Commission of the European Communities

energy

An investigation of the sensitivity of the economic appraisal of geothermal energy resources to energy price rises

Report

EUR 8584 EN

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An investigation of the sensitivity of the economic appraisal of geothermal energy resources to energy price rises

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Final report

Contract No EG-C4-001-UK

Directorate-General
Science, Research and Development

1983 EUR 8584 EN

Published by the
COMMISSION OF THE EUROPEAN COMMUNITIES

Directorate-General
Information Market and Innovation

Bâtiment Jean Monnet
LUXEMBOURG

LEGAL NOTICE

Cataloguing data can be found at the end of this publication

Luxembourg, Office for Official Publications of the European Communities, 1983

ISBN 92-825-3961-X Catalogue number: CD-ND-83-120-EN-C

Printed in Luxembourg

CONTENTS PAGE

Technical Acknowledgements

Dr. P. Ungemach, Project Manager for Geothermal Energy R & D at the Commission of the European Community.

Dr. J.D. Garnish and colleagues at the Energy Technology Support Unit, Harwell.

Dr. B. Kelk and the staff at the Natural Environment Research Council, Swindon.

M. P. Jaud and A. Raymond, EDF, Chatou, Paris.

M. J. Vathaire, Geotherma S.A., Paris.

Dr. A. Whittaker of the Institute of Geological Sciences, Keyworth.

Dr. R.A. Downing of the Institute of Geological Sciences, Wallingford.

Mr. C. Nunn, Geologist and Geothermal Mud Logger.

Mr. R. Pidskalny and Mr. J. Jameson of Kenting Drilling Services Ltd., Nottingham.

Mr. S. White, British Gas Exploration Ltd., London.

Mr. A.S. Orford, National Supply Company, Houston, Texas.

Dr. D.J. Entingh, The Mitre Corporation, McLean, Virgina.

Dr. C.C. Carson and Dr. Y.T. Lin, Sandia National Laboratories, Albuquerque, New Mexico.

Mr. S. Palmer, Centrilift-Hughes Inc., Weybridge.

Mr. M. Elliot, TRW-Reda Pumps, London.

Mr. M. Jaehme, Hoare Lee and Partners, Bristol.

1. Introduction

This study considers the economic appraisal of the direct use of the low enthalpy brines which are found in European sedimentary basins in the particular application of space heating. All cost estimating relates to the U.K. context.

The elements of a typical scheme are shown in Figure 1. While in some circumstances a single well is acceptable, normally two wells are drilled into aquifers at depths of between 750 and 3000 m. Submerged pumps deliver the water, which may be at temperatures between 50 and 90°C, to the surface. Here it passes through a heat exchanger delivering useful heat to the heating system and it is then normally reinjected into the reservoir using a surface pump. Some back-up heating, fired by a conventional fuel, is also provided to supplement the geothermally-derived heat in the coldest parts of the heating season.

In order to perform an economic appraisal a series of physical and cost calculations are necessary.

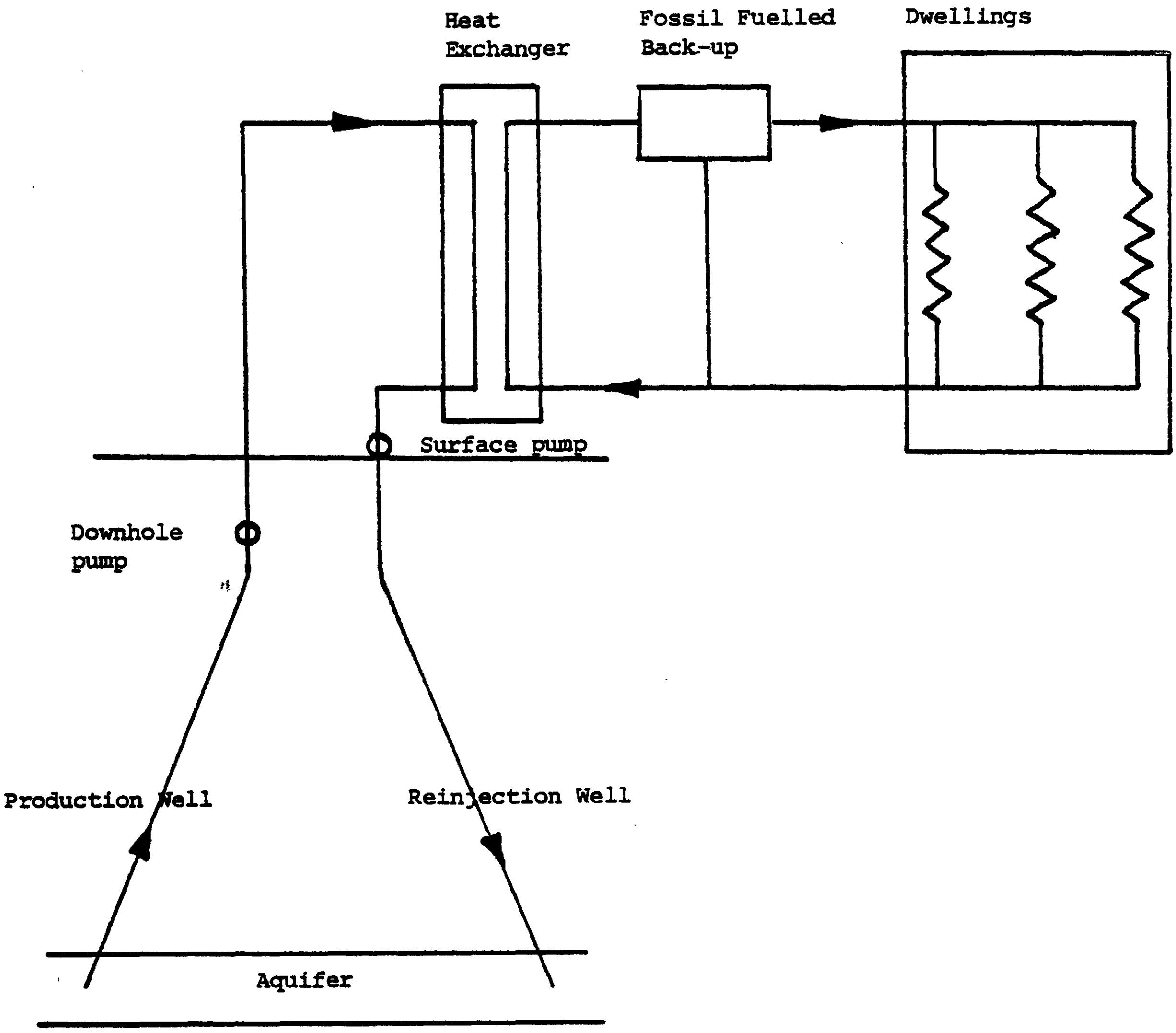
The important physical calculations are as follows:

i) Calculation of the doublet spacing and the production and reinjection pump powers from a knowledge of the important reservoir parameters and for the desired volume flow range. The equations used to perform these calculations are given in Section 2.

ii) Calculations of the load which can be supplied from the wells supplemented by the fossil fuel fired back-up. This is a complex calculation which depends upon climate through the load duration curve; the size of the geothermal flow from the wells, the temperature of the geothermal fluids; the proportion of the heat supplied by back-up boiler and the mode of operation of the building internals. The approach adopted is described in Section 3.

These physical calculations of the system performance must be accompanied by estimates of U.K. costs. Drilling costs are a major element in scheme costs but in addition they are also an area where costing is difficult particularly in the U.K. context. Although a number of simple approaches

Figure 1 Geothermal Heating Scheme



were examined it was eventually necessary to develop a detailed procedure for estimating U.K. costs. U.K. drilling costs appear to be anomalously high in comparison with average U.S. costs and it has been suggested that the reason for this is that activity is low resulting in high rates for rig hire and services. Also there have been indications that drilling costs are inflating at a rate which is faster than the general inflationary trend. The development of the cost estimating procedure and the examination of U.K. and U.S. drilling costs and inflation rates has formed a major part of the study. The results are given in Section 4.1.

The information produced by these studies has been used to calculate the unit costs of fluid at the wellhead and show how these unit costs depend upon important reservoir parameters. The results of these calculations are given in Section 6. Also the effects of changing energy and general prices on the unit cost of delivered heat in some hypothetical schemes have been calculated and the results are given in Section 7.

As the work in individual areas of the study has been completed it has been the practice to write this up fully in the form of working papers. This final report contains mainly the results and conclusions from the study, and reference is made to the individual working papers for full details of the work.

2. Reservoir Calculations

There are two main areas which require examination in relation to doublet and singlet exploitation of the resource. One is the method of calculation of spacing which, in the doublet case, is required to give a reasonable lifetime before the production well begins to draw cold water. Provided certain reasonable assumptions are made about doublet design, i.e. separation of the wellhead and length of vertical drilling before deviation 'kick off' then doublet spacing can be used to determine a deviation from the vertical of each well. This influences well costs through the extent of the directional drilling required. It also affects pumping through the actual length of the well as opposed to the depth below ground level.

Pumping powers are the second area examined. The calculation of pumping power, as a function of flow rate required to produce the fluids in the case of the singlet and to both produce and reinject geothermal fluids in the case of the doublet is very important, as it determines pump power ratings which affect capital costs and also electricity consumption which affects running costs. The doublet calculation is simpler in that reinjection maintains pressure in the reservoir. In the singlet case pressure varies over the lifetime of the well.

The approach to these calculations which has been adopted relies heavily on two particular sources of information (Refs. 1 and 2). It is fully described in Working Paper No. 9.

For a horizontal, homogenous, isotropic reservoir with constant thickness, infinite extension and no natural hydrodynamism, operated under constant conditions, the important equations are given in Appendix I.

3. Heating System Calculations

The way in which the fluctuating pattern of demands of the heat load is met by a heating system consisting of a geothermal heat supply supplemented by a back-up fossil fuel fired boiler depends in a complex way upon a number of factors. It depends upon geothermal fluid temperature and also flow and its relation to the size of the load; it depends upon environmental factors through the load duration curve. It also depends upon the technology of the heating systems through the heat exchanger characteristics and through the operating characteristics of the individual heating elements.

Thus a given geothermal resource can be linked with varying degrees of energy and cost effectiveness to a variety of heating demands and schemes. The approach adopted in these calculations is to take the geothermal resource as the starting point (a resource which has the same characteristcs as that of Marchwood is taken as a base case) and then determine the size and outline features of alternative domestic heating schemes which match it.

The approach draws upon the physical modelling results of the OET and EDF studies (Refs. 3 and 4) of different resource and scheme combinations so it shares the same basic modelling assumptions. The sequence of calculations is as follows:this is fully described in Working Paper (13). Basic parameters relating to the geothermal resource, the type of load duration curve and the scheme are fixed, see Table 1.

Then beginning with a chosen level of coverage (fraction of the total energy demand met from geothermal) the ratio of demand/unit flow for fluid of this temperature which will achieve this coverage is determined from curves given in the OET study (Ref. 3). Multiplying this figure by the assumed flow rate then gives the total energy demand of the scheme and the number of dwellings can be calculated .

Knowing the total energy demand the peak power level can be calculated and also the quantity of back-up fuel required. The power derived from the geothermal supply at the peak demand condition is then calculated from the assumed radiator control characteristics and the assumed heat exchanger characteristics. This enables the backup boiler to be sized and costed. Also the fraction of the demand which is met from the geothermal fluid is calculated for demand conditions intermediate between the peak demand conditions and the zero heat demand condition. In this way it is possible to estimate the numbers of hours in the heating season for which the heat derived from the geothermal fluid flowing at its maximum flow would undersupply demands in situations of high power demand and would oversupply demands in situations of low power demand. Knowing the numbers of hours of under and oversupply allows the calculation of units of electrical energy required for pumping.

