching load categories have a demand of 141,000 GWh with 64,000 GWh being domestic load. That area in Sheffield is fed by a 45MW (thermal) district heating scheme with 45 km of pipework feeding some 140 buildings including two universities and various municipal buildings.

Whilst the two areas are very different in nature and no conclusive comparison can be made, it would appear that this area around Redruth, which is probably typical of other small Cornish towns, could well be supplied with heat from a Deep Geothermal plant of 2.5 MWe net giving 5.0 MWth output.

The mapping shows that a large proportion of the relevant heat demand in Redruth (87%) is domestic. Typical consumption profiles for domestic properties show that around 75% will be seasonal demand for heating homes and will only be required in winter and the remaining 25% will be for heating hot water and will be required all year round.

In order that a large proportion of the available heat from the geothermal plant can be used it would need to be matched close to the base load available throughout the year, with the peak winter demand being met by conventional heating plant.

The capital cost per MWe has been varied between £3M/MWe and £9M/MWe, which are generally in the range used for other studies and these levels approximate to the Low/Medium/High figures in Ref. 12. As

expected the NPV and IRR decrease with increasing capital costs. This shows for any geothermal project that the capital costs need to be as low as possible and it is expected that capital costs would decrease as the geothermal industry matures (see section 8.4.7).

Table 9–4 shows the effect on NPV and IRR for a power only scheme. The results assuming 50% heat utilisation are shown in Table 9–5.

Table 9–4 Cornwall: Capital cost sensitivity (0% heat use)

£ / MWe	Capital Cost £	NPV £	IRR %
£3,000,000	£7,560,000	£8,311,524	18.5%
£6,000,000	£15,100,000	£1,439,070	10.9%
£9,000,000	£22,680,000	-£5,433,385	7.3%

Table 9–5 Cornwall: Capital cost sensitivity (50% heat use)

£ / MWe	Capital Cost £	NPV £	IRR %
£3,000,000	£7,560,000	£15,649,994	24.0%
£6,000,000	£15,100,000	£8,777,540	15.1%
£9,000,000	£22,680,000	£1,905,085	10.9%

Any heat sales would attract the RHI tariff, which is currently £35.00/MWh for Deep Geothermal and also potentially an additional price per MWh from the heat load customer. The costs for any heat network have not been included at this stage but would (depending on distance, size and location) increase the project capital costs and also add a cost of sales in delivering the heat to the customer. Under the base case the heat sale price to the customer has been assumed to be £25.00/MWh. In comparison, the cost to generate heat from a natural gas boiler is approximately £30.00 - 50.00/MWh for a residential customer, depending on the gas price and boiler efficiency, so the geothermal heat price has been set lower in the base case model so that it is more economically attractive than conventional heating. The heat sale price that could be achieved would be dependent on the heating network and its ownership e.g. if the heating network was pre-existing then a lower heat sale price may be expected, but the project returns may remain the same or better due to the capital cost for the heating network being reduced or not required.

Based on an assumption of being able to use 50% of the heat volume, a sensitivity analysis was carried out on the effect of increasing or decreasing the price at which the geothermal heat could be sold. This analysis has been carried out with the RHI fixed at the current rate and changing the heat price only, e.g. at a heat price of £0/MWh, the project would still be attracting the RHI on 50% of the heat volume and hence receiving a revenue income for the heat. This heat revenue income will then increase with an increasing heat sale price (assuming 50% of the heat volume is sold).

Table 9–6 shows how NPV and IRR increase as the assumed heat sale price rises. NB. Even with zero heat sale price the revenue of the plant is still increased by the value of the RHI.

Table 9–6 Cornwall: Heat Sale Price sensitivity (50% heat use)

£/MWh	NPV £	IRR %
0.0	£5,567,429	13.4%
15.00	£7,439,496	14.4
25.00	£8,777,540	15.1%
35.00	£10,061,584	15.8%
50.00	£11,987,651	16.7%

A sensitivity analysis was carried out to look at the effect of varying the operational cost on NPV and IRR. Table 9–7 shows the results on the analysis and it can be seen that a £100k/MWe per annum increase in the opex cost results in approximately a £1.7M decrease in the NPV and a 0.8% decrease in the IRR.

Table 9–7 Cornwall: Opex sensitivity (50% heat use)

Annual Opex (year 1) £'000 / MWe	NPV £	IRR %
150	£9,648,949	15.5%
200	£8,777,540	15.1%
250	£7,906,131	14.7%

9.2.4. Potential of scaling up

To assess the potential that geothermal energy may contribute to the UK in the long term, the scaling up of the industry has to be assessed. This could be from scaling individual plants from the case study size of 2.5 MWe in this case to much larger single plants and also by increasing the number of plants tapping into the geological reserve in an area.

Normal investment cases would be expected to require an IRR of in excess of 15%. However due to the high up front risk of Deep Geothermal where a large amount of the capital cost is required for drilling before the success of the project can be guaranteed, we could expect investors to require IRR figures in excess of 20%. Generally 50-60% of the capital costs of a project are involved in the drilling and preparation of the wells.

Based on the financial analysis presented above we can conclude that there is a potentially viable investment case (IRR circa 15% plus) for this case study based on the lowest assumed capital cost and the ability to use 50% or more of the available heat for sale through a district heating network to commercial and residential loads for space and hot water heating.

We can therefore use information about the populations in Cornwall and West Devon, which are situated on the granite formations being utilised for geothermal energy in this case, to extrapolate the potential for the technology based on electricity and heat generation. The example for heat use above is discussed for the largest conurbation in Cornwall of Camborne and Redruth, which has a population of around 40,000. There are five communities in Cornwall with a population of 20,000 – 30,000. In West Devon there are three large communities of Plymouth (circa 260k pop), Exeter (circa 120k pop) and Torbay (circa 130k pop) and five with populations of 10,000-30,000.

Very roughly therefore, scaling on population one might envisage an opportunity for 10 projects of approximately the size of this example plus three larger schemes at the larger conurbations in west Devon. These together could therefore amount to around the size of twenty two of the plants in this case study. This would equate to a net generation capacity of 55 MWe over the whole of the granite thermal resource in the region that could support heat and power schemes. Given the levels of uncertainty around this methodology, this could be expressed as somewhere in the range of 0 - 100 MWe.

The case study example assumes the extraction of heat from an area of 2.6km². These plants combined would therefore utilise an area of approximately 60km² of the granite resource. This is a very small fraction of the resource area in the cornubian batholith granite which amount to some 2,500 km².

An alternative approach to this estimation is to consider the regional heat demand as assessed from the DECC on-line heat mapping tool. This shows that the total heat load for non industrial users is around 3000 MW of thermal demand. As our case study produces 5 MW of thermal energy this implies there could be an opportunity to replicate the plant 300 times in the region assuming half of the heat load could be fed from similar plants which would result in some 750 MWe of electricity production. Whilst this is unlikely to be realistically possible (due to the excessive cost of the heat network that would be required and the complexity of creating heat networks with long term heat contracts for multiple existing heat users) it forms another estimation of the upper limit of utilisation. This would represent heat being extracted from approximately 800 km² of granite or around 30% of the total resource area.

There is therefore plenty of energy resource that is available but cannot be utilised as a combined heat and power scheme based on assessments of heat demand. Power only schemes have been shown to provide a lower attractive economic return (circa 11%) than those with heat use under the assumptions made to define the base case described above. However, if future economies of scale and technology development were to reduce the capital cost significantly then the IRR would again rise to around 18%.

If such plants become economically attractive then they are not limited by the thermal loads but by the heat available in the underlying geology. In that case using the 'heat in place concept' explained in the SKM report 2012 (Ref. 61), then, a purely theoretical installed gross generation capacity of up to 4,000MW is possible for 25 years. However, a number of constraints apply such as the parasitic power required for producing and re-injecting the geothermal brine and the availability of suitable production temperatures, both of which would constrain the overall amount of net energy that could be extracted for the purpose of power conversion. Properties (e.g. permeability), which preferentially can be found in fault zones determine the likelihood of EGS being successfully applied in granite. Although, as technologies improve, the application of EGS may become employable for a wider range of conditions, at present, the reliance on properties with favourable conditions has a significant influence on the amount of energy that can be extracted for the purpose of power conversion (see also Section 8.4.4).

The fault zones are shown in Figure 9–3 below, together with the granite outcrop in solid red and subcrop in shaded red.

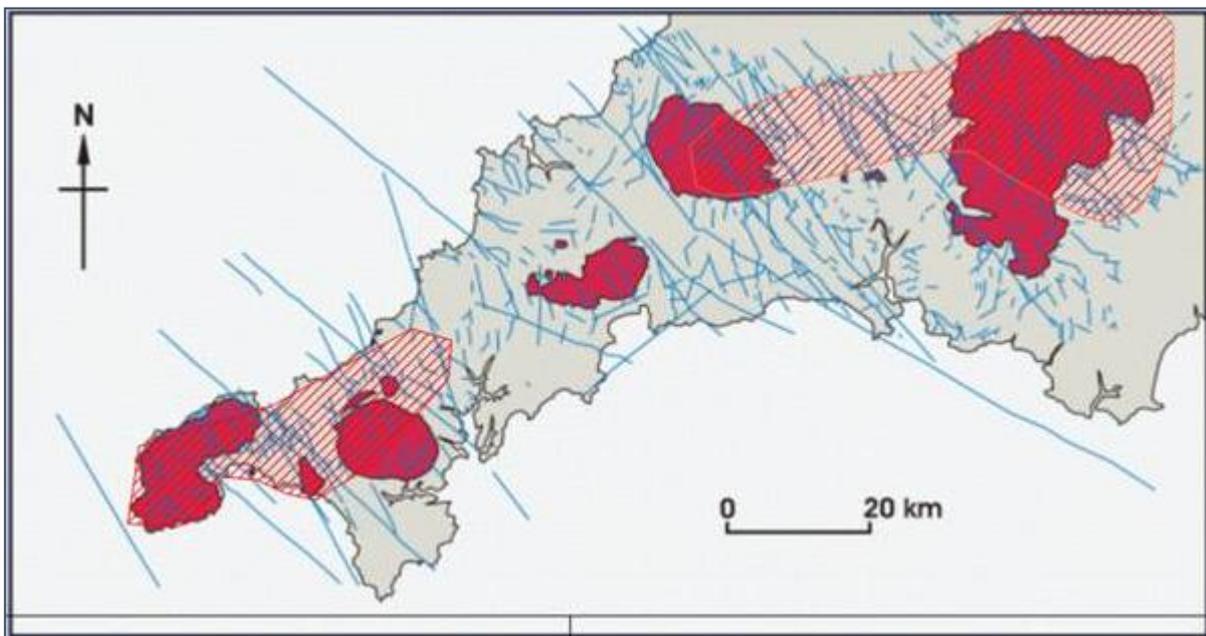


Figure 9–3 The Major Fault Systems of Cornubia (after Camborne School of Mines, 1988)

Cornubian Granite Scenario - Key Points

- The resource for power is in the granites of South West England.
- Inferred temperatures are circa 180 – 200°C at 4.5 to 5km depth.
- Power only applications have potential over much of the region.
- Targeting faults zones should provide best permeability.
- Plants could be replicated across the region to supply heat to local communities as well as energy to the grid.
- Local communities in a number of areas could provide suitable heat loads for CHP although heat networks/connections would need to be developed.
- Power generation from CHP applications will be limited by the available heat loads.

9.3. Deep Hydrothermal (non- EGS) System: Weardale

9.3.1. Heat reservoir conceptual model

A potential scheme utilising heat from the radiogenic granite, without the use of EGS, is illustrated below.

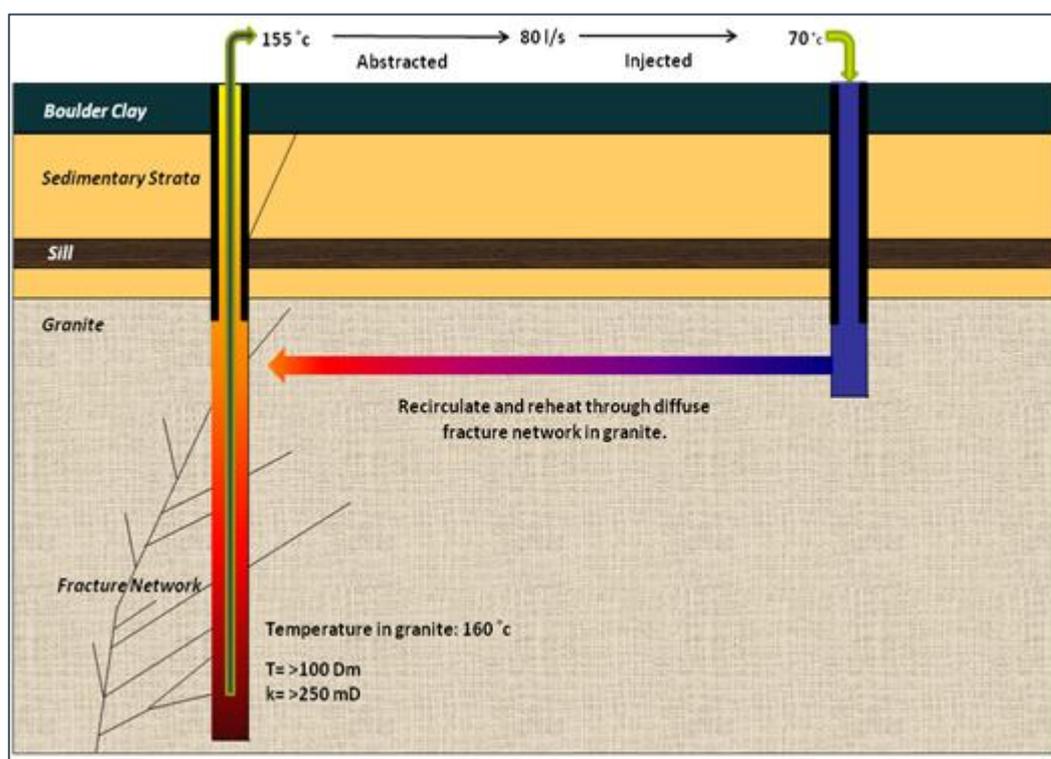


Figure 9-4 Weardale geothermal power conceptual model

Optimistic abstraction rates in this scenario are based on findings from the Eastgate geothermal well drilled to a depth of 995 m (723 m of which was within the granite) into the Weardale batholith (granite) targeting to intersect the Slitt Vein, a major, linear, sub-vertical and potentially permeable natural fracture-zone (see Section 2.3).

The geothermal fluid in this scenario is assumed to be available at rates that a doublet system (one abstraction and one injection well) would support. This is based on the Slitt Vein and associated network of fractures in the granite to be highly transmissive (a transmissivity of > 2,000 Dm was recorded during the well drilling mentioned above) and assuming such transmissivity extends to 4000m then at such depths water may be present at temperatures of circa 160°C.

Outline assumptions are presented in Table 9-8.

Table 9–8 Weardale Scenario Heat Reservoir Parameter

Parameter	Value
Stratigraphy	Granite
Thermal gradient	38 – 39 °C per 1,000m
Depths (reservoir thickness)	3,500 m – 4,000 m (500m)
Reservoir Temperature	160 °C
Geothermal (reservoir) fluid type	Brine
Geothermal (reservoir) fluid density	1200kg/m ³
Geothermal (reservoir) fluid viscosity	0.0007 Pa s
Permeability	> 2.6 * 10 ⁻¹³ m ² (>250 mD)
Transmissivity	> 1.3 * 10 ⁻¹⁰ m ³ (>100 Dm)
Reservoir index (productivity / injectivity)	>8 l/s/bar (>290 m ³ /h/MPa)
Injection pressure	<10 MPa (<10 bar)
Flow rate	0.080 m ³ /s (80l/s, 288m ³ /h)
Volumetric heat capacity (Granite)	2.4MJ m ⁻³ K ⁻¹
Recovery factor	10%
Conversion coefficient	13%
Plant capacity factor	0.9
Economic life of project	25 years
Heat reservoir volume	0.64 km ³
Power generation (gross)	4.4 MW
Parasitic load (pump for pressure difference)	0.5 MW
Power generation (net)	4.1 MW

9.3.2. Outline Discussion on Sensitive Parameters

Reservoir temperature

With the presumed heat gradient of 0.038 – 0.039 °C/m, together with findings of water chemistry (see Section 2.3) it seems plausible an average reservoir temperature in the order of 160 °C may be encountered at depths circa 4000 m as suggested by the equation below.

$$R (\text{°C}) = 0.038 - 0.039 \frac{\text{°C}}{\text{m}} * d(\text{m}) + 12\text{°C} \quad \text{Equation 3: Reservoir temperature}$$

With $R (\text{°C})$ = reservoir temperature, $0.0038 - 0.039 \text{ °C/m}$ = thermal gradient; $d (\text{m})$ reservoir depth and 12 °C subsurface temperature

Reservoir permeability

Due to the high transmissivity of the granite that is associated with the Slitt Vein and network of fractures, the geothermal fluid in this scenario is available at any rate that a doublet system (one abstraction and one injection well) would support. On this basis a flow rate of 80 l/s is suggested.

9.3.3. Financial Analysis

Financial analysis was again conducted for this case study using the general parameters described above and the specific assumptions shown in Table 9–9 below.

Table 9–9 Weardale: Specific Modelling Assumption

Term	Assumption
Electrical efficiency	13%
Gross Capacity	4.45 MW
Net Capacity	4.15 MW
Capacity factor	90%
Capital Cost	£24.8 m (£6m per MW net)
Opex cost (year 1)	£829 k £ pa (£200 k per MW net)

With the base case assumptions set as per Table 8–3, a sensitivity analysis has been carried out on the volume of heat sales for the Weardale case and the effect on the project NPV and IRR. The results of the sensitivity analysis are shown in Table 9–10. It can be seen initially with the base case of zero heat sales that the NPV is low however as an increasing volume of heat sales will increase the revenue to the project, it can be seen that when 75% of the potential heat volume is sold, the IRR reaches approximately 18%.

Table 9–10 Weardale: Heat sale sensitivity

% Heat sold	Heat sold (MWh)	NPV £	IRR %
0%	-	£415,224	10.2%
25%	19,683	£8,845,521	12.9%
50%	39,366	£16,555,817	15.3%
75%	59,050	£24,626,114	17.5%
100%	78,733	£32,696,411	19.4%

Tables of Sensitivity to Cap Ex, heat sale price and opex for the Weardale case study are presented in Table 9–11, Table 9–12, Table 9–13, and Table 9–14 below. In general the trends are similar to the Cornwall case study, with reducing Cap Ex, increasing heat sale quantity or price, or reducing operational costs all increasing the IRR for the project. In all cases, with optimistic scenarios, there appears to be the level of return that an investor would require for a project with a ‘normal’ degree of risk.

Table 9–11 Weardale: Capital cost sensitivity (0% heat use)

£ / MWe	Capital Cost £	NPV £	IRR %
£3,000,000	£12,400,000	£12,844,224	17.4%
£6,000,000	£24,860,000	£415,224	10.2%
£9,000,000	£37,287,000	-£12,013,776	6.6%

Table 9–12 Weardale: Capital cost sensitivity (50% heat use)

£ / MWe	Capital Cost £	NPV £	IRR %
£3,000,000	£12,400,000	£28,984,817	24.3%
£6,000,000	£24,860,000	£16,555,817	15.3%
£9,000,000	£37,287,000	£4,126,817	11.0%

Table 9–13 Weardale: Heat Sale Price sensitivity (50% heat use)

£/MWh	NPV £	IRR %
0	£9,495,340	13.2%
15	£13,731,627	14.5%
25	£16,555,817	15.3%
35	£19,380,008	16.1%
50	£23,616,294	17.2%

Table 9–14 Weardale: Opex sensitivity (50% heat use)

Annual Opex (year 1) £'000 / MWe	NPV £	IRR %
150	£18,131,781	15.7%
200	£16,555,817	15.3%
250	£14,979,854	14.9%

9.3.4. Potential of Scaling Up

In the Weardale example, it is assumed that the geothermal fluid is abstracted from a vein geological structure (Slitt Vein) within the granite, facilitating high rates of groundwater flow. The vein intersects the geothermal reserve area over a length of approximately 14km based on drawings presenting in Ref. 48. Although hard to judge given the length of the vein and considering abstraction and reinjection, it seems possible that the scheme utilising geothermal fluid from the vein could be scaled up to an approximately 20 to 40 MW power station (7 abstraction and 7 re-injection wells, i.e. at 2km intervals, with a combined flow rate of ~560l/s and a geothermal fluid temperature of 160°C).

Properties (e.g. permeability), which preferentially can be found in fault zones determine the likelihood of EGS being successfully applied in granite, which is applicable for any granite and not just that in Weardale and the Lake District. Although, as technologies improve, the application of EGS may become employable for a wider range of conditions, at present, the reliance on properties with favourable conditions has a significant influence on the amount of energy that can be extracted for the purpose of power conversion (see also Section 8.1.1).

The Weardale and Lake District resource area (see Figure 9-5 below) is approximately 2,800km² in size.

It can be seen that the concentrations of heat load in the region do not coincide with the region of granite in the area. If only combined heat and power plants were used to support heat loads in the region, the potential would be limited to a few relatively small plants in the conurbations such as Penrith, Bishop Auckland and Keswick. DECC online heat mapping tools suggest that the annual heat load above the region of geological reserves is 1,300 GWh and if all of this could be met from the deployment of geothermal CHP it would only support approximately 70 MW of electrical generation. In reality, with such widely dispersed communities, only a very small percentage of this would be practical.

