The concentration of open fractures towards the upper part of the granite, and most particularly in Zone 3, may reflect deformation produced by stress unloading during the unroofing of the granite in the late Carboniferous. Strong fracturing in these regions is consistent with petrological evidence which points to significant, long-lived hydrothermal alteration. The observation of active fluid flow out of these fractures indicates that these processes are probably ongoing, the presence of organic matter implying a reducing environment. In the case of Zone 3 this may support the assertion that the observed passive sericite-pyrite alteration is relatively recent, overprinting an older oxidised chlorite assemblage. In contrast, the highly altered Zone 5, clearly fractured in the CBIL image, is host to relatively few flowing structures supporting the inference that the observed alteration may be old. That there are likely to be both open and closed fractures present downhole is evidenced by the multiplicity of fracture orientations identified by the CBIL. Given the known strong anisotropy in the stress system it stands to reason that there must be a proportion of fractures which are unfavourably oriented and which, subsequently, remain sealed.

**Gamma Log**

Spectral gamma logs are able to identify local variations in composition wherever those changes affect the concentration of radiogenic U, Th and K. As for the CBIL, the gamma log clearly mark the granite contact around 12030’ (3667m) with a sharp spike in both Th and K content (Figure 11.20). U content in the same region is initially low but spikes several metres into the granite, possibly implying some remobilisation along fractures near the contact zone. A noticeable ‘step’ in Th content at 12072’ (3680m) is evident as a boundary in the CBIL and may reflect an aplite/granite contact. Fine-grained aplitic material was positively identified between 12040 – 12060’ (3670 – 3676m). Mud log ROP data indicates that it may extend further to 12072’ (3680m), the relatively small cuttings size in this area possibly prohibiting its identification.

At between 180-200API total count the spectral gamma is notably lower in Zone 1 than that of deeper granite intersections which typically vary between 200-250API. This is consistent with existing log data derived from the Cooper Basin which attributes a low radiogenic zone identified in the upper Big Lake Suite Granite to weathering or contact related alteration (Boucher, 1997). From the available
geochemical data it is evident that this observation would also be consistent with the presence of more felsic material within this zone. The decrease in radiogenic element content observed in the spectral gamma log of Zone 1 does not continue into Zone 2 however and the concentration of radiogenic elements detected in the geochemical analysis of the biotite aplitic is lower than that indicated by the gamma log. At present it is uncertain why this should be the case, the Zone 2 sample lies around 30m away from the Zone 1 contact, implying contamination from this region should not be significant. It is possible that the fine grained nature of the sample may have resulted
in the preferential loss of some minerals during sample preparation. Element correlations evident in Figure 11.13 imply that a physical loss of zircon, for instance, could decrease the absolute concentration of these elements without affecting the relative geochemical abundances. In any event, the radiogenic element content of the deeper granite indicated by the gamma log (typically between 4 – 5% K, 10 – 20ppm U and 20 – 30ppm Th) is consistent with the available geochemical analyses, confirming the veracity of the log data, at least in these regions (Table 11.4, 11.5).

It is clear from Table 11.5 that the radiogenic element content of aplite may vary widely from that of the granite, the sampled felsic rocks typically being lower in these elements. This being the case, it would be expected that aplite occurrences should be associated with localised negative anomalies in the gamma log. Unfortunately, the relatively small size of many aplite intrusions, combined with the issues of depth uncertainty discussed above, often implied that the interpretation of the gamma log was not straightforward. Direct correlation between aplite observed in the cuttings and anomalies appearing in the gamma log was usually difficult. Variation in the orientation of the dykes, together with unavoidable instrument lag implies that some aplite-related anomalies are likely to be distorted. Nevertheless, given the relatively immobile nature of Th it seems probable that isolated peaks observed in the concentration of this element should be related to aplite occurrences (Figure 11.21). Observed Th spikes are both positive and negative implying that the assertion made during logging that aplite may be highly variable in composition is probably correct. This being the case it is also probable that not all of the aplite observed during cuttings logging will be possessed of a composition capable of producing a clearly detectable gamma anomaly.

Not all of the observed gamma spikes are likely to correlate with aplite intrusions. In many cases distinct peaks in U content are observed that are independent of Th and K content. Like the U peaks identified near the granite contact, these anomalies often coincide with fractures identified in the CBIL log. A relatively mobile element, the abnormal enrichment in U in these zones may imply redistribution along these structures. Particularly common in Zones 1-3 and Zones 5E, U peaks are often found on or near the margins of what appear to be aplite anomalies, once again pointing to the presence of fracture zones along the periphery of these bodies. Intriguingly, the
Figure 11.21: Gamma log image showing negative Th anomalies (red) most likely related to the occurrence of isolated aplite dykes. The solid blue line indicates estimated potassium content, red thorium content and broken purple line uranium content. Scale is read from left to right 0–40% potassium and 0–40 ppm uranium and thorium. Within this region cuttings logging records several aplite occurrences between 12500–12520’ (3810–3816m) and 12560–12580’ (3828–3834m). Given the known uncertainty in cuttings depth it is likely that one of these dykes is producing the gamma anomaly at 12540’ (3822m) and 12560’ (3829m). Depth scale of the image is in feet (logger). Log data courtesy of Geodynamics Ltd.

redistribution of U, presumably as uraninite (UO₂), is reliant upon oxidising fluid conditions. Whilst this is consistent with the observation of oxidised iron associated with chlorite in some zones, the presence of (reduced) organic compounds in the
present day fluid (as indicated by the mud log data) implies the mobilisation of this material must have occurred at some earlier stage in the granite history.

Caliper Log
Three and four arm caliper logs were used to record the minor and major borehole axes respectively. Once again the granite contact at 12030’ (3667m) is clearly visible, as a competency contrast in the well wall. The upper granite to around 12350’ (3764m) is characterised by a relatively uniform hole with little evidence of distortion or borehole breakout. One notable exception lies at around 12250’ (3734m) where a distinct breakout is observed, corresponding closely to a zone of lost circulation (Appendix 6). The end of Zone 2 coincides with the onset of both breakout and well distortion which continues virtually uninterrupted until the end of the logged interval. Only in two relatively thin intervals between 12930 – 13000’ (3941 – 3962m) and 13140 – 13180’ (4005 – 4017m) is there no increase in well diameter. Intriguingly, the first of these corresponds almost exactly to the depth of the relatively unaltered Zone 5B inferred from the CBIL whilst the second is close to that of Zone 5D.

11.6 Discussion
The data available from the Habanero 1 deep geothermal well enables the construction of a coherent picture of the in-situ Big Lake Suite granite, its history and characteristics. Mineralogical evidence preserved in the cuttings points to a long history of alteration within the local granite, probably beginning shortly after intrusion in the Mid-Late Carboniferous with the migration of high temperature pneumatolytic fluids throughout the rock. Primary differentiation within the magma had already seen the formation of a layered or zoned pluton with a noticeably felsic cap succeeded by zones which are host to numerous aplite intrusions. Shortly after intrusion the granite was uplifted and unroofed in a process that almost certainly generated many joints and fractures as a result of stress unloading. Subsequent weathering of the exposed rock lead to oxidation and possible migration of uranium into fracture zones. This low temperature alteration is just one of several to have affected the granite since its emplacement. The effects of these events, some of which probably remain ongoing, are recorded in the secondary mineralogy variably as sericitisation, mineralisation, silicification and multiple episodes of carbonation. For the most part,
alteration has been strongest within the upper regions of the granite above around 13830' (4215m). Below these depths the rock is noticeably less altered with less carbonate and virtually no secondary sulphide.

The mineralogical data derived from the cuttings is consistent with available geochemical data which indicates that the pluton is most likely an altered, fractionated I-type granite. Derived from a source similar to that which produced the majority of Proterozoic felsic rocks, the Big Lake Suite pluton has analogues within the Lachlan Fold Belt of NSW/Vic. Fractionation of the primary magma produced a relatively felsic composition with high concentrations of the radiogenic elements uranium and thorium. Energy release produced by the decay of these elements is credited with causing the local heat flow anomalies known to be spatially associated with the granite (Chapter 10). The insulating effect of overlying coal bearing sediments in the Cooper and Eromanga Basins has resulted in a noticeable increase in the geothermal gradient above the granite contact with the net result that temperatures encountered at the bottom of Habanero 1 are in excess of 245°C.

Evidence from the available geophysical logs indicates the presence of a diverse fracture network at depth, comparable to those identified in core from the surrounding Warburton Basin sediments (Sun, 1999). The observation of a wide variety of orientations and dips within the known anisotropic stress field of the Napperamperri Trough implies the existence of both open and closed structures. This conclusion is supported by evidence from the mud logging data which was able to identify open or flowing structures by the presence of organic fluids. Differences between the distribution of the sonic CBIL fracture density and that of the mud logging data point to the existence of major sealed fracture zones, most notably within the leucogranite of petrographic Zone 5 12920 – 13620’ (3938 – 4151m). In most cases good correlation exists between the fractured zones identified in logging and the observation of relatively intense alteration in the cuttings. This in turn implies that the existence of fractured zones may be reliably inferred from close examination of cuttings mineralogy alone. There are limits to the resolution of the cuttings data, however, and it was not possible to distinguish open from closed fractures in the mineralogy nor to pinpoint the location of major flowing zones.
In terms of the four key HDR resource parameters, data gathered from Habanero 1 is a good testament to the suitability of the Nappamerri Trough site for geothermal development. The presence of a relatively shallow, high temperature crystalline basement was confirmed. The likelihood of a favourable stress field, characterised by high horizontal stress anisotropy and a vertical minimum principle stress, was established. An in-situ fracture network was identified within the crystalline substrate and was found to support both open and closed structures. Good evidence for existing fracture permeability was found, even at very great depths (>4400m). These parameters alone do not form limits to the relevance of the Habanero 1 data to HDR development however. Included within the information derived from this well are a number of other details which are also of direct relevance, both to immediate resource development and future HDR exploration.

The distribution of alteration with depth observed in the cuttings mineralogy of the Habanero granite is of significance to the immediate development of a local HDR heat exchanger. Of particular interest is the noticeable decrease in alteration intensity below 13830' (4215m). Below these depths the content of alteration minerals, most specifically carbonate and sulphide, is observed to decrease. This decrease is likely to be advantageous to the development and long-term performance of an HDR reservoir. Carbonate, which becomes more soluble under conditions of low temperature and precipitates at high temperature, is often associated with issues of scale in conventional geothermal developments (Pauwels, 1997). Within an HDR heat exchanger it has the potential to decrease the performance of the high temperature reservoir by depositing onto open fracture surfaces at depth, reducing system permeability. Whilst carbonate dissolution may be controlled to some extent by manipulation of the input fluid chemistry (pH) it is obviously more desirable to develop a heat exchanger in areas where the impact of these minerals are naturally minimised. At the Habanero site the cuttings logging shows this may be done relatively easily by restricting reservoir development to the deeper granite regions. Such a restriction would have the added bonus of operating in areas where the concentration of secondary sulphide is also low, minimising issues of sulphide solubility and the potential for dissolution of H$_2$S.
Also of significance to the immediate development of an HDR reservoir is the observation in the gamma logs of what appears to be uraninite deposited along fracture zones. Although relatively immobile under the current in-situ fluid conditions (assumed to be reducing due to the known presence of organic material) an input of fresh, oxidised water into the HDR reservoir could potentially result in the dissolution and remobilisation of UO₂. Fortunately, it is clear from the available gamma logs that most fractures are not characterised by uranium deposits, which likely only formed along a limited set of structures that were permeable at the time of alteration. The inferred association between the mobilisation of UO₂ and low temperature propylitic alteration also implies that these structures are likely to be most concentrated within the upper granite region. This could be easily tested by the running of a supplementary gamma log to total depth.