The heat exchanger can be costed from its characteristics and the level of geothermal fluid flow.

Finally the electrical consumption of the heating system circulation pumps is calculated from the number of dwellings and length of the heating season.

The quantities calculated which correspond to the base case defined in Table 1 are shown in Table 2.

TABLE 1

Parameters in Heating Scheme Calculations

Resource (values input from Reservoir Model)			
Well configuration	Doublet: 1 production, 1 reinjection		
Geothermal Fluid:			
Temperature at wellhead	T_g	70	°C
Volume flow rate: total	Q_g	100	m^3/h
Mass density	ρ_g	1056	kg/m^3
Specific heat	C_g	3900	J/kg°C
Pumping electrical power:			
Production well	W	176×10^3	W
Reinjection well	Wo	474×10^3	W
Climate and Demand			
Climatic region		Continental - Oceanic	
Coldest temperature	T_c	-7	°C
Required room (effective demand) temperature	T_d	18	°C
Allowing for incidental gains of		2	°C
Heating period	t_d	250	days
Heating degree days	Θ	2500	°C days
Scheme			
Type of Scheme:	Heat Exchanger and Fossil Back-Up		
Coverage of energy demand by geothermal	U_h	0.8	
Heat exchanger:			
Type	Titanium plate		
Number of transfer units $\frac{KS}{M_gC_g}$ =	N_{TU}	5	
Approach temperature	T_{gs}	3	°C
Effectiveness	e	0.95	
Room heaters, heating circuit:			
Type	Radiators		
Maximum inlet temperature	$\hat{T}_{hs}$	70	°C
Maximum outlet temperature	$\hat{T}_{hr}$	50	°C
Minimum inlet and outlet temperature	$\check{T}_b$	20	°C
Dwelling:			
Volume	V	190	m^3
Volumetric heat loss	G	1.1	W/m^3°C

TABLE 2

CALCULATED QUANTITIES

Demand/unit flow ($\frac{GJ}{m^3/hr}$)	695 $\frac{J}{m^3h}$
Demand	69.5 x 10^3 GJ
Number of Dwellings	1540
Quantity of Fossil fuel derived energy required	13.9 x 10^3 GJ
Peak Power Demand	8.044 MW
Geothermal Power Coverage at Peak power demand	2.17 MW
Capacity of Back up Boiler	5.87 MW
Number of hours in 'under supply condition'	2000
Number of hours in 'over supply condition'	4000
Circulation pump power	28.1 KW
Heat exchanger KS	0.572 x 10^6 W/°C

4. Cost Estimation

4.1 Drilling Costs

4.1.1 Modelling Approach

The estimation of drilling costs can be approached in two distinct ways, by using historical cost statistics, or by constructing a model of the drilling process by which the costs of individual elements can be estimated and the total drilling cost is determined by aggregation.

Although historical data can provide useful information about trends in drilling economics, models that are well designed and detailed are more flexible and give greater insight to the cost of drilling.

Numerous geothermal drilling cost models have been assembled by other researchers and their features have been described in Working Paper No. 1. However, most of these models cannot be applied directly to the situation in the U.K. and rest of the E.E.C. for a number of reasons. In general, these models either address special problems or relate to specific situations. Some models are especially concerned with the impact of technological improvements on drilling economics, whereas others determine costs for given countries. In all, the WELCST model developed by the Mitre Corporation in the U.S.A. (Ref. 6) is probably the most useful because it avoids a number of these limitations. However, this model cannot be used directly without certain adjustments, if only because it was originally designed to estimate the costs of high-enthalpy vapour and liquid-dominated geothermal prospects in the U.S.A. Using WELCST as a guide, it has been possible to develop a procedure for estimating geothermal well costs in the U.K. and rest of the E.E.C.

4.1.2 Outline of the Procedure

The aim of this procedure is to provide estimates of the cost of drilling and completing a relatively straight (undeviated) geothermal production well. The procedure enables the effect of well depth on total costs to be investigated, and ultimately, in its general form, will be able to incorporate variations in drilling environment, well profile, mud formulation and cost inflation. The procedure achieves this by identifying two separate categories of information required for cost estimating. The first category consists of information on the time and quantities of materials needed for all the various operations involved in well drilling and completion. In effect, this forms a 'physical' model of drilling. The second category of information used in this procedure consists of unit prices of drilling services, materials, supplies, etc. By adopting this particular approach of combining physical data with prices, the procedure becomes relatively flexible since it can accommodate changes in the two independent pieces of information. This is an important feature because, in theory, it allows the procedure to reflect the impact of technological changes and price inflation, as well as enabling it to provide costs in the currency of any given country. Most other cost models do not distinguish between physical and price information and this limits their usefulness.

At this preliminary stage, however, the procedure is developed by reference to estimating the costs of geothermal well drilling and completion in the United Kingdom, during the 1980 period. The reason that these particular conditions were chosen for cost estimating is that U.K. price data was readily available for this recent period. Provided suitable price data is available in other currencies, the procedure can be fairly easily adapted to determine costs in other countries and over different periods.

The categories into which drilling costs are broken down are listed in Table 3 and the full details of the estimating procedure for each of these elements are given in <u>Working Paper No. 7</u>.