If the heat loads of the major conurbations of Newcastle and Middlesbrough can be included, the annual heat load increases to approximately 20,000 GWh. If all of this could be met from geothermal CHP it would support around 1,000 MWe of electrical generation. As those centres of population are some way from the main reserves this would involve piping the heat some considerable distance which will likely be impractical or at excessive cost. Again in practice meeting 100% of the thermal load in any area is not practical so the real capacity of geothermal CHP electricity production that could possibly be developed in the long term would be limited to a few hundred megawatts, although probably at excessive costs to be financially viable.

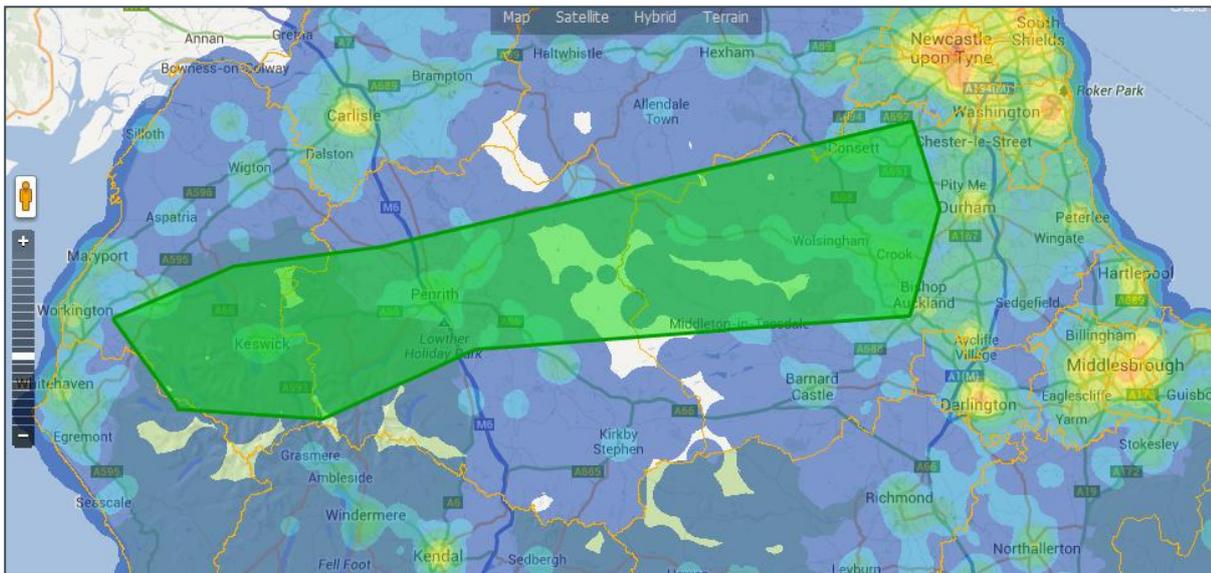


Figure 9-5 National Heat Map for the Weardale and Lake District resource area (green area is approximate boundary of the geological resource)

For power production only, without the use of CHP, if the economic case became sufficiently strong there could be a number of large plants constructed across the region constrained mainly by land use, planning and suitability of electrical connections.

The SKM report (Ref. 61) indicates from their “heat in place” process that a theoretical 5.3 GWe is available from the Weardale and Lake District granites combined. The scale of this would equate to having power plants of 50 MWe spaced with approximately 3 miles between each across the whole region and is not considered to be practical, especially as this region encompasses remote areas of natural beauty such as the Lake District.

Weardale Granite Scenario - Key Points

- Main resource for power is in the granites of the Weardale and the Lake District, with other granites such as those in Scotland considered likely to be unsuitable for power generation, although potentially with useable heat.
- Inferred temperatures are circa 160°C.
- Power only applications have potential over much of the region.
- Targeting faults zones should provide best permeability.
- Power generation from CHP applications will be restricted mainly to the large heat loads available in the East of the region.

9.4. Hot Sedimentary Aquifer (non-EGS) System: Crewe

9.4.1. Heat Reservoir Conceptual Model

A potential scheme utilising heat from the aquifer at the base of the Cheshire sedimentary basin for geothermal power generation is illustrated in Figure 9–6 below.

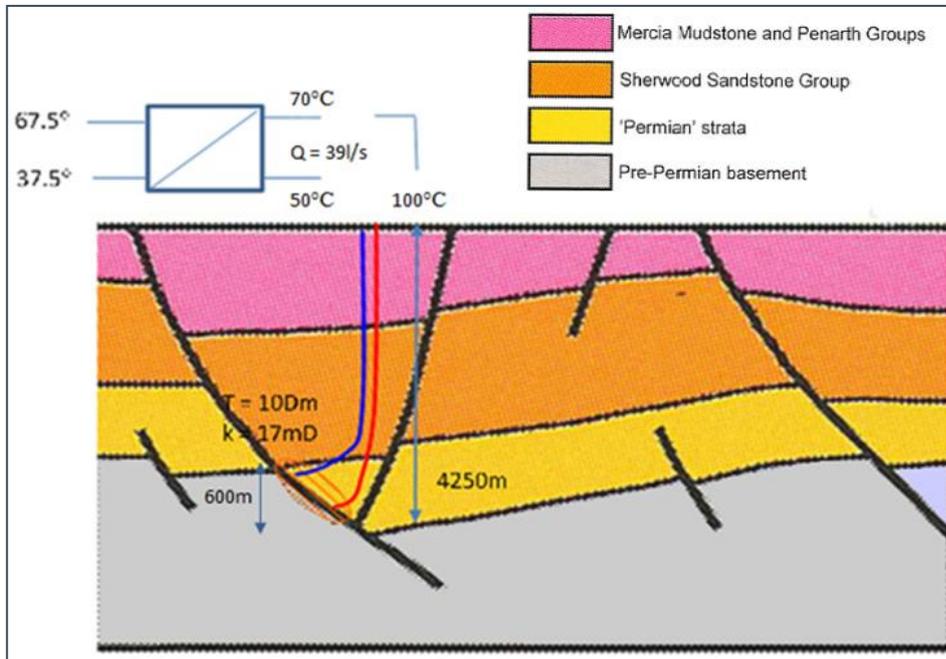


Figure 9–6 Crewe geothermal power scheme conceptual model

Key data of case study / scenario

The heat in this model scenario is abstracted from Permian Sands at its deepest point of the Cheshire Basin. Here, at a depth of approximately 4250 m, a reservoir temperature of approximately 100°C is presumed. Further to this, parameters, specific for the reservoir presumed in the scenario are summarised in Table 9–15 below.

Table 9–15 Crewe scenario heat reservoir parameter

Parameter	Value
Stratigraphy	Permian Sands
Thermal gradient	0.023 °C/m
Subsurface temperature	10 °C
Depths (reservoir thickness)	3650 m – 4250 m (600m)
Reservoir Temperature	~100 °C
Geothermal (reservoir) fluid type	Brine (saline)
Geothermal (reservoir) fluid density	1100kg/m ³
Geothermal (reservoir) fluid viscosity	0.001 Pa s
Transmissivity	9.9 * 10 ⁻¹² m ³ (10Dm)
Permeability	1.6 * 10 ⁻¹⁴ m ² (17mD)
Reservoir index (productivity / injectivity)	0.5 l/s/bar (17.7 m ³ /h/MPa)
Injection pressure	8 MPa (80 bar)
Flow rate	0.039 m ³ /s (39l/s, 142m ³ /h)
Volumetric heat capacity (Sandstone)	2MJ m ⁻³ K ⁻¹

Parameter	Value
Recovery factor	20%
Conversion coefficient	10%
Plant capacity factor	90%
Economic life of project	25 years
Heat reservoir volume	0.12 km ³
Power generation (gross)	0.7 MW
Parasitic loads (pump for pressure difference)	0.5 MW
Power generation (net)	0.2 MW

9.4.2. Outline discussion on sensitive parameters

Reservoir temperature

With the presumed heat gradient of 0.023 °C/m, it is assumed a reservoir temperature in the order of 100 °C would be encountered at depths of 3650 m to 4250 m suggested by the equation below.

$$R (^{\circ}\text{C}) = 0.023 \frac{^{\circ}\text{C}}{\text{m}} * d(\text{m}) + 10^{\circ}\text{C} \quad \text{Equation 4: Reservoir temperature}$$

With $R (^{\circ}\text{C})$ = reservoir temperature, $0.023 ^{\circ}\text{C}/\text{m}$ = thermal gradient; $d (\text{m})$ reservoir depth and $10 ^{\circ}\text{C}$ subsurface temperature

Reservoir permeability

Based on current data, it is unlikely the Cheshire Basin sandstones permeability values at its base exceed 10Dm. However, higher permeabilities may be present in the area of faults.

With the above values for transmissivity, viscosity and maximum injection pressure (pressure difference) the flow rate is calculated to equate to 0.039m³/s (39l/s, 142 m³/h).

$$Q_f = \frac{T * \Delta p}{2 * \mu} = \frac{9.9 * 10^{-12} \text{ m}^3 * 8 * 10^6 \text{ Pa}}{2 * 0.001 \text{ Pa} * \text{s}} \quad \text{Equation 5: Geothermal fluid flow rate}$$

9.4.3. Crewe: Financial Analysis

As the expected temperature available at the well depth of this case study is lower than either Cornwall or Weardale, it has a number of significant effects that make the necessary assumptions and outcomes different to the other two cases. A slightly lower electrical conversion efficiency of 10% has been used and this gives around 0.7 MWe gross and 0.17 MWe net after assumed pumping power for the geothermal fluid.

As the costs of drilling makes up a large proportion of the total capital costs and are similar to the other case studies, the effective cost per MWe is much higher in this case. It has therefore been assumed a base case capital cost of £15M and an annual opex cost of £400,000 which are similar to the other two cases despite the power output being an order of magnitude lower. The potential heat output for district heating however remains similar to the Cornwall case.

The general base case assumptions are summarised in Table 8–3 but the case specific assumptions are given in Table 9-16 below.

Table 9–16 Crewe: Base Case Assumptions

Term	Assumption
Electrical efficiency	10%
Gross Capacity	0.7 MW
Net Capacity	0.17 MW
Capacity factor	90%
Capital Cost	£15,000,000
Opex cost (year 1)	£400,000 £ pa
Discount Rate	10%

Table 9–17 Crewe: Heat sale sensitivity

% Heat sold	Heat sold (MWh)	NPV £	IRR %
0%	-	-£14,611,580	n/a
25%	9,656	-£10,739,516	-0.5%
50%	19,312	-£6,975,453	4.3%
75%	28,968	-£3,157,390	7.7%
100%	38,624	£660,674	10.4%

It can be seen that with the base case assumptions, the NPV is -£14 m. As the electrical output is low the returns do not increase to levels that look even remotely attractive compared to the other cases unless heat sales are at 75-100% of the available heat output. It has therefore assumed for the following sensitivity tables that heat sales are 100%.

Table 9–18 Crewe: Capital cost sensitivity (100% heat)

Capital Cost £	NPV £	IRR %
£7,500,000	£8,160,674	18.5%
£15,000,000	£660,674	10.4%
£22,500,000	-£6,839,326	6.6%

The effect of sensitivity of the returns to varying capital cost assumptions is shown in Table 9–18. As explained in Section 8.5.1, using the baseline cost per MW installed figure for this case study is not relevant as the power output is very low due to the lower water temperatures compared to the other case studies, despite similar boreholes being required. With a low capital cost scenario the returns begin to approach the lower bounds of investible levels.

As the plant output is more skewed towards heat than for the other two case studies, as one would expect, the returns are more sensitive to heat sale price with the IRR increasing approximately three fold over the range of heat sales prices investigated.

Table 9–19 Crewe: Heat sale price sensitivity (100% heat)

£/MWh	NPV £	IRR %
0	-£5,702,765	5.6%
15	-£1,884,702	8.7%
25	£660,674	10.4%
35	£3,206,049	12.0%
50	£7,024,112	14.2%

As can be seen in Table 9–20 below, the returns are not highly sensitive to variations in opex costs.

Table 9–20 Crewe: Opex sensitivity (100% heat,)

Annual Opex (year 1) £	NPV £	IRR %
£300,000	£1,421,457	10.9%
£400,000	£660,674	10.4%
£500,000	-£100,110	9.9%

9.4.4. Potential of scaling up

Due to the limited extent of the Cheshire Basin depression with Basal Sands at greater depth (the length and width is presumed some 1-2km only), the potential for scaling up is limited. If scaling up was considered it is likely this would be covered by expanding the one suggested (0.2 MW_{net}) pilot plant to a more economically viable sized scheme only.

Based on the financial analysis presented above we can conclude that there is only a potentially viable investment case (IRR circa 18%) for this case study based on the lowest assumed capital cost and the ability to use 75% or more of the available heat. i.e. heat sale through a district heating network to commercial and residential loads for space and hot water heating or a connection to a low temperature industrial demand.

We can therefore use information about the populations in towns which are situated on the Permian being utilised for geothermal energy in this case to extrapolate the potential for the technology based on electricity and heat generation.

A plant the size of the base case could supply a community with a population of approximately 3,000 people. The largest conurbation situated on the Permian and which happens to be at the highest temperature of the Permian is Crewe with a population of around 68,000. There are approximately 3 other nearby towns with populations of circa 40,000 – 50,000.

Considering the distance between abstraction and injection well should be between 1000m and 2000m and the approximate Cheshire Basin area is 3km², there is relatively limited scope for scaling this case study up other than by increasing the pilot plant to an approximately 0.5MWe net scheme.

An alternative approach to this estimation is to consider the regional heat demand as assessed from the DECC on-line heat mapping tool. Using a 1km radius around Crewe, the domestic heating load is around 85 MW, which far exceeds the 5 MW thermal production of the case study at the base case.

There is therefore plenty of heat load within the area (assuming that it can all be connected) to utilise CHP in this case. A power only scheme would not provide an economic return under the assumptions made to define the base case and therefore the scheme and scalability depends heavily on the heat resource and load.

The conclusion for this case study is therefore that although there is a possibility to develop a Deep Geothermal CHP plant to serve a local community the overall potential in relation to the national picture is negligible in this region.

Crewe: Deep Sedimentary Cheshire Basin Scenario - Key Points

- At depths of c.4km temperatures of 100°C are inferred.
- Power generation at these temperatures will be lower for a similar pair of wells than for the other two thermogenic regions considered which are in granite.
- The plant costs will be similar to the granite regions, so the cost per kWe for the installed project will be significantly higher than for the granite regions.
- The sale of heat will therefore be much more important to the economic viability of these schemes.

9.5. Discussion on Modelling Parasitic Loads

Depending on the reservoir permeability, the majority of auxiliary power (parasitic load) requirements relate to the uptake of pumps to overcome the difference in height between the dynamic fluid level (h_{DFL}) in the production well and the surface.

For the Crewe, Cornwall and Weardale example, using Equation 6, neglecting static fluid levels (h_{SFL}), h_{DFL} levels equate to 740m, 510m and 100m respectively. For such conditions, using Equation 7, further neglecting friction losses (p_{loss}) and wellhead pressures (p_{wh}), pump parasitic load requirements of 0.5 MW (Crewe), 0.4 MW (Cornwall) and 0.3 MW (Weardale) have been calculated. Wellhead pressures (p_{wh}) and static fluid levels (h_{SFL}) depend on site conditions. Given the variability of site conditions such losses have been considered by rounding pumps parasitic loads to 0.5MW.

For example, with 200m for h_{SFL} and 10 bar for p_{loss} and p_{wh} , the total parasitic load requirement (P_{prod}) to produce fluid from the geothermal reservoir (as per Equation 8) equates to 0.5 MW. With higher fluid production rates (if testing confirmed this not to result in unacceptable high risks of fluid loss or short circuiting for example), then increasing h_{DFL} would result in higher pump parasitic load requirements.

However, in this case the gross power rate would be increased too. For example, if for the Cornwall scenario the geothermal fluid production rate is increase from 40l/s to 60l/s, then the parasitic pump load increases from 0.5 MW to 1 MW (the latter is a level which Legarth 2003 (Ref. 49) regards as the pump power upper technical limit). However, in this case rates for gross and net power increase to about 4.6 MW and 3.5 MW respectively.

$$h_{DFL} = \frac{V_{geo}}{PI \times \rho_{geo} \times g}$$

Equation 6: Calculation of dynamic fluid levels (hDFL) neglecting static fluid levels (hSFL)

$$P_{prod} = V_{geo}(-\rho_{geo} \times g \times h_{DFL}) \times \frac{1}{\eta_p}$$

Equation 7: Calculation to calculate the effort to produce geothermal fluid (Pprod) neglecting friction losses (ploss) and wellhead pressures (pwh)

$$h_{DFL} = h_{SFL} + \frac{V_{geo}}{PI \times \rho_{geo} \times g}$$

Equation 8: Calculation of dynamic fluid levels (hDFL) (Source: Huenges 2009(Ref. 42))

$$P_{prod} = V_{geo}(-\rho_{geo} \times g \times h_{DFL} + \Delta p_{loss} + p_{wh}) \times \frac{1}{\eta_p}$$

Equation 9: Calculation to calculate the effort to produce geothermal fluid (Pprod) (Source: Huenges 2009 (Ref. 42))

For these equations: V_{geo} is the volume of geothermal fluid; PI is the productivity index of the reservoir; g is the gravity constant; ρ_{geo} is the density of the geothermal fluid; η_p is the efficiency of the pump; and Δp_{loss} is the pressure increase applied by the down hole pump. All other terms are described above.

9.6. Discussion on EMR and RHI Consultations

9.6.1. EMR

The Government has reiterated its commitment to support the low-carbon generation sector through the use of Contracts for Differences (CfDs) as part of the wider Electricity Market Reform (EMR) package. The Government are currently working on the finalised Strike Prices, however draft Strike Prices were made available at the end of June. The Strike Price in a CfD:

- sets the level of the pre-agreed 'top-up' to the revenue which a generator will receive from selling its output into the market (based on a market reference price); but
- also puts a 'cap' on the total revenue available to a generator from the sale of its electricity, as generators must pay back the difference when the market reference price goes above the Strike Price.

For Geothermal power (with or without CHP) the draft Strike Price is £125/MWh for 2014/15 falling to £120/MWh thereafter. The Strike Price is consistent with the level of support currently offered to developers though the RO, i.e market electricity export price + 2 ROC's. So for the purposes of the financial modelling above, with the draft geothermal Strike Price having a similar value to 2ROC's plus the export price of electricity the models are relatively unaffected. If anything the draft Strike Price value is slightly lower which will slightly reduce the revenue and hence returns of a project however a CfD provides increase price certainty for an investor and is linked to RPI for 15 years.

9.6.2. RHI

In September 2012, the Government initiated three consultations covering the RHI, these consultations covered proposals for the domestic sector, proposals to expand the existing non-domestic RHI scheme and proposals for air to water heat pumps and energy from waste. The non –domestic RHI scheme is applicable to Geothermal heat only and Geothermal CHP.

Currently deep geothermal heat is supported under the RHI with a tariff of 3.5p/kWh, however a new tariff of 5.0p/kWh is currently proposed by the Government. This is likely to further support geothermal heat only schemes and encourage power schemes to become geothermal CHP where possible. For geothermal power generation, which is the purpose of this report, the effect of the proposed new tariff will be very dependent on a scheme by scheme basis and its ability to supply heat to a nearby heat demand. For example, The new RHI tariff will have relatively small effect on a geothermal CHP scheme that has very little heat sales compared to say an increase in the power Strike Price. However where a geothermal CHP scheme has a high volume of heat sales, the new tariff will provide a significant increase to the RHI revenue to the scheme.

To compare the case studies above, the model was run again with the base case assumptions, with the RHI at the existing tariff and the new tariff for various percentage heat loads. The results are shown in Table 9-21.

Table 9–21 Effect of RHI change on project IRR

% of Available Heat Sold	Project IRR with RHI @3.5p/kWh			Project IRR with RHI @5.0p/kWh		
	Cornwall	Weardale	Crewe	Cornwall	Weardale	Crewe
0%	10.9%	10.2%	n/a	10.9%	10.2%	n/a
25%	13.1%	12.9%	-0.5%	13.6%	13.5%	1.0%
50%	15.1%	15.3%	4.3%	16.0%	16.4%	6.1%
75%	16.9%	17.5%	7.7%	18.1%	18.9%	9.8%
100%	18.6%	19.4%	10.4%	20.1%	21.2%	12.6%

The results of the analysis clearly show that where a geothermal CHP scheme can make more use of the available heat, the project IRR increases due to increasing RHI revenue. If the RHI price was to increase as per the proposed new tariff then for the same heat volumes the RHI revenue would increase further still therefore improving the project IRR. If 50% of the available heat is sold, for both the Cornwall and Weardale case studies, an increase in the RHI to 5.0p/KWh improves the project IRR by approximately 1%. However for the Crewe case study the project IRR improved by nearly 2%, this is due to the Crewe case study having a relatively small power output compared to heat, i.e. the project is more heavily heat weighted than power – a higher heat to power ratio.

9.7. Discussion on Levelised Cost of Electricity (LCOE)

One approach for comparing the costs of various power generation technologies is Levelised Cost of Electricity (LCOE). The LCOE is calculated by dividing the net present value of the costs for the generation technology over the life of the plant by the total discounted power produced over the lifetime, to derive a lifecycle cost of energy in terms of £/MWh.

Utilising the Cap Ex ranges set out in section 8.4.7 a range of potential LCOE values has been calculated using the methodology set out in DECC report (Ref 13) similarly utilising a discount rate of 22%. For projects becoming operational in 2018, the LCOE values obtained are shown in Table 9–22.