The detection by mud loggers of organic materials within the natural granitic fluids points to the existence of a hydraulic connection between basin and basement. This prospect is probably confirmed by high fluid pressures which, known to be present within the overlying sediment are also found within the granite. High fluid pressures within the granite are significant to the HDR resource development for a variety of reasons, some of which are clearly apparent when examining the extent of fluid penetration during well stimulation (Figure 11.5). The presence of high pore pressure appears to have induced a state of near-failure in the rock mass, implying relatively little pumping pressure was required to stimulate favourably oriented structures and produce an extensive artificial permeability. Indeed, the size of the reservoir inferred to have been created at Habanero is larger than any formed at any other HDR site around the world (Appendix 1).

Overall, the Habanero data builds upon the Nappamerri Trough resource model, adding to a database of knowledge that is of direct relevance to future exploration. Evidence available from temperature mapping in Australia, and the relative lack of active tectonism, implies that sedimentary basins are the most prospective geothermal environments in the country. The Nappamerri Trough resource provides an excellent geological model for this style of resource that will likely be used as a reference point for future exploration (Figure 11.22). Significantly the known features of the Nappamerri resource illustrate that HDR exploration may be targeted by using more
Figure 11.22: The southern Cooper Basin (Habanero) geothermal resource model as determined from available data showing the depth, temperature, stress and geological characteristics of the resource.

than temperature alone. This is important as it is clear from the available borehole temperature database (Chapter 2) that many areas exist in which this data is relatively scarce. Furthermore, as the temperature logs in Habanero 1 illustrate, true resource temperatures can only be estimated from wells that penetrate the main insulating layer, in this case the deeply buried coal beds of the Patchawarra Formation. Geothermals recorded shallower than this depth are variable and often lower, leading to misleading resource estimations in cases where they are relied upon exclusively. Importantly, this also indicates that the drilling of shallow wells for temperature measurement is likely to be of dubious benefit for geothermal exploration and is, of course, why heat flow data is generally preferred.
Knowledge of the geological environment that has produced a viable basin-related HDR resource in Australia is thus an important addition to geothermal exploration. The identification of favourable host geology is an excellent means of targeting expensive exploration programs in areas where existing thermal data is sparse or unreliable. It is clear that the ingredients required for Nappamerri-style HDR include a thick coal-bearing sedimentary basin overlying a crystalline substrate. Felsic granite bodies are a particularly desirable substrate as they may be detectable using remote gravity data. Encouragingly, the new data from Habanero 1 indicates that the high heat producing composition of the Nappamerri pluton, largely responsible for the magnitude of the geothermal resource in this area, is not unique and has good potential for reproduction elsewhere in Australia. Equivalent compositions are known from the Lachlan Fold Belt and doubtless also occur further afield. Certainly, areas in which older Lachlan granites may be buried beneath coal bearing sediments, such as the Sydney or Murray Basins, stand out as excellent targets for future exploration.

11.7 Conclusions

Geological conditions encountered at the Habanero site to date have almost unanimously proved to be highly advantageous for HDR development. Drilling of the first deep geothermal well Habanero 1 has confirmed the presence of high temperatures at depth. Stress conditions encountered by this well are almost certainly akin to those previously predicted by Hillis et al. (1997) with evidence of a strong horizontal stress anisotropy and minimum principle vertical stress. Geologically, cuttings derived from Habanero 1 describe a highly fractured, fractionated I-type granite which has experienced a complex history of uplift, alteration and re-burial. Importantly, the enrichment in radiogenic elements in this granite, believed to be responsible for the generation of the local heat flow anomaly, is found to be akin to that of other fractionated felsic granites observed within the Lachlan Fold Belt. The potential for other HDR resources arising from buried granite bodies of similar composition would thus seem to be high. In many ways the Habanero resource provides an excellent model for the kind of geological conditions which are desirable in future Australian HDR resources. Ultimately these conditions may form useful avenues for future exploration, reducing the reliance upon temperature mapping as the sole means of geothermal target generation.
CHAPTER 12
SUMMARY OF CONCLUSIONS

The technology of non-conventional geothermal resource development is now at a stage where it sits on the cusp of commercial application. Large-scale, long-term circulation of engineered geothermal systems has been successfully demonstrated at a number of HDR sites including Soultz-sous-Forêts, Hijiori, Ogachi and Fenton Hill. Industrial developments, aimed ultimately at the production of geothermal power are currently underway at a number of overseas sites including Soultz-sous-Forêts in France, the Basel DHM project in Switzerland and the Bad Urach joint venture in Germany. The development of this new geothermal technology has changed the definition of what may be considered as an exploitable geothermal resource. Far from being devoid of high temperature geothermal resources, the Australian continent is now known to be host to numerous temperature anomalies, some of which are capable of being exploited as world-class HDR resources. With no active tectonic plate boundaries on the Australian mainland, these resources are novel compared to those under development elsewhere in the world. The focus of current geothermal research in Australia centres upon the Habanero model developed in the Cooper Basin of South Australia. Here, granite characterised by enrichments in U and Th, lies beneath thick layers of insulating sediment. This model of buried, high heat producing basement rock is set to be repeated in other sedimentary basins around Australia, most notably the McArthur Murray and Carnarvon Basins, themselves host to either significant temperature anomalies and/or potentially favourable geology.

The sudden change in the geothermal prospectivity of the Australian continent that has accompanied the rise of HDR technology has highlighted deficiencies in the available thermal database. Existing heat flow compilations, whilst reliable, are based on relatively few data points and have a limited spatial resolution. Temperature mapping, as first developed by Somerville et al., (1994) has already proved to be a useful substitute in the absence of detailed heat flow data. Images produced from these early compilations are flawed however and are characterised by strong linear artefacts and unrealistic anomaly shapes. These were generated by applying a
relatively simplistic interpolation technique to a highly heterogenous data distribution. Utilising all available commercial borehole temperature data a new Australia-wide geothermal database, AUSTHERM03, has been constructed and forms the basis for an updated crustal temperature coverage. The techniques developed by Somerville et al. for the extrapolation of borehole temperatures to 5km depth have been revised and adapted to take advantage of the availability of more sophisticated GIS techniques. These include the development of new, more detailed, coverages of mean annual surface temperature and depth to basement and the use of geostatistical kriging in the final image interpolation. Benefiting from both these adjustments and the availability of an expanded database the new, improved, Australian crustal temperature image is characterised by more realistic, rounded anomalies. These features are well constrained within areas of reasonable data density although heterogeneity in the data distribution implies the image still retains numerous artefacts in areas of low data density. Detectable temperature anomalies observed in the new coverage confirm the existence of distinct thermal provinces across the continent. Evident on a variety of scales, large areas of low temperature are typically associated with older cratonic regions (e.g. Western Australia) whereas large highs are found in some regions of sedimentary cover. A geothermal resource analysis indicates three major regions of prospectivity associated with the Cooper, McArthur and Carnarvon Basins. Numerous other basins are host to smaller, less well constrained resources which, with addition of more data, may also prove to be prospective.

The reliance of the AUSTHERM03 coverage upon commercial well data has meant that much of the temperature data included in this database is perturbed, that is, affected by the drilling induced thermal anomaly. Whilst it is possible to correct for this effect in the bottom of hole region by using established models of well thermal recovery, relatively little empirical data has yet been gathered regarding the accuracy of these models in real world application. Temperature data available from within AUSTHERM03 itself provides the key to this problem. Included within data from the Cooper Basin region of South Australia are a number of wells with temperature measurements derived from completion or CBL logs recorded months or years after the end of drilling. Combined with series of time-consecutive bottom of hole temperatures (BHT) recorded shortly after drilling this data provided a unique opportunity to assess the accuracy of formation temperature prediction by models for
bottom of hole thermal recovery. Data from these wells were combined to form a new, more detailed database, the Cooper Basin Static Temperature or CBST.

Data validation processes identified a subset of 61 CBST wells with CBL temperatures that satisfied the physical requirements of thermal modelling. Average time elapsed between the end of drilling and measurement of the CBL temperature in these wells is 482 days, confirming they are likely to be reasonable estimates of true formation temperature. Four commonly used models of borehole thermal re-equilibration were applied to these data: the theoretical models of Bullard (1947) (Horner plot) and Cooper & Jones (1959) (dual-media, zero-circulation cylindrical model) and the empirical solutions of Pitt (1986) (semi-log plot) and Nakaya (1953) (exponential model). Comparisons of predicted and known formation temperature for each of these models indicated that in this instance most were, on average, biased to some extent toward under-prediction. For solutions based in physical theory this under-prediction appears to be systematic and is directly related to model failure at short lag times. For empirical solutions, failure is also related to the length of lag time. In these cases however the behaviour of the model at short lag time is more random and is dependent upon the slope (semi-log plot) or concavity (exponential) of the fitted temperature-time curve. The common dependence of model performance upon lag time implies that conditions may be set for each model which, if met or exceeded by well data, should produce unbiased predictions within around 5% of the true formation temperature. For most models, prediction was found to be improved for wells with at least one temperature measurement greater than 20 hours after drilling. For theoretical models this condition was supplemented by an independent condition of initial lag time (>7 hours) which, if exceeded, will also ensure an improved result. Of the models tested, the theoretical Horner plot was considered to have the best overall combination of accuracy, precision, utility and predictability.

Knowledge of the conditions governing the accuracy of predicted formation temperatures produced by the Horner model in the Cooper Basin enabled the identification of a subset of 307 local wells that were suitable for temperature correction using this model. A detailed coverage of temperature at 5km depth within the Cooper Basin was created by applying the techniques employed in the larger AUGHERM03 image to this corrected data. A second temperature image was also
created using thermally perturbed temperature data from the same points. Comparison of these two images enabled an assessment of the impact of using the drilling perturbed temperature data upon geothermal resource analysis. As expected, the image created from thermally perturbed data was characterised by lower absolute temperatures and smaller estimated geothermal resources. Significantly, however, the use of uncorrected temperature data did not disrupt the overall pattern of temperature anomalies. Temperature images based upon uncorrected data were found to be sufficiently reliable for geothermal exploration although resource analyses conducted using these data should take into account the likelihood of absolute temperature suppression.

The ability to locate thermal anomalies using images of crustal temperature distribution is an important tool for geothermal exploration. Clearly visible on detailed temperature map images of the Cooper Basin is a large bullseye temperature anomaly, now confirmed as a major geothermal resource. Located primarily in the southern portion of the basin this anomaly, previously recognised by a number of authors including Middleton (1979b) and Somerville et al. (1994), coincides with a region of elevated heat flow. Believed to be the product of high heat producing Big Lake Suite granite buried beneath coal-rich sedimentary strata, crustal temperatures in this region are inferred to be above 240°C at 5km depth. Included within this area is the Nappamerri Trough which hosts the site of Australia’s first HDR geothermal project, Habanero. The drilling of the first deep geothermal well at this site, Habanero 1, has generated new data and confirmed that temperatures in this region are in excess of 245°C at 4.4km. Stress data derived from this well appears to corroborate predictions of a reverse faulting regime characterised by high horizontal stress anisotropy. Geological data from well cuttings provides a picture of a highly felsic granite subject to a long history of alteration and fracturing. Significantly, geochemical analyses of these samples indicate that the local granite composition, relatively high in the radiogenic elements U and Th, was probably derived from fractionation of an I-type magma. This composition is not unique and many analogous plutons are known to exist elsewhere around Australia, most notably within the Lachlan Fold Belt in the SE of the continent. A geological resource model, constructed from the Habanero data provides a useful supplement to temperature mapping as a means of geothermal exploration. Using this model, prospective regions
may be identified on the basis of their known geology, allowing discriminations to be made in areas where temperature data is scarce or unreliable. One such region, identified by its geology as an area of interest for future geothermal exploration, is the Murray Basin of western NSW and Victoria which overlies and obscures older Lachlan Fold Belt units.