It should be noted that a number of the categories listed in Table 3 are connected by common elements. In particular, this is true for items 1A, 3A to 3E, 4A and 4B, 4E and 5A to 5E. All these items depend, either directly or indirectly, on the time required for

TABLE 3

Drilling Cost Categories

1.	Drilling Contract	1A	Rig charges
		1B	Rig mobilisation charges
		1C	Rig demobilisation charges
2.	Site Preparation	2A	Site preparation cost
		2B	Site restoration cost
3.	Consumables	3A	Fuel costs
		3B	Mud chemical costs
		3C	Water charges
		3D	Mud disposal charges
		3E	Drilling bit costs
4.	Well Hardware	4A	Casing costs
		4B	Casing accessory costs
		4C	Liner hanger cost
		4D	Production screen cost
		4E	Cement costs
		4F	Wellhead cost
5.	Services	5A	Cementing service cost
		5B	Mud engineering cost
		5C	Mud logging cost
		5D	Well logging cost
		5E	Drill stem test cost
		5F	Production test cost
		5G	Other service costs
		5H	Consultancy fees
6.	Miscellaneous Items	6A	Miscellaneous costs
		6B	Contingency

given drilling operations, which subsequently depends on well depth and design. Hence, it has been necessary to develop a 'rig time' sub model which enables the time involved in different drilling operations to be estimated. The validity of the final cost estimates depends strongly upon the reliability of time estimates produced by this submodel. The main area of uncertainty in the estimation procedure for rig time is the choice of appropriate values for the instantaneous rate of penetration at different depths for the provinces of interest. Entingh (in Ref. 6) gives generalised values for the instantaneous rate of penetration as a function of depth for a range of gradations of geological provinces designated 'soft' to 'hard'. The soft and hard designations are characteristic of the rocks in two U.S. provinces the Imperial Valley and the Geysers respectively. The extreme ranges of these rates of penetration are illustrated in Figure 6 which is taken from Working Paper No. 2. Actual rate of penetration data for non-experimental wells in the European provinces of interest is difficult to obtain. Hence it was decided to use Entingh's generalized values of rate of penetration as input data to work through the rigtime estimation submodel to generate times to drill as a function of depth for 'hard' and 'soft' provinces. The results are shown in Figure 7a and 7b.

In order to test the relevanceof these results to the European provinces of interest statistics of actual drilling times were collected. These statistics are for oil and gas exploration and development wells. However, a study reported in Working Paper No. 11, has indicated that in the European context these wells are generically similar to low enthalpy geothermal wells.

Plots of time-to-drill versus depth for the Hampshire-Wessex basin the Paris basin and Aquitaine basin are shown in Figures 8, 9, 10. It can be seen that no single defined relationship between time and depth is discernable from these plots. The scatter could have three causes. Firstly, variations in the drilling plan; for