Table 9–22 LCOE comparison table

LCOE £/MWh	Scenario		
	Central Cap Ex	High Cap Ex	Low Cap Ex
Deep Geothermal Power	218	313	123
Deep Geothermal CHP *	162	257	68

These estimates broadly align with previous figures published by DECC (Ref 13). While this report uses slightly different central modelling assumptions² from DECC's most recent central case all assumptions remain within the range previously modelled. The high discount rate utilised is commensurate with technology uncertainty (as it is similar to that utilised for wave and tidal energy), but it does not necessarily reflect the resource uncertainty, nor the risk profile of individual projects. As such, LCOE figures should be treated with caution, as they are highly sensitive to Cap Ex spend profile and discount rate, both of which are highly uncertain in a nascent industry.

² This includes slightly different central capital and operational costs, and a different hurdle rate. Please also note that these figures are not comparable with DECC's recently published estimates (Ref 13) as they apply for a different time period.

* The Cap Ex of a district heating network for the transportation of heat to clients is excluded from this calculation as explained in Section 8.4.7.

9.8. Sensitivity to Resource Degradation

To investigate the effect of degradation of the geothermal resource over time an annual degradation was applied to the financial modelling. An annual degradation of the resource by 1% per annum will reduce the IRR by between 0.8% to 0.4% depending on the amount of heat use. The lower the heat use the greater the effect that degradation has upon the IRR. The project returns therefore seem to be fairly insensitive to degradation.

10 Outlook on Opportunities

Deep Geothermal energy has the potential to deliver economic benefits to the UK through the generation of economic activity and jobs, as well as through the economic benefits associated with delivering a non-intermittent renewable energy source and aiding the UK's transition to a low carbon economy.

This section undertakes a review of the available literature on the economic benefits associated with the potential development of a Deep Geothermal energy sector in the UK. The majority of literature surrounding Deep Geothermal energy is focussed on the resource potential and the techno-economic feasibility of exploiting it. Given that the Deep Geothermal market is still in the process of moving from research to commercialisation this is unsurprising. As such only tentative conclusions can be drawn from this review. It is recommended that an analysis from first principles is undertaken to establish a realistic understanding of the potential economic benefits, in part reviewing the proliferation of demonstration projects across Europe.

10.1. Innovation

Deep Geothermal is an established global industry which continues to evolve and innovate. With reference specifically to the UK application, the following areas provide the most likely opportunities with the greatest potential to make a significant impact.

There are a number of exploratory and investigative methods used in the oil and gas industry that have potential application to the geothermal sector including well logging and reservoir modelling. Typically these tend to be less cost effective when applied to geothermal as they have been developed for use in a higher cost base environment. However, it can be anticipated that as technology matures and the global geothermal market grows the cost base will decrease and they will become increasingly affordable. An example would be the application of 3D seismic geophysical investigative methods although further innovation will be required to improve usefulness in UK crystalline rocks but this method could allow better targeting of more permeable fault zones.

There have been recent developments that improve the stimulation modelling and prediction of micro-seismicity (Ref. 5) and, given the need for informed public consultation in the UK, further innovations and studies in this area have the potential to have a significant impact on the UK deep geothermal sector.

Exploration and research work to further develop the overall understanding of the geology at depth in the UK in relation to geothermal power generation is required if resources are to become characterised as reserves. Innovative coupling of new and revised ground models to targeted drilling programmes seeking particular fault zones and other preferential zones would improve drilling success rates. This would also inform, and potentially be financed by, subsequent auctioning of geothermal rights.

A key criterion assumed in this report is the minimum temperature required at which geothermal power generation becomes viable. For example, this temperature relates to binary systems which use a secondary working fluid that vaporises at a lower temperature than water. Further innovations and efficiencies are likely as recently introduced technology matures and evolves. This would assist the exploitation in the UK where there is a lower enthalpy resource than found in many other areas of the world.

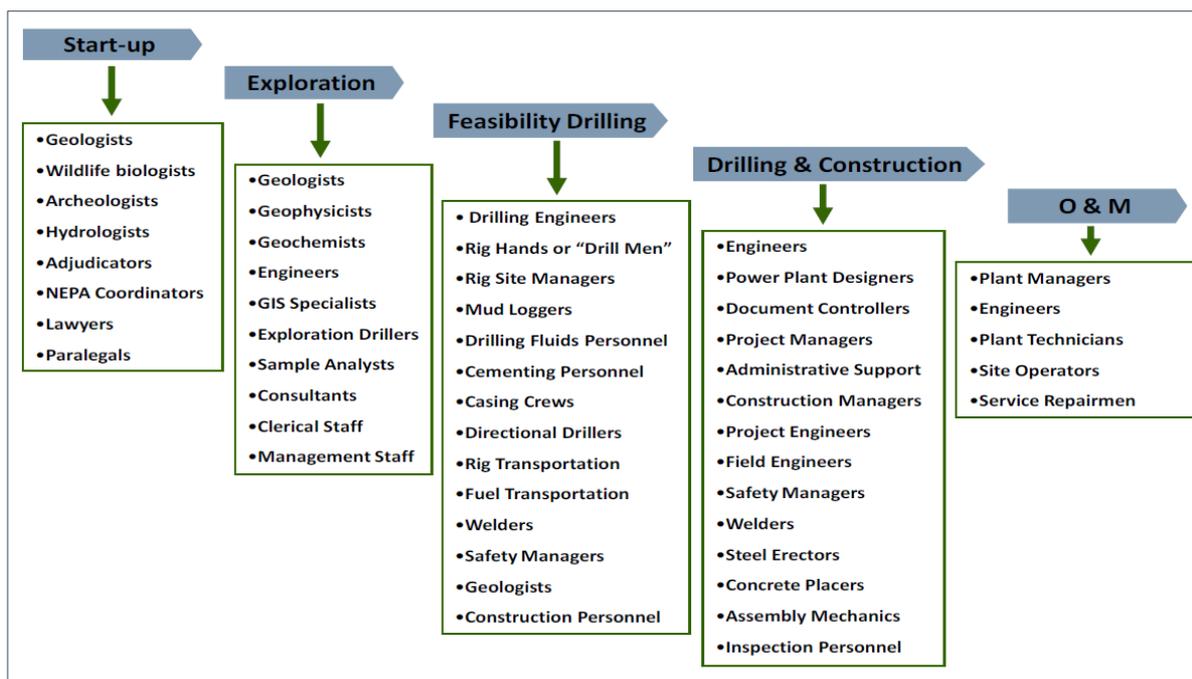
To date the UK deep geothermal power sector is proving to be commercially unappealing. Innovation in financial models could provide a step change in commercial feasibility. Drawing on experience in continental Europe, Chile and elsewhere suggests some form of insurance backed exploratory drilling would reduce the investor risk profile significantly. The specialist insurance industry could be engaged but it is likely government involvement, at least in the early stages, would also be required. If exploration can be underwritten, with payback tied to operational revenues, this would constitute an innovation for the UK that could have a significant impact.

Some of the innovations considered here will develop naturally as part of the global evolution of deep geothermal for power generation. Other innovations such as UK focussed financial modelling and the improvement of the UK geological understanding and associated targeted drilling are more UK specific and would require UK policy and strategy development.

10.2. The Supply Chain

This section reviews existing literature to understand the potential for the development of a UK geothermal energy supply chain. A supply chain spans the entire timeline of project development, from start-up leasing activities to manufacturing and operations. A strong supply chain, whether through domestic or international firms, is essential to the development of a sector. Based on the estimated potential development of plants between now and 2050 and the average cost figures in this report, the capital value for the industry is estimated at £250M per annum. Figure 10–1 establishes a picture of the basic supply chain associated with a geothermal energy development. These stages are supported by component and system manufacturing. **Table 10–1** provides an estimate of the economic opportunity associated with each stages of the supply chain, in terms of jobs associated with delivering a 50MW geothermal energy development.

Figure 10–1 Geothermal Supply Chain and Jobs



Source: Geothermal Energy Association (2010) (Ref. 35).

Table 10–1 Geothermal Supply Chain Jobs

Supply chain stage	% of jobs supported	
	Lower bound	Higher bound
Start-up	1	2
Exploration	2	3
Feasibility drilling	13	13
Drilling & construction	55	57
Operation & maintenance	1	3
System manufacturing	28	23

Source: Adopted from Geothermal Energy Association (2010) (Ref. 35).

The IEA (2011) (Ref. 44) notes that skilled companies and well-trained personnel for Deep Geothermal drilling and reservoir management are currently concentrated in just a few countries.

A report by Arup (2011) (Ref. 12) notes that current geothermal development in the UK appears to be focused on radiogenic granites. If this trend continues then much of future geothermal technology will be located within the granites of Cornwall, north of England and Scotland. The report concludes that there are no significant supply chain constraints for the development of this resource, as technologies can be imported from countries where geothermal energy developments are already established. Furthermore, the likely

scale of future UK geothermal development is unlikely to be of a significant scale as to strain the resources of the established global industry.

However, a report by AECOM (in press) (Ref.1) highlights that the technology requirements for the development of UK resources may not match those employed elsewhere in the world. It notes that the global geothermal industry has to date concentrated on developing easily accessible high temperature resources, whereas in Scotland³ opportunities are low temperature resources. As such it concludes that 'there is a significant opportunity for Scotland to develop unique skills in developing low temperature geothermal resources, and then exporting these skills internationally, to countries with similar types of geothermal resource' (Ref.1). Some of these skills might be applicable to geothermal power generation even though the Scottish resource is likely only to be used for heat generation.

The European Commission's research concurs with the position portrayed in AECOM (in press) (Ref.1). It is noted in European Commission (2011) (Ref. 28) that new technological developments for EGS are necessary for the broader development of HDR resources. EGS technologies are still at an early stage of exploitation and the associated supply chain is therefore considered to be a future market, not a current one. Whilst there is limited current installed capacity, there has been a proliferation of demonstrator projects across Europe. The European Commission notes that the market has 'huge potential'.

A simple review of the available resources across Europe shows that the UK does not have a natural comparative advantage in the sector, unlike the wave and tidal energy sector. As such domestic demands on the supply chain may grow at a slower rate and to a lower level than that serving the European (and global) markets. If this is the case, as the US and Europe move towards geothermal energy, UK companies will need to capitalise on serving non-UK developments in order to establish a position in the supply chain.

The success of UK companies contributing to this supply chain will determine the extent to which the UK geothermal energy sector relies on imported goods and services, and will therefore directly affect the extent of the economic benefits which may arise. Examples already existing of UK companies exporting Deep Geothermal energy goods and services into international markets.

There are currently no active geothermal projects in the UK producing electricity. However some UK firms are active in the sector and are involved in the broader European and global market. There are 17 companies who are members of the UK Renewable Energy Association's (REA) Deep Geothermal group. It should be noted that this does not necessarily represent the extent of UK commercial activity in the global geothermal market, and does not represent the extent of existing companies who could respond to the supply chain demands that would be created through a broader development of Deep Geothermal energy resources.

10.3. Economic Benefit of Sector Development

This section provides a synthesis of the available literature on the potential scale of economic benefits (focussing on jobs) that could be generated through Deep Geothermal activity. It should be noted that none of the available literature provides a robust estimate associated with Deep Geothermal activity, being either focussed on a broader set of geothermal technologies, or being based on proxy averages from other sectors.

Roger Tym & Partners (2008) NI Renewable Energy Supply Chain (Ref. 57)

The study includes an estimate of the potential GVA and jobs that could be generated through exploitation of renewable energy resources in Northern Ireland. The estimate for geothermal/GSHP is based on an assumption that such energy developments **deliver 10 jobs per MW**. This assumption is based on the weighted average of jobs per MW for the renewable energy sector as a whole, published by DTI (2004) (Ref. 21).

The original DTI study does not establish sector-specific estimates per MW for the geothermal sector as it considers the sector to be unlikely to achieve commercialisation within the study's assessment time horizon (2030). The jobs data in the report refers to direct, indirect and induced jobs supported by renewable energy

³ The report is focussed on the Scottish sector, however the supply chain conclusions can be considered to apply to UK sector.

developments (not including geothermal), adjusted for imports and exports. The weighted average of 10 jobs per MW includes a range of 5.3 to 24.8 jobs. Gross jobs per MW, excluding adjustments for imports and exports is estimated at between 13.4 and 29.9.

Innovas (2009). Low Carbon and Environmental Goods and Services (LCEGS): an industry analysis (Ref. 46).

The report assesses the value of a range of UK LCEGS sectors and their supply chains, including geothermal. A definition of the sector is not provided in the report, although it is assumed not to include significant activity associated with Deep Geothermal. The report values the UK geothermal sector and its supply chain at £9.2bn in 2007/8, made up of activities including manufacture of pipes, pumps and heat exchangers as well as ground source heat pumps. The industry has a large supply chain contribution, with 65% additional market value uplift due to the supply chain. It is estimated that 75,800 jobs are supported by the sector (2007/8 data). No 'per MW' data is provided in the report and it is not appropriate to use these figures to generate such a figure.

Geothermal Energy Association (2009). GEA Issue Brief. Geothermal Energy and Jobs (Ref. 34).

The report includes a number of sources and calculations that demonstrate the potential levels of employment supported through geothermal energy developments.

The report cites a 2004 employment survey (Ref. 32) that estimated the total number of jobs (direct, indirect and induced) support by the sector in the US. These estimates correspond to **1.7 permanent jobs per MW**. As the report notes, employment in the industry is probably at a historic low since power plant construction has been minimal between 1993 and 2004. As a snapshot of the geothermal sector at a point in time, the jobs per MW figure does not include the full level of employment generated through the construction and operation of geothermal energy plants – i.e. construction employment associated with existing plants is not included. In terms of just operation and maintenance of plants, the report cites figures from the employment survey of **0.74 O&M jobs per MW**.

The report cites U.S. Department of Energy (DOE) (2006)(Ref. 64) estimates of total job creation for a 500MW geothermal plant at 27,050 person-years. This can be assumed to equate to **5.4 jobs⁴ per MW**.

The report cites a report by Deloitte (2008)(Ref. 15) which establishes estimates of jobs per MW for a series of energy resources. These figures are set out in **Table 10–2** below. The total employment estimate for geothermal energy is **5.7 jobs per MW**.

Table 10–2 US Jobs Created by Resource Type (recreated from Deloitte, 2008 (Ref.15))

Power Source	Construction employment (jobs/MW)	O&M employment (jobs/MW)
Wind	2.6	0.3
Geothermal	4.0	1.7
Solar electric	7.1	0.1
Solar thermal	5.7	0.2
Landfill gas	3.7	2.3

Western Governors Association (WGA) (2005). CDEAC - Geothermal Task Force (Ref. 66).

The report (cited in Geothermal Energy Association (2006) (Ref. 33) estimates that the development of the U.S western states' near-term geothermal potential of 5,600 MW of geothermal energy would result in the

⁴ Using Atkins rule of thumb assumption that 10 person years = 1 full time job.

creation of almost 100,000 new power plant, manufacturing, and construction jobs. Direct employment results in 1.7 fulltime positions and 6.4 person-years per MW (which can be assumed to equate to 2.3 jobs per MW). Induced and indirect impacts were calculated assuming a 2.5% multiplier; for a total direct, indirect, and induced employment impact of 4.25 full-time positions and 16 person*years per MW. This can be assumed⁵ to equate to **5.85 jobs per MW**.

Conclusions

Data on the geothermal energy sector in the US indicates a possible range of between 5 and 6 jobs per MW. For the UK, no real comparable data is available. The Roger Tym & Partners (2008) (Ref. 57) study for Northern Ireland uses a figure of 10 jobs per MW, although the figure is a crude proxy based on the average of other renewable energy technologies and should not therefore be relied upon. There is no currently published data available on the jobs generated through the construction and operation of demonstrator Deep Geothermal projects across Europe.

The average 10 jobs per MW for the UK renewable energy sector presented in DTI (2004) (Ref. 21) and used by Roger Tym & Partners (2008) (Ref. 57) for the geothermal sector compares to between 5 and 6 for US studies. Coincidentally a similar order of magnitude difference exists between UK and US estimates for jobs per MW in the wind sector. A comparison of UK and US jobs per MW from DTI (2004) (Ref. 21) and Deloitte (2008) (Ref. 15) respectively shows that for wind energy (onshore only for UK), jobs per MW are estimated at approximately 6 for the UK and 2.9 for the US, and for landfill gas jobs per MW are approximately 8 for the UK and 6 for the US. It is unclear to what extent these US/UK differences are due to actual differences in the level of jobs supported or due to methodological differences between the studies.

However, existing estimates of the economic contribution of the geothermal energy sector in the UK and elsewhere cannot be considered to be sufficiently robust data from which to make estimates of inferences on the likely scale of economic benefits of a potential UK Deep Geothermal sector. This is because existing geothermal energy activity does not include HDR Deep Geothermal activity, for which many of the technologies involved will differ from other forms of geothermal energy activity. In markets such as the US, a variety of shallow and deep resources are exploited by the sector.

This report does not therefore establish any such estimates, but recommends that primary analysis should be carried out to establish the potential economic contribution. This could include an assessment of the current and developing demonstrator projects in the UK and the rest of Europe.

⁵ Using Atkins rule of thumb assumption that 10 person years = 1 full time job

11 Stakeholder Consultation

As part of this study stakeholders were consulted to identify the key issues as they perceived them for developing geothermal power production in the UK. This consultation took the form of a questionnaire, a workshop event and a number of one to one interviews. The overall consultation process is presented in Appendix C with key issues that were raised and not dealt with elsewhere in this report or warrant repeating summarised as follows.

11.1. General Issues

- Micro-seismic issues with Basel scheme could have been avoided if the public perception issues had been better handled.
 - **Learning point:** Public consultation and awareness is essential in carrying out a geothermal power scheme.
- Effective communication of the risks and uncertainties to government, the public and the investment and insurance communities is a key factor to successful commercial deployment.
- Permitting and ownership of 'geothermal rights' is currently not clear and therefore could provide an upfront barrier to development.
 - **Learning point:** In order to remove such barriers the government needs to provide clarity on the issue to give confidence to investors as to extent and length of ownership.
- There is a balance of cost versus return from power generation relating to the interacting effects of drilling depth, heat flows encountered and stimulation measures. Drilling costs are not linear with depth. Stimulation measures add considerable cost and the degree required is not known with certainty from the outset.
- Understanding the Deep Geothermal resource, including the geology (better than we do currently) and associated temperature, stress regimes (which affect stimulation fracturing process), existing amounts and locations of fractures is a key starting point. Where existing fractures provide better permeability this should be targeted by geothermal wells but the required detailed data does not currently exist. There is a lack of relevant data in the UK regarding the potential for thermal degradation of the Deep Geothermal resource over the lifecycle of the project and beyond.
- The carbon friendly base load from geothermal power would be beneficial to the grid and help to compensate for the intermittency of other forms of renewable such as wind power.
- There are environmental challenges but they appear solvable at project scale including water issues. However if the industry is scaled up this could prove limiting if for example multiple plants are required in close proximity, particularly in densely populated areas.

11.2. Financial & Investor Issues

- A number of trial wells would increase confidence in the likelihood of success for subsequent wells in the same area and possibly elsewhere as overall confidence in the UK sector gains momentum. Early wells will have a lower chance of economic success and the percentage likelihood of economic success can be expected to improve with each additional well.
 - **Learning Point:** Without an example scheme or example wells to prove the resource (using suitable logging, geophysics and trialling), Deep Geothermal for power generation is unlikely to proceed in the UK.

Risk versus return ratios are currently not attractive to investors. Subsidy levels do not effect initial decision to invest in terms of the upfront risk uncertainties. There are current uncertainties regarding strike prices and future subsidy levels given the design life and financial model lifecycles of 20 to 25 years that are commonly

considered. Investment market understands the risks and uncertainties well and this is why investment has not occurred. It is not the case that they need educating. Past experience with renewable energy has been patchy and there are clear risks that investors could potentially lose money in this sector. The government would benefit from listening to the market rather than trying to create and impose a market solution. A relatively small government funding outlay of £50m to £100m could finance a number of trial wells. Only then will there be clarity as to whether there is viable Deep Geothermal for Power potential in the UK at a reasonable scale that is worth further investment in. Key risks and potential investors views are summarised in Figure 3–2 presented in Section 3.8.

If government funding for a demonstration or commercial scale project was provided there could be an opportunity to assemble a collective of companies and experts to undertake the scheme to provide the best chance of success and to help with onwards effective knowledge transfer to subsequent schemes. However there would be a number of issues to overcome.

12 Conclusions

Opportunity

It is concluded that the potential for geothermal power production is concentrated in the granites of South West England (Devon and Cornwall) and Northern England (Weardale and the Lake District), with a much smaller potential in the deepest parts of the Wessex and Cheshire sedimentary basins. However, the economic viability of geothermal power schemes relies heavily on the associated sale of geothermal heat (as district heating through combined heat and power (CHP) schemes) and this becomes a limiting factor, especially in rural areas where the lower density of heat demand makes district heating less economically viable.

In the granite of South West England a current potential for the development of up to 100 MWe of electrical production has been determined based on plants supplying the potential heat loads in the area. This could grow considerably as the sector matures, uncertainties are removed and costs reduce making power only schemes more viable.

In Weardale and the Lake District, whilst the geological resource may theoretically support up to a few gigawatts of electricity production, there is very little heat demand locally due to the rural nature of the area. Hence the potential is determined as being less than 70 MWe, with the proviso that if heat could be economically piped to major conurbations in the east of the region this could rise to between 100 and 1000 megawatts.

The total resources in the deep sedimentary Cheshire and Wessex Basins are of a lesser extent and of lower temperature than in the granites of South West and Northern England. The reduced temperature in these basins (and therefore reduced power yield) means that the economic returns for power only plants are currently uninvestable. There is therefore less scope for scaling up the size and number of plants, and it is unlikely these resources would prove viable for more than a small number of district heating schemes in the area with potentially small amounts of power generation.