It is clear that the Australian continent has a significant potential for the development of a new geothermal industry based upon the novel HDR technology. One key to the success or failure of this industry will be its ability to successfully explore for future high-temperature resources. Exploration itself is an integrated process that relies upon the incorporation of data from a variety of sources. Work completed to date on temperature mapping, modelling and geological resource analysis has contributed to the development of techniques suitable for truly Australian geothermal exploration. This work has not been exhaustive however and there have been many areas identified which bear further investigation. These include:

1. The production of better, more reliable crustal temperature map images through the use of tailored basement geotherms and the application of geological control to the kriging process.

2. The testing of more sophisticated models for borehole thermal re-equilibration which may allow for correction of short lag time data unable to be treated by the models investigated here.

3. Expanding the knowledge of BHT model behaviour to areas outside the Cooper Basin, thereby enabling construction of a crustal temperature image based more completely on corrected data.

4. The creation of a reliability diagram for current and future crustal temperature map images based on data distribution and the status of the temperature data employed.

5. Collation of additional geological data from the Habanero resource including, but not limited to, geochemical analyses, downhole stress measurements and the retrieval of core cut from the Big Lake Suite. Such data would lead to further refinement of the current resource model, providing a more reliable understanding of the local geology and, by extension, of Australian-style geothermal resources.
It is hoped that the work conducted to date will continue to be revisited and improved by the addition of new data and the use of more advanced techniques. Such a commitment to ongoing research will lead to the amassing of a significant national geothermal database that will, in turn, produce real and lasting benefits for the future geothermal exploration of Australia.
REFERENCES


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MNEMONIC GLOSSARY

AMS
Auxiliary Measurement Sonde see also TTRM. Attachment for downhole logging string designed by Schlumberger Ltd.. Tool monitors real time mud conditions, including temperature, throughout the logging run.

BH
Bottom of Hole see also EOH. Total depth of a well.

BHT
Bottom of Hole Temperature. Temperature measured at total depth in a borehole.

BHTV
BoreHole Tele-Viewer. Downhole logging instrument designed to produce an acoustic image of the borehole wall.

BOPD
Barrels of Oil Per Day. Measure of oil well production rate. 1 barrel = 42 gallons (US) or 158.987 L.

BWPD
Barrels of Water Per Day. Measure of water well production rate. 1 barrel = 42 gallons (US) or 158.987 L.

CBL
Cement Bond Log also Completion Log. A combination logging tool (sonic-gamma) run into a well some time after completion in order assess the quality of the casing cement.

CBIL
Circumferential Borehole Imaging Log. A sonic logging tool designed by Baker Ltd. to produce images of the borehole wall.
CBST
Cooper Basin Static Temperature database. Compilation of CBL BHT in wells from the Cooper Basin, South Australia.

CCL
Casing Collar Locator. Electrical downhole tool designed to detect and locate the position of the casing collar.

CFD
Cubic Feet per Day. Measure of gas well production rate. Also million cubic feet per day or MCFD.

CST
Sidewall Coring Tool see also MSCT. Downhole tool designed to recover formation samples from the well wall via an explosive gouge c.f. sidewall core gun.

DMFC
Dual Media Finite Circulation BHT model. Model for thermal recovery of well EOH region based upon assumption of constant mud temperature, dual media (mud and rock) and a finite circulation time.

DMZC
Dual Media Zero Circulation BHT model. Model for thermal recovery of well EOH region based upon assumption of constant mud temperature, dual media (mud and rock) and no circulation time.

DST
Drill Stem Test. An oilfield procedure by which formation fluids are vented to surface in order to assess formation pressure, permeability and fluid composition.

DTB
Daily Time Breakdown. Detailed record of daily drilling activity. Included in most modern well completion reports see also → WCR.
EOH
End Of Hole see also BH. Total depth of a well.

FDC
Formation Density Compensated log see also LDL. Downhole density or porosity (gamma ray) log designed by Schlumberger Ltd. Precedes LDL.

FLSS
Full Line Source Solution. Refers to the Bullard (1947) solution of the line source model for BHT recovery.

FMS
Formation Micro-Scanner. Downhole logging tool designed by Schlumberger Ltd. to produce images of the borehole wall by measuring variations in local resistivity.

FTEX
Formation Temperature Extrapolated CBL temperature. CBL BHT extrapolated to average evaluation log BHT depth using individual formation temperature gradients.

GIS
Geographic Information System. Computational tool designed to collect, store and display spatial data.

HDR
Hot Dry Rock. Geothermal resource where heat must be extracted via an artificial circulatory system of water.

HGS
High Gravity Solid. High density additive (c.f. barite) used to increase or maintain drill mud weight.

HHP
High Heat Producing → of granite. Granites which contain high concentration of radioactive heat-producing elements e.g. uranium, thorium, potassium.
HWR
Hot Wet Rock. Geothermal resource where heat must be extracted via an engineered or enhanced natural circulatory system of water.

IRC
Inter-Run Circulation. Refers to periods of conditioning circulation undertaken between evaluation logging runs. Two evaluation logs separated by IRC are not valid for use in any BHT model.

LDL
Litho-Density Log see also FDC. Downhole density or porosity (gamma ray) log designed by Schlumberger Ltd. Supersedes FDC.

LGS
Low Gravity Solid. Low density solids present in drill mud e.g. bentonite clay, formation cuttings.

MAST
Mean Annual Surface Temperature. Average recorded surface temperature at a given location determined from measurements recorded across the standard period 1961-1990.

MDT
Modular Dynamics Tester see also RFT. Downhole formation testing tool designed by Schlumberger Ltd to assess formation pressure, permeability and fluid composition. The MDT supplants the earlier RFT.

MRT
Maximum Reading Thermometer. Mercury thermometer which retains record of maximum temperature experienced since last mechanical re-setting (spinning).

MSCT
Mechanical Sidewall Core Tool see also CST. Downhole tool designed to recover formation samples from the well wall via a mechanical gouge.
ppg
Pounds Per Gallon. Drilling industry units of mud density. 1 ppg = 119.8264 kg/m³

P/T
1. Conditions of Pressure and Temperature see also STP
2. Downhole Pressure-Temperature logging tool

RFT
Repeat Formation Tester see also MDT. Downhole formation testing tool designed by Schlumberger Ltd to assess formation pressure, permeability and fluid composition. The RFT precedes the newer MDT.

RHOB
(literal) \( \rho_b \) see also LDL; FDC. Bulk formation density recorded from downhole density logging tool.

ROP
Rate Of Penetration. Velocity of drill bit during drilling. Usually reported in feet/hour.

RR
Rig Release. Date on which drilling rig relinquishes control of a well.

SBT
Segmented Bond Tool. Sonic completion log designed by Baker Ltd. to assess the quality of downhole casing cement.

SLEX
Straight Line Extrapolated CBL temperature. CBL BHT extrapolated to average evaluation log BHT depth assuming a straight line geothermal gradient.
SMZC
Single Media Zero Circulation BHT model. Model for thermal recovery of well EOH region based upon assumption of constant mud temperature, single homogenous media and no circulation time.

STP
Standard Temperature and Pressure conditions c.f. 1 atm at 25°C

TD
Total Depth. Depth of a well.

TTRM
Auxiliary cable-head tool designed by Baker Ltd. to record real time Temperature, cable Tension and Resistivity of well Mud during logging descents see also AMS.

VSP
Vertical Seismic Profile see also WST. Seismic survey produced in a vertical well using a surface source and an array of downhole geophones.

WCR
Well Completion Report. Technical document produced by commercial operator upon completion of exploratory or development well and which contains details regarding both the drilling and evaluation of the borehole.

WH
Whole of Hole. The entire length of a well.

WST
Well Seismic Tester. Downhole seismometer designed to receive acoustic shock waves from controlled surface or downhole seismic survey.
APPENDIX 1
HOT DRY ROCK CASE STUDIES
**CONTENTS**

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**Figure A1.1:** Timeline of activity at Hot Dry Rock sites around the world.
A1.1 Fenton Hill HDR, New Mexico USA

Summary
Workers at the Los Alamos National Laboratories (LANL, previously Los Alamos Scientific Laboratories, LASL) first conceived the Hot Dry Rock (HDR) concept in the early 1970’s. Fenton Hill, located several kilometres north of Jemez Springs, New Mexico, USA, is the product of their work and is the world’s premier HDR test site. LANL’s initial technical vision for HDR was that of a system of buoyant circulation dependent upon a single circular (penny-shaped) artificially generated crack, connecting injection and production wells. Concordant with this vision initial reservoir creation at Fenton Hill was conducted at 3km depth using the relatively high injection pressures required for hydraulic fracture. Work at this level was successful, creating a functioning circulatory system. The decision to pursue a deeper, hotter reservoir development was dogged by problems, however, arising largely from the assumption of the induced fracture model. Confident in their understanding of the local geology the team chose to drill both production and injection wells for the new system at the same time. It was subsequently found that no amount of applied pumping pressure was able to create new fractures to connect these wells at depth. Fluid accepted by the opening or ‘stimulation’ of unfavourably oriented natural joint sets prevented pressure build up in the open hole region. Repeated fluid injections were unable to solve this problem and circulation was only established after physical re-direction (re-drill) of one well. In the years that follow several successful circulation tests were conducted, including a series of cyclic or load-following experiments in the 1990’s. Work at the Fenton Hill site can justifiably be considered ground-breaking. Lessons learnt at Fenton Hill, although often hard, have influenced and enhanced HDR projects around the world.

Detailed Timeline

1970
An informal group of LASL staff members meet to discuss the potential of a rock-melting drill (the “subterrene”) developed at the laboratory some years earlier (Smith
1975). It is proposed that the melt produced by the device (a major problem for its successful operation) could be disposed of by pressurising it, causing it to hydraulically fracture the surrounding country rock and then disperse into the fractures produced. Subsequent brainstorming upon the use of hydraulic fracturing at depth in a borehole results in a new proposal: that the technology could be used to create artificial water circulatory systems within hot impermeable rock. Such a system would, it is suggested, be capable of exploiting an otherwise inaccessible earth-heat resource. Although it is not stated explicitly, the primary goal appears to be the use of this heat for the generation of electrical power.

Initially termed “the Dry Hot Rock Project” (Smith, 1975) the concept, as it is originally proposed, is to drill two boreholes to depth within a region of hot impermeable rock. These wells are hydraulically connected at depth via the creation of a single large ‘penny-shaped’ fracture by application of downhole pressure. Pressurised water is then circulated through the system where it is heated, becomes buoyant and rises to the surface. At surface it is passed through a heat exchanger, cooled, and returned to the subterranean system in what becomes a continuous cyclical loop.