Figure 6 General Variation for Rate of Penetration Against Depth

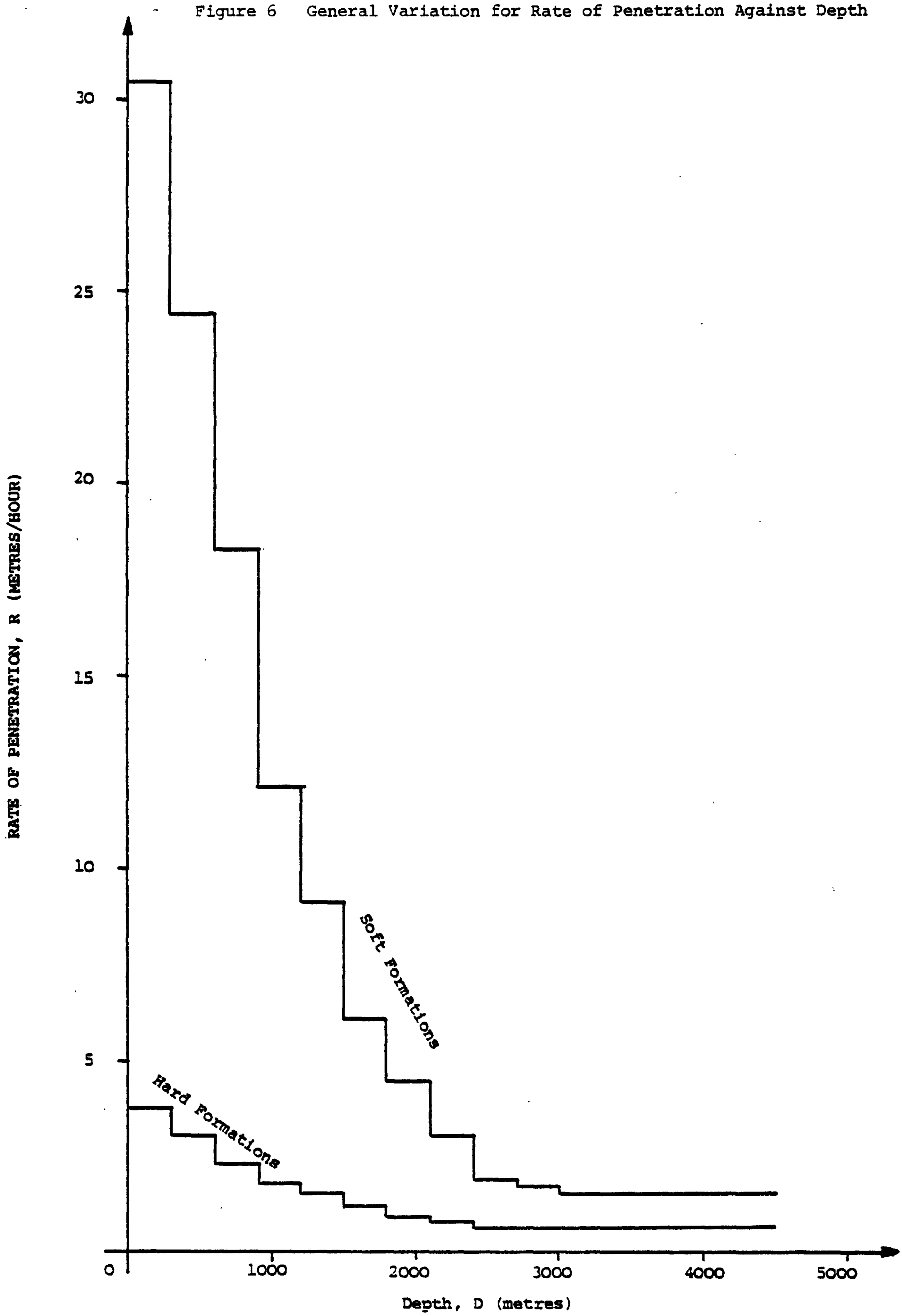


Figure 7a Estimated Rig Time for Softer Formations