Risks

The project development risk profile for deep geothermal power schemes does not currently support investment principally because of uncertainties about the geological and geothermal conditions (the 'ground risk'). In many renewable energy technologies, risk can be reduced at an early stage of the project development process through investigation and analysis at a cost which is a relatively low proportion of project Cap Ex (for example, a wind resource analysis study to de-risk energy yield, and ground investigation to de-risk foundation design). In contrast to this, a deep geothermal project is only substantially de-risked through the drilling of the boreholes and subsequent reservoir investigation, which absorbs approximately 50% of the overall Cap Ex of the project.

A Government sponsored research campaign drilling test boreholes across a region would go some way to mitigate the ground risk. However, a substantial level of individual project risk would remain after regional borehole investigations, and stakeholder engagement undertaken as part of this study indicates that bearing this risk remains an unattractive proposition for the investor community.

Other risks include the technological risks of extracting, using and distributing geothermal energy and the regulatory risks of planning and operating such schemes, including: the local appetite for such plants; emotive attitudes to and perception of hydraulic stimulation; ownership of resource; and uncertainty of regulatory approach to such schemes.

Costs

With the current level of two ROCs/MWh for electricity and RHI of 3.5p/kWh, scenario analyses of costs have suggested pre tax Internal Rates of Return (IRR) for schemes in granite regions of between 13% and 19% when heat sales are taken into account. However, this reduces to around 10% for power only schemes at the baseline levels of costs, whilst in the most optimistic capital cost scenario considered this increases to around 17%. The IRR for deep sedimentary basins varies between 0% and 10% depending on the level of

heat sales. With the proposed higher level of RHI of 5p/kWh the IRRs increases to circa 20% for granite regions and 13% for deep sedimentary basins at the baseline capital costs and where significant levels of heat sales can be achieved.

It should be noted that these scenarios are generic for illustrative purposes, with analysis to demonstrate the sensitivity of the modelling to changes in capital cost, operational cost, heat sale volumes and heat sale price. In cases assuming heat sales the returns do not take into account the cost of installing a district heating network which may, in many instances prove prohibitive as it drives returns below investable levels. However, over the next two to three decades, it is expected that district heating schemes will increase in number and will be considered at the planning stage for most new developments.

Whilst the calculated levels of return are generally at the lower end of the investable scale for mature power generation projects, it is the high level of risk that developers currently face that is currently preventing investment. The likelihood of subsidy levels continuing at the modelled rate for projects developed over the next decade should also be considered, as CfD auctions move to a technology-neutral basis under current Electricity Market Reform plans.

Levelised cost of electricity figures have been calculated using a range of Cap Ex values and these broadly align with those previously issued by DECC, differing slightly for reasons discussed in 9.7. They are highly sensitive to discount rate and Cap Ex spend profile, and these are both of which are highly uncertain in a nascent industry.

Risk Reduction Opportunities

In order to limit the risks and make projects more investable, stakeholders consulted during this study suggested the following:

- Further research studies and investigations of the identified resource areas to improve the characterisation of the potential thermal reserve;
- Two or three test boreholes drilled in each location;
- Clear permitting and thermal rights of ownership clarified;
- Funding or insurance for early stage test boreholes put in place; and
- Adjustment of subsidy levels would promote investment. However the current large uncertainties regarding the development stages of the project (i.e. borehole drilling and reservoir investigation) make initial investment decisions relatively insensitive to subsidies based upon operational revenues.

At present there is insufficient private sector appetite to de-risk the sector for power generation schemes. Steps to limit the risks, as set out above, would need to be led and funded by Government.

If uncertainties can be reduced, resources become proven reserves, capital costs reduce with scale, and experience and/or subsidy levels are altered such that expected rates of return based upon power generation alone become acceptable to investors, then more of the potential resource can be exploited and realised. This potential for geothermal power is currently difficult to quantify, but tentatively 1 to 1.5 GWe could be argued in the longer term (2050) for the UK as a whole. This equates to 3-4% of current average UK electricity demand (or 1.0 – 1.7% of current UK generating capacity).

Recommendations and next steps

If Government determine that they wish to provide further support to the industry, a full scale power generation demonstrator project is considered currently to be a sensible future step if investment needs to be attracted. However, notwithstanding the need for a demonstrator, the initial priority is to prove the reserve. Therefore it is recommended that actions are taken to resolve this through:

- Establish a roadmap for deep geothermal power generation which should include clarification on geothermal rights of ownership
- Provide a Government backed development fund to support initial project phases including drilling insurance and to finance deep boreholes for research and development (to be undertaken by academic or professional institutions and organisations such as joint industry projects in collaboration with the British Geological Survey)

In addition, the strike price for geothermal energy should be fixed at a rate for sufficient time to make such schemes attractive to investors, particularly large financial institutions looking to make long term investments.

Conclusions - Key Points

- A development potential of 100MWe of electricity generation in the South West of England and 70MWe in Weardale and the Lake District has been identified. Limitations are set by available heat demand. Sedimentary basins in Cheshire and Wessex are deemed not economically viable for power generation schemes.
- Investable level returns are potentially attainable if the lower end of the estimated Cap Ex range is achieved. However, this is based on the existing support mechanism of two ROCs/MWh for electricity and RHI of 3.5p/kWh. It is unlikely that such levels of support will remain available under technology-neutral CfD auctions.
- The risk profile of project development is inherently unattractive to investors, as up to 50% of the capital cost of the project is required to de-risk the project by drilling boreholes and fully investigating the reservoir. A level of project risk reduction can take place through a broader, regional, characterisation programme, but this would require Government leadership and funding.
- If Government is to actively pursue a deep geothermal energy programme, efforts should concentrate on proving reserves and developing a power generation demonstrator project. This will need to be supported by an appropriate level of financial support certainty to encourage investment over the long term to develop projects.

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Appendix A. Exploration Strategies and Techniques

A.1. Introduction

Deep Geothermal projects are usually executed in a phased process. The main execution phases related to the underground are as follows:

1. Preliminary survey
2. Exploration
3. Test drilling
4. Well testing and logging
5. Reservoir development
6. Production and reservoir monitoring

In this Section, the various underground technologies are presented for each of these phases.

A.2. Preliminary Survey

A.2.1. General Considerations

The first phase towards the development of a geothermal power plant is a preliminary survey. The preliminary survey aims to assess the economic and technical feasibility of a project and to identify potential barriers for the development of a geothermal power plant. A preliminary survey is usually based on already available information. This information should already provide any evidence of geothermal potential within an area of investigation. The area of investigation could be considered on a local, regional, national or international scale. This project will consider those potential resources and reserves present within the UK (England, Wales, Scotland and Northern Ireland).

The preliminary survey can be broken down into a list of aspects to be considered or addressed. However, these aspects are not restricted to the preliminary survey only and can be considered or revisited in later phases. The topics for consideration and general order of progression is as follows:

- Literature review;
- Data collection, compilation and evaluation, e.g. geological, structural, petrophysical, thermal and geophysical data;
- Conceptual modelling;
- Numerical modelling;
- Potential study and resources assessment;
- Seismic risk evaluation;
- Environmental Impact Assessment;
- Technical and economic feasibility; and
- Legal and societal aspects.

All of these topics need to be addressed in order to identify possible barriers towards the development of a geothermal project in the UK, although the degree to which each is undertaken can vary according to available information or early indications in the process of insurmountable risks.

In the following sections, a few topics related to the preliminary survey are explored in more detail.

A.2.2. Data collection, compilation and management

During the preliminary survey, the most important and time consuming task consists of collecting and compiling all the existing relevant data related to the topics listed above.

The most pertinent data relates to information such as the temperature profile with depth, but also the evidence of the presence of high permeability structures in the deep subsurface.

Available data sources and data providers should be consulted as part of the data collation process. Data providers could be private companies or public authorities. Data could be collected from individuals, companies, public agencies or from international databases. Remote sensing data are becoming increasingly important.

Whilst collecting data, legal aspects relating to the rights of use of these data needs to be correctly assessed.

For compiling the data, appropriate data management tools are required. The data management tools should be flexible enough to integrate the existing data, but also sufficiently flexible to integrate additional and diverse data that will be acquired during the further phases of the project. Data management tools based on geographical information system (GIS) technologies constitutes the principal tools which are currently available. Such tools allow the operator to process two dimensional (2D) information, but can have limited capability when it comes to handling three dimensional (3D) data, where more complex data management tools may be required. 3D CAD can be integrated with the GIS to enhance the 3D understanding of the systems. The increasing degree of sophistication of such tools can improve understanding but also increases costs, which can be a significant consideration for a project and therefore the degree of 3D modelling needs careful consideration.

Geowatt has in recent years assisted some sectors in Europe with the development and implementation of highly sophisticated tools initially developed for the oil and gas industry. Although these tools provide high-end solutions for data management, structural modelling and reservoir modelling, their use for a geothermal project is questionable due to the associated costs. These tools offer a function that has been specifically developed for the oil and gas industry. Most of these functions cannot be applied to a geothermal project. The costs associated with the application of these tools are very high and are not suitable in the context of the framework of a geothermal project. The main drawback of these tools is that they are based on protected formats that are not easily transferable to other systems.

When these tools are utilised as part of a project it is difficult to transfer them to another system further down the line. Previous experience has also shown that the associated costs become extremely high at the end of a project.

Geowatt has also assisted in the development of private and public nationwide or international online geothermal databases. The data is accessed through so-called web portals, directly accessible by the classical web browsers. The rights on these data, the related costs and the kind of data that are effectively accessible depend on the database and/or on the subscription form.

Because induced seismicity is a detrimental factor for the development of geothermal projects (see for instance Basel in 2006, Ref. 17), it is essential to collect information about the rock mechanics, the natural seismicity and the regional stress field during the preliminary survey phase of the study.

A.2.3. Conceptual Modelling

As a result of the preliminary survey, a conceptual model should be established. A conceptual model is a representation of the current best understanding of a geothermal system. The conceptual model should describe all relevant processes of the geothermal system and the relationship between each process.

The conceptual model is established according to the investigation scale (local or regional). It is of major importance for site screening. The conceptual model will be refined and updated during the exploration and drilling phases, as more data will be gathered and the knowledge of the subsurface will increase.

A.2.4. Numerical Modelling

3D geological modelling

3D geological modelling is becoming the state-of-the art method of integrating a variety of pre-existing geological and geophysical data in a 3D structural model, as well as newly acquired geophysical data. 3D geological modelling is also used as a basis for the calculation of the geothermal potential. Therefore it is

strongly recommended to start setting up a regional 3D geological model (to include the structural elements) already during the preliminary survey phase of the study.

The regional 3D geological model will then be used in the further phases, mainly for the following purposes:

- seismic data interpretation;
- to run hydraulic or hydro-thermal computations;
- to test different assumptions (structural or flow directions), by verifying the model results with the observations;
- to calibrate the gravimetric and thermal model;
- to calculate the temperature at depth and to estimate the geothermal potential; and
- to serve as a basis for constructing the reservoir models.

Moreover, the regional 3D geological model can be used during the exploration phase to best define the borehole target.

The model should be updated throughout the duration of the project with borehole data (e.g. geological logs) or production data (e.g. temperature, flow), to validate previous assessment and assumptions

The use of the standard oil and gas tools for the development of the geological model may be cost prohibitive. However, other more economical tools might be suitably effective, such as those used for geotechnical engineering ground modelling.

Numerical modelling (hydraulic, thermal)

Based on the regional 3D geological model, a 3D hydrothermal numerical model could be implemented to evaluate the geothermal potential within a given area.

These models allow the best estimation of the temperature at depth (prediction) as well as a quantitative estimation of the geothermal potential (heat in place, and recoverable heat), and an assessment of the uncertainty.

Results are provided in the form of maps that could be used as an additional criterion during the site screening process.

These numerical models usually consider thermal diffusive processes only. 'Natural convection'⁶ processes could be included as well, but the associated costs are generally an order of magnitude higher. Natural convection processes should be taken into consideration only if evidence of high velocity flow circulations exist based on the conceptual and geological models. However, such convection processes might be added at a later stage if identified from the exploration phase and should additional modelling be considered beneficial.

Model sensitivity should be tested and verified where possibly, although this verification will only occur in the later exploration stage, should the project progress that far. The sensitivity analysis provides an understanding of the uncertainty which should be used to focus further investigation and data gathering to refine the 3D geological and geothermal modelling at later phases prior to constructing the reservoir model.

⁶ Natural convection is a mechanism, or type of heat transport, in which the fluid motion is not generated by any external source (like a pump, fan, suction device, etc.) but only by density differences in the fluid occurring due to temperature gradients.

A.3. Exploration

A.3.1. General Considerations

The exploration phase ideally aims to characterise the structure and the properties of the deep subsurface. The main objective is to identify and target the geothermal reservoir before proceeding with the first drilling. The first phase of drilling, commonly called exploration drilling, can be considered as part of the exploration phase. However, other less costly and complex investigation is needed prior to drilling to limit the risks of abortive drilling costs. Therefore, drilling could be considered as a separate phase to this initial exploration phase.

During the exploration phase, most of the methods that could be used to investigate the deep structure and their petrophysical characteristics prior to drilling are applied from the ground surface (e.g. surface based geophysical methods). Such investigation techniques result in an indirect image of the subsurface. This image needs careful interpretation to obtain the relevant characteristics of the subsurface together with an understanding of the uncertainty in the technique used. Only once there is sufficient confidence in the interpretation would the investigation move to the more costly and technically complex drilling phase to validate the model interpretation.

Most common exploration methods are geophysical methods that include seismic methods (see Section A3.2 here below) and more recent methods such as gravimetric, electric and electromagnetic methods, and thermal gradient boreholes (see Sections A3.3, A3.4 and A3.5 below). Non geophysical methods such as geochemistry and other geoscience surveys are described in Sections A3.6 and A3.7 respectively.

A.3.2. Seismic Survey Methods

2D seismic

2D seismic is the traditional method for oil and gas exploration, but also for geothermal exploration. Where supported by conditions and budget, 2D seismic methods are supplemented by 3D methods (see next sub-section).

As the method is based on seismic velocity contrast, the application of this method in crystalline or basement areas can be of limited efficiency. Very often, 2D seismic data already exists for a given region. These data should be utilised where possible. Due to the rapid advances in improvement of seismic data post-treatment methods, reprocessing and reinterpretation of already existing seismic data are highly recommended. However, because the target investigation depth defines the frequency of the seismic source, an old seismic campaign that is aimed at shallower oil and gas prospect, would not necessarily give sufficiently accurate information for deep rocks underlying oil and gas reservoirs and therefore more characterised targeted seismic investigation might be required to characterise geothermal reservoirs at depth.

Benefits:

- Data often already available (for reinterpretation/reprocessing);
- Standard and commonly used method; and
- Deep investigation penetration depth.

Limitations:

- Limited efficiency in granite or basement rocks, as seismic velocity remains relatively homogeneous in such rocks;
- Inability to detect vertical faults;
- Inability to derive fault directions in three dimensions;
- Limited information about the hydrodynamic properties; and
- Not relevant for the thermal properties.

3D seismic

3D seismic campaigns are recently more frequently used in the geothermal industry than traditional 2D surveys. 3D seismic allows a much better characterisation of the geothermal reservoir than 2D seismic, but the associated costs are much higher.

The area covered by 3D seismic campaigns is usually larger than a single small target reservoir for one specific power plant. Results of a 3D seismic campaign could then be used for the implementation of several geothermal power plants. For example, such campaigns were carried out for geothermal exploration in the following geothermal areas in Europe:

- Rhine Graben (Germany)
- Lardarello geothermal site, Toscana (Italy)
- St. Gallen area (Switzerland); and
- South German molassic basin, Bavaria (Germany)

None the less, 3D seismic campaigns may lead to limited results in granite or basement rocks, due to the low seismic velocity contrasts of the deep structures.

It should be noted that some private insurance companies, insuring non discovery risk for geothermal wells, require the execution of a 3D seismic campaign during the exploration phase, in order that best efforts are used to define the target zone and assess the risk of non-discovery.

Some successful projects across Europe would have failed without the use of 3D seismic (see case studies in Section 5).

Furthermore, the characterisation of the geothermal reservoir can be increased by the computation of the seismic attributes of 3D seismic. Seismic attributes are measurements derived from the seismic data, like amplitude, shape and position of the seismic waveform. They can provide additional information on the geological facies and on fracture patterns, which is important when considering likely fluid and heat flow within the potential reserve and thus potential for exploitation. Additionally, these data can influence the engineering considerations, risks and constraints to reservoir exploitation.

Benefits:

- A high resolution of the underground structures; and
- The ability to derive fault directions in 3D.

Limitations:

- Higher costs than 2D;
- Difficult to deploy in an urban environment; and
- Requires a larger survey area.

A.3.3. Other Geophysical Methods

Gravimetry

Gravity data provides information about the geological structure at depth and at a local scale, when correlated with other kinds of data, such as 3D geological models. They are used to better characterise subsurface geological structures.

By attributing reasonable densities to the lower crust, to the upper mantle and to the major rock types in the area, the density distribution in the upper crust can be defined through a modelling approach. Because density is temperature dependent, the geothermal gradient within the area of investigation should be considered as well. Density values could then be attributed to the various formations and elements of the geothermal systems, e.g. intrusions, faults and reservoirs.

The comparison between the simulated distribution of gravimetric anomalies based on the geological model and the measured gravimetric anomaly distribution can be used to eliminate, constrain or select hypotheses on the subsurface structures.

Gravity data are particularly effective for determining location and depth of vertical and sub-vertical geological structures with density contrasts. These density contrasts can be, for example, limits of sedimentary basins, vertical or sub-vertical faults (steps) and boundaries of bodies with different porosities. These data also allow the determination of the shape of sedimentary basins where the density contrast is strong enough ($> 50 \text{ kg}\cdot\text{m}^{-3}$) although it is unlikely that an accurate outline of the basin is obtained as image resolution is generally too poor.

Benefits:

- Lower cost than other investigation techniques;
- Delineation of vertical or sub vertical structures; and
- Most useful for identifying hydrothermal areas and large igneous intrusions.

Limitations:

- Only effective for structures with good density contrast; and
- Would ideally require a 3D geological model for comparison between modelled and measured anomaly distribution.

A.3.4. Electrical and Electromagnetic Methods

Geothermal resources are ideal targets for electromagnetic (EM) methods since the liquid phase produces strong variations of electrical resistivity in the subsurface. Electrical resistivity is affected by properties such as temperature, porosity, permeability, fluid salinity, partial melt fraction and viscosity. Many of these parameters may take an important role in defining a geothermal system. Therefore, the interpretation of EM signals could provide some indication of these properties and thus of the understanding of the geothermal systems.

Since the behaviour of the geology is profoundly affected by temperature and the presence of fluids, low electrical resistivity may be an indication of structurally weak zones in the lithosphere within which deformation is most likely to occur. Moreover, active deformation greatly influences fluid interconnectivity, so that low resistivity may also represent the degree of deformation. Electrical resistivity models may offer an image of fluid generation during active crustal thickening and its transportation towards the surface in major zones of crustal weakness (Ref. 65).

In addition to investigating the structural geology, resistivity distribution at various depths may show the location of possibly enhanced fluid concentration and the presence of intrusions that are still molten. On the other hand, resistivity should always be considered with care. Experience has shown that the correlation between low resistivity and fluid concentration is not always correct since mineral alterations produce comparable and often a greater reduction in resistivity. Moreover, although water-dominated geothermal systems have an associated low resistivity signature, the opposite is not true, and the analysis requires the inclusion of geological and possibly other geophysical data in order to limit the uncertainties.

Among EM methods only magnetotelluric (MT) may provide the suitable investigation depth for regional characterization. Disadvantages of the MT method are its low geometrical resolution (though lateral resolution may be improved when using short site spacing) and noise (both geological and industrial) sensitivity.

Benefits:

- Lower cost than other investigation techniques;
- Identification of rheologically weak zones; and
- Phase changes from liquid to gas can be clearly visualised

Limitations:

- Low geometrical resolution at higher depth; and
- Non-unique explanation for low-resistivity zones.

A.3.5. Geothermal Gradient

One of the basic methods to outline prospective areas for geothermal research is the analysis of terrestrial heat flow density (or terrestrial heat flow), which defines the amount of heat flowing across a unit surface area during a time unit. It is expressed as the product of the thermal conductivity of rocks and the temperature gradient. The temperature gradient is the rate of increase of temperature with depth. Assuming that the heat is transported only by conduction, the temperature at any depth (relevant for exploration) can be calculated using the temperature gradient (Ref. 37). Accordingly, areas characterised by high heat flow and low thermal conductivities resulting in a large temperature increase with depth should be the most favourable sites for geothermal research.

However, heat flow is influenced by numerous phenomena and processes such as the spatial variation of thermal conductivity and heat production due to different rock types, sedimentation and erosion, groundwater flow, volcanism, etc. In such cases the heat flow and the temperature gradient vary with depth and the prediction of temperature at great depth is carried out by numerical modelling. Most of these processes act on a local scale (e.g. groundwater flow) and less on a regional scale (e.g. erosion). On continental and regional scales the assumption of conductive heat transport is a good approximation. Therefore, the average heat flow describes well the underground temperature conditions.

Benefits:

- Lower cost than other investigation techniques; and
- Identification of geothermal active area.

Limitations:

- Only suitable where geothermal anomalies occur.