1971

Commencement of Phase I – Research. A new informal group “LASL Geothermal Energy Group” is created to investigate the potential of the proposed man-made geothermal systems (HDR) (Smith, 1975). The nearby Valles Caldera, a large-scale tertiary volcanic structure last active between 50 - 100Ka is chosen as an initial target area for an HDR site (Smith, 1975). Advantages of the site include both its proximity to Los Alamos and the presence of a known local geothermal anomaly, evident at surface as natural hot springs within the southern margin of the caldera ring and further south along a connecting radial fault.

A series of seven, 30m deep holes are drilled around the caldera rim to asses relative heat flows and locate the optimal site for a deep HDR well. Highest flux (5-6HFU) is recorded to the west of the caldera in an area previously determined as being relatively undisturbed (geologically) and with only moderate depth to Pre-Cambrian crystalline basement (Smith, 1975).
1972

Four deeper holes are drilled to 185m to confirm the heat flow data in the west of the caldera and test the local geology. Heat flow is found to increase with radial proximity to the caldera rim. A deep exploratory hole GT-1 (785m) is drilled at Barley Canyon on the western edge of the caldera and penetrates 143m into crystalline basement. Bottom hole temperature is recorded as 100.4°C (Smith, 1975). Several hydraulic fractures were created at depth in the well.

1973

The LASL geothermal energy group is formally organised with backing by the US Atomic Energy Commission. Ongoing investigations in GT-1 include studies of basement rock which indicate very low in-situ permeability and an absence of naturally circulating hydrothermal systems within the basement rock (Smith, 1975). Several hydraulic fractures are created at depths between 740 and 776m (Robertson-Tait et al., 2000). Fractures are generated by pumping pressures of up to 10.3MPa and are able to be held open with pressures of around 6.9MPa. Seismic monitoring is used to assist in fracture location and orientation. All induced fractures are found to be vertical and consistently strike NW-SE. It is concluded that the crystalline basement rock present within this area is "well suited to the creation and containment of a pressurised-water energy-extraction loop" (Smith, 1975).

1974

Drilling of a second deep exploratory hole, GT-2 to 2,929m is completed in December, 1974. GT-2 is located upon a flat-topped mesa (Fenton Hill) several kilometres south of GT-1. The well intersects Pre-Cambrian basement at a depth of 730m, geology at reservoir depth is comprised of monzogranitic and biotite granodioritic gneiss with lesser amounts of hornblende-biotite schist and pegmatite (Laughlin, 1975). Undisturbed bottom hole temperature is recorded as 197°C, temperature gradient increasing with depth from 50 to 60°C/Km (Laughlin, 1975). Experimentation in GT-2 includes hydrological testing, targeted hydraulic fracturing, downhole geophysics, seismic surveys and core studies (Smith, 1975). Fracturing experiments at relatively shallow levels (1,981-2,042m, 1,951m) are successful
requiring pressures of 13.8 and 17.2MPa above hydrostatic respectively (Laughlin, 1975). Fracturing is characterised by almost complete recovery of the injection fluid despite problems with packer seals. Such high recoveries are interpreted to confirm the very low natural rock permeability (Laughlin, 1975).

1975
Drilling of the deep ‘energy extraction hole’ EE-1 is targeted to intersect fractures generated in GT-2. Total depth is 3,064m with recorded bottom hole temperature 205°C (Brown, 1976). Although separation of the two wells is only 76m, little correlation is found in basement geology above a large natural fracture zone identified at 1,829m (West, 1976). Correlation below this zone is fair to excellent with the number of natural fractures appearing to decrease with depth.

According to Heiken et al. (1981) and Murphy et al. (1981) instrument errors during the drilling of EE-1 result in a failure to intersect the target GT-2 fracture, the well missing by some 6-9m. This is in contrast with Brown (1976) who claims the well targeting was successful. Both Brown (1976) and Aamodt (1976) refer to an initial hydraulic connection between 2,949m in EE-1 and 2820m in GT-2. This connection may be the result of an initial pressurisation in EE-1 although no other specific mention has been found. Murphy et al. (1981) state that ‘despite the close proximity (of EE-1 to the known GT-2 fractures) the intervening rock was so impermeable...a viable heat extraction experiment was not permitted’. He does, however, refer to ‘various attempts, such as fracturing the EE-1 well (aimed at) improving flow communication between the boreholes’. Robertson-Tait et al. (2000) record a number of different attempts at hydraulic fracturing during 1975 both in the newly drilled EE-1 and the existing GT-2.

1976
Flow experiments continue on the GT-2/EE-1 system (Robertson-Tait et al., 2000). Detailed work is undertaken to map the precise locations of both fractures and wells (Cremer, 1982). Efforts to improve the hydraulic communication between the two wells by creation of a new connecting structure fail ‘apparently because the fractures (formed) in both wells are vertical and parallel and do not intersect’ (Murphy, 1981).
Stress measurements at depth in the basement indicate the minimum compressive stress is horizontal, at 37MPa it is equivalent to about half the overburden (Murphy, 1981). Ongoing attempts at fracturing in EE-1 utilise nearly 200m³ of water at injection pressures up to 12MPa and ultimately compromise the well casing cement enabling formation of an annular flow (Willis-Richards et al., 1995). This flow in turn results in the stimulation of a large fracture in EE-1 located at approximately 2.75km depth.

1977

GT-2 is deviated from a depth of 2,500m towards the top of the vertical hydraulic fracture at 2,750m in EE-1. Several attempts are made with the second attempt achieving a successful hydraulic connection at 2,705m. The sidetracked GT-2 is now referred to as GT-2B. Investigation of the connection between the two wells is undertaken by various means including temperature and spinner log surveys, tracer tests, caliper and teviewer logs. Results of these surveys indicate the geometry of the well connection is complex (Murphy, 1981). GT-2B does not intersect directly with the EE-1 fracture but rather with a series of inclined (60°) natural joints which in turn intersect the vertical fracture. Impedance to flow along this connection is sufficiently low to enable circulation testing. The flow connection is termed the research or shallow Phase 1 reservoir.

A loop circuit is set up with EE-1 as injection and GT-2B as production hole connected at surface by a heat exchange system. Initial flow testing of the reservoir circuit comprises a four day run (RS1) and produces fluid to surface at a temperature of around 130°C, with an inferred rate of heat extraction around 3.2MW(t) (Cremer, 1982). Surface construction continues in preparation for longer term flow testing and includes the creation of a seismic array for the monitoring of micro-seismic events (Dash et al., 1983).

1978

Following the success of RS1 a second flow test, RS2 is run during which 68,000m³ of water are injected into EE-1 across a period of 75 days at wellhead pressures ranging down from 9.4 to 6.3MPa (Murphy et al., 1981). Injection flow rates vary
between 14.5 and 8l/s (Willis-Richards et al., 1995). High initial water loss declines rapidly to 0.13l/s or 1.5% of flow. The thermal draw-down is significant with water temperature at the end of the test stabilising around 87°C, down from an initial value of 175°C (Dash et al., 1983). The size of this decrease is attributed to a combination of relatively small fracture area and high flow rate (Murphy et al., 1981). In spite of the strong draw-down the high flow rates imply that heat extraction rates remain good, peaking at 5.1MW(t) with a test average of 4MW(t) (Murphy et al., 1981). Impedance, ‘initially 1.7GPa.s/m³, decreases by a factor of five’ (Dash et al., 1983) throughout the test, the output flow increasing at an essentially constant pressure difference to eventually reach the limit of the surface plumbing at 17l/s (Cremer, 1983). The decrease in impedance is thought to be at least partly due to the opening of fractures as a result of cooling and thermal contraction in the reservoir (Murphy et al., 1981; Dash et al., 1983). Produced water quality remains within the range deemed as acceptable at all times (<2,000ppm total dissolved solids), no induced seismicity is recorded at surface during the test period (Cremer, 1983).

Thermal modeling of the RS2 draw-down, based upon the assumption of a single circular fracture, suggests the reservoir has a constant effective heat exchange area (EHEA) (fracture half surface) of around 8,000m² (Murphy et al., 1981). An alternative multiple fracture model suggests growth of the reservoir during the test from 7,500m² to 15,000m² (Dash et al., 1983). The suggested cause of this growth is fracturing due to thermal stress effects.

Six months after the completion of RS2 a third flow test, RS3 or High Back-flow Pressure Experiment, is undertaken with 9.6MPa of back-pressure applied to GT-2B. Injection flow rates are between 6.3 and 9.5l/s (Willis-Richards et al., 1995). The test is cut short at 28 days due to further deterioration in the casing cement of EE-1. Despite this truncation another significant drop in impedance is observed during the test, initially falling from 0.82GPa.s/m³ to 0.22GPa.s/m³ and then again to around 0.6GPa.s/m³ by the end of injection (Dash et al., 1983). Water loss reaches 14% of the total flow, the increase attributed to the greater pressurisation (Dash et al., 1983). An average of 2.1MW(t) is extracted to surface throughout RS3, the reservoir output displaying a temperature drop of 37°C from 135 down to 98°C (Dash et al., 1983).
Spinner evidence indicates that the flow entering the production well during RS3 is originating from a point around 25m below the outlet point in RS2 implying (in the 100m high vertical fracture) a loss of ~25% of the heat exchange area. It is concluded that the increased pressurisation has opened new fluid pathways, most likely producing a short-circuit in the flow path and decreasing the available heat exchange area. The effects of this decrease are offset by a decrease in impedance which in turn allows for more efficient heat removal from a smaller area (Dash et al., 1983). Records indicate relatively little seismic activity is associated with this test.

Tracer studies indicate an increase in the modal volume of the reservoir (Dash et al., 1983). Modeling (single cylindrical fracture) of the thermal drawdown in RS3 suggests that the EHEA is unaffected by the higher pressurisation i.e. the increased pressure does not facilitate the opening of new fractures (Dash et al., 1983). Once again this is contradicted by results for the multiple fracture model which predicts an increase of 3,000m² from a base of 6,000m². The overall increase in EHEA from RS2 is attributed to both thermal and mechanical effects (Dash et al., 1983). It is noted that the calculated values for EHEA are small when compared to other measures of reservoir volume such as total volume of injected and vented fluid.

**1979**

Re-cementing of the deteriorated EE-1 casing is undertaken. The main entry point into the well of the reservoir fracture (2,750m) is deliberately sealed in order to allow the development of a deeper, larger fracture system. Three attempts are made to extend a previously developed vertical fracture at 2,930m in EE-1. Termed MHF or Massive Hydraulic Fracturing the experiments are characterised by peak injection pressure up to 19.5MPa (Willis-Richards et al., 1995). Successful fracture propagation is achieved with upward growth extending to at least 2,600m where it intersects the pre-existing joint/fracture network at GT-2 and forms the deep or Phase I (2) reservoir (Dash et al., 1983). Height from injection to withdrawal point in the new reservoir is now of the order of 300m, more than three times that of the shallow Phase I.

Testing of the new reservoir begins with RS4, a 23 day heat extraction and reservoir assessment experiment undertaken in late 1979. Willis-Richards et al. (1995) record a
single test injection pressure of 9.65MPa with a small production well back pressure (1.1MPa) and a corresponding injection flow rate around 6l/s for this test. (Cremer, 1982) indicates that these conditions represent the establishment of a steady-state in the reservoir. Data included in Dash et al. (1983) and Murphy et al. (1983) indicates that both injection and back pressure is varied for short periods in the first week of RS4 prior to the achievement of a steady state with initial high injection pressures (~17MPa) followed by a period of high back pressure (~10MPa).