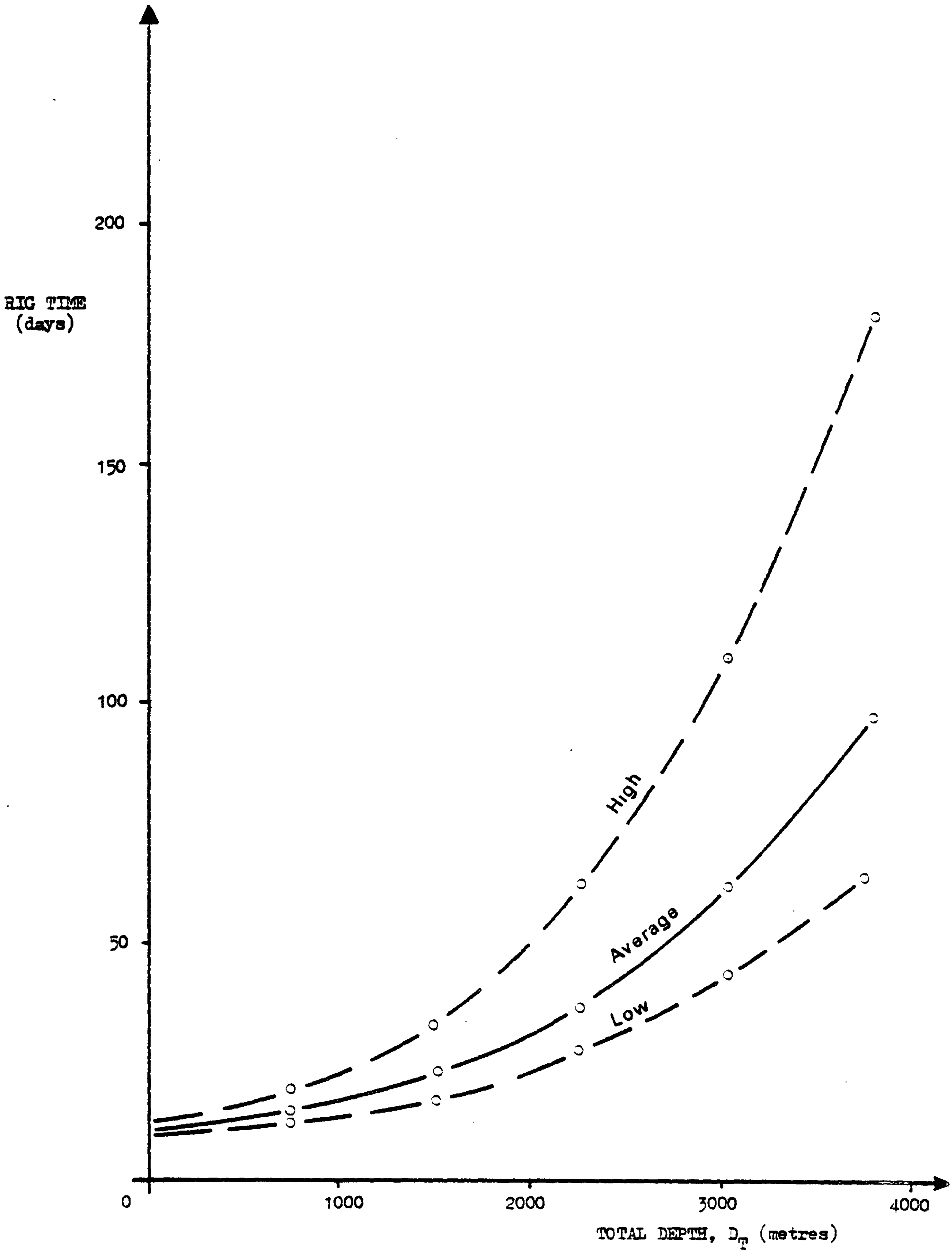


Figure 7b Estimated Rig Time for Harder Formations

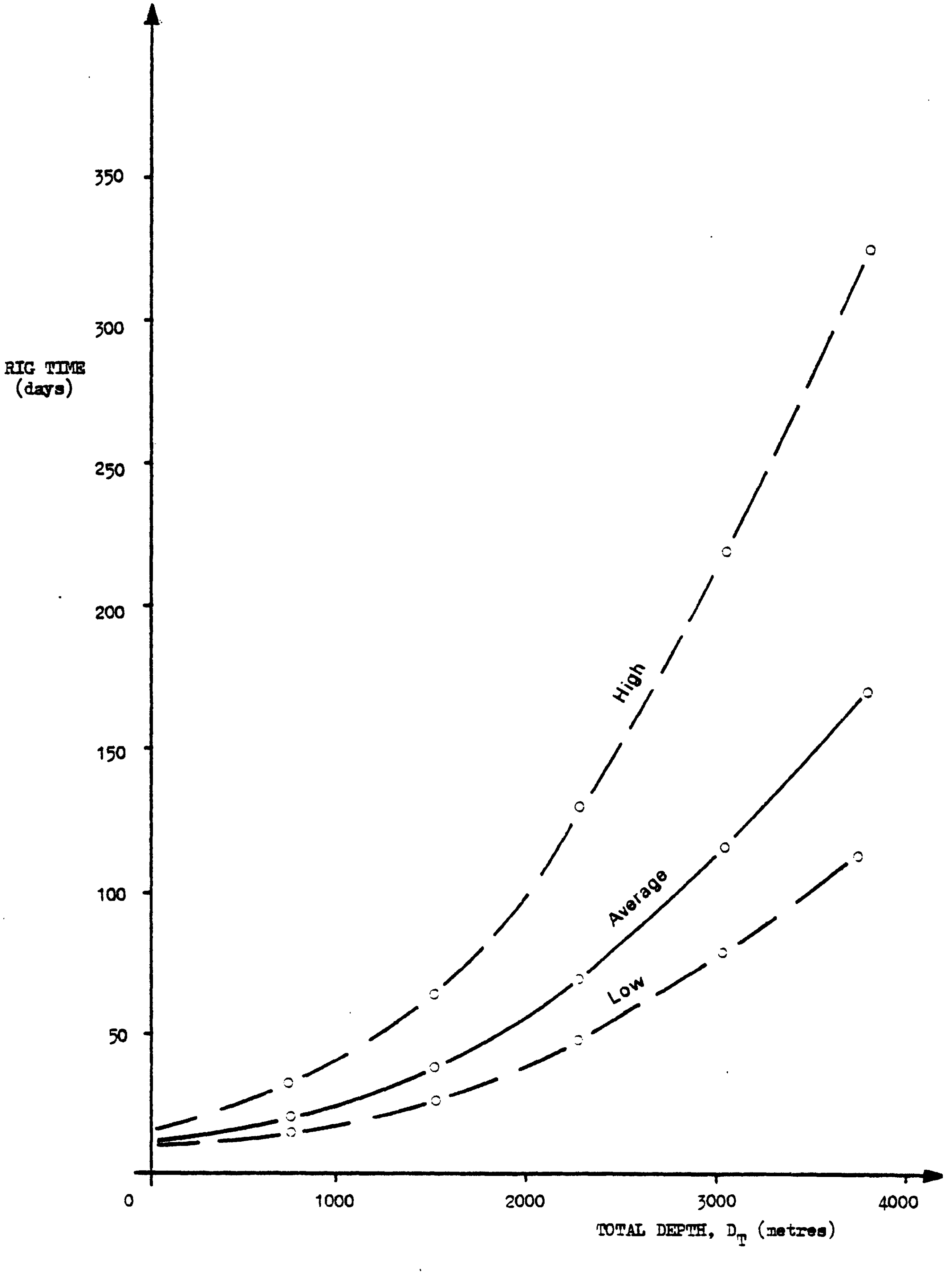


Figure 8 Total Drilling Times in the Hampshire Wessex Basin

