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COSTS OF DRILLING DEEP WELLS IN GRANITE IN THE UNITED KINGDOM

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ABSTRACT

The costs of drilling HDR doublets to depths of between three and eight kilometers in granite rocks in the U.K. have been estimated. The estimating method uses a model of the drilling process which determines drilling times, quantities of materials etc. and combines these with unit costs to give the overall costs. Drilling times have been forecast using the experience of drilling wells to two km in Cornwall. The results indicate that overall drilling times in granite could be lower than times to drill to similar depths in sedimentary formations.

INTRODUCTION

'Hot dry rock' (HDR) geothermal technology has been the subject of sustained investigation in the U.K. over a period of ten years. The studies have centred around the experiments being carried out by the Camborne School of Mines (CSM) in Cornwall (Ref. 1). The work has been funded by the U.K. Department of Energy with some contributions from the Commission of the European Community. A thorough review of HDR Technology together with an assessment of potential economics is currently being conducted. The aim of this review is to determine the best way forward for HDR research in the U.K. This could include the development of a commercial prototype power station drawing heat from a deep system. This paper describes some work on drilling costs which has been carried out as part of this review. Two major issues have been given specific consideration, these are rig day rates and drilling times.

Demand for the services of drilling contractors fluctuates broadly in line with fluctuations in the oil market. Day rates quoted by contractors can be substantially different between periods of high and low demand. An uncertainty exists surrounding the rates which should be assumed in connection with a commercial HDR drilling programme. Also it may be that a fleet of dedicated rigs would be able to operate at rates which are lower than those which are possible for drilling contractors.

The best HDR targets in the U.K. have relatively low thermal gradients of 35 to 40°C per km. It will be necessary to drill wells between 5 to 7 km deep in granite rocks in order to access temperatures suitable for power production. Very few wells have been drilled in granites and estimating drilling times to these depths is a major problem.

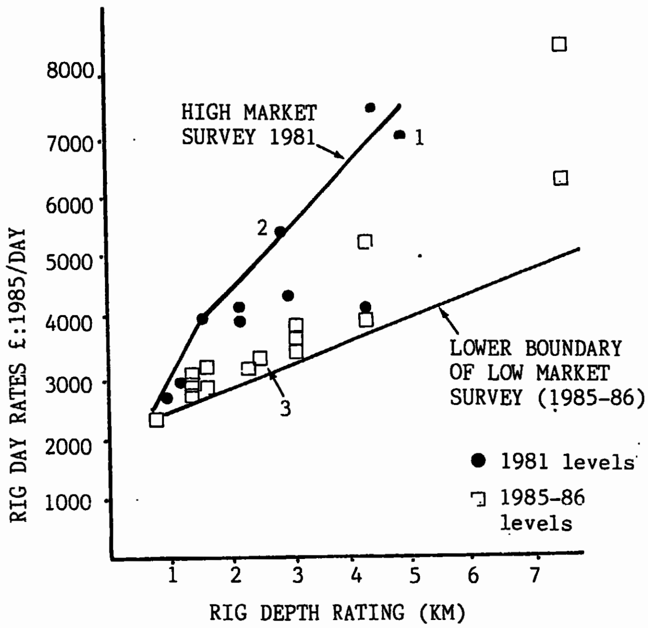


Figure 1 MARKET FOR DEEP DRILLING RIGS IN THE UK

In this study well costs have been calculated using a drilling cost model which has been developed to estimate drilling costs in the U.K. This model and its variants are described in Ref. 2 to 5.