A.3.6. Geochemical Methods

Geochemistry encompasses a wide range of methods, each one fulfilling a different objective. Geothermometers, for instance, are based on isotopic ratio. They aim to estimate the fluid temperature at a depth to provide better understanding of the flow systems (e.g. depth of the circulation, groundwater transit time, mixing processes). Electrical conductivity measurements are performed on rock samples in the laboratory to characterize the thermal characteristics of the different rock type. This parameter is mandatory for good prediction of the temperature at depth. Other classical hydrochemical fluid parameters such as pH, Eh, cation and anion concentrations provide relevant information for the understanding of deep flow systems. Information about the fluid chemistry also provides important information for the design of some components of the well and of the power plant.

Gas content (e.g. Radon, CO₂) at the surface or in natural springs or water wells may give important information on subsurface structures. For example, it is well known that the detection of Radon anomalies in surface waters can reveal the presence of moving groundwater at depth (see for example Durrance, 1986, Ref. 22).

A.3.7. Surface Geological Studies

Surface geological surveys are a fundamental and cost effective way of investigating the subsurface. Field assessment of geological outcrops, i.e. where the subsurface geology is exposed as an outcome of erosion and weathering at the surface and also topographical variations often indicate the geology that is present at greater depths.

Characteristics of the underlying geology such as its petrology and lithology, allow the rock type to be better understood in the context of its reservoir potential. Evidence of past chemical changes such as the alteration of the rock mineral fabric may indicate its close proximity to an igneous intrusion. Indicators of geological structural deformation that have occurred over time such as faulting, folding etc. can also be observed at a cliff face for example and may also be reflected as hummocky or 'hilly' surface topography.

Many kinds of surface geoscience studies, such as geological mapping or surface facies characterisation, could be applied during the exploration phase to contribute to the site selection process or in identifying and locating a geothermal reservoir. This information can also be combined with subsurface data to improve the characterisation of the 3D geological model.

A.4. Drilling Phase

A.4.1. General Considerations

Drilling operations are performed in order to open up geothermal reservoirs for energy exploitation. The drilling phase is probably the most important phase of the overall project, as it typically accounts for more than half of the overall budget. Therefore, detailed and comprehensive planning of the drilling is required.

The choice of an appropriate drilling rig is one of the most important decisions in well planning. The rig should have a sufficient safety margin against failure at the depths anticipated to ensure that it can drill safely beyond the anticipated depth if so required. Its technical specifications (e.g. hook load, rig horse power) should fit to the specifics of the planned well. In order to avoid unnecessary costs, standard bit sizes and casing diameters should be used wherever possible.

During the drilling process, the drilling rig has to fulfil the following functions:

- Rotation of the drilling bit, either by rotating the whole drill string or by delivering the hydraulic energy to drive the downhole motor, in order to achieve penetration through the rock formations;
- Ensure circulation of the drilling mud, so that the drill cuttings can be transported up the well bore to the surface; and
- Provide traction power for the drill string to be pulled out of the well and to control the weight on the drill bit during drilling.

The design of geothermal wells presents important differences to the design of hydrocarbon wells. For example, due to the high production rate in geothermal wells, the well diameter and corresponding diameters of injection and production strings have to be larger.

With only very few exceptions, a drilling mud will be circulated within the well bore to the surface during the drilling operations. The drilling mud has to fulfil various functions within the drilling process:

- Transportation of the cutting material away from the drill bit, up the well bore;
- Stabilization of the well bore by means of balancing the pressures at the borehole wall; and
- Cooling of the drilling equipment.

To enable a continuous operation, a sufficient supply of drilling mud has to be ensured. Mud pumps have to be dimensioned such that they are capable of providing drilling mud at adequate rates. Mud cleaning facilities have to be installed and, if necessary, mud cooling services as well.

A.4.2. Drilling of a Geothermal Reservoir

The drilling techniques applied for geothermal reservoir exploitation do not fundamentally differ from those applied in drilling oil and gas wells. Drilling techniques are described in standard textbooks such as Nguyen (Ref. 52) or Jackson (Ref. 47). Particular attention should be paid to the large diameter of geothermal wells, directional drilling and techniques that avoid formation damage to the ground from which heat may be extracted at depth.

In order to obtain flow rates in geothermal wells, which are high enough to sustain an economically viable operation of a geothermal power plant, the borehole and casing diameters have to be sufficiently large. Diameters of geothermal wells are therefore generally larger than the diameters of corresponding hydrocarbon wells of comparable depth. This has implications not only on drilling costs, but also for the borehole wall. Taking into account the strength of any particular formation and stress field with its associated anisotropy, the potential for borehole failure increases with the borehole diameter. This becomes even more important for wells deviated from vertical. It is therefore necessary to carefully investigate the in-situ stress field and borehole stability ahead of well planning, such that the well path (particularly its direction in relation to the stress field), the weight of drilling mud and the casing programme can be selected accordingly.

In order to hit the subsurface target zone with a sufficient degree of accuracy, it is generally necessary to proceed with directional drilling. Directional drilling is accomplished through the use of proper bottom hole assembly (BHA) configurations, 3D well bore path measurement instrumentation, data linking instrumentation to communicate downhole measurements to the surface, mud motors and special BHA components and drill bits. Drilling parameters like weight on bit (WOB) and rotary speed (rpm) are also

sometimes used to deflect the bit away from the axis of the existing well bore. The orientation of the bit in the desired direction is done through the use of a bend in a downhole steerable mud motor assembly.

The drilling bit generally has to be chosen according to the geological formation to be drilled. In sedimentary environments this will in most cases be a roller-cone bit, which either has steel teeth or may have hard metal inserts made from tungsten carbide (TCI-bits). Polycrystalline Diamond Compacts (PDC) bits have been used successfully when drilling uniform sections of carbonates and evaporates, that are not broken up with shale stringers (Ref. 6). Although successful use of these bits has also been reported from sandstone, siltstone and shale formations, PDC bits cannot be recommended generally in these formations. Although a high drilling speed (ROP = rate of penetration) is generally desirable in order to keep drilling costs low, for technical reasons it is not always recommended. While drilling ductile formations like clay or claystone for example, it may be appropriate to reduce drilling speed and, if necessary, also the WOB in order to keep the bit in a cutting mode, and not turn into a pressing mode.

In order to achieve the highest flow rates possible from the geothermal well formation damage, for example due to mud invasion, has to be avoided. When drilling in sandstone dominated formations it is desirable to avoid mobilisation of clay minerals. Special drilling mud should be used which will reduce clay mineral mobilization. A marble-flour might be added to the drilling mud which will help to build up a thin mud cake, which protects the reservoir formation. If necessary, this thin mud cake might later easily be removed through acidization.

Thermally induced stress on the casing during hot water production has to be considered. Casing damage in general has to be prevented. As the casing 'heats up' the casing material can become more elastic and start to stretch or elongate. This commonly requires a complete cementing of the casing along the whole well profile. Alternatively the uncemented part of the casing string has to be pulled in tension in order to compensate the thermally induced elongation.

In order to prevent fluid circulation behind the casing within the overburden, cementation up to the surface is essential. The bond between tubing, cement and the rock has to withstand the thermal tensions and the pressure changes during the entire life span of the well. Blast furnace cement has turned out to be very suitable for this purpose. The process of cementation up to the surface represents a high pressure load for the unlocked formations. The cement slurry density can be adapted to these conditions by specific additives.

Usually cementing of a well will be performed from the base to the top, but in case this is not successful then other techniques can be used such as a squeeze cementation performed from the top of the well to the former cement infiltration zone. It is generally recommended to verify the successful placement of the cement. This can either be achieved by means of conventional cased-hole logging (Cement Bond Log, CBL) operations or by thermal logging.

Attention has to be paid when drilling through gas bearing formations. The choice of mud weight has to be great enough to avoid the gas entering the drilling mud. Potentially gas bearing formations also have to be considered when planning the casing program for the well.

A.4.3. Drilling in Granite

In order to optimize drilling cost and effectiveness, rotary drilling should be applied wherever possible. Directional drilling with downhole motor could be used only for short sections, for kick-off and build-up of the planned deviation angle, for instance. However, no improvements of drilling performance are to be observed when applying downhole mud motors. Due to frequent grain size changes at short distances, the presence of alteration zones and the number of fractures, no Polycrystalline Diamond Compacts (PDC) bits are used in granitic environments. Slick, packed or pendulum bottom-hole assemblies are applied.

A.4.3.1. Sidetrack

A sidetrack is a secondary wellbore drilled away from the original hole. It is possible to have multiple sidetracks, each of which might be drilled for a different reason. A sidetracking operation may be done intentionally or may occur accidentally. Intentional sidetracks might bypass an unusable section of the original wellbore or explore a geologic feature nearby. In the bypass case, the secondary wellbore is usually drilled substantially parallel to the original well, which may be inaccessible due to an irretrievable object in the hole, or a collapsed wellbore.

A.5. Well Testing, Tracer Testing and Logging Phase

A.5.1. General Considerations

The well testing, tracer testing and logging phase aims at characterizing at best the properties of the well and of the target geothermal reservoir. This well testing phase usually commences directly after the achievement of the first exploration well although for some tests at least one pair of wells, an abstraction and an injection well, will be required. It might happen that other geological formations are tested during the drilling process.

Well testing comprises the different technologies based on water or air pumping or injection in order to evaluate the quantity of water/gas/oil that can be extracted/injected from/to the reservoir.

Tracer testing consists of injecting solute compounds directly into the reservoir formation. The behaviour of the solute compounds provides information about the hydrodynamic properties of the reservoir, such as porosity, permeability and dispersivity. It also enables the hydraulic connections between the reservoir and overlying or underlying aquifers, that may be separated from the reservoir by an aquitard, to be detected, thus helping determine whether there might be impacts on other water bodies as a result of water abstraction or injection in the geothermal reservoir.

Well logging describes all the technologies that are aimed at determining the properties of the well, the surrounding rock or the fluid itself, throughout the borehole profile.

A.5.2. Well Testing

With regards to well testing, it is necessary to distinguish between the well test technologies (such as air lift) and the well-test scheme (such as injection, pumping or a step-drawdown test). The choice of the technology and of the scheme depends on the investigated property. A clear definition of the objectives of the test is thus of prior importance to determine the type of test to carry out. A well test programme is then defined.

The objectives of well test could be:

- Identification and evaluation of existing fracture systems;
- Assessment of fractures induced by hydraulic stimulation;
- Investigation of the transport properties of the matrix;
- Determination of the reservoir boundaries; and
- Compartmentalisation of the reservoir.

A.5.2.1. Production Testing Scheme

A pressure drawdown or pumping test measures the bottom hole pressure while the well is flowing. It is primarily a method for measuring the productivity index (PI). A stable rate over a long period can be difficult to establish. This could induce some uncertainty in the analysis.

Pressure build-up or recovery tests measure the bottom hole pressure response during the shut in period which follows a pressure drawdown. It is also called the recovery phase. Such testing is useful for measuring reservoir properties and near well interferences such as skin effects, without perturbations of the pump itself. In this test the flow rate is known and equal to zero.

Injection testing scheme

A step-flow and stimulation test consists of injecting water with a step-increased flow rate until reaching stimulation pressure. The aims are primarily to determine the minimum stimulation pressure of the reservoir and secondarily to reduce near well bore hydraulic impedances.

In a multi-rate-pre-fracturing hydraulic test, the injection flow rate is increased in steps. In each step the flow rate is maintained as constant until the injection pressure reaches an asymptotic value. The test delivers valuable information on the reservoir transmissivity, the significance of turbulence and on details of fracture dilation (Ref. 51).

A.5.2.2. Testing Techniques

For production, well tests are generally conducted using the air lift pumping technique. This technique consists of injecting air using a compressor. Air is injected in the production pipe at a depth usually comprised between 200 m - 500 m. Buoyancy will enable the air to circulate to the top of the production pipe, reducing the mean density of the fluid in the production pipe. As a consequence, the downhole pressure at the reservoir depth reduces, and the fluid will flow from the formation into the well. This technique is extremely simple and very easy to use for well tests carried out over a short period. The air can be replaced with nitrogen if required.

For injection tests, common surface pumps are generally used (see details in section A7.1).

A.5.2.3. Tracer Testing

Tracer testing is an efficient method to detect and characterize hydraulic connections between two Deep Geothermal wells. Tracer tests aim at understanding the migration process of injected and natural fluids, and at estimating the proportions in discharged fluids, the fluid velocities, flow rates and residence times.

Depending on the tracer test methodology, different information on transport properties and hydraulic connections can be obtained. This information is essential for characterizing heat exchange and for fluid re-injection in geothermal reservoirs (Ref. 59, Ref. 36). Information is derived from the data collected during the tests after their interpretation through a modelling approach.

As the physicochemical behaviour of the tracers under given reservoir conditions (e.g. high salinity fluid, very low redox potential, low pH) is not always well known, the use of a minimum of two tracers is recommended. Comparison with a natural tracer or laboratory experiments could be executed as well.

In the literature, the following tracer compounds (liquid phase tracers only) are recommended for application at high temperature conditions:

- Naphthalene (di, tri)sulfonates (nds, nts, ns) family: 1,5-, 1,6-, 2,6-, 2,7-nds, 1,3,5- and 1,3,6-nts, 1- and 2-ns (Rose et al., 2001);
- Aromatic compounds: sodium benzoate or other benzoates (Adams et al., 1992);
- Fluorobenzoic acids are water tracers widely used and preferred in oil reservoirs; and
- Fluorescein ($T < 260^{\circ}\text{C}$; the other organic dyes are not recommended).

A.5.2.4. Logging

Temperature log

The aim of temperature logging is to provide direct information about the temperature in a borehole.

Drilling and drilling fluid circulation alter the original temperature by cooling the bottom of the borehole and heating the upper part of the borehole. In the case of deep boreholes the decay of the disturbances takes a few months. Due to economic reasons it is generally not possible to wait for steady state conditions to be reached. The original formation temperatures can be corrected from repeated temperature logs measured during the recovery period (Ref. 41). Undisturbed temperature profiles provide information about relevant heat transport processes near the borehole.

The temperature log is interpreted together with available geophysical, geochemical, hydrogeological and geological data. One of the routine methods is the calculation of the heat flow per depth interval. The lithology along the borehole profile is known from core samples, cuttings, gamma ray and resistivity logs. The estimated thermal conductivity of the rock is based on the lithology. The heat flow is then calculated using the thermal conductivity and the temperature gradient that has been measured or derived from the temperature log. Heat flow variation with depth is indicative of groundwater flow.

Temperature measurements are also good indicators for locating drilling fluid losses or entry points of formation fluids into the borehole. These locations are marked by rapid temperature changes. Gas release into the borehole is indicated by a temperature drop. Temperature logs are also applied to check the quality of cementing behind the casing.

Vertical seismic profile

As the reflection surface seismic method is hardly able to image subsurface structures within the crystalline basement, the borehole seismic techniques constitute an attractive way to collect spatial information about the major and potentially permeable structures in the vicinity of the geothermal wells drilled in fractured basement rocks. Vertical Seismic Profiling (VSP) permits acquisition of an inter-well image of the deep-seated rock beyond the borehole wall. The main permeable major faults can be imaged and localised by the VSP method. Moreover, VSP data allow a better constraint of the velocity model, useful for reflection and refraction interpretation. 3-D geophysics and VSP are not routinely used in geothermal exploration, due to their high costs.

Borehole imaging and sonic log

Borehole acoustic imaging tools (such as “Ultrasonic Borehole Imaging” – UBI from Schlumberger or “Formation Micro Imaging” – FMI from Baker-Hugues) provide essential information concerning the fractures intersecting the borehole. Orientation and damage zone thickness of faults and fractures can be derived from such acoustic logs. Local variations of the fracture orientations can also give important information on the variations of the stress field orientation. A sonic log allows an estimation of variations in porosity along the borehole. Borehole electrical image logs are also a very valuable method for characterising the fracture system and the present-day stress field in EGS.

Gamma ray logs

Gamma ray logs provide valuable information about the natural radioactivity and therefore the various lithologies penetrated by the well. Spectral gamma ray logs provide continuous variations of uranium, thorium, and potassium content of the well, which, combined with density, allows the calculation of heat production of the rock mass. In a granitic context, lithology variations as well as hydrothermal alteration can be evidenced from these logs.

Resistivity log

Resistivity logs provide information about the electric conductivity of the rock. Resistivity is expressed in Ohm·m. It is sensitive to the type of rock and to the amount of water in the rock mass (depending on the porosity). Other factors also influence the resistivity, such as temperature and composition of the formation fluid. Therefore, the correlation between temperature, porosity and resistivity is not straightforward. In spite of this, contrasts observed in resistivity logs, cross-checked with other well data can provide information concerning the ability of the media to constitute an economical and accessible geothermal reservoir.

Stress determination

The knowledge of the in-situ stress field within a geothermal reservoir is fundamental for the design of the stimulation tests.

The characterisation of the in-situ stress field is mainly done by determining the orientation and the magnitude of the three principal stress components: the minimal horizontal stress, the maximal horizontal stress and the vertical stress.

The orientation and amplitude of the three principal stress components and their depth dependency have to be determined with sufficient accuracy.

A comprehensive review of stress characterisation has been achieved for engineered geothermal systems (Ref. 31).

To measure the stress field, the following methods could be applied:

- Stress measurement can be essentially achieved by overcoring and hydraulic fracturing.
 - Based on borehole samples, overcoring allows the calculation of the magnitude and directions of the stresses existing in hard rocks.

- Borehole hydrofracturing is used to measure the minimum horizontal stress and the orientation of the maximum horizontal stress. For example, the HTPF (hydraulic testing of pre-existing fractures) method provides a means of deriving stress related parameters. (Ref. 10).
- UBI/FMI and calliper logs allows observation and analysis of vertically induced fractures, ovalisation processes, borehole breakouts, en echelon fractures, or more general borehole instabilities. In cases of inclined wells, the rotation of borehole-near stress tensor need to be considered in analysing artificial fractures. As such tools have their own system of inclinometry, the orientation of principal stresses can be deduced.
- The stress field can also be deduced at a more regional scale from a focal mechanism solution of earthquakes, i.e. the use of seismic waves produced by earthquakes to produce a seismic model of the resource geology.

Surface geological observation and interpretation.

If no information on stress magnitude is available, stress models can be developed. These models usually assume that in-situ stress magnitude in the crust does not exceed the condition of frictional sliding on well-oriented faults.

If the in situ stress field is known, geomechanical reservoir models could help defining local stress perturbations along faults and in compartment blocks.

The slip-tendency analysis helps to understand the fault behaviour under changing stress conditions whilst drilling and stimulating the rock mass.

Wellbore stability and fault reactivation potential could then be quantified by classical geomechanical approaches.

A.6. Reservoir development phase

A.6.1. Hydraulic stimulation

Hydraulic stimulation consists of large volumes of water injected at a high flow rate and at a pressure close to the breakdown pressure. Two mechanisms should be distinguished:

- Shearing and opening of natural fractures through shear failure, at low pressures. The shearing of fracture planes induces seismicity; and
 - Creation of artificial fractures (Hydrofrac or fracking), at high pressures (tensile fracturing).
- It should be noted that shearing of large fracture planes could lead to a seismic event. An event induced by this kind of mechanism would occur at a magnitude of approximately three on the commonly used Richter Scale (which is a base-10 logarithmic scale ranging from one to ten).

Since the early 1980s, research at various sites confirmed that shearing is the dominant process rather than tensile fracturing (Ref. 56). Natural joints, favourably aligned with the principal stress directions, fail in shear mode. As a consequence, formations with high stress anisotropy and hence a high shear stress should be best candidates for hydraulic fracturing in low permeability rock.

Knowledge about the stress regime is of great importance to understand or even to predict the hydraulic fracturing process. Borehole breakouts, borehole fractures, location and amplitude of micro-seismic events and stimulation pressures could be evaluated to better determine the orientation and amplitude of the principal stress components.

Proppants are used as part of the hydraulic stimulation process to keep the fracture open after pumping has stopped and pressure drops below the fracture opening pressure. The proppant is injected into the subsurface as part of the hydraulic stimulation medium, and usually comprises a sand or man-made aggregate material. The choice of proppant and proppant concentration used in the hydraulic stimulation process is important to ensure that the long term productivity of the reservoir is maintained.

Proppant 'trials' should be carried out in a controlled, laboratory environment, prior to injection. Larger diameter proppants generally have an overall higher hydraulic conductivity, but are more sensitive to stress. Smaller diameter proppants have an initial lower hydraulic conductivity; however this is maintained over time and generally has a higher average hydraulic conductivity over the life span of the well. Proppant concentration affects the hydraulic width and is important for long-term hydraulic conductivity under production conditions (Ref. 42).

The response of the rock mass to hydraulic stimulation can be predicted with geomechanical analysis, and thus prior to the water injection. This analysis requires the following data:

- The fracture orientations and distribution, resulting from the interpretation of a UBI log; and
- A knowledge of the orientation and magnitudes of the regional/local stress fields, through literature analysis and well tests (hydrofrac/minifrac test or HTPF Hydraulic Test in Pre-existing Fractures).

One method to reduce the risk of creating shortcuts is the isolation of intervals in the borehole. Stimulation is then performed successively along these intervals. The effective fracture area obtained by proceeding this way is larger than by applying a massive stimulation over a long open-hole section. Such strategy is also favourable to reduce the risk of inducing large seismic events. This methodology is limited by the efficiency of the open-hole packers, which are often subject to leaks in deep hot reservoirs.

Cases of induced seismicity have been reported from hydraulic stimulation programs in geothermal and oil & gas wells. However, not all geological formations are prone to induce such events. Induced seismic events, which could be felt at the surface, have been reported from hard rock environments (such as in Basel, see Section 6.3.1).