Average heat extraction from the new reservoir is estimated at a rate of around 3MW(t) (Cremer, 1982). Initial rock temperature is determined to be 197°C with initial fluid temperature 190°C cooling to 153°C as it passes through the previously cooled Phase I(1) fracture zone. No thermal draw-down is observed during the test (Cremer, 1982). Dash et al. (1983) record a steady-state flow impedance of 1.85GPa.s/m³ similar to that observed in the initial stages of the shallow Phase I reservoir. By contrast, Cremer (1982) records a steady state flow impedance for the whole reservoir of 1.4GPa.s/m³, most of which is derived from within the production well area. Rate of fluid loss decreased to 1.3l/s by day 23 and water quality remains high. Cremer (1982) notes that there is no detectable surface seismic activity. For the first time however downhole geophones are placed within the vicinity of the reservoir. Recorded microseismic events are noted as not exceeding magnitude ~1.5 (Richter) but are nonetheless sufficient to form a “cloud” (Dash et al., 1983). It is noted that the seismic events observed during the “initial stages of pressurisation in general are clustered in a vertical zone striking NNW” (Dash et al., 1983).

Tracer studies again indicate an increase in the modal volume of the reservoir (Dash et al., 1983). The lack of any notable thermal draw-down and short duration of the RS4 test, however, implies thermal modeling exercises are indicative only. Single Fracture estimates of EHEA attribute 15,000m² to the upper “old” fractures and 30,000m² to the lower “new” fractures (total 45,000m²) (Murphy et al., 1981). Similarly, multiple fracture model estimates point to a gain in EHEA of between 6,000-9,000m² to 21,000-24,000m² (Dash et al., 1983). Once again the apparent increase in reservoir size is attributed to a combination of thermal stress cracking and high injection pressure (Dash et al., 1983).
Commencement of Phase II – Engineering. Concurrent with the ongoing research of Phase I, formal establishment of the national HDR Geothermal Energy Development Program based at Los Alamos, administered through US Department of Energy takes place in 1979. Formal international co-operation begins with the West Germans through the International Energy Agency while negotiations for similar ties with Japan and Italy get underway. A decision is made to build upon the success of the existing Phase I reservoirs, by proceeding immediately towards the development of a deeper, hotter prototype reservoir, one which will operate in conditions akin to those believed to be required for commercial success. Drilling of the first of a new, deeper borehole pair commences in April 1979. The borehole system is designed in the expectation that stimulation will create vertical fractures within the rock and holes are placed such that the production well is aligned vertically approximately 350m above the injection. Multiple vertical hydraulic fractures are anticipated with fracture spacing around 35m. In order to accommodate as many fractures as possible the lower portion of the holes are inclined 35° to the vertical and drilled to the NE so as to maximise the advantage from the expected NW-trending vertical hydraulic fractures (Cremer, 1982).

1980
A long-term flow & heat extraction test, RS5, is commenced in the deep Phase I reservoir. Injection pressures around 9MPa with back-pressure ~1.5MPa and injection flow rates 6-7l/s maintain a steady state in the reservoir for a period of 286 days (Willis-Richards et al., 1995). for recovery ~90%). Flow testing is accompanied by the occasional use of a 60kVA binary cycle electrical generator. Heat liberated from the borehole system is proved capable of driving the generator to full capacity (60kWe) at several times throughout the test (Cremer, 1982). System impedance remains constant at 1.75GPa.s/m³ after an initial decline (Dash et al., 1983). Water loss by the end of test is around 10% (Willis-Richards et al., 1995). Thermal draw-down is small, reservoir temperature initially rising from 156°C to 158°C after 60 days (attributed to an initial extraction of deep hot waters) before dropping to 149°C by 286 days (Dash et al., 1983). Average heat extraction is 2.3MW(t) (Dash et al., 1983). Total reservoir EHEA is estimated to be of the order of
45,000 (multiple fracture model) to 50,000m$^2$ (single fracture model). All models used suggest a continuous growth of the reservoir throughout operation from. In the case of RS5 this attributed to the effects of thermal stress cracking alone as injection pressures are less than minimum earth stress (Dash et al., 1983).

Following on from the end of RS5 Stress Unlocking Experiment (SUE) commences to allow the reservoir to adjust to the new stress regime created by the long-term flow test. The system is shut in at 15MPa for 2 days during which time numerous seismic signals are recorded. Examination of the produced seismic cloud indicates a quiet zone adjacent to the injection point which is attributed to the effects of thermal stress relief in this, the cooler part of the reservoir. It is noted that “microseismic mapping techniques may provide the long sought predictive tool needed in HDR reservoir engineering” (Dash et al., 1983). An impedance drop to 0.9GPa.s/m$^3$ is observed during the SUE and attributed to self-propping of fractures during readjustment (Dash et al., 1983).

Completion of the SUE marks the end of the focus on Phase I of the Fenton Hill project. From this point on most energy is devoted to the ongoing development of the Phase II reservoir. The drilling of the first Phase 2 deep energy extraction hole EE-2 is completed in May 1980 at a depth of 4,660m (4,390m vertical). The bottom 1,000m of the well is deliberately deviated toward the east at an angle of around 35° to the vertical (Brown & Duchane 1999). Recorded bottom hole temperature is 327°C (Smith, 1987). At this time EE-2 represents perhaps the deepest US attempt at conventional drilling in hot crystalline rock and drilling is not without its problems (Kerr, 1987). Core produced from EE-2 indicates the deep geology is complex with both igneous and metamorphic rocks present and numerous alteration zones and sealed fractures (Cremer, 1983). Drilling the second Phase II well EE-3, spudded 46m to the west of EE-2, commences in May, 1980. Intended as a production well, EE-3 is designed to sit some 380m vertically above EE-2 (Brown & Duchane 1999).
1981

Completion of EE-3, the Phase II production well takes place in August. The extended drilling time reflects measures taken to prevent reoccurrence of problems encountered in EE-2 as well as numerous experiments undertaken throughout drilling.

1982 – 1984

Hydraulic fracturing of the Phase 2 system commences. Preliminary pressure testing is followed by a number of attempts at connecting the wells EE-3 and EE-2 (Brown & Duchane 1999; Robertson-Tait et al., 2000). Initial attempts at fracturing the end of hole region in EE-2 encounter problems with repeated packer failure inhibiting pressure build-up (Brown & Duchane 1999). Insertion of a ‘scab liner’ cemented into place 136m off the EOH enables re-commencement of testing. Three further deep fracturing operations, the largest with injection volume of 4,880m$^3$ at pressures up to 49.6MPa, fail to establish communication with EE-3 (Brown & Duchane 1999).

Seismic monitoring of the initial experiments, based on the single-tool hodogram method, is interpreted as indicating the development of sets of inclined fractures which fail to intersect either each other or connect the two wells (Kerr, 1987; Brown & Duchane 1999). This result is unexpected, Keppler et al. (1983) noting that “unlike the RR (Phase I reservoir) where the fracture systems are generally vertical, the event locations in the ER (Phase II reservoir) suggest a set of en-echelon 45° dipping fracture planes which strike slightly west to north”. As if to compound these problems, it is found that hydraulic fracturing attempts at depths greater than around 3,250m encounter a true volcanic environment and are accompanied by the release of large quantities of gas, a proportion of which is corrosive, attacking steel casings etc (Smith, 1987).

As the current seismic interpretation implies that developing hydro-fractures are passing below the bottom of EE-3 a decision is made to sand in the bottom of EE-2 and instead work at a level immediately below the casing shoe (Brown & Duchane 1999). Three fresh attempts at hydraulic fracturing at this level all fail to produce a connection to EE-3.
In December 1983 a concerted assault to connect the wells, the Massive Hydraulic Fracture (MHF), experiment is undertaken. 21,300 m$^3$ of water are injected at 48MPa into an isolated section of EE-2 (3529 – 3550m) (Brown & Duchane 1999). Surface pumping rates are maintained at 106l/s for a total of 61 hours during which time no flow connection to EE-3 is observed (Brown & Duchane 1999). The experiment is unexpectedly terminated by the failure of a flow line connection which results in an uncontrolled vent of around 13,000 m$^3$ of fluid in a geyser up to 10m high (Brown & Duchane 1999). Damage to the casing and lining of EE-2 includes a partial casing collapse at 3,200m (Brown & Duchane 1999). The large volume of fluid injected, and subsequently vented, is taken to indicate the presence of a large, well-confined reservoir at depth (Smith, 1987).

Seismic monitoring during the MHF, utilising a multi-sonde seismic travel time method to locate individual events, indicates the formation of a “great elliptical cloud of microseismic activity that (is presumed to) reflect the slippage of rock on a myriad of joints” (Kerr, 1987). The dimensions and orientation of the reservoir fracture system are determined as ~900m (h) x 1,000m (l) x 400m (w) striking 8° and inclined ~20° to the vertical toward the east cutting the injection well at an angle of ~15° (Smith, 1987). Reprocessing of seismic results post-fracturing indicates that the initial hodogram method is ‘seriously flawed’ implying that the apparent discrepancy between early seismic interpretations and the MHF results is likely to be spurious (Brown & Duchane 1999).

The final attempt at creating a well connection through hydraulic fracturing takes place in the production well with injection of around 7,570 m$^3$ of water at pressures up to 41MPa and a flow rate of 25l/s (Brown & Duchane 1999; Willis-Richards et al., 1995). Seismic data indicates the resultant fracture system is similar to that seen in EE-2 i.e. roughly parallel to the trace of the well, 1150m (h) x 670m (l) x 150m (w) striking 4° and inclined ~ 35° to the vertical toward the east (Smith, 1987). Seismicity produced by this test fails to overlap the volume produced by the previous MHF in the injection well (Smith, 1987). It is noted that this outcome is more a product of poor well orientation than any fundamental problem with the concept or the rock itself (Brown & Duchane 1999).
Finally, it is observed that, in all cases, wellhead pressure at the commencement of fracturing is around 33MPa (Smith, 1987). This is notably different from the conditions in the Phase I reservoirs where fracturing commences at around 13MPa. It is concluded that “there is a major change in rock structure or stress field or both” at a depth of around 3,100m (Smith, 1987).

1985

Of the numerous failed attempts at creating new hydro-fractures between the Phase II wells Kerr (1987) states that “the Los Alamos researchers had chosen between two schools of thought on hydraulic fracturing and chosen wrong”. By “subscribing to the theory of fracturing as (developed in) the oil and gas industry” they had assumed that sufficient downhole pressurisation would create “new fractures...whose orientations are determined by the region’s crustal stress” (Kerr, 1987). This is in spite of the fact that numerous “field studies and laboratory work...suggest that pre-existing fractures can control the behaviour of rock, even at depths where no voids remain” (Kerr, 1987).

The failure of the Phase II hydraulic fracturing experiments mark a fundamental change in thinking at Fenton Hill as it is realised that the rocks under pressure are opening preferentially along old lines of weakness (joints) long before the conditions required for hydraulic fracture are achieved. This new rational is in part influenced by the now concurrent work being undertaken at Rosemanowes in the UK. From this point onwards in HDR the concept of connecting wells by man-made hydraulic fractures is replaced by one where wells are instead connected by a network of “stimulated” natural joints.