MARKET FOR DRILLING SERVICES

Figure 1. shows day rates for U.K. drilling rigs collected during 1985 and 1986. It also shows rates collected during a similar survey in 1981. These latter observations have been adjusted for inflation so that they can be compared with the recent data. Although the data is sparse it is clear that current rates are in general much lower than the rates which were obtained in '81. 1981 was a period of high activity in oil exploration

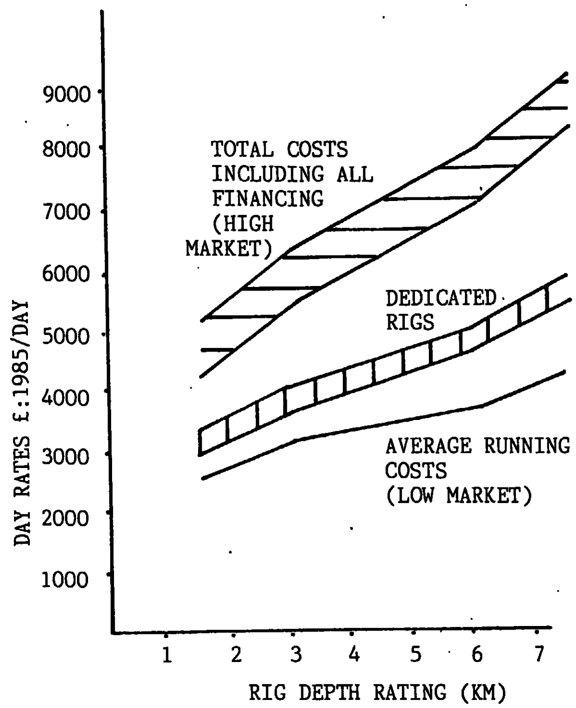


Figure 2 SIMULATION OF RIG DAY RATES

and development; demand for drilling rigs was high. Today we are observing a slump in oil-related activities and a very low level of demand for drilling rigs.

There is no definitive way of characterising the rates which will apply under any market conditions. Thus in high demand situations some contractors will be able to obtain exceptionally high rates due to special short-term circumstances while others, because of local effects, may only command relatively modest rates. Also in a low market situation some contractors will be better placed to resist pressure on rates than will others because of special skills and/or facilities. However, general economic principles will set the trends in both situations. In high demand situations rig rates will rise to levels which make it attractive to contractors to buy and commission new rigs and the costs of doing this will tend to limit the levels which rig rates will reach in the medium term. In economic terms the rates are determined by the average total costs including financing of producing and operating drilling rigs. It is interesting that the points 1 and 2 taken from the 1981 survey represent new rigs commissioned at this time.

In low demand situations contractors will not operate rigs at day rates which are below the day to day running costs of the rig. In economic terms, the lower rates are limited by the average running costs (excluding financing) of drilling rigs. Rigs which cannot command these rates would be decommissioned. It is interesting that the rig represented by point 3 taken from the 1985 survey has now been decommissioned.

In order to test this theory, estimates were made of the average running costs and of the total costs including financing of drilling services.

The average running costs include the costs of labour, tool pushers, administration, insurance, minor maintenance, fishing reserve, drill pipe and collars, transport, site management. Major renewals were estimated from an annual charge of 2% of capital apportioned over an assumed 300 days per year of operations. The other categories were estimated from information obtained from a drilling contractor.

The total costs including financing: in addition to the running costs specified above, these also include the costs of financing the purchase of a new rig. These have been calculated assuming that 30% of the capital cost is financed through secured debt and is repayed over 10 years. The remaining 70% is provided as an unsecured equity contribution by shareholders. This is repayed over 5 years; a 5% discount rate is assumed for both contributions. The shareholders accept a considerable risk in financing the rig; they do this in the expectation of a rapid payback of the investment (at a low interest) and the prospect of large profits from the operation of the rig over the remainder of its lifetime (assumed to be 15 years). The capital costs of drilling rigs are also affected by the level of demand for drilling services. The majority of the data available here was collected during 1979-81 when demand was high. This was supplemented by some more recent data from a drilling contractor. A wide range of costs was indicated and this introduces an additional uncertainty in the estimated rates.

The estimation of rig rates in this way is an exercise with many imponderables; in addition, the data exhibits a high degree of scatter. Because of these factors, a detailed analysis of the effects of inflation and changing exchange rates is not justified. Costs were adjusted to 1985 levels using general inflation rates and an exchange rate of 1·5$ to £ was used.