Since the permeability in these formations is a fracture-permeability, the pressures generated to stimulate the formation can only diffuse through the fracture and fault network, which will lead to a reduction in the effective stress. In sedimentary environments, due to the nature of their matrix porosity and permeability, elevated pressures will commonly diffuse through the porous matrix rather than fracture and fault pathways. A potentially considerable sedimentary coverage of a hydraulically stimulated hard rock formation may also dampen induced seismic events.

A.6.2. Chemical Stimulation

Chemical stimulation consists of acid injection into the open hole at pressures low enough to avoid formation fracturing. Main features of chemical stimulation are as follows:

- Dissolution of formation damage (drilling cuttings, mud cake);
- Mineral dissolution in the well vicinity and in fractures;
- Acid composition:
 - Conventional acids HCl-HF;
 - Chelating agents NTA;
 - Retarded acid systems.

Three sequences are needed for the treatment of a classic geothermal reservoir: preflush, main flush and overflush. The preflush is performed most often with an HCl solution, first to displace the formation brines. The main flush is used to remove the damage and most often, a mixture of HF and HCl or organic acids is pumped into the well. Finally the overflush performs the displacement of the non-reacted mud acid into the formation and of the mud acid reaction products away from the well bore.

Coiled tubing is a very useful tool for improving acid placement. Coiled tubing is of less use in fracturing acidizing because of pumping rate limitations. It is still best to pump fracturing treatments through larger strings, such as production tubing. In larger open-hole sections, acid diversion is important, otherwise only the immediate borehole area or open fractures will be treated first. Diversion of acidification fluids to specific areas of the borehole and reservoir can be achieved with packers.

A.7. Production phase

A.7.1. Production and injection

A.7.1.1. Production pump

Self-flow of the well could occur due to artesian effect or due to thermosyphon effect as soon as production starts. When self-flow is not sufficient to guarantee an economic viability of the power plant, the installation of a production pump is necessary. Depending on the setting depth and water temperature different types of pumps could be used. They include line shaft pumps, submersible pumps and turbopumps.

The shaft driven submersible pump comprises a multistage downhole centrifugal pump and surface mounted motor plus long drive assembly extending from the motor to the pump. This pump is used for shallow depths down to 200 m, and 80-130°C temperature.

Electric submersible pumps (ESP) consist of a multistage centrifugal pump connected to an electrical motor, directly set in the base of the well. They can be used at larger depths and have a capacity of up to 2,000 L/min, about seven times more than that of the shaft driven pumps. As 50% of the pump breakdowns are due to electrical problems, any water infiltration must be eliminated by the waterproof design for the motor. In the case of bottom hole high fluid temperature (200°C), special electric oil filled motors are available. Submersible turbopumps have a hydraulic part driven by a turbine, itself driven by pressurised geothermal water circulation aided by a surface pump. It has lower energy efficiency, but needs less maintenance. However, it should be noted that this type of technology is not commonly used and is relatively innovative in comparison with the other pump mechanisms that have been discussed.

A.7.1.2. Injection pump

To minimize environmental impact and enhance fluid recharge into the geothermal system during exploitation, reinjection of waste water becomes a model feature of all geothermal developments. In some cases the use of reinjection pumps become necessary and part of the production facilities. Horizontal pumps may be adopted for this purpose. They have a capacity up to 1,500 l/min and can operate within water temperatures of up to 80°C.

A.7.1.3. Corrosion and scaling

Effective protection from corrosion and scaling can take place by injecting into the fluid inhibitors based on quaternary amines, whose filming capacity ensures an optimum protection of the casing. Chemical inhibition systems, such as down-hole injection lines, have been installed in production wells at more than 40 plants in Europe.

A.8. Reservoir management and monitoring

There is no standard procedure currently applied for monitoring of geothermal fields and their production. Goals, purpose and design of any geothermal monitoring program mainly depend on the local geological environment and production conditions. Potential monitoring parameters are the production temperatures and flow rates, pressure and temperature of the reservoir, fluid chemistry, seismicity, gravity and the electrical potential. An adequate monitoring program helps to avoid overexploitation of the geothermal reservoir. It leads to a better understanding of the geothermal system and allows for a more reliable reservoir modelling.

The implementation of a seismic monitoring network constitutes best practice in every geothermal project. A seismic monitoring network should be in place before the drilling phase, in order to monitor the natural seismicity.

Monitoring of the chemical composition of water and steam discharged from wells in exploited geothermal fields provides valuable information on the response of the reservoir to the production load. For example, withdrawal of deep reservoir fluid generally induces recharge, which may alter the chemistry of the fluid, especially if a significant portion of the recharge water has a very different chemistry. Monitoring of the dilution trends can provide information about the rate of lateral movement of the invasion front.

Any monitoring of a geothermal reservoir should commence at the latest at the time the actual production begins (Ref.43). It should be performed frequently enough that natural variations can be distinguished from

exploitation induced changes. The data have to be archived and documented in such a way that they are accessible for the potentially changing personnel that will interpret these data over the entire field life.

For reservoir management purpose, integrated numerical modelling at a geothermal site scale is being developed more widely in Europe (instead of reservoir scale modelling).

Appendix B. Single well/Standing Column Wells (“coaxial tube”) systems

B.1. Single well systems

A single well system is a bore-hole from which water is pumped up from the aquifer, and discharged at the surface, for example into a river or lake. Due to high salinity and temperatures utilised in Deep Geothermal systems and associated environmental concerns the discharge to surface without treatment is unlikely to be a viable option.

B.2. Standing column wells

Standing column wells are a relatively new technology with some experience existing in association with shallow ground source heat pump systems. Largely they are boreholes cased to shallow depths only and in direct contact with the surrounding aquifer, creating a standing column of water from the top of the groundwater table down to the bottom of the well. In a standing column wells, heated water is drawn from the bottom part of the well for example via an inner standpipe and returned at the top after passing through a heat exchanger (see Figure).

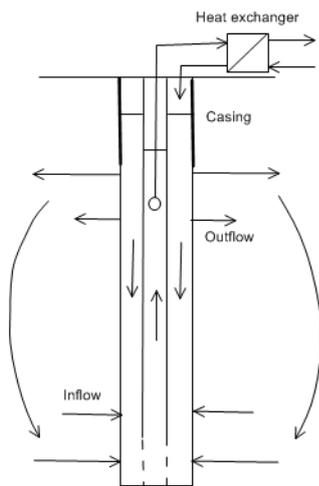


Figure B1: Standing Column Well

Where preferential hydrogeological conditions exist (i.e. the heat reservoir formation is or can be modified to become permeable due to stimulation), the efficiency of a Standing Column Well is lower compared to a multiple well solution.

However, in a standing column well, the reliance on the permeability of the ground is reduced to the following effect.

A lower than anticipated permeability of the geological formation at the depths of the heat reservoir results in less drawdown within the rock matrix whilst still ensuring sufficient flow rates. However, the lower permeability also results in higher rates of flow through the annulus between the open well bore and inner standpipe, bypassing the rock/sediment representing the heat reservoir. This results in a reduced contact of the water with the aquifer matrix and reduced rates of efficiency.

However, a benefit of the Standing Column Well system is the reduced capital costs due to the need for the construction of one rather than two wells.

Appendix C. Results of Stakeholder Consultation

C.1. DECC Deep Geothermal UK Review Study Stakeholder Engagement

Background

The Department of Energy and Climate Change (DECC) has commissioned Atkins to undertake a review study of the deep geothermal potential in the UK with respect to the power sector. Deep Geothermal as a power source has a number of advantages given it can provide carbon friendly base load to the grid provided it can be successfully exploited commercially and at sufficient scale. The study is considering the potential of power generation from sedimentary aquifers and crystalline rocks, some of which may require the application of EGS technologies to stimulate existing fracture networks. In the past the UK Government has financially supported some Deep Geothermal activity. However there is currently only one Deep Geothermal scheme operational in the UK (at Southampton) and this is a heat only scheme. DECC requested that Atkins engage with a range of stakeholders to inform the report. The agreed format for engagement was a three stage process with an initial questionnaire sent out, followed by a workshop event and finally a series of one to one telephone interviews or meetings for identified key individuals or sector representatives. The lists of participants invited to contribute to the engagement process was agreed with DECC. Project timescales have limited the ability to analyse and incorporate the engagement process findings, particularly post workshop where additional submissions have been received. This section provides a factual report of the stakeholder process and responses together with a summarised view of the Key findings and comments received.

The approach adopted is to report comments and findings from the workshop and interviews as unattributed other than by general sector or organisational type. This is intended to assist freedom of expression.

Acknowledgements

Atkins and DECC would like to thank all those that participated in the engagement process. It is recognised that people and organisations have generously donated their time and expertise on a voluntary basis.

Aims

In summary the aim of the stakeholder engagement was to identify the main reasons why Deep Geothermal schemes have not developed in the UK with respect to Power or Combined Heat and Power.

The aim was to have a diversity of participants to ensure views were received from a range of organisations. Although as the process was voluntary, the views and comments received are necessarily limited to those that were willing to take part.

Outline

In total 30 questionnaires were sent out, in general to people and organisations which were considered to have a specialist Deep Geothermal knowledge relevant to the UK and 9 responses were received. All received an invite to the workshop event. The questions asked were:

1. *What expertise do you have in the drilling of deep wells in the UK and internationally, developing geothermal reservoirs, and operating geothermal plants in the last five years?*
2. *For those directly involved in UK deep geothermal projects:*
 - a) *For each project, please provide a brief description covering for example: temperature, geological prognosis, anticipated geothermal system and projected scale of deep geothermal energy output (MWe/MWth), time scale and project cost*
 - b) *What is the current status of the project?*
 - c) *What do you perceive as the major financial and non-financial barriers to the project progressing now?*
 - d) *In addition, are you able to identify the barriers to development you have either met or anticipate meeting at the various points in the project lifecycle?*
 - e) *What is the timescale (after the removal of any barriers to progress) for developing the project to the point of commercial operation?*

- f) *How reliant is your commercial model on supplying heat in addition to exporting electricity to the grid?*
3. *What is the potential for replication of different types of deep geothermal project in terms of plant numbers and/or MW in the UK? What evidence can you provide to support your answer?*
4. *What technological innovation will be needed to maximise the potential of deep geothermal power generation, and to help de-risk projects?*
5. *What are the potential synergies with other renewable and oil and gas technology developments?*
6. *What are the wider potential benefits to the local and/or national economy of deep geothermal energy? What evidence can you provide to support your answer?*
7. *What potential do you foresee to use your geothermal technology and knowhow for the export market worldwide and how are you intending to do this?*

The invitation list for the workshop was expanded to also cover other sectors such as financiers, insurers and cross over skill sets such as deep drilling and renewable energy specialists. An overall total of 66 workshop invitations were sent out.

On 12th June 45 people attended the stakeholder workshop event in London comprising:

8 DECC

8 Atkins

4 Local Councils

6 Companies specialised in Deep Geothermal

5 Engineering Consultancies

2 Oil & Gas companies

2 Power Sector companies

The balance included representatives from academia, the BGS, the Environment Agency, legal consultancy and carbon and power markets.

DECC representatives attended but largely in a passive role although they were able to contribute at some points to answer points arising from debate and discussion. The workshop format consisted of a series of presentations in the morning session to provide an introduction and background to the study and the engagement process. The afternoon session was devoted to a series of breakout sessions in smaller groups. The timings were arranged to provide significant amounts of time for discussion. The overall aim was to listen and capture views. Mark Hinton (Atkins Chief Geotechnical Engineer) chaired the workshop throughout the day providing attendees with the opportunity to contribute to the discussion and express their views.

The workshop agenda was:

09.30 – 10.00 Registration and Coffee

10.00 – 10.15 Welcome Introduction - Mark Hinton, Atkins (Chair)

10.15 – 10.30 DECC Introduction - Dr Paul Hollinshead, DECC

10.30 – 10.45 Definitions and Timeline of events to date - David Shilston, Atkins

Break

11.00 – 11.20 The Current Review Study Report - Natalyn Ala , Atkins

11.20 – 11.40 Scenarios Presentation - Andreas Neymeyer , Atkins

11.40 – 12.00 Costings, Subsidy, Scale and Economics - Ian Richardson, Atkins

12.00 – 12.30 Questions + Comments from Attendees - Mark Hinton

Lunch

13.00 – 13.15 Introduction to breakout sessions - Mark Hinton

13.15 – 15.15 Sessions 1 to 4 – rotation - Mark Hinton + Facilitators

Break

15.30 – 16.30 Breakout Session Feedback & Discussion - Mark Hinton + Facilitators

16.30 – 16.45 Closing Remarks - Mark Hinton

During the afternoon, the attendees were split into four groups rotated through four breakout sessions, where they were provided with further opportunity to exchange their opinions on the commercial barriers to investment; the technical barriers; the next steps that should be taken to advance the sector; and finally the opportunities of economic growth and the public perception of the sector. These sessions were facilitated by Ian Richardson, Andreas Neymeyer, Mark Hinton and Natalyn Ala. At the end of the sessions each facilitator presented to the audience the main findings of the exercise to stimulate further collective discussion.

Presentations

Mark Hinton gave the welcome talk, outlining the structure of the engagement process and the workshop and explained that it was taking place under a form of the Chatham House rules to encourage expression of views without concern of attribution.

He also discussed the stakeholder questionnaire which all attendees were given a copy of.

Dr Paul Hollinshead, Director of the Science and Innovation Group from DECC, welcomed the attendees on behalf of DECC.

The presentations session started with David Shilston (Atkins) outlining definitions of the terms related to deep geothermal with regards to geology and methods of exploitation, discussing the Hot Dry Rock (HDR), Hot Fractured Rock (HFR) and Hot Sedimentary Aquifer (HSA) types of geology and fractured conditions and the need of Engineered Geothermal System (EGS). This prompted a debate regarding terminology.

Key finding: The terminology and definitions used need to be understandable to a non-expert audience. There are a confusing number of interrelated terms used, some of which apply to types of geology and others that relate to processes. Within our report we are resolving this by referencing the geology in terms of either Crystalline Rocks or Sedimentary Rocks.

Varying degrees of natural fracturing will be present with associated levels of permeability. Varying levels of temperature will be present depending upon the particular depth and temperature gradient. Scheme requirements as they evolve during geothermal well development will require varying degrees of stimulation to be applied in the form of EGS processes which commonly include artificial fracturing of the rock mass. The use of the terms Hot Dry Rock (HDR) and Hot Fractured Rock (HFR) could in particular lead to some confusion.

Within the report three specimen case scenarios have been developed to allow cross comparison and to illustrate the only areas where applied criteria dictate viable Deep Geothermal schemes with a power component can be developed. These relate to the chosen definitions in that Crystalline rocks apply to the Granites of the South West e.g. Rosemanowes Quarry and Redruth United Downs in Cornwall, and also apply to the North East of England e.g. Newcastle and Weardale areas. Sedimentary rocks relate to the Cheshire Basin e.g. Crewe area, and also the Wessex Basin e.g. Southampton's operational district heating only scheme.

Key finding: Feedback has illustrated the report needs to be clear that the three scenarios developed are not directly applicable to any actual schemes. Investment decisions should not be developed for particular schemes by direct comparison with the developed scenarios as conclusions drawn are likely to be flawed.

The scenarios have been developed at a scale and type to allow comparative statements, comments on scalability and overall viability criteria to be made. They relate to the overall potential of Deep Geothermal for an area or volume of technically or economically recoverable resource.

David Shilston then highlighted, with chronology, the main relevant reference studies and publications dating back to the BGS study from 1986 to the present. Seven notable commercial or research projects were highlighted:

- Fenton Hill, New Mexico, USA (1974-1993), the first HDR project using EGS;
- Rosemanowes Quarry, Cornwall, UK (1977-1992), an HDR project using EGS;
- Southampton, Hampshire, UK (1986-Present), which is the only commercial use of geothermal energy as district heating in the UK;
- Soultz-sous-Forêts, France (1986), an EU financed pilot HDR project;
- Weardale, County Durham, UK (2004), an HFR project intersecting the Slitt Vein natural fracture zone;
- Basel, Switzerland (2006), an HDR project in which operation ceased in 2006 due to induced seismicity; and
- Unterhaching, Munich, Germany (2009), the first HSA project in the low enthalpy region of South Germany.

Key finding: Some participants had knowledge of the scheme in Basel and observed that the situation with the project stopped due to seismic issues could have been avoided if the public perception issues had been better handled.

Natalyn Ala presented on the structure of the report including the literature review, discussion of investigation and exploitation technologies, the lessons learnt from past projects in the UK and abroad, environmental, regulatory and other considerations. She went on to explain the methodology adopted in the report which included the criteria used to develop the finding that viable Deep Geothermal potential 'reserves' for power in the UK is limited to three geographic areas (although heat only schemes could be more widely applicable). Namely the Granites of south West England; the Granites of North East Weardale area extending west towards the Lake District area; and sedimentary Cheshire Basin in the Crewe area.

A number of lessons learnt were compiled from five projects in the Rhine Valley and additional international EGS projects located in UK, Austria, France, Germany, US, Australia and Japan. They were grouped according to the geothermal project phases: exploration, test drilling, well testing and logging, reservoir development, and production and reservoir monitoring. .

The environmental considerations mainly referred to the use of water and potential pollution, gas emissions, radioactive solids and waste disposal, noise and visual nuisance, land-take and habitat removal and induced micro-seismicity. The regulatory considerations included the Environmental Impact Assessment as part of the planning and groundwater abstraction and discharge considerations. The ownership of geothermal rights was questioned as part of the regulatory framework.

Key finding: Permitting and ownership of 'Geothermal rights' is currently not clear. It is analogous to mineral rights and could be subject to auction in the same fashion. It is an upfront barrier to investment and scheme development from the outset. This requires government to provide clarity as a matter of urgency and is a first step barrier that prevents any further commercial development stages. Investors demand clarity on extent and length of ownership.

Such auctions could be used to recoup expenditure on research work to characterise the resource to sufficient detail to promote investor involvement. Stakeholders considered in general that this should be a relatively straightforward issue to resolve but had not been given sufficient attention to date. Becomes especially relevant if scale is applied when multiple developments take place in adjacent areas where there is the potential to draw on or influence the thermal resource of the neighbouring scheme.

The selection criteria of the three geothermal heat to power conversion scenarios of the report were explained in more technical detail by Andreas Neymeyer, who explained the technical principles used to assess the basic parameters (viscosity, permeability, flow etc) and then compared them for each of the cases.

Ian Richardson's presentation was focused on the commercial aspect of deep geothermal projects. He outlined the key assumptions made in the three scenarios including plant type, sizing, outputs and the pricing, costing and subsidy levels and financing assumptions used to establish the viable economic case.

The basic findings in relation to the balance between heat and power sales and returns were outlined. The approach used where heat sales is required as a component of a viable case business requires a heat customer in reasonable proximity. This was illustrated with heat load maps for the three areas under consideration. The presentation also outlined some of the limitations that would apply that would prevent the full technically recoverable resource being exploited, even where a viable economic case could be made, due to practicalities, permitting, scaling and heat market considerations.

The event was then opened up to the floor for discussion and questions.

Morning Session Discussion

The term EGS and definitions were debated. There was consensus that a distinction based upon crystalline and sedimentary rocks would provide clarity. Past definitions had been arrived at for a variety of reasons. Distinctions associated with porosity could also be useful as matrix and local fractures mean permeability can vary for sedimentary rocks whilst in crystalline rocks permeability relates solely to the fracture properties and is often therefore enhanced by some form of EGS fracture stimulation process.

Key finding: There is a balance of cost versus return from power generation relating to the interacting effects of drilling depth, heat flows encountered and stimulation measures. Drilling costs are not linear with depth. Stimulation measures add considerable cost and the degree required is not known with certainty from the outset.

Understanding of the geology is key and several participants emphasised that this should be the starting point for everything else and that currently there is a general lack of suitable data to allow resources to be confidently quantified. However the basic geology is known and it was argued that a staged approach could nearly always ensure that a technically viable solution could be found by drilling deeper or increased amounts of stimulation or additional wells. However there was less clarity offered as to where the economically viable cut off points would be. Where heat is required an understanding of the local market which exists or needs to be created through new district heating systems is required.

Key finding: Understanding the geology (better than we do currently) and associated temperature, stress regimes (which affect stimulation fracturing process), existing amounts and locations of fractures is a key starting point. Where existing fractures provide better permeability this should be targeted by geothermal wells but the required detailed data does not currently exist.

Afternoon Breakout Sessions and Final Discussion

The four breakout sessions were rotated to allow everyone to participate in each. They were on the topics of:

- Commercial Barriers to investment
- Technical Barriers to investment
- Next Steps to advance the sector
- Opportunities for economic growth; Public Perception of Sector.

There was a wide range of views and plenty of discussion during the breakout sessions and the final period where the results were summarised and opened for general debate. There were some points of general consensus or noteworthy comments or views which can be summarised as follows

Key Finding: Some degree of increased certainty can be provided by investigation surveys involving for example geophysical survey methods. Survey alone will not provide sufficient increase in certainty of resource to lead to unaided investment.

There is a limit to the increase in certainty provided and expensive techniques used in the oil and gas industries are not always appropriate to apply due to costs. Geological conditions can vary over short distances and depths.

Key finding: A number of trial wells would increase confidence in the likelihood of success for subsequent wells in the same area and possibly elsewhere as overall confidence in the UK sector gains momentum. Early wells will have a lower chance of economic success and the percentage likelihood of economic success can be expected to improve with each additional well.

After a number of successful wells the commercial insurance market would be encouraged to offer underwriting of exploratory wells. Views on the number of wells varied but generally 2 to 3 no. to 5km depth in each region would be thought a good start and be relatively inexpensive compared to government investment in other renewable industry sectors. Models around government match funding or 100% underwriting of early wells were suggested. Slim hole wells for research work of a lesser diameter than commercial wells would reduce drilling costs.