Unfortunately, at Fenton Hill the orientation of the Phase II wells could not be worse for the exploitation of the existing natural joints. A decision is made to abandon further attempts to connect the wells by hydraulic fracturing. EE-3 is instead sidetracked at 2,829m and redrilled to 4,018m to intersect the large blind reservoir created by the MHF in 1983 (Brown & Duchane 1999). The new well extension is termed EE-3A. A series of televiewer logs are run to depth in the new well (Burns, 1988). Upon completion a small flow connection is achieved intersecting EE-2 at
3,570-3,850m (Smith, 1987). The established connection is improved by a series of hydraulic stimulations which are in turn interrupted by further hole extension (Robertson-Tait et al., 2000). Finally, an 84 hour open-loop flow test is completed successfully in fractures below 3,650m where initial rock temperature is recorded at 265°C (Smith, 1987). The effective volume of the newly formed Phase II reservoir is estimated to be up to 20,000,000m³, approximately 200 times larger than that of Phase I. It is centred at a depth around 3,500m in rock at temperature ranging 220-240°C (Duchane, 1996; Duchane & Albright, 1996).

1986

An initial closed loop flow test (ICFT) is undertaken in the new Phase II reservoir over a thirty day period in May-June 1986. Around 37,000m³ of water is injected through EE-3A at flow rates of 10.6 and 18.5l/s corresponding to injection pressures of 27 and 31MPa respectively (Brown & Duchane 1999). Production rate at EE-2 increases over time from 6.3 to 13.9l/s at a backpressure of 3.5MPa (to prevent boiling) (Smith, 1987; Brown & Duchane 1999). Over the thirty day period production well-head temperature increases to around 200°C, corresponding to energy production of 10MW(t) (Brown & Duchane 1999). In all, a total of 66% of the injected fluid is recovered from EE-2 during the test with a further 20% returning to surface during post-test venting of the pressurised system (Brown & Duchane 1999). System impedance is observed to drop during the test from 4.5 to 2.1GPa.s/m³ and is still decreasing at test termination (Brown & Duchane 1999). Relatively little seismicity is observed whilst injection pressure is low. At higher pressure a large number of events are seen to be located on the side of the reservoir away from the production well (Brown & Duchane 1999). It is noted that the presence of the production well appears to have relieved stress on its side of the reservoir (Brown & Duchane 1999). EE-2 is, effectively, a pressure ‘sink’ implying that were a second production well sunk to the other side of EE-3A then the overall seismicity, and hence reservoir growth and water loss, may be significantly reduced (Brown & Duchane 1999).
A full assessment of the damage caused to EE-2 during the MHF in 1983 indicates that impairments to well performance are likely to worsen in the face of repeated reservoir testing. A decision is taken in January 1987 to repair the hole by sealing the casing leaks and sidetracking and redrilling from above the damaged section (Brown & Duchane 1999). The redrilled hole is designated EE-2A. A seven-day flow test between EE-3A and the newly drilled well is undertaken in late 1987. Injection pressure of 24MPa at 5.9l/s results in a production flow rate of 4l/s at 125°C and 1.17MPa back-pressure (Brown, 1992). Construction of an automated closed-loop surface plant installation begins (Duchane, 1996).

Results of detailed studies of borehole breakouts recorded in EE-3A televiewer logs are published. Best estimate of the orientation of $\sigma_h$ is $110 \pm 10.3^\circ$ east of true north (Burns, 1988). Seismic data indicates the relative magnitude of stresses to be $\sigma_v \geq \sigma_h > \sigma_h$ (Burns, 1988; Barton et al., 1988). Magnitude of $\sigma_h$ is given as around $0.6\sigma_v$ (Barton et al., 1988).

A number of pressurisation tests, including a long term experiment, are conducted in the redrilled Phase II reservoir. The testing serves several purposes including studies of water loss, fracture connectivity, reservoir volume, fluid partitioning within the reservoir, response time at the production well and the effects of pressure change on the reservoir (Brown & Duchane 1999). Static pressurisation testing, where injection flow rate is varied to maintain a constant reservoir pressure, indicates that water loss declines over time, eventually decreasing to a very small amount ($<0.2l/s$) as the reservoir becomes saturated and steady-state is reached (Brown & Duchane 1999).

Commissioning of the Phase II surface plant begins in late 1991. The plant is fully automated and designed to maintain continuous flow, allowing the onset of continuous circulation testing. Preliminary reservoir flow testing commences prior to the start of long term flow testing. Tests are brief, typically 3 days duration (Brown, 1992). Data from the first test indicate injection pressures of 25.5MPa at flow rates of around 5.4l/s (Brown, 1992). Back-pressure of 15.2MPa is maintained on the
production well. Production rates rapidly level off at 4.7l/s with water temperature rising throughout the test to around 157°C (Brown, 1992). Effective system impedance is notably low at around 2.2GPa.s/m³; net recovery is around 89%; no seismicity is recorded (Brown, 1992).

1992

Long Term Flow Testing (LTFT 1) of the Phase II reservoir commences in March but stalls 10 days later due to technical difficulties which arise from the thermal expansion of the production piping (Brown, 1992). Injection pressure is 25.9MPa at a flow rate of 7l/s, back-pressure 10.3MPa and production flow rate 6l/s (Brown, 1992). Production fluid temperature rises to 180°C and is still increasing at the termination of the test (Brown, 1992). Effective system impedance is 2.6GPa.s/m³; net recovery is around 93%; no seismicity is recorded (Brown, 1992). Comparison with the results of the previous short term flow testing leads to the conclusion that the use of production backpressure appears to reduce impedance within the vicinity of the production well.

The technical problems are rectified by early April enabling re-commencement of the LTFT 1. From April to the end of July (112 days) 24 hour circulation is maintained with only minor interruptions due to power outages (Duchane, 1995). Injection pressure is held at 27.3MPa (determined as maximum allowable whilst remaining aseismic) by a flow rate of 6.8l/s (Duchane, 1995). Back pressure is held at 9.7MPa resulting in a typical production flow rate around 5.7l/s (Duchane, 1995). Temperature of the produced fluid reached around 183°C thereafter remaining constant throughout the rest of the test period. Average heat extraction throughout is 4MW(t). Water loss rate after five weeks is 0.88l/s (Brown, 1996a).

No microseismicity is recorded during the test however there is an estimated 23% increase in total contained reservoir fluid interpreted as the effects of thermal contraction within the rock Brown (1994). Tracer tests at monthly intervals also indicate changes in the reservoir flow paths with an apparent increase in overall residence time Brown (1994). Water loss averages 11% with 17% of this attributable to the increased reservoir storage space Brown (1994). Both injection and production
flow rates decrease over time indicating an overall increase in system impedance Brown (1994). Impedance increases are in turn attributed to increased viscous drag on cooled fractures and may explain the changing flow paths as despite thermal contraction, the cooling of ‘short-circuit’ flow paths increases viscous drag at the fracture surface Brown (1994). This in turn effectively ‘blocks’ the channel, causing fluid flow to divert through more circuitous routes Brown (1994).

LTFT 1 is ultimately terminated by a catastrophic failure of the injection pumps (Duchane, 1995). Low rate circulation is continued in the reservoir after the shut down of LTFT 1 in the form of an Interim Flow Test (IFT). Relying upon an old backup pump to provide pressurisation, the IFT is itself terminated in late October by pump failure Brown (1994). After shut-in of about one month flow testing continues with substitute pumps but is interrupted by frequent surface technical problems and shut downs. Testing of the effect of backpressure variation at constant injection pressure (27.3MPa) takes place in late December. Results indicate a broad maximum flow rate at back pressures between 9.7 and 15.2MPa Brown (1994). This range is likely to give optimum fracture openings within the production well area whilst still not being so high as to reduce the pressure drop across the system to levels where flow is reduced Brown (1994).

1993

Replacement of the injection pump enables commencement of LTFT 2 in February 1993. Circulation continues for 55 days until April when funding constraints cause it to be shut down and the system put into stand-by mode (Duchane, 1995). The operating parameters used in this test are similar to that of LTFT 1 with injection pressure of 27.3MPa at a flow rate of 6.5l/s and production well back-pressure of 9.7MPa (Duchane, 1995). Results of the test are entirely compatible with those of the previous test with typical production flow rates of 5.7l/s at temperature around 184°C (Duchane, 1995). Water loss is lower at 7.3% of the injected volume (Duchane, 1995). Produced water chemistry is relatively benign with salinity of around 3-4,000ppm and pH between 5-6. Dissolved gas content is less than 3,000ppm and is almost entirely CO₂ (Duchane, 1995).
The compatibility of LTFT 2 and LTFT 1 results is taken to reflect a certain resilience of the reservoir system in the face of repeated shut downs and interruptions to flow Brown (1994). Downhole production well temperature logs indicate no change in temperature from LTFT 1 in the cased portion of the hole with only small (0.4 to 3°C) decreases in temperature at depths below the casing in the fractured fluid production zone Brown (1994). The overall lack of change in the production temperature is interpreted as an indication that the system has a form of self-adjustment or regulation whereby cooling fractures intake less and less water and the flow of water through previously un-utilised warm zones increases Brown (1994). Evidence from successive tracer tests confirm that this is likely to be the case (Duchane, 1995).

After the completion of LTFT 2 a number of small flow experiments are undertaken in early May to assess the effects of cyclic reservoir operation (Brown, 1996b). The reservoir is subjected to continuous injection (pressure 27.3MPa) for three days during which time production is effectively choked by high back pressure for 16 out of every 24 hours (Brown, 1996b). It is found that reservoir output across the eight hours of production is temporarily boosted by an average 62% compared to that of steady-state production in the LTFT (Brown, 1996b). Such flexibility is important when considering the variation in electrical loads required commercially between peak and off-peak usage (Duchane, 1996). On the third cycle a rapid and seemingly irreversible drop in impedance was observed, together with an increase in flow rate of almost 50% from 9.84 to 14.5l/s Brown (1994). The event is aseismic and results in a rise in production temperature of about 6°C. In order to assess the phenomenon fully the system is brought into full production for the next ten days until the rental lease on the injection pump expires Brown (1994). Injection pressure is returned to 26.6MPa at flow rate of 8.2l/s (Brown, 1996a). Production back pressure is maintained at 9.65MPa. Production flow is faster at 7.7l/s and is noticeably warmer at 190°C (Brown, 1996a). Despite this increase, temperature logs run into the production well at this time do not indicate a temperature change at the base of the casing Brown (1994). It appears that the reservoir is continuing to sample rock of the same temperature as prior to the impedance drop event. Tracer tests indicate a shorter residence time pointing to the creation of new short circuit paths although no difference is noted in the production fluid chemistry Brown (1994).
Final shut-in occurs on May 18. Studies of the reservoir pressure drop associated with this event indicate two sets of joints with closure pressures below 22MPa, one at 10.3, another at 14.5MPa Brown (1994). Overall the tests of cyclic operation point to a number of potential benefits, most significantly an apparently cumulative decrease in production impedance and increase in production flow Brown (1994).

1994
The reservoir remains shut in. Pressure and temperature are monitored. Reservoir pressure ultimately drops to 10.8MPa.

1995
The third and final long term flow test, LTFT 3, commences in May following two years of inactivity at the site (Brown, 1996a). Also referred to as the reservoir verification flow testing (RVFT), duration of the test period is 65 days and is executed in three main phases (Brown, 1996a; 1996b). A major aim of LTFT 3 is to establish whether the dramatic change in reservoir flow observed in May 1993 would persist given the intervening thermal recovery period (Brown, 1996a).