The results of the calculations are shown in Figure 2. A comparison of the total costs including financing with the high market line in Figure 1 and the average running costs with the low market line in Figure 1 show a reasonable degree of consistency. This supports the market interpretation advanced above.

Low market rates are unstable. At these rates some drilling contractors will not be able to meet debt repayments and will go bankrupt. In general old rigs will be decommissioned, they will not be replaced and thus rig fleets must decline. Ultimately reduction in supply will cause rates to rise again and these will stabilise at the level at which it becomes economic to buy and commission new rigs. The industry is stable in this condition with fleets being maintained by new rigs replacing old ones. Thus the higher rates shown in Figure 1 are more stable than the lower rates, in the long run. It is these high market rig

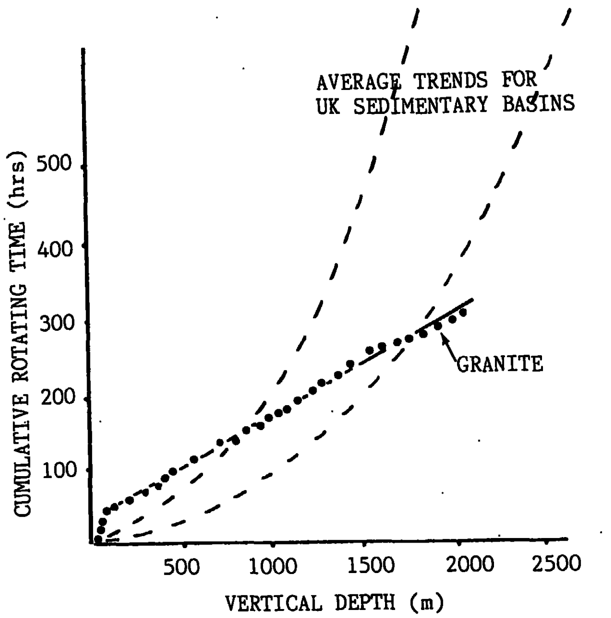


Figure 3 CUMULATIVE ROTATING TIME INCREASING WITH DEPTH IN VERTICAL WELLS

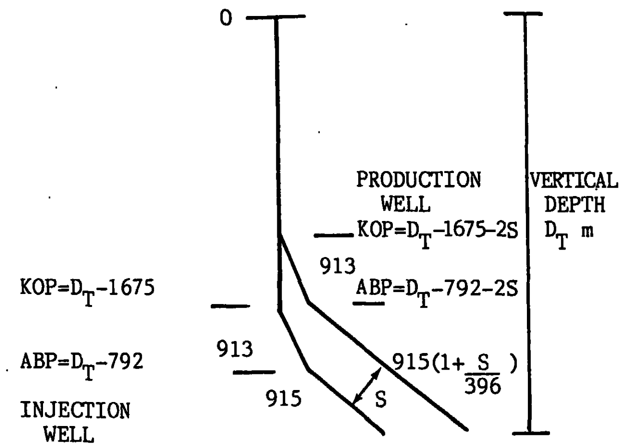
rates which should be assumed when forecasting the costs of an HDR drilling programme based upon the use of contractors.

HDR developments in the U.K. are likely to be concentrated in a small number of areas and any significant commercial development will require a series of wells drilled as part of a programme over an extended period. In this situation the use of rigs solely dedicated to the drilling of HDR wells over their lifetime offers the prospect of reducing rig day rates. This is because 'dedication' could lead to improved utilisation of the rig and of the trained labour.
- Rigs can be financed over the whole of their operating lives.
- Crews will be based at home, they will work a more normal 'factory' shift routine and this will reduce dislocation and standby premiums.