Resource exploitation is always planned with mitigation strategies in mind. In order to be successful measures such as increased well depth, additional wells, directional drilling and stimulation can be applied to maximise the chances of a technically successful well(s) being developed.

Key finding: Without an example scheme or example wells to prove the resource (using suitable logging, geophysics and trialling), deep geothermal for power generation is unlikely to proceed in the UK.

Heat only schemes have a lower threshold barrier and are more likely to progress without government funding intervention. In the future Heat only schemes could act as a catalyst for the eventual emergence of power schemes but this would take time for the sector to mature sufficiently.

Key finding: The scenario parameters used in the report will need to take due regard of the likelihood of existing fractures and the need for some form stimulation being required to induce fractures. This needs to be evidentially based where possible but also should allow reasonable assumptions to be made to ensure fair comparisons to be drawn between the two areas. It should not be presumed that there are no faults in Cornwall and all the granite in the North of England is highly fractured.

Some of the scenario parameters presented included flow rates that differed between the granites of the North East and those of the South West of England. There is more evidence in the North East of zones of existing fracturing associated with faults from a trial bore undertaken. However it is known that faulting and natural fracturing of granites in the South West is present but it has not as yet been proven in a trial well. This could be addressed by considering a range of parameters for each scenario.

Key finding: Effective communication of the risks and uncertainties to government, the public and the investment and insurance communities is a key factor to successful commercial deployment.

If handled correctly the public perception can be positively maintained as illustrated by the successful engagement of local communities and government in Cornwall and to other extents in other areas as well. If the public expectations around the induced seismic risks are not managed effectively there is a risk that public support will be withdrawn.

Key finding: Deep Geothermal offers an opportunity to develop a new UK industry, with some export potential, in areas that would welcome economic development. With the co operation of local government this could be associated with local enterprise or development zones, leading to both direct and in direct employment opportunities.

This could suit CHP particularly well as a means to create a heat market without the costs of retro fit. However where there is a reliance in part on heat sales there is a 'what comes first problem' with a requirement to create a heat market for CHP and CHP being required before a heat market (that requires a heat network investment) develops.

Key finding: There is scope for technology transfer from the oil and gas sector although differing cost models may prove limiting. In time drilling costs will decrease as scale and experience grows but only to an extent.

Rig availability and costs could be a future problem if Deep Geothermal develops at scale at least for a period until the supply chain matures. In the short term the supply chain can provide some drilling rigs but this a global market with other energy markets and territories having their own developing demands.

Key finding: The carbon friendly base load would be beneficial to the grid and help to compensate for the intermittency of other forms of renewable such as wind power.

Secondary benefits leading to economic growth would be the grid development, high skilled and salary jobs especially at construction phase, creation of new businesses and even development of tourism (e.g. Eastgate planning permission for a spa).

Key finding: Public perceptions of shale gas drilling, hydraulic fracturing and associated risks could be linked to Deep Geothermal by the public although currently local government and community support have generally managed to promote a positive image for the sector. The experience of stakeholders is that pro active public engagement is crucial from the earliest stages.

Seismic risks could be managed with regard to public perception by adopting a mitigation approach with baseline monitoring. For example in London, tunnel induced settlements are assessed on an individual structure basis and specific mitigation measures developed. This could help to differentiate Deep Geothermal stimulation from Shale Gas fracturing and the association with general measurements of seismic activity. Support from NGO's can help with public support.

Key finding: Risk versus return ratios are currently not attractive to investors. Subsidy levels do not effect initial decision to invest in terms of the upfront risk uncertainties.

Investor views were under represented at the workshop but the views were consistent that investors are unlikely to finance schemes where there are large degrees of uncertainty and risk. At the workshop there was not a clarity as to what degree this was due to permitting and rights issues, uncertainties of the proven resource, relatively high exploratory and development phase costs or the power and heat market subsidy levels.

Key finding: Deep Geothermal has the potential to improve UK Energy Security. There are uncertainties but there is a known power resource that can provide low carbon base load and can be developed relatively quickly when compared to other forms of energy such as Nuclear.

There are a handful of projects poised to commence that have the potential to act as a catalyst to further sector development. Deep Geothermal projects have the potential to reach operational phase relatively quickly when compared to nuclear or offshore wind farms for example.

Key finding: There are environmental challenges but they appear solvable at project scale including water issues. However if the industry is scaled up this could prove limiting if for example multiple plants are required in close proximity.

The deep geothermal resource does happen to coincide with areas of natural beauty and therefore planning, permitting and environmental impact assessments will be issues. However the footprint for deep geothermal plants are relatively small and once the short term drilling phase is over the impacts on the environmental are considerably reduced. The issues will however multiple the larger the scale of overall deployment in an area.

Key finding: There is a lack of relevant data in the UK regarding the potential for thermal degradation of the deep geothermal resource over the lifecycle of the project and beyond.

Until an actual deep geothermal power scheme is operational in UK conditions for a number of years it is not yet clear if there is any potential for the thermal resource to reduce over time. For crystalline rocks the heat is generated from radioactive decay and there is a lack of data regarding the steady state condition and the heat recharge cycle. For the government to invest in a new industry at a large scale they need to see a long term future and a sustainable resource. There were differing views from stakeholders on this issue ranging from being a non issue to an important piece of research being required.

Key finding: The report scenarios are based around a relatively small power output model and commercial scale project would likely need to be larger.

The model used in the report scenarios for comparison is 2.5 MWe. This allows cross scenario comparison and an investigation of scaling effects. However a commercially viable project is more likely to be 5 to 15 MWe.

Key finding: Heat markets are local and deep geothermal would be competing against other heat sources such as waste to energy. Geology is also local and therefore the two need to be matched where heat sales are a governing factor. The electricity markets are national and energy markets are international and therefore for power generation project location can be more flexible and suitable geology targeted.

Financial support measures and subsidy levels for local and national and international forms of energy are different as different factors are in play.

Key finding: There are current uncertainties regarding strike prices and future subsidy levels given the design life and financial model lifecycles of 20 to 25 years that are commonly considered.

In addition to comments regarding the ongoing current uncertainties in energy policy, some stakeholders pointed out the current differences with wave and tidal power (higher) subsidy levels which they considered to be sectors at a similar level of maturity to deep geothermal.

Key finding: If government funding for a demonstration or commercial scale project was provided there could be an opportunity to assemble a collective of companies and experts to undertake the scheme to provide the best chance of success and to help with onwards effective knowledge transfer to subsequent schemes. However there would be a number of issues to overcome.

There would be a number of issues around building a 'collective' of national and local government, major energy companies, leading academics, drilling companies etc. Each have different business drivers and priorities. Government would need to demonstrate that any financial support given had been fairly and effectively deployed which could for example suggest some form of competition for funding would be preferred.

One to One Interviews

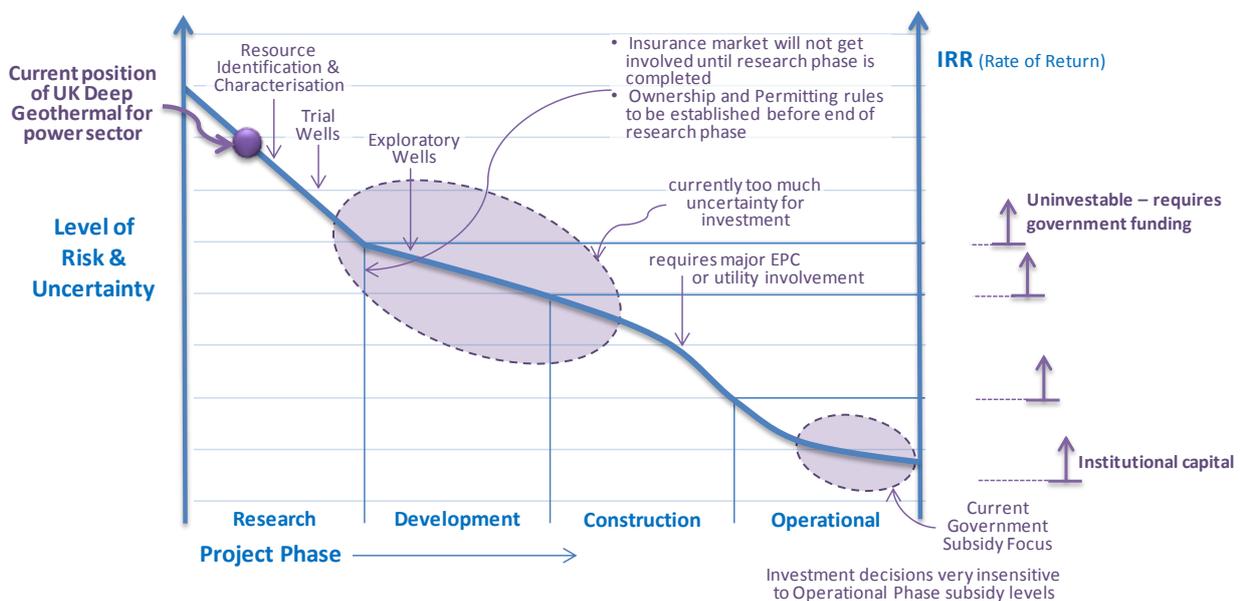
A number of individuals and sectors were not able to attend the workshop event and were interviewed on a one to one basis. These included academics that have specialised in Deep Geothermal and the investment sector which was not well represented at the workshop.

These discussions were to an informal format although the central theme for discussion was centred around the reasons why Deep Geothermal schemes have not as yet progressed in the UK otherwise described as identifying the tipping points to investment.

The Key findings arising from these less formal discussions can be summarised as:

- *A new paper has been recently published by Younger et al that proposes that heat flow estimates in the UK have to date been under estimated.*
- *There have been developments in knowledge and drilling since the original work on Deep Geothermal was undertaken in the 1970's and 1980's by BGS and others.*
- *Natural permeability can be expected in the granites associated with re-activated faults during the tertiary period and there is evidence these have resulted in open fractures that exist currently. The stress regime suggests vertical or sub vertical faults with a NW/SE or NE/SW orientation.*
- *Drillability of granites is becoming less of an issue and there is relevant world experience to draw upon. A scale of market will be required to establish a UK deep drilling industry.*
- *Detecting and targeting faults is not easy and investigation techniques such as geophysics are helpful but not definitive.*
- *In the Cheshire basin the sandstones run out and therefore looking at the Sandbach area as well as Crewe for heat customers is sensible.*
- *With best effort targeting initial wells could be considered to have a 60% chance of technical success rising to 80% in an area after more wells installed.*
- *The best approach is to target permeability to try and achieve a viable well without the need for additional stimulation. However the need for EGS and the risk if induced micro seismic activity cannot be ruled out.*
- *The UK sector would at this stage benefit from a research focus in terms of immediate next steps.*
- *Newcastle geothermal district heating scheme is likely to go out to tender shortly. Power is not the main consideration currently. There has been investor interest but the local council wishes to retain a degree of control. However seeking funding remains an issue. Aim will be for local government to invest in research and aim to recover costs once sold onto a developer. The local heat market is not yet in place but planned e.g. planned science park development and retro fit of existing hospitals.*
- *Energy to Waste schemes have not always been a positive experience and Heat from geothermal therefore has attractions.*
- *Investment market understands the risks and uncertainties well and this is why investment has not occurred. It is not the case that they need educating. Past experience with renewable energy has been patchy and there are clear risks that investors could potentially lose money in this sector.*
- *Carbon pricing needs sorting out as currently the market lacks clarity and this feeds uncertainty for renewable energy investment decisions.*
- *The government would benefit from listening to the market rather than trying to create and impose a market solution.*

- A relatively small government funding outlay of £50m to £100m could finance a number of trial wells. Only then will there be clarity as to whether there is viable Deep Geothermal for Power potential in the UK at a reasonable scale that is worth further investment in.
- At the current time the sector is un-investable as it remains in the research phase. Some expenditure on research and development would therefore be beneficial and could be recouped via the government taking equity stakes in return for early stage investment or via rights auctions.
- The sector will only take off at scale once the smaller independent developers are replaced by larger energy and utility companies and significant EPC contractors become involved.
- There is a scale of expected return on investment associated at each project or sector phase. This is a progression from higher returns at venture capital entry points at early stage development though equity type returns profile during the construction phase reducing to institutional levels of return at the operational phase where revenues and levels of subsidy are more certain. At the current time the sector can be characterised as being in the research phase and will not attract investment other than via government measures.



Conclusion

Deep Geothermal for power is at the research phase = unproven = uninvestable

NOTE: IRR levels, funding types and boundaries are for broad illustrative purposes and should not be considered as exactly defined.

- Regardless of the size of the theoretical technically or economically exploitable resource there will be several limiting factors that reduce the UK potential for power from Deep Geothermal including – rig and supply chain availability; grid connections; infrastructure such as roads required for the construction phases of multiple plants, environmental issues. In summary it will not be practical to deploy a grid of geothermal plant every few miles.
- Key parameter assumptions are based on a limited evidential basis and therefore sensitivity needs to be addressed around which are known and which are unknown and which can be determined at what degree of certainty. Technical and financial models can be sensitive to key parameter variation.
- Although there is overseas experience of Deep Geothermal for power in broadly similar enthalpy conditions, such as can be found in Germany, there is less clarity as to the actual levels of power output achieved in relation to the level of government subsidy deployed. Pumping effort can lead to high parasitic loads for example.

END

C.2. Results of Stakeholder Questionnaire

DECC Deep Geothermal Stakeholder

Questionnaire Responses Summary

In advance of the DECC Deep Geothermal Stakeholders Workshop held on the 12th of June 2013, a questionnaire was sent out to the majority of the invitees in order to ensure that the Atkins team are able to engage with a full range of key UK deep geothermal stakeholders to inform the final report. Out of the 30 questionnaires sent, 9 responses were received and 8 respondents agreed to publish their replies. It should be noted that the views expressed in the responses are the personal views of the respondents and do not essentially represent the views of their organisations nor those of DECC.

<i>Responses received</i>

- 1 **Chris Pomfret (Cornwall and Isles of Scilly Local Enterprise Partnership)**
- 2 **Neil Hook (Cheshire East Council)**
- 3 **Doug Parr May (Greenpeace)**
- 4 **Peter Hamnett & Ben Watts (Cofely District Energy)**
- 5 **Steve Wilson (Baker Hughes Reservoir Engineering)**
- 6 **Professor Jon Gluyas (Durham University)**
- 7 **Peter Ledingham (Geoscience)**
- 8 **Svein Roar Engelsen – David William Nunn (Statoil)**

General notes and responses

Chris Pomfret (Cornwall and Isles of Scilly Local Enterprise Partnership)

As you will be aware, two UK based companies have formed to develop deep geothermal projects in Cornwall. EGS Energy Ltd plans to deliver a 4.3MWe power plant at the Eden Project and Geothermal Engineering Ltd plans to develop a 10 MWe power plant at United Downs in Cornwall. Both projects received planning permission in 2010 and aim to drill to 4.5km, with two wells at Eden and three at United Downs.

Geothermal Engineering Ltd and EGS Energy Ltd will respond individually to the DECC Deep Geothermal Review Study Stakeholder Engagement Questionnaire. On behalf of the Cornwall and Isles of Scilly Local Enterprise Partnership we would like to support these submissions and reiterate the potential benefits to the economy that the development of this sector would bring to Cornwall and potentially the United Kingdom.

Professor Jon Gluyas (Durham University)

In 2013 the leading geothermal research organisations in the UK: Durham, Glasgow and Newcastle Universities plus the BGS have combined to form BritGeothermal. This new organisation, managed by Durham University, will ensure the UK comes to the fore in global geothermal research as well as providing the underpinning for geothermal energy development and commercialisation in the UK.

8. What expertise do you have in the drilling of deep wells in the UK and internationally, developing geothermal reservoirs, and operating geothermal plants in the last five years?

Neil Hook (Cheshire East Council)

Cheshire East Council is not a direct drilling or operating company. Instead, the Council is a lead partner in bringing forward geothermal energy schemes in the Cheshire Basin, both as major landowner and key stakeholder. Therefore we have developed extensive experience of the systems, frameworks and legislation in place covering the delivery of deep geothermal schemes and the differing models of delivery available to the public sector.

Peter Hamnett & Ben Watts (Cofely District Energy)

Our geothermal well was originally drilled over 25 years ago. However, we have recently removed the old turbine based pump from the well, as part of a programme to replace this with a new electric submersible pump (ESP). This has involved working with a specialist geothermal consultant and a drilling contractor to remove the pump set, fish and remove the packer, wash and log the well condition, and undertake injectivity testing. We continue to operate the district energy scheme that was built around the geothermal resource, now primarily producing its heat from gas-fired CHP. Following the pump replacement, we will continue to operate the geothermal well as a heat resource, as part of the district heating scheme.

Steve Wilson (Baker Hughes Reservoir Engineering)

None as our involvement has been limited to providing an initial advisory role regarding the ability to translate oilfield practices to geothermal test projects for potential investors.

Professor Jon Gluyas (Durham University)

Durham University, led by me, has been the joint venture partner with Newcastle University in the drilling of Eastgate 2 to 470m in 2010 and Science Central (Newcastle) to 1850m in 2011. Previously I worked in the oil industry on late field life reservoirs and of which were low enthalpy geothermal systems with hot water production massively exceeding oil production. These projects included planning and executing operations.

Peter Ledingham (Geoscience)

We are not developers, so we haven't done any hands-on development in the last 5 years. In the past we have had, both on UK and USA programmes. We have provided consultancy services to others carrying out these activities and we have done all the technical, drilling, geological and geothermal reconnaissance and feasibility work for the United Downs project.

Svein Roar Engelsen – David William Nunn (Statoil)

Statoil has extensive experience in drilling deep wells (mostly offshore) but has not developed or operated any geothermal plants.

9. For those directly involved in UK deep geothermal projects:

Svein Roar Engelsen – David William Nunn (Statoil)

No planned projects in the “pipeline”.

a) For each project, please provide a brief description covering for example: temperature, geological prognosis, anticipated geothermal system and projected scale of deep geothermal energy output (MWe/MWth), time scale and project cost

Neil Hook (Cheshire East Council)

The Cheshire East deep geothermal scheme is in the latter stages of development, with an intention to go to market with a proposed site in January 2014 with a partner in place by June 2014. As part of the 'All Change for Crewe' programme, this project will develop a deep geothermal energy centre at Leighton West, near Crewe and potentially a deep geothermal research and development hub outlined in Point 9.

The project will provide renewable heat and potentially power for local use, focused on nearby major industrial users as the primary heat loads, followed by forthcoming residential development and ancillary industrial and agricultural users as secondary loads. The project has been estimated to cost approximately £27m, which includes a 20% contingency. We have added this relatively high contingency because this will be the first deep geothermal energy project developed in the Cheshire basin. There is therefore a greater likelihood that this project will encounter some cost over-runs that have not yet been foreseen.

Below is the outline model for costs and heat / energy usage which summarises the proposed model based on forthcoming geophysical testing.

	Case 1	Case 2	Case 3	
Flow Temperature	75	100	110	°C
Return Temperature	60	60	60	°C
Flow Rate	35	35	35	l/s
Peak energy	2.2	5.9	7.3	MWth
Percentage heat used	60%	60%	60%	
Annual heat use	11540	30773	38466	MWh
Total Cap Ex	£27,000,000	£27,000,000	£27,000,000	

O&M costs (per annum)	£115,398	£307,728	£384,660	
Plant lifetime	25	25	25	years

The Council has prepared a proposed model based on the above and use of the Council's land on a lease basis. The envisaged model will follow the timescale set out below;

1 Full Council approval of proposals and business case. Initial promotion commences.	Sept/ Oct 2013
2 PQQ for restricted procurement process issued and advertised extensively.	Jan 2014
3 Bidders appraised and successful party agreed. Terms of lease agreed.	June 2014
5 Developer submits planning application and applications for EA licences	July 2014
6 Full geophysical study of site carried out	Sept 2014
7 Drill rig and services tender process	Jan 2015
8 Measurement and testing programme developed, seismic monitoring systems installed, and community liaison group established	July 2015
9 Drill site preparation	Oct 2015
10 Well 1 drilled and cased	Jan 2016
11 Financial and geological case for Well 2 established. Stimulation and further testing of Well 1	April 2016
12 Design, planning and preparation for Well 2	Aug 2016
13 Well 2 drilled and cased	Nov 2016
14 Completion of surface plant purchase	Feb 2017
15 Site infrastructure completed and plant constructed	May 2017
16 System connected	Dec 2017

Please note, the above timetable is based on comparative procurement schemes for other infrastructure. However, as this will be the first such scheme, and there are a number of existing operators in place they may be able to massively expedite the delivery of the scheme and the infrastructure provision once they are on board.

In terms of the geological prognosis, the proposed site is located on the Triassic age. The Keuper Marls at out crop at the surface, overlying sandstones and pebble beds of the lower Triassic age. It is probable that Permian age red beds are present below the Hercynian age rocks. Structurally, the site is in the Cheshire Basin, a large Permo-Triassic age graben, which appears to comprise sandstones up to 4km deep to the east of the Crewe area. There are many geologic faults in the area and these are associated with the graben structure.

The permeability of the sedimentary rock at the target depths is not known, although sandstone units do typically have a higher permeability than many other rock types. The extent to which geologic faults pass through the sandstone at the required depth beneath the site is not known. If the wells can be targeted at pre-existing geologic

faults then the permeability is likely to be greater than within the surrounding formation. This would enable commercial flow rates to be achieved with acceptable pumping costs. The actual permeability and associated flow rates will only be known once one of the deep wells has been drilled at the site. For the purpose of evaluating the resource, a flow rate of 35 L/s was used and is similar to that achieved from a deep well drilled into the Sherwood Sandstone formation in Southampton.