Initial testing involves five weeks of circulation at injection pressure of 27.3MPa (flow rate 8.0l/s) and back pressure of 9.65MPa (Brown, 1996a). Test parameters are designed to mimic those near the end of LTFT 2 in 1993 (Brown, 1996a). Owing to the low initial reservoir pressure it takes nearly 5 weeks to re-establish steady-state conditions. Test production flow rate is quoted as 6.6l/s at a water temperature of 185°C (Brown, 1996a). Reservoir performance appears to be intermediate between that of the pre- and post-1993 impedance drop. It is concluded that the thermal recovery of the reservoir has produced an overall increase in reservoir impedance (Brown, 1996a). At 14% (1.07l/s) water loss is notably higher than during equivalent tests, a fact attributed to the previous loss of pressure in the system and the re-filling of the far-field reservoir (Duchane, 1996; Brown, 1996a).

Upon reaching steady-state, the second phase of testing commences with an 18-day long high back pressure experiment. Injection pressure is maintained at 27.3MPa
(flow rate 7.84l/s) and back pressure raised to 15.2MPa (Brown, 1996a). Steady-state conditions are observed after around 8 days of circulation, production flow rate settling to 6.25l/s at a temperature of 183°C (Brown, 1996a). Comparison of current production flow rate with that observed during similar high back-pressure tests in late 1992 indicate a 17% increase in flow attributed to the effects of the 1993 impedance drop event (Brown, 1996a). Downhole temperature logging indicates an overall cooling of the reservoir with a loss of around 2°C since 1992 (Brown, 1996a).

The final stage of testing comprises a high back-pressure cyclical load-following experiment (LFE). The test lasts for a total of 6 days during which time the system is kept in constant production at an injection rate of around 8.2l/s (Brown, 1996c). Production well back pressure is held at 15.2MPa for twenty hours a day and lowered to around 3.4MPa for the remaining four thus simulating a situation of peak-demand where power production needs to be significantly increased for a relatively short period of time (Brown, 1996c). Results indicate that power production levels can be raised by as much as 65% across the four-hour peak period compared to the subsequent 20 hours of baseline production (Brown, 1996c). Time required for this increase is around two minutes (Brown, 1996c). Overall, it is found that average reservoir performance is enhanced by the pressure cycling, the average flow rate and production temperature for the last 24 hour period (6.41l/s; 183.9°C) being greater than that observed immediately prior to the beginning of testing (6.13l/s; 182.7°C).

**Footnote**
The 1995 flow testing proved to be the last conducted at the Fenton Hill site. In the years that follow the geothermal energy program project is progressively closed down, the wells are plugged and the plant decommissioned. In September 1997 the main sponsor of the Fenton Hill project, the US Department of Energy, awards a private contract to develop a plan for future HDR development in the US. Indications are that the preferred direction of this research is Hot Wet Rock or enhanced (natural) geothermal systems akin to that under development at the European Soultz site rather than the original HDR concept envisioned by the Los Alamos workers (McLarty et al., 2000).
A1.2 Rosemanowes HDR, Cornwall UK

Summary
The Camborne School of Mines Geothermal Energy Project, jointly financed by British Department of Energy and the EU commenced at the site of the Rosemanowes Quarry, in Cornwall, Southwest England in the mid 1970’s. Unlike the Fenton Hill project, which had inspired this work, the aim of testing at Rosemanowes was not the direct development of an operational heat exchanger. Research at Rosemanowes was primarily aimed at investigating the engineering techniques required for extraction of heat from an HDR system. The project deliberately operated in a low temperature environment and set out to explore the possibility of creating flow systems by simulation of existing natural fractures. Reservoir development was undertaken at three different depths during the course of nearly 15 years work on site. During this time many technologies, such as explosive stimulation, viscous gel injection and proppant use were trialed. Work at the site provided a clear demonstration of the importance of the interaction between natural fractures and the in-situ stress field. Here, a highly anisotropic horizontal stress field, misaligned with several natural joint sets, resulted in shearing and downward propagation of vertical fractures, perpendicular to the minimum stress direction. Difficulties in intersecting the vertical stimulated zones to form a single large reservoir and relatively high water losses saw the rise of a concept for multi-cell reservoirs servicing well pairs. Work at Rosemanowes was ultimately put on hold in 1991, the accumulated expertise developed at this site re-directed to work on the higher temperature EU project underway at Soultz-sous-Forêts.

Detailed Timeline

1975 – 1977
Work on the first and only British Hot Dry Rock project begins as a research project at the Camborne School of Mines. Unlike the ‘single-fracture’ vision of the American project at Fenton Hill, the early British concept of HDR envisions a heat exchanger comprising an interconnected fracture network. This network is to be created first by
the deployment of explosives at depth within a well, then by the use of downhole fluid pressure to further open or ‘stimulate’ the existing fractures. The reservoir formed is thus a mixture of man-made and natural fractures (Smith, 1987).

Initial project work involves the completion of “a series of explosive-fracturing experiments at shallow depths in exposures of the Cornubian granites of south-western England” (Smith, 1987). Also taking place during this stage of the project is site reconnaissance aimed at identifying a suitable location for the envisioned future stages of the project.

1977 – 1980

The Rosemanowes granite quarry in south-east England is acquired as a suitable project site. Phase 1 of the overall program commences with a detailed local site survey. Geologically the site is located with the Carnmenellis Pluton, an exposed Permo-Carboniferous coarse-grained porphyritic biotite-muscovite granite. Massive in nature, the granite contains at least two well defined vertical joint sets oriented 150°/330° and 75°/255° (Batchelor, 1984). The Carnmenellis Pluton is a cupola, one of several granite bodies rising above the much larger subterranean Cornubian batholith which underlies much of the region. Local heat flow is determined as 120mWm² with a local geothermal gradient of 30-40°C/Km (Batchelor, 1984). Systems of natural hot water are known to circulate within the NW-SE striking joints (Batchelor, 1984).

A total of four 300m deep boreholes are completed at the site so as to enable shallow-level fracturing experiments. A fracture network is created between these wells by “using an explosive charge in one well to initiate fractures that (are) extended by fluid pressure” to intersect the other three wells located “about 40 to 50m away” (Smith, 1987). The shallow ‘reservoir’ is horizontal and comprised of flow paths which are “apparently...open or re-opened natural fractures” (Smith, 1987). Fluid is successfully circulated between the wells (Parker, 1989a). The apparent success of the shallow project in stimulating the existing joint system leads to the concept of an HDR system entirely created by pressurisation and the opening of in-situ fractures (Batchelor, 1984).
1980 – 1983

Following the success of the shallow fracture experiments in Phase 1 it is decided to extend the program by drilling to a depth where both thermal and fracture-related studies could be undertaken. A depth of around 2,000m is selected to be both within current capability of drilling rigs and, whilst warm enough to allow “academic” thermal studies, not so hot as to pose a problem for the drilling (Batchelor, 1984; Kerr, 1987).

Phase 2A of the project begins with the drilling of the first injection well RH12. Initially vertical, the well deviates along a NW orientation to a maximum inclination of 30° in order to best intersect the existing natural (vertical) joints (Batchelor, 1984). Total vertical depth of the well is 2,156m (Parker, 1989a). A number of downhole stress measurements (hydraulic fracture) are taken throughout drilling. The minimum principle stress below around 400m is found to be horizontal (Batchelor, 1984). Furthermore, the maximum and minimum horizontal stresses are found to be highly anisotropic, the difference increasing slightly with depth such that $\sigma_H$ at 2,000m (~70Mpa) is over twice the magnitude of $\sigma_h$ (~30Mpa) (Batchelor, 1984).

Drilling of the production well, RH11, commences immediately upon completion of RH12. Spudded approximately 10m away from RH12, RH11 is designed ‘to lie in a vertical plane above the injection well, vertically separated by 300m’” (Batchelor, 1984). Like RH12, RH11 is deviated at depth to reach an angle of 30°. Total vertical depth achieved is 2,038m (Parker, 1989a). Bottom hole temperature is recorded as 79°C, temperature gradient increasing from 31 to 35°C/km at a depth of around 2,000m (Batchelor, 1984). A series of geophysical logs were undertaken in both wells (Batchelor, 1984).

In order to check the validity of the downhole stress measurements in RH12, and also to determine the as yet unknown stress directions, an over-coring operation is conducted at 780m depth in a near-by mine. Results confirm the presence of a strong horizontal stress anisotropy and indicate a NE orientation for $\sigma_h$ (Batchelor, 1984). The orientation of the stress field is, in fact, found to be misaligned with the recorded
joint sets. By unfortunate coincidence the orientation of $\sigma_H$ turns out to be almost perfectly aligned with the vertical plane of the drill holes (Batchelor, 1984).

A series of low pressure/low flow rate tests are undertaken in order to test the undisturbed hydraulic properties of the two-well system (Batchelor, 1984). A number of discreet flowing zones are identified in each well but do not correspond to any single set of characteristics on the geophysical logs (Batchelor, 1984). In-situ permeability is determined as $1-2\mu D$, rock bulk modulus as 35GPa and porosity as 1% (Batchelor, 1984). It is noted during later tests at higher pressure (6MPa) permeability appears to be enhanced to the order of 50-60$\mu D$ (Batchelor, 1984).

An explosive stimulation is conducted at a depth of 2,125m in the injection well. Explosives are considered necessary as a result of the low pressure tests which indicate that the natural outflow from the well is both limited and discrete (Batchelor, 1984). Hydraulic stimulation begins in early November, 1982. A total of 26,000m$^3$ of water is injected into RH12 at a flow rate of up to 100l/s (Willis-Richards et al., 1995). Maximum well head pressure of 14MPa is reached some three hours after the commencement of the test and is accompanied by the onset of intense microseismic activity (Batchelor, 1984). Connection to the production well is achieved 13 hours later but due to a shortage of water the input flow rate is eventually reduced. A second stimulation of the RH11 uses up to 4,000m$^3$ of water at pressures up to 11MPa (Willis-Richards et al., 1995).

Microseismic monitoring during stimulation uses a network of surface seismometers and reveals a cluster of events around the explosively stimulated section of RH12 (Batchelor, 1984). Propagation of fractures appears to be vertically downwards with nearly two-thirds of recorded events located in a thin vertical cloud parallel to, but below, the plane of the drill holes (Batchelor, 1984). The downward propagation extends nearly 2km beneath the wells and is attributed to high shear stress arising from the horizontal stress anisotropy. Shear fracturing is found to begin at pressures of only 4.5-5MPa making it nearly impossible to achieve the high downhole pressures required for the ‘jacking’ of tensile fractures (Smith, 1987). Although shear stress increases with depth (in proportion to the increase in stress anisotropy) the rate of
increase is less than that of the hydrostatic pressure (Batchelor, 1984). This, together with the orientation of the local joint systems implies that fractures tend to shear downward (Parker, 1989a). Furthermore, the growth of the reservoir through a shear rather than tensile mechanism implies that there is likely to be significant resistance to flow along the formed fluid pathways (Parker, 1989a).

Flow distribution tests (spinner logs) recorded during stimulation confirm that microseismic activity in the zone of explosive stimulation is related to a progressive increase in fluid intake (Batchelor, 1984). At least two other zones (1,930 & 2,000m) are also noted where fluid is being absorbed. These areas are aseismic and are considered to be natural joints aligned with the stress field which are opening to receive water (Batchelor, 1984). Reduction of pressure results in closure of the explosively stimulated zone implying that proppants may be required to maintain permeability.