Dedicated rig fleets do exist in the geothermal field operated by Orkustofnun in Iceland and by ENEL in Italy. No useful data on these operations were available to the authors. Thus a variety of assumptions have been made and calculations of running costs and financing charges have been carried out to estimate rig rates for dedicated rigs which can be compared with the 'contractor' rates given above. The results are included on Figure 2. Clearly, substantial reductions may be possible. These arise mainly from reductions in financing charges.

If reductions in rig rates are possible through using dedicated rigs, similar reductions may also be obtained by using dedicated facilities to provide other services used in well drilling. The

Figure 4 SIMPLIFIED DOUBLET GEOMETRY AND CASING PROGRAMME



Angle inclinations from vertical
KOP to ABP=14°50'
ABP to D_T =30°00'

Vertical setting depth of casing

D_T=3000m	20" O.D 10m
	13 3/8" OD 60m
	9 5/8" O.D ABP
D_T 4000m	30" OD 30m
	20" OD 330m
	13 3/8" OD 1500m
	9 5/8" OD ABP

logical result would be an integrated drilling operation using dedicated facilities and long-term buying of supplies. This could give costs which are significantly different from those calculated assuming the normal methods of organising drilling operations.

DRILLING TIMES

Production doublet drilling costs were simulated by using a simplified modelling approach developed in earlier studies (Refs. 2-5). This involves estimating the total rig hire time from selected rig time elements, as summarised in Table 1, and calculating the total doublet costs from specified cost groups, as summarised in Table 2.

The importance of calculating the total rig hire time is that it is used with the appropriate estimate of rig day rate to evaluate the third cost group "Payments to Drilling Contractors". This is normally the largest individual contribution to total drilling costs. As shown in Table 1, the total rig hire time is composed of seven separate time elements. The first time element is the "Rotating Time" which is the period of time during which the bit actually penetrates the rock. This is a significant time element because it affects certain other time elements and has a strong influence of the total rig hire time. For this reason, it is essential to derive a realistic forecast of the variation of cumulative rotating time with vertical depth. This can be achieved by analysing bit records from previous wells using

Table 1 Example of Simulated Total Rig Hire Time For a 6Km Doublet

Time Element	Rig Hire Time (hours) Injection Well	Production Well
1. Rotating Time	879	894
2. Tripping Time	825	865
3. Casing and Cementing Time	297	290
4. Mishap Time	308	310
5. Logging and Surveying Time	554	559
6. Well Testing Time	70	-
7. Miscellaneous Time	1173	1167
TOTAL	4106	4085

methods described elsewhere (Ref. 5).

Bit records were available for three wells drilled in the Carnmenellis granite as part of the Camborne School of Mines (CSM) geothermal energy project (Refs 7 and 8). In order of drilling, these wells are referred to as RH12, RH11 and RH15. It was necessary to choose one "representative" bit record from which to derive an equation relating the cumulative rotating time to vertical depth. The bit record from RH12 was not considered to be appropriate because, as the first well in the series at this site, there will have been no opportunities to benefit from experience in bit selection. Although the bit record for RH15 should reflect experience, the geometry of this well is complex and analysis would have been overly time-consuming. Consequently, the bit record for RH11 was used even though it is believed that high rates of penetration were experienced in this well due to unusually favourable drilling conditions.

The bit record for RH11 provided information on the "time on bit" and measured "depth in/out" for each drilling bit. The sum of the values of "time on bit" equals the cumulative rotating time to a given point and the measured depth indicates the distance down the well from the surface. In deviated wells, the measured depth does not equal the vertical depth so data on measured depth were converted to vertical depth by multiplying by the cosine of the vertical angle of inclination of the well from the vertical. After adjusting for coring and reaming, the variation of the cumulative rotating time with vertical depth for vertical drilling was obtained. Adjustments were also made for the effect of deviation on the rotating time. It was assumed that the effective weight on bit in the direction of penetration is reduced by the cosine of the angle of inclination of the well from the vertical and, subsequently, this reduces the rate of penetration of the bit and effectively increases the cumulative rotating time. The resultant effective variation of cumulative rotating time with depth for a vertical well is shown in Figure 3. This indicates that the