Peter Hamnett & Ben Watts (Cofely District Energy)

Triassic sandstone aquifer, circa 1,800 metres deep. Water in aquifer at 76°C (74°C at surface). Heat only. Circa 2MW useful heat available.

Peter Ledingham (Geoscience)

The United Downs project envisages a 10MW power plant producing from a depth of 4,500 – 5,000m within a faulted fracture system in the granite, at a temperature of 180 – 200°C. Project cost of approximately £50million.

b) What is the current status of the project?
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Neil Hook (Cheshire East Council)

As noted above [*response to previous question*], the Council is in the final stages of preparation ready to go out to market with a detailed and financially viable model for delivery. The Council has full control of the land for delivery, has ongoing and detailed engagement and support from the Environment Agency and has end users ready to enter in to an agreement with any provider coming on board.

Peter Hamnett & Ben Watts(Cofely District Energy)

Ongoing pump replacement works.

Professor Jon Gluyas (Durham University)

Durham University, sponsored by BP alternative energy are undertaking an assessment of all low enthalpy geothermal systems in the UK. Current work is concentrating upon: North Pennines, Cheshire, East Midlands and Wessex. Heat is the principle target output. This is research that will underpin subsequent commercial development.

Peter Ledingham (Geoscience)

Planning permission granted almost three years ago. On hold, awaiting funding.

c) *What do you perceive as the major financial and non-financial barriers to the project progressing now?*

Neil Hook (Cheshire East Council)

As with all geothermal projects, there is significant upfront capital expenditure associated with drilling the wells, in this case circa £27m to get the system up and running. This capital is at risk until the wells have been shown to maintain sufficient flow for commercial production. In many countries in Europe, this risk is covered by State or World Bank funded risk insurance. This is not the case in the United Kingdom and the potential returns from such a project would not be considered attractive enough to justify the risk exposure to private capital. It is for this reason that a bid was made to the Regional Growth Fund to cover 29% of the total cost, a comparative percentage to that offered in Germany, France and other locations in order to attract delivery partners to take the initial capital risk on the scheme. This lack of up front risk reduction is, in our view, the primary financial and non financial barrier to project delivery.

The other key issue going forward is the certainty of the RHI funding. The RHI funding scheme offers the primary incentive for delivery partners to become involved in renewable energy in the UK and particularly deep geothermal schemes. Simply put, it will be this payment that will make any and all scheme's viable. At the current levels, our financial modelling shows that the £50Mwh RHI payment, coupled with a useable flow rate and critically the target temperature will make a scheme not only commercially viable, but very attractive to investors. However, there is concern about the levels of RHI subsidy going forward and even the commitment to its ongoing future within the context of the Government's austerity measures. The Government have given a number of welcome reassurances about the nature of this funding and these have been well received, the perception remains, particularly with end users who aren't part of the industry, that the Government may end or much reduce the RHI tariffs which in turn would be a cost passed on to consumers, which dissuades them from entering in to such arrangements.

Peter Hamnett & Ben Watts(Cofely District Energy)

Extra works required, not originally identified by the geothermal specialist. Not able to receive Renewable Heat Incentive despite expectation that the system would be able to (the legislation with regard to re-payments of grants was drafted differently to the expected policy mechanism, resulting in our project effectively being locked out of the RHI funding, due to having received a capital funding grant from the Deep Geothermal Challenge Fund). Programming the works can be challenging, as the well-head is located in land used as a car park by a retail third party.

Peter Ledingham (Geoscience)

The project is perceived as being too risky. The high initial capital costs discourage investors. Support is required to mitigate the risks and/or increase the incentives for successful development. The lack of a regulatory framework is also a problem.

d) In addition, are you able to identify the barriers to development you have either met or anticipate meeting at the various points in the project lifecycle?

Neil Hook (Cheshire East Council)

As part of its detailed modelling and work, Cheshire East Council has examined, in detail, the potential risks and issues that may arise moving forward and how they can be proactively mitigated or reduced. This is detailed below for information;

Risk register

Deep geothermal System – Construction/ Design stage

RISK	MITIGATION
Planning permission difficult to obtain	Engage in public consultations and perform EIA
Loss of hole due to failure of drilling rig or associated equipment	Ensure competent drilling contractor is selected
Loss of hole due to difficult drilling conditions	Proper well engineering and supervision
Drilling significantly more time consuming, and expensive than planned	Ensure competent drilling contractor with high standard, proper supervision
Temperature significantly lower than expected at target depth	Consider usefulness of lower temperatures, or abandon project
Fail to hit defined geological target	Assess data and evaluate likelihood that target can be reached by further drilling or sidetrack
Fail to encounter sufficient natural permeability	Carry out stimulation and reassess
Excessive seismicity during stimulation	Comprehensive seismic monitoring and implement decision tree system
Fail to develop sufficient permeability during stimulation	Consider options for further stimulation or, if none are available, abandon project
Fail to successfully drill second, or subsequent, wells	As above
Fail to connect the wells together in a circulating system	Consider further stimulation and / or recompletion options or, if none are available, abandon project
Rapid temperature decline in connected system	Consider recompletion options to stop short circuit

Deep geothermal System – Commissioning/ Operation

RISK	MITIGATION
Corrosion or scaling in the wells or production system	Consider downhole or surface inhibition

Downhole pump failures	Proper pump selection and comprehensive preventive maintenance programme, possible recompletion if solids are the cause
Ongoing unacceptable seismicity	Consider operating at lower pressures
Declining injectivity	Investigate cause and consider injection well workover
High water consumption	Consider operating at lower pressures

From its initial work it is clear that one of the other major barriers faced by the construction and development of deep geothermal plants will be the public perception of such infrastructure. Whilst the principle of deep geothermal energy is strongly supported by a number of key bodies and lobby groups, and initial indications are there is also strong public support for the principle of such a scheme, it is anticipated that when the first scheme comes to the development stage, unless there is significant advanced preparation, publicity and strong high profile support from Government and other bodies it is likely to meet opposition from a vocal minority. The actions necessary to facilitate drilling, particularly the geophysical survey work and the resulting drilling operation can be easily misconstrued by unaware members of the public, which in turn may become opposition to a scheme based on false assumptions that these operations (drilling, surveys using explosive devices etc).

Peter Hamnett & Ben Watts(Cofely District Energy)

Additionally [*response to previous question*], there was risk of failures at a number of stages of the re-pumping project, some of which would have incurred extra costs and some of which could have resulted in loss of the well as a usable resource.

Peter Ledingham (Geoscience)

There are many technical challenges. We will also have to deal with the mis-information and exaggerated (but understandable) concern over induced seismicity.

e) *What is the timescale (after the removal of any barriers to progress) for developing the project to the point of commercial operation?*

Neil Hook (Cheshire East Council)

As outlined above [*response to previous question*], in terms of the Cheshire East scheme, the only barrier to delivery is the perception of risk and the resulting need to underwrite such risk. We anticipate moving forward on the timetable set out in Part 2 a), with a delivery partner on board by June 2014 and start on site in September 2014.

Peter Hamnett & Ben Watts(Cofely District Energy)

Expected to be fully operational end December 2013.

Peter Ledingham (Geoscience)

Four to five years.

f) *How reliant is your commercial model on supplying heat in addition to exporting electricity to the grid?*

Neil Hook (Cheshire East Council)

As the industry is aware, any geothermal scheme is unable to accurately confirm the flow rates and final levels of heat generated until the infrastructure is in place and the wells dug (hence the need for risk insurance). Accurate estimates can be taken using geophysical surveys and other advanced analysis, but until the well is in the ground and pumping and settled in to an operational cycle, the flow and temperature can never be truly confirmed.

In order to be commercially viable, it's our view, and one shared with our advisors and other partners we have discussed emerging schemes with, that any business model for deep geothermal energy needs to be based around achieving commercial viability as a heat only source, with the potential for electricity generation as an additional extra, rather than a prerequisite. In the simplest terms, a scheme will always be able to draw heat from the ground (albeit to differing temperatures), commercially and technically viable electricity schemes require a source of a particular minimum heat, and it is not viable to base a commercial model on an uncertain estimate and potential.

Therefore the model is based around supply of heat to industrial partners and forthcoming residential properties, with the additional potential for electricity generation to the grid or via direct supply dependant on the final agreements reached with end users. We have identified that at a base temperature of 90 degrees, which is very achievable in the Cheshire Basin, a heat only model is very viable.

Peter Hamnett & Ben Watts(Cofely District Energy)

Heat only project.

Peter Ledingham (Geoscience)

It isn't reliant on it, but clearly it would add significant benefit.

10. What is the potential for replication of different types of deep geothermal project in terms of plant numbers and/or MW in the UK? What evidence can you provide to support your answer?

Neil Hook (Cheshire East Council)

The Cheshire East scheme is purposefully designed to be a proof of delivery project, kick starting investment in the UK geothermal market and particularly within Cheshire East and the Cheshire Basin. Through initial discussions with delivery partners, users and industry professionals it is clear that the emerging view is that there is strong support for the geothermal industry within the UK and significant potential for geothermal heat and potentially power – however the up front risk outlined previously is holding back any investment required to deliver these schemes. It is proposed that by using public sector influence and resources to prove that a scheme can be both deliverable and profitable, that this will unlock the investment in further schemes within the area. This is a position backed up by the UK Green Bank which identifies that whilst it will invest in deep geothermal schemes, they must be proven viable and operational – and so the Cheshire East scheme will unlock investment from the UK Green Bank in the geothermal industry, in turn delivering many other sites. To this end, Cheshire East Council have identified 6 other suitable sites within its ownership which it will look to bring forward private sector investment to deliver deep geothermal plants (both heat and electricity) once the first scheme is in place.

Peter Hamnett & Ben Watts(Cofely District Energy)

We are not sufficiently expert in the geology and drilling of new wells to answer this. We are aware of the recent SKM report on the subject.

Steve Wilson (Baker Hughes Reservoir Engineering)

We have not been involved in that breadth of investigation but more focused on individual local schemes.

Peter Ledingham (Geoscience)

The potential for power generation has been grossly exaggerated in most reports. However, there is no reason why several (perhaps tens) of power plants cannot be developed across the UK, if the concepts are proven by the proposed pilot projects, and their sizes can increase with experience. I think if the UK had 500MW of installed capacity within 20 years that would be a worthwhile and commendable achievement.

11. What technological innovation will be needed to maximise the potential of deep geothermal power generation, and to help de-risk projects?

Neil Hook (Cheshire East Council)

Whilst there are many innovations that would make the delivery of deep geothermal schemes more cost effective and quicker to deliver, the primary technical innovation that would maximise the potential for deep geothermal energy in the UK would be a more efficient and effective electricity production process. Currently Organic Rankine Cycle and similar technology relies on efficient transfer of heat, and therefore an ideal extracted water temperature of approximately 120 degrees (though operational from 90 degrees, commercial viability is only achieved at 120 degrees plus).

Any enhancement and innovation in this field, particularly in improving conductivity and reducing the underlying heat requirements would go some significant way to making electricity generation more viable with UK temperature levels which in turn would make schemes exponentially more commercially viable and deliverable.

Peter Hamnett & Ben Watts(Cofely District Energy)

We are not sufficiently expert on the technologies to answer this fully, though we expect that sufficient growth in the UK market could bring down costs for later projects, improving financial viability.

Steve Wilson (Baker Hughes Reservoir Engineering)

The majority of potential for the UK appears to reside with EGS schemes which will require the reliable placement of injector producer configurations such that efficient transfer of heat from deep rocks via an efficient transfer fluid can be accomplished in reasonable time frames. Thus technology that we hope to be able to bring and improve is well placement and fracture prediction at a reservoir scale.

Professor Jon Gluyas (Durham University)

Current organic rankine systems are very low efficiency at typical deep basin temperatures experienced in the UK. Durham University is in the midst of a research project addressing optimisation of power extraction from such systems. Results to date indicate the potential to double power off take.

Peter Ledingham (Geoscience)

The pie-in the sky innovation would be a surface-based exploration technique that could reliably identify potential deep reservoir host rocks. That won't happen any time soon (if ever). Improved/novel drilling technologies have also been proposed as game-changers but, again, that is not in our near future. The key to successful development now is to properly understand the engineering requirements to create systems with commercial circulation performance.

Svein Roar Engelsen – David William Nunn (Statoil)

Statoil has only considered deep geothermal projects in the Cornwall region. In this region there are a number granite occurrences and we would expect that resource potential can support 5-10 10-MW.

12. What are the potential synergies with other renewable and oil and gas technology developments?

Neil Hook (Cheshire East Council)

Whilst there are numerous technological synergies and learning between the renewable energy industry and the oil & gas industries, the particular linkage that Cheshire East Council has been looking to explore is biodigestion and composting. After initial usage for industrial and residential customers, there is significant potential for residual heat to be used in anaerobic digestion and composting facilities and the Council is exploring how this might be best utilised. As the municipal authority in charge of waste collection and disposal there is a significant opportunity to link the two operations to more effectively deal with both waste handling and the generation of heat and potentially electricity.

Peter Hamnett & Ben Watts(Cofely District Energy)

Significant potential synergy with district heating but only where the deep geothermal resources are developed near to sufficient heat loads. Heat appears to be something of an afterthought currently.

Steve Wilson (Baker Hughes Reservoir Engineering)

I am hopeful that 3D reservoir modeling of fluid flow can emulate heat flow with thermal conductivity emulating permeability. This advancement would allow 3D reservoir modeling for thermal resources to be modeled.

Professor Jon Gluyas (Durham University)

The oil and gas industry has a massive contribution to make in terms of drilling, completions, injection, water conditioning, fluid processing and recycling, pump systems, sand control... The list is extensive. Published work by Gluyas indicates that the power depleted N Sea platforms in the Viking Graben could supply 30-60% of their power requirements from co-produced water. On a global scale waste water from the oil industry could supply an optimised power at 13x greater than the global geothermal industry combined (Gluyas unpublished work).

Peter Ledingham (Geoscience)

Limited, other than the oil & gas-driven improvements in drilling and geophysical logging technologies. The main synergy should be with the 'conventional' geothermal industry.

13. What are the wider potential benefits to the local and/or national economy of deep geothermal energy? What evidence can you provide to support your answer?

Chris Pomfret (Cornwall and Isles of Scilly Local Enterprise Partnership)

It is well documented that in the short term, development of deep-geothermal does not offer a very attractive financial return. However, the potential economic and socioeconomic benefits that deep-geothermal energy can deliver in the longer term are significant. These are highlighted below:

Direct employment opportunities: A detailed analysis into employment in the geothermal sector has been conducted by the United States' Department of Energy and Geothermal Energy Association. The full reports are provided at Annex 1 to this letter.

This research concludes that geothermal projects in the USA produce nearly 5 times as many permanent jobs per 500 MW than solar and wind projects. According to data for a proposed deep-geothermal project in California, the average wage is more than double that for the surrounding areas. As a significant amount of the employment created is skilled or highly skilled, it is estimated that the average salary at a geothermal power plant in the United Kingdom will be twice that of the national average.

The data analysis for the development of the deep-geothermal sector in Cornwall confirms that the number of direct jobs created from the proposed developments at the Eden Project by EGS Energy Ltd and United Downs by Geothermal Engineering Ltd can be estimated at 210 to 260. This data also suggests that if deep-geothermal development progressed in the long-term, between 1400 and 1720 jobs could be created. This is clearly very significant and does not include any employment related to the use of renewable heat.

Indirect and induced employment opportunities: The employment generated by the development of the deep-geothermal industry in the United Kingdom will not only mean job creation in the sector but related industries, such as engineering, manufacturing and construction. It is also anticipated that indirect employment will be generated through economic activity associated with businesses supplying goods and services to those involved in the primary industry i.e. plant works that purchase goods and services in the local community. The multiplier effect generated by the re-spending of wages earned by those directly and indirectly employed is typically considered to be a factor of two i.e. there are likely to be twice as many indirect and induced jobs in addition to the direct jobs created.

An existing business base: The development of the geothermal industry in Cornwall will present an opportunity for current businesses in the geological and related sectors to expand capacity. There will also be an opportunity to attract further industry to the area through the use of renewable heat.

Secondary industry: In other countries such as Germany the development of the deep-geothermal sector has attracted a number of secondary industries. For example, the accessibility of readily available heat has proved attractive to a broad range of industries including, horticulture, aquaculture, animal husbandry, food processing, resort and spa developers etc.

Deep-geothermal enterprise zone: The establishment of a Cornwall deep geothermal enterprise zone will also encourage secondary spin-off industries around the deep-geothermal projects. These secondary industries are necessary for the intermediate and longer-term development of the sector and will provide significant socio-economic and employment opportunities. Cornwall Council and the Local Enterprise Partnership already have experience of successfully initiating an enterprise zone at Newquay Aero-hub and we are therefore in a very good position to lead this activity.

Expanding academic research: Cornwall is internationally recognised for its deep geothermal resource due to the world renowned Department of Energy research programme that was run at the Rosemanowes quarry near Penryn in the 1970s and 1980s. During this period leading academic expertise was developed and this research base has continued through the Camborne School of Mines and the Environment and Sustainability Institute at the Combined Universities in Cornwall, Tremough Campus.

The development of the geothermal sector in Cornwall will further enhance the academic research and expertise which, given the international growth in geothermal energy, could lead to significant opportunities for exporting skills and local knowledge nationally and globally.

Neil Hook (Cheshire East Council)

Cheshire East (with support from external partners) has undertaken significant research in to the economic benefits and particularly the job creation benefits of not only the first deep geothermal scheme at Leighton West, but the resulting potential job creation within the wider industry.

We believe that the project will be a prime example of how energy developments can bring growth and jobs to an area. Not only will the project create and safeguard at least 60 highly skilled jobs in Crewe, but it will also create jobs through an extensive supply chain, and will benefit a major local employer through the delivery of an affordable and reliable source of energy. The equivalent industry in Germany has created 9000 new jobs in the last 10 years, and has brought significant inward investment to those regions involved.

As a result of the Councils work on submitting a Regional Growth Fund Round 4 bid we have compiled detailed information on the job creation and resulting economic impacts of both a single well and rolling this on to future wells within the sub region. A copy of this evidence is attached and should provide significant information on the potential for geothermal energy within the UK.

Doug Parr May (Greenpeace)

Deep Geothermal offers system advantages in delivering low carbon heat or power which is potentially scalable, dependent on the available resource.

Dispatchable renewable power options are relatively few on the ground giving system advantages.

Also, given the clear policy direction or move to low carbon heat, and the low number of options, suggests that if the costs are not excessive it would have valuable system advantages. DECC policy on heat is now for district heating in urban areas – because of the excessive network strain that heat pumps would cause - which would complement geothermal well.

Peter Hamnett & Ben Watts(Cofely District Energy)

Low carbon and potentially lower cost energy (including heat). Potential for jobs growth and exportable skills.

Professor Jon Gluyas (Durham University)

Low enthalpy geothermal systems could replace the majority of domestic and industrial heating requirements in the UK with a reserves to production ratio of 100 years. This would cut >30% from the nation's indigenous and imported fossil fuel bill as well as a similar quantity of the nation's emissions.

Peter Ledingham (Geoscience)

Provision of low carbon, sustainable, reliable, clean baseload power, at very high utilisation rates, with minimal land use and disturbance to the environment. Provision of renewable heat to local communities, businesses and facilities. The evidence is abundantly available from the conventional geothermal industry, which has been doing this for 50 years.

14. *What potential do you foresee to use your geothermal technology and knowhow for the export market worldwide and how are you intending to do this?*

Neil Hook (Cheshire East Council)

We see the Leighton West deep geothermal well as leading the innovation and delivery of deep geothermal energy within the UK. The site is identified, end users are on board or willing to enter in to partnership arrangements and significant background research has built a strong business case. Once a delivery partner is on board and the issues with up front risk are dealt with, this scheme will be the first deep geothermal scheme of this magnitude within the UK, and will set the precedent for further UK investment.

Crewe has a strong industrial background, substantial industrial facilities in place and significant university links through both Manchester Metropolitan University and Keele University (both of which with strong renewable and geothermal credentials) and alongside its geothermal heat potential it therefore presents the potential to become the hub for geothermal research and development within the UK.

With relatively little investment or effort, DECC and its partners could be in a position to deliver a UK hub for geothermal exploration and innovation in Crewe within 12 months. With significant geothermal resources under Crewe, facilities already in place, University partners ready to lead the development and innovation in these technologies and a test scheme ready to deliver, if DECC was so inclined there would be no other better place to begin the development and delivery of a UK hub for geothermal research.

By creating such a hub for geothermal research and development within the UK (similar to existing hubs for space and bio-sciences) the UK will be able to export its learning and technological innovations to a worldwide market, both from innovations and knowledge developed by the drilling and operation of the Leighton West scheme, and by the development of a research and development hub in Crewe which could turn this learning in to commercially saleable products.

Peter Hamnett & Ben Watts (Cofely District Energy)

We remain focussed on district energy delivery rather than geothermal development in particular. We are potentially interested in developing district energy schemes around geothermal resources that are developed by others. We remain committed to share our experiences with geothermal energy for the betterment of the industry.

Professor Jon Gluyas (Durham University)

Significant! Geothermal energy is good for base load, has low impact both in terms of materials and visual (size of plant), is flexible (can be combined with gas to power inc biogen), will not run out (on any human timescale) and is pretty evenly spread on a global basis. It will become one of the leading parts of global energy provision. The UK can adapt its oil and gas know how to make us international leaders in geothermal energy development and production.

Peter Ledingham (Geoscience)

Limited. We are the new kids on the block. However, if we can demonstrate engineering techniques that can reliably create commercial “EGS” systems, the geothermal world will take a lot of notice.



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