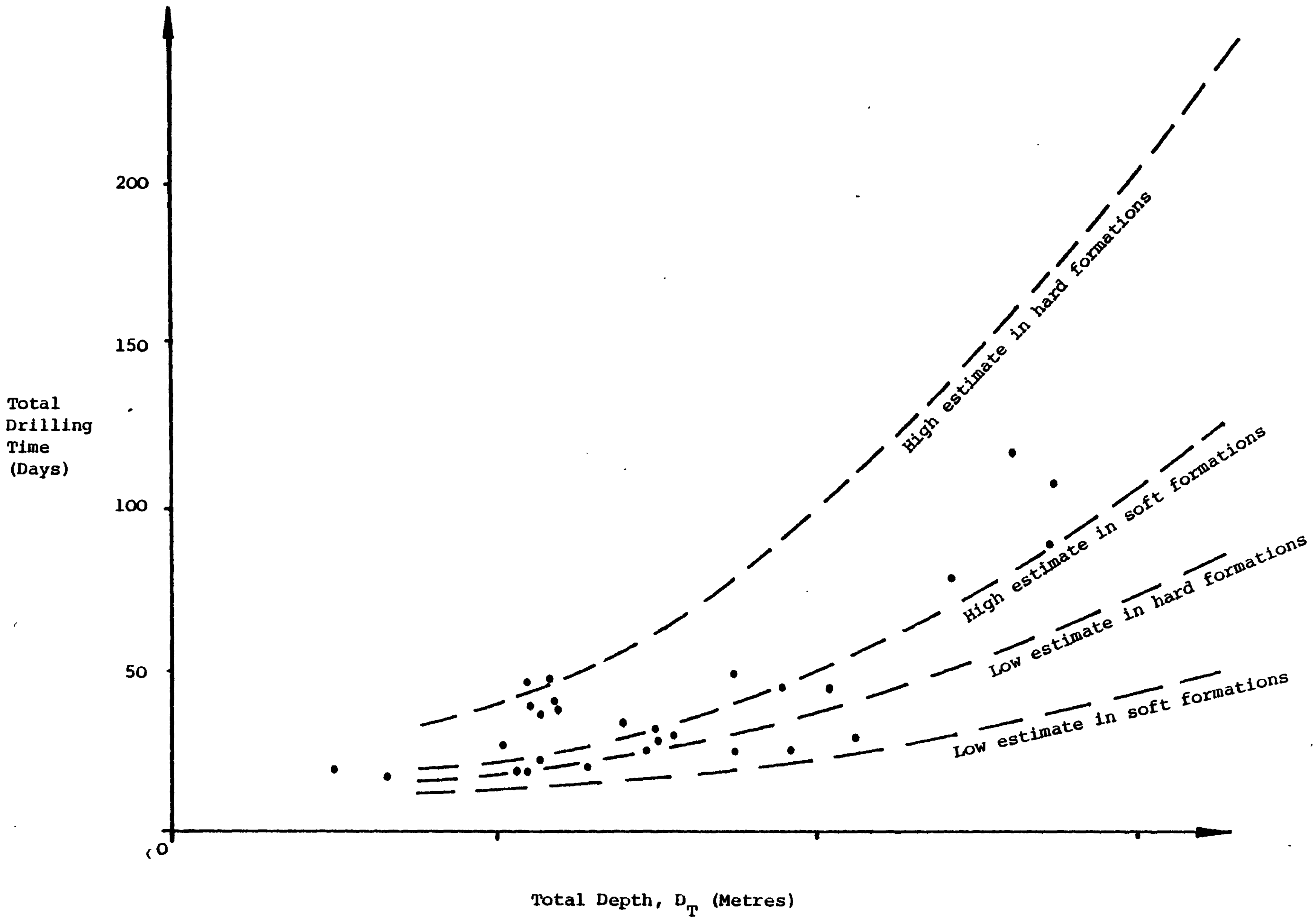


Figure 9 Total Drilling Times in the Paris Basin

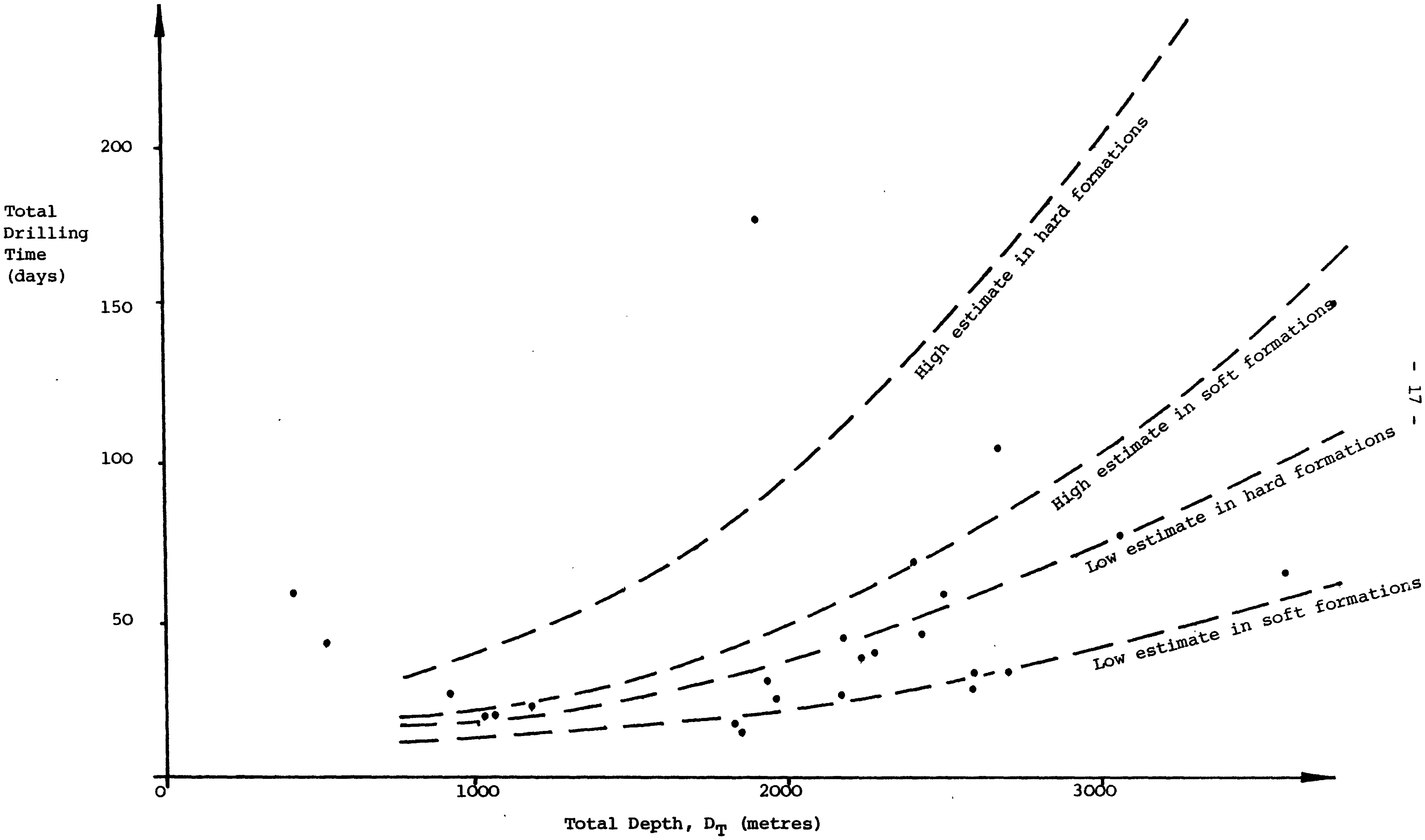
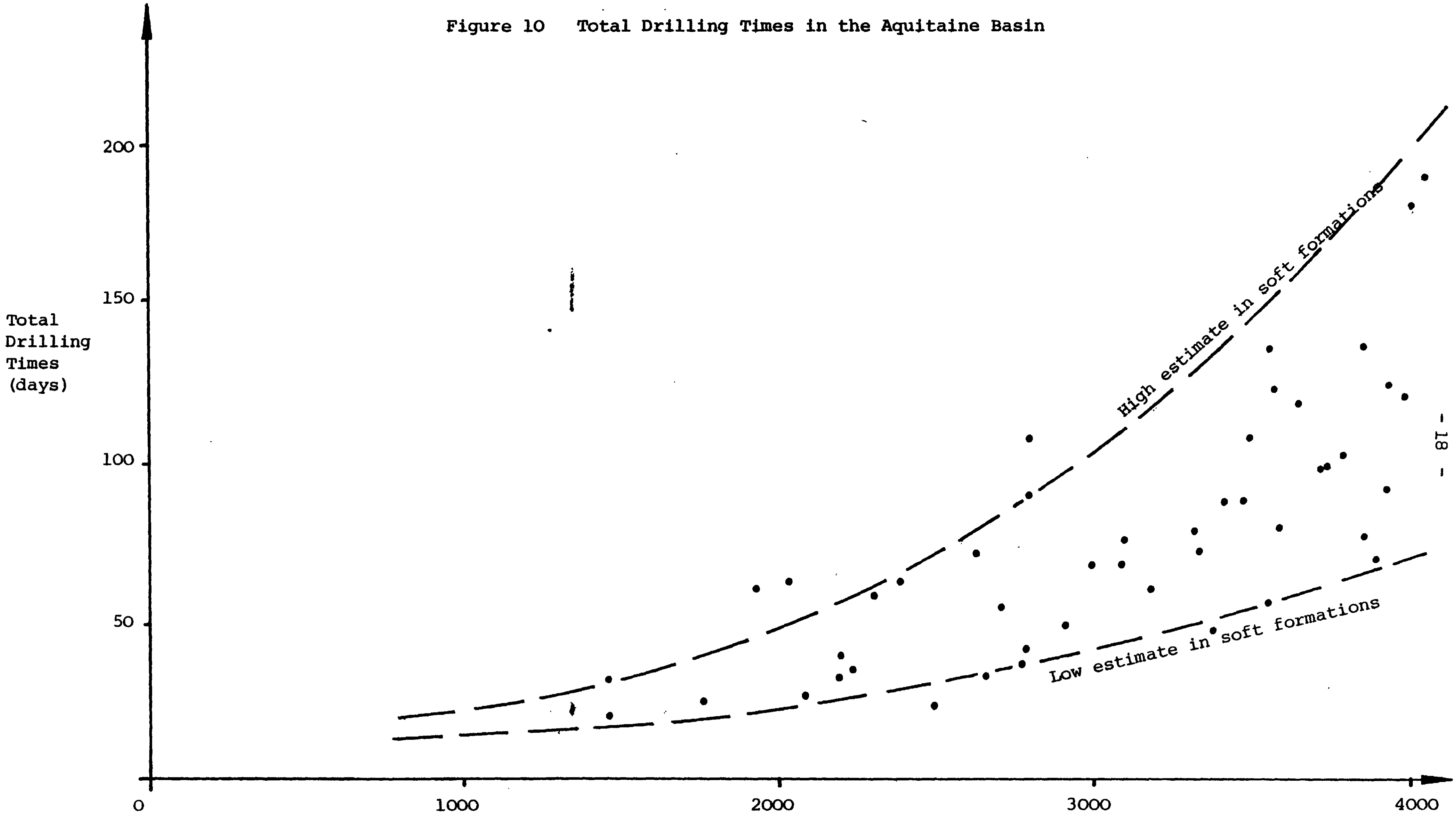