Table 2 Estimated Costs for a 6Km Production Doublet

Cost Group	Costs (£K:1985)
1. Civil Engineering	200
2. Rig Moves	123
3. Payments to Drilling Contractors	2775
4. Directional Drilling	542
5. Surveying	97
6. Downhole Motors	617
7. Stabilisers and Reamers	1376
8. Rock Bits	921
9. Drilling Muds	1200
10. Casing	1078
11. Wellheads	100
12. Cementing	313
13. Christmas Trees	400
14. Logging	353
15. Testing	107
16. Fuel and Lubricants	375
17. Abnormal Drillstring Wear	305
18. Inspection	160
19. Fishing Tools and Services	567
20. Miscellaneous	2206
TOTAL	13814

variation of cumulative rotating time with depth in a vertical granite well is linear at depths below about 40 metres. Or conversely that rates of penetration in granite are essentially constant with depth. This behaviour can be compared with rotating times observed in wells drilled in sedimentary regions in the U.K. The general trends are also indicated in Figure 3. It can be seen that, in contrast with the data for the granite the rotating times for the sedimentary regions appear to increase exponentially with vertical depth. Thus a simple linear equation can be used to relate cumulative rotating time to vertical depth for a straight well and this can be easily modified to take account of the effects of deviated drilling. These equations have been used here to estimate drilling times to 8km and thus the assumption of constant rates of penetration is implicit in the results.

In the deviated wells it is assumed that the well trajectories can be approximated by the simplified forms shown in Figure 4. This consists of three sections; vertical drilling from the surface to the "kick-off point" (KOP) deviated drilling at a constant initial angle of inclination from the "kick-off point" to the "angle built point" (ABP) and deviated drilling at a constant final angle of inclination from the "angle built point" to total depth.

The second time element is the "Tripping Time" which is the period of time involved in changing drilling bits. This time depends on the sum of the measured depths from which each trip begins, referred to here as the tripping distance, and the effective speed at which trips are performed - the round tripping rate. The tripping distance