Circulation commences in the reservoir shortly after the initial stimulations and lasts for a period of approximately 12 weeks (Batchelor, 1984). Injection pressures of 10-11MPa (flow rate 17.5-20l/s) are accompanied by high water losses, up to 70%, and continued reservoir growth (Parker, 1989a; Willis-Richards et al., 1995). Utilisation of a small back-pressure on the production well (3.2MPa) makes the situation worse with water recovery of only 21% (Willis-Richards et al., 1995). Only when injection pressure is decreased to 5MPa (flow rate 5l/s) is recovery increased to around 60% (Willis-Richards et al., 1995). An attempt at reverse circulation (RH11 → RH12) at injection pressure 10MPa (flow rates 17.5 & 12.5l/s) does not reach steady state, recovery being in excess of 50% (Willis-Richards et al., 1995).

Reservoir analysis conducted throughout the circulation includes thermal studies, tracer tests and geochemical analysis of the produced water. Production temperature is constant at 50°C (Parker, 1989a). No thermal drawdown is observed across the test period, the downhole temperature at the casing shoe instead rising steadily throughout (Batchelor, 1984). Tracer tests indicate that there is no direct connection between wells, rather a diffuse network of multiple non-intersecting parallel planes with poorly stimulated cross-linked connections (Batchelor, 1984). The contained reservoir
volume is estimated to be of the order of $825 \times 10^6 \text{m}^3$ (Parker, 1989a). Fluid chemistry is consistently basic (pH 9.3) but is otherwise benign, the stable nature of the production fluid a further indicator of a large reservoir (Batchelor, 1984).

Some 30,000 microseismic events are recorded in the reservoir during the circulation reflecting an almost continuous fracture growth. Smith (1987) notes that “at the pumping pressures required to inject water at high rates, most of the water is lost either in producing new shear fractures elsewhere in the reservoir or into storage in existing fractures.” To add insult to injury the reservoir impedance is found to be high, around 1.8MPa/kgs$^{-1}$, also likely a result of the shear stimulation (Parker, 1989a). In an attempt to find a way of increasing reservoir pressure sufficiently to allow tensile fracturing an experimental stimulation is conducted in RH11 using around 400m$^3$ of a high viscosity fluid (Parker, 1989a). Smith (1987) notes that “subsequent (downhole) logging with a borehole teviewer” reveals “extensive tensile fracturing along the bore wall” but “pressurisation tests indicate that (while) permeability near the well bore has increased significantly...there is no accompanying reduction in flow impedance between the two wells.”

1983 – 1988

The relatively poor performance of the Phase 2A reservoir implies it is “unsatisfactory for the purpose of demonstration of the feasibility of reservoir development for HDR exploitation” (Parker, 1989a). In order to meet the original project aims it is deemed necessary to modify the reservoir with the drilling of a new well. It is hoped that a correctly positioned well will provide access to the stimulated zone beneath the two existing wells (Parker, 1989a). It will serve to improve reservoir performance by increasing the swept area, enabling an increase in production flow rate and a decrease in reservoir impedance (Parker, 1989a).

**Phase 2B** of the project begins with the drilling of small extensions to RH12 (~70m) and RH11 (~170m) (Parker, 1989a). The extensions are designed to facilitate logging through the explosive zone (RH12) and enable emplacement of a downhole hydrophone string (RH11) itself aimed at improving the accuracy of microseismic depth determinations (Parker, 1989a). Drilling of the new (third) well, RH15, commences following completion of this work. Spiraling to a depth of 2,800m (TVD
2,600m) RH15 lies some 300m beneath RH11/RH12 (Parker, 1989a). The lowermost portion of the hole is inclined 35° to the NNE such that it is at right angles to the known major natural joint set (Parker 1999; Willis-Richards et al., 2000). The well is designed to sample both seismic and aseismic reservoir zones as it is not certain which represents the true flowing zones (Parker, 1989a).

Upon completion of the well a series of geophysical logs are run to depth and bottom hole temperature is recorded as around 100°C (Parker, 1989a). The majority of natural joints recorded as intersecting RH15 are found to be sub-vertical (Parker, 1989a). A good correlation is found between the joint pattern in RH15 and that of RH11, RH12 and the surface jointing pattern at depths above the original total depth of the latter two wells (Parker, 1989a). Below this depth in RH15 the pattern of jointing is found to be more dispersed with some orientations either not present or not visible in the unstimulated well and a “substantially different frequency” to that observed in the shallower section (Parker, 1989a). The change in jointing is found to coincide with a variation in granite lithology at depth (Parker, 1989a).

Production logging of the unstimulated open-hole section of RH15 indicates that there are a small number (23) of flowing joints (Parker, 1989a). Correlation of the flowing zones with seismic data indicates that these structures are all associated with seismically active regions of the reservoir (Parker, 1989a). Preliminary attempts at dual well circulation (RH12 → RH15; flow rate up to 10l/s) indicate reservoir conditions similar to those encountered in Phase 2A with high diffusive water loss and high system impedance (2MPa.l¹.s⁻¹) (Parker, 1989a).

A viscous stimulation is decided upon as the best way to improve the flow connection between RH15 and RH12. The bottom portion of RH15 is sanded in leaving a 100m open-hole interval into which a small explosive charge is detonated (Parker, 1989a). Around 5,500m³ of viscous fluid is pumped into the open hole section at a rate of around 200l/s and pressures up to 15MPa (Parker, 1989a). Viscosity of the fluid is 50cP, slightly less than that used previously in RH11 in hope that the formed fractures will penetrate further into the natural joint system (Parker, 1989).
Post-stimulation logging indicates “considerable axial fracturing” but contrasts with syn-stimulation production logging which indicated that fluid was accepted only by pre-existing, pre-flowing joint structures (Parker, 1989a). Microseismic data collected throughout the test indicated movement within a vertical region stretching upward from RH15 towards RH12, “in a region previously stimulated...during Phase 2A” (Parker, 1989a). Again the primary mechanism of reservoir growth is shear and it is concluded that the test has once more achieved the stimulation of existing natural structures rather than the creation of new fractures (Parker, 1989a). Crosshole seismic surveys conducted before and after the stimulation indicate the presence of a low velocity zone located between the wells and which corresponds to the location of the microseismic events (Parker, 1989a). It is concluded that the stimulation has produced a network of small joints and fractures, the location of which is defined by the microseismic cloud (Parker, 1989a).

Following stimulation a number of small tests are conducted in order to characterise the new RH12 → RH15 system. An initial injection test (24l/s; 0.5 hours) indicates the reservoir is likely contaminated by viscous gel (Parker, 1989a). Subsequent injection (21l/s; 72 hours) is followed by production from RH15 (Parker, 1989a). Response time from the production well is much faster than previous and by the end of test production flow rate in RH15 is 7l/s at an injection pressure of 11MPa (Parker, 1989a). This corresponds to a reservoir impedance of 1.6MPa.l⁻¹.s⁻¹, a definite improvement on pre-stimulation conditions (Parker, 1989a). It still appears that there is residual viscous fluid within the system however and, following an initial shut-in and staged venting in RH12, a series of huff-puff cycles are conducted in RH15 (Parker, 1989a). At completion of these tests “it was felt that there was sufficient uncertainty about the nature and location of the remaining impedance in the RH12/RH15 system to prevent any further treatment being contemplated...consequently the system was put on a long term circulation trial” (Parker, 1989a).

Circulation between RH12 → RH15 commences in August 1985 and operates more or less continuously until mid-1988 (Parker, 1999). The form of the tests comprises an “investigation of reservoir behaviour under various steady-state injection rates.”
(Parker, 1999). Injection flow rate is increased in a stepwise manner from 5 to 7, 10, 17, 22-24 and finally 38l/s with corresponding injection pressures between 4 and 11.8MPa (Parker, 1989a; Richards et al., 1994). Each step takes up to six weeks during which time steady state is achieved and “tracer tests, transient and steady-state analyses are carried out” (Parker, 1989a). Following completion of the step-wise circulation tests the reservoir is returned to circulation at 17l/s in order to test whether changes observed during the previous injections are permanent (Parker, 1989a).

Overall results of the circulation indicated that the performance of the RH12/RH15 system is ‘fundamentally different’ to that of the Phase 2A reservoir with what appears to be a much more direct connection between the injection and production wells (Parker, 1989a). Production flow rate in RH15 and temperature increases from 4l/s (56°C) at the lowest injection rate up to 21.1l/s (70°C) at the highest (Richards et al., 1994). A small amount of additional flow is recovered through the open RH11 (Parker, 1989a). Reservoir impedance experiences a notable drop with increasing production flow reaching a minimum of 0.56MPa/(l/s) (Richards et al., 1994). Water loss is variable, down to 20% in some tests but increases dramatically at injection pressures greater than about 10MPa, at which point relatively intense microseismic activity begins (Parker, 1999).

Experimentation with oscillation of production flow during a small backpressure test (1.3MPa) at some point in the 10l/s (7.0MPa) injection produces a sudden and irreversible drop in reservoir impedance of about 0.3MPa/(l/s) (Parker, 1989a; Parker, 1999). Tracer tests reveal this event is associated with an increase in the modal volume of the reservoir (Parker, 1989a). Downhole temperature logs recorded throughout the circulation period show a total thermal drawdown of around 10% (Richards et al., 1994). Production logging indicates that the flow into RH15 is dominated by the same relatively small number of joints first identified post-stimulation. Similarly, data from RH12 indicates that the majority of flow is accepted by stimulated natural structures, there being no evidence that the explosively stimulated zone is accepting water (Parker, 1989a).
Around 1,300 microseismic events are recorded during the circulation with the majority of located events occurring within zones previously active during Phase 2A (Parker, 1989a). A strong downward trend of events is visible at injection pressures above around 10MPa when seismic activity becomes most intense (Parker 1989a; Parker 1999). The overall intensity of events is less than that observed during Phase 2A however, possibly an indication of the reactivation of previously stimulated structures (Parker, 1989a). In all cases detected activity points to shear failure (Parker, 1989a).

Studies of produced fluid chemistry indicate nothing more than the expected irreversible hydrothermal alteration of feldspar, mica etc. and no inhibiting chemical precipitation is detected (Parker 1989a). The numerous tracer tests conducted throughout the circulation period indicate a steady system volume prior to the 10l/s backpressure test. As mentioned above this test saw an irreversible increase in reservoir volume. Subsequent to this event increases in flow rate are accompanied by increases in both modal and fracture volume but not in breakthrough volume (amount of fluid retrieved) (Parker 1989a). Modal volume is also found to increase with circulation time and in all cases is irreversible (Parker, 1989a). It is found that changes at the fringes of the reservoir do not affect the internal flow regime and that whilst flow path volume may increase the fundamental pressure/flow rate relations do not change (Parker, 1989b).

Circulation in the reservoir is maintained at 17l/s for several months after the completion of the Phase 2B testing sequence. Phase 2B officially ends in September of 1986 and is superseded by Phase 2C which begins in October. Aims of the new phase include the full characterisation of the RH12/RH15 reservoir, its formation, physical features and performance through time via generation of a working reservoir model. A corollary aim is the completion of a feasibility study for development of a HDR project in England.

Initial Phase 2C experiments are similar to those of Phase 2B with a series of step-wise injections over a period of around ten months (Richards et al., 1994). The range of injection flow rates is higher than that of the previous phase with steps varying from 21.3 to 23.6, 29.6 up to 33.2l/s (Richards et al., 1994). Subsequent to this steady