Figure 10 Total Drilling Times in the Aquitaine Basin



instance coring and logging programmes, and also the precise nature of different completions will produce significant variations in rig time. Secondly, geological inhomogenities within a particular basin will produce variations in the instantaneous rates of penetration achieved. This will also cause variations in rig time. Finally, drilling problems such as stuck pipe and lost circulation can increase rig time. The effect of mishaps in particular are very difficult to model, and the estimates of rig times shown in Figures 7a and 7b include no contingency allowance for mishaps. With the limited data currently available it is impossible to identify the major causes of the scatter in the statistics of times to drill. This can only be done by studying a large number of time breakdowns for the drilling of actual wells. These are difficult to obtain.

There is no upper limit to the time to which special drilling programmes and mishaps can increase drilling times. However, there must be some lower limit of drilling time which cannot be avoided by reducing mishaps and by economizing on the programme. Thus there may be reasonably well defined lower limits to the plots.

The estimated drilling times for 'soft' and 'hard' provinces determined from the rig time estimation submodel are reproduced on Figures 8,9, and 10. It is interesting that the lower boundary of the estimations for the 'soft' province reasonably coincides with the lower limit to the scatter of the statistical points. This implies that these particular rates of penetration are appropriate to these provinces and that the rig time estimation sub model accurately estimates the rig time for simple wells where there are a minimum of operations such as coring, logging and testing, where completions are simple and there are no mishaps.

This is a useful validation of this submodel. Also it can be seen that the scatter of the points in the plots are reasonably well bracketed by the highest and lowest boundaries of the estimates for the 'soft' province.

The second category of input information to the cost estimation procedure is the well profile. This is less critical than rate of penetration but it does have an important effect on costs through casing quantities, bits, and also on the number of casing runs which affects the rig time estimate. From a study of U.K. oil and gas wells and French geothermal wells, standard well profiles were chosen to input to the cost estimation procedure. These are shown in Figure 11 which is taken from Working Paper No. 11. The casing programmes for these wells were chosen for simplicity. It is difficult to obtain information from which to estimate the time required for operations such as setting liners, testing shoes etc. Thus for our initial cost modelling purposes simple casing programmes were chosen where the casing is run the complete length of each section of hole. It is recognised that this over-estimates the quantities of casing required and also the rig time required for running casing. However, the extent of the over-estimate in cost is reduced by the costs of installing and testing 'shoes' and any time required for liner hanging over and above that required for normal casing runs. Nevertheless this is an area which needs examining in further modelling studies. Figures 12a and 12b summarize the costs in £'80 of wells of a range of depths drilled in provinces ranging from 'sft' to 'hard'.

4.1.3 Comparison U.S. and U.K. Drilling Costs

A simple comparison of U.K. onland drilling costs with the average of U.S. drilling costs in which £ are converted to $ using the official exchange rate indicates that U.K. wells are two to three times more expensive than comparable depth wells drilled in the U.S. The implication which is often drawn from this comparison is

Figure 11 Generic Geothermal Well Designs