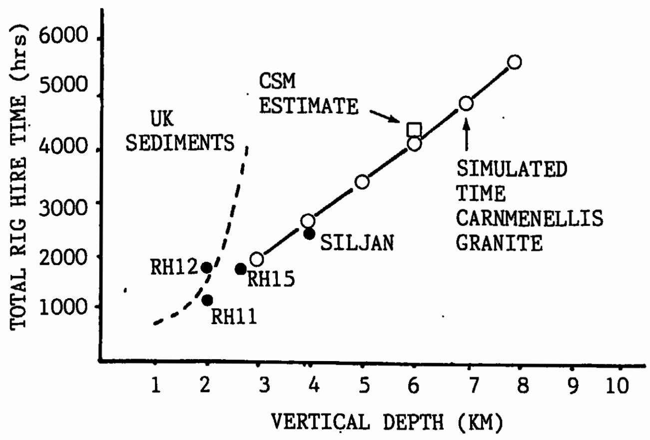


Figure 5 SIMULATED AND ACTUAL TOTAL RIG HIRE TIMES FOR SINGLE WELLS

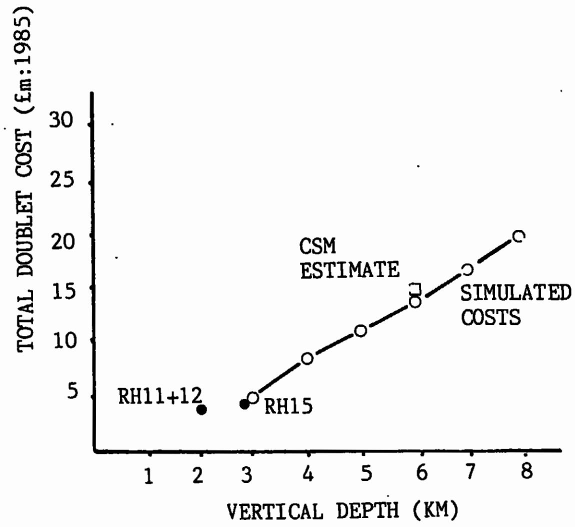


Figure 6 TOTAL COSTS OF DOUBLETS

depends on the number of drilling bits used and both these factors were calculated using the simplifying assumption that drilling bit life is constant. Both the average bit life and the round tripping rate and other rig time modelling parameters were derived using data recorded for wells RH11 and RH12 (Ref. 7). These parameters enable the remaining time elements to be calculated from information which summarises the well design.

The relevant features of geometry and casing programme for the standard doublet assumed in this study are illustrated in Figure 4. It can be seen that these features are generalised in terms of the total vertical depth, D_T, and the minimum separation of the doublet, S. These features were based on a CSM design for a 6 kilometre doublet (Ref. 9). A separation, S, of 175 metres was assumed for the 6 kilometre doublet design and this value was used in all subsequent calculations in this study. An example of simulated total rig hire times obtained from the modelling approach described here is shown in Table 1 for the injection and production wells of a 6 kilometre doublet.

In addition, total rig hire times were calculated at 1 kilometre intervals for doublets with total vertical depths ranging between 3 and 8 kilometres. Figure 5 which summarises the results, indicates that there is a good comparison between the simulated times for the Carnmenellis granite and the times for wells RH11, 12 and 15 and the CSM estimate for a 6 kilometre deep early production doublet. There is also relatively good comparison with time for the Swedish Siljan deep well prior to major drilling problems encountered below 4 kilometres. Simulated rig hire times from previous work on low-enthalpy geothermal drilling are also included in Figure 5 to demonstrate the distinction between drilling in sedimentary and granite settings.

TOTAL DRILLING COSTS

Estimates of total rig hire times were used as a basis for calculating the total cost of doublets. Each cost group was estimated separately. This involved deriving and applying a variety of simple costing rules. Wherever possible, attempts were made to use independent costing rules developed during previous modelling work. An example of this is the derivation of rig day rates, described earlier. These were used in conjunction with the simulated rig hire times to provide estimates of "Payments to Drilling Contractors". Similarly, other important cost groups were calculated using independently collected data such as rock bit prices for cost group 8 and fuel consumption rates for cost group 16. Where necessary, costs were inflated from 1981 to 1985 £ sterling values using either the U.K. retail price index or US/UK exchange rates and appropriate US drilling cost indices (Ref. 10).

The mud programme and its costs represent a special problem for wells at these depths and in this area it was necessary to rely upon information given in the CSM prognosis (Ref. 9).

The resulting variation in total costs for doublets with vertical depth, assuming a normal market for drilling rigs, is illustrated in Figure 6. This shows that there appears to be reasonably good agreement between this simulated variations and suitably adjusted costs for RH11 and RH12, and RH15, as well as the CSM prognosis for a 6 kilometre early production doublet. If the day rates, shown above, for dedicated drilling rigs are used then total costs can be reduced by between 8% and 11%.

CONCLUSIONS

Although data on well drilling in granite rocks are sparse analysis of some of the data which does exist indicates consistent trends. It seems that cumulative rotating time varies linearly with depth for vertical drilling indicating that rates of penetration are essentially constant over the depths drilled so far. If this behaviour is assumed to continue to greater depths then estimates of drilling times and costs can be obtained. These suggest that drilling times could be significantly lower than those observed at similar depths in sedimentary formations. Only by drilling deeper wells in granite will the validity of these conclusions be tested.

Drilling rig day rates undergo large changes as demands for drilling services fluctuate. However, 'high' market rates which include charges for rig financing are more stable than lower rates which just cover running costs. It is advisable to assume that high rates will pertain when fore-casting costs over an extended period.

ACKNOWLEDGEMENTS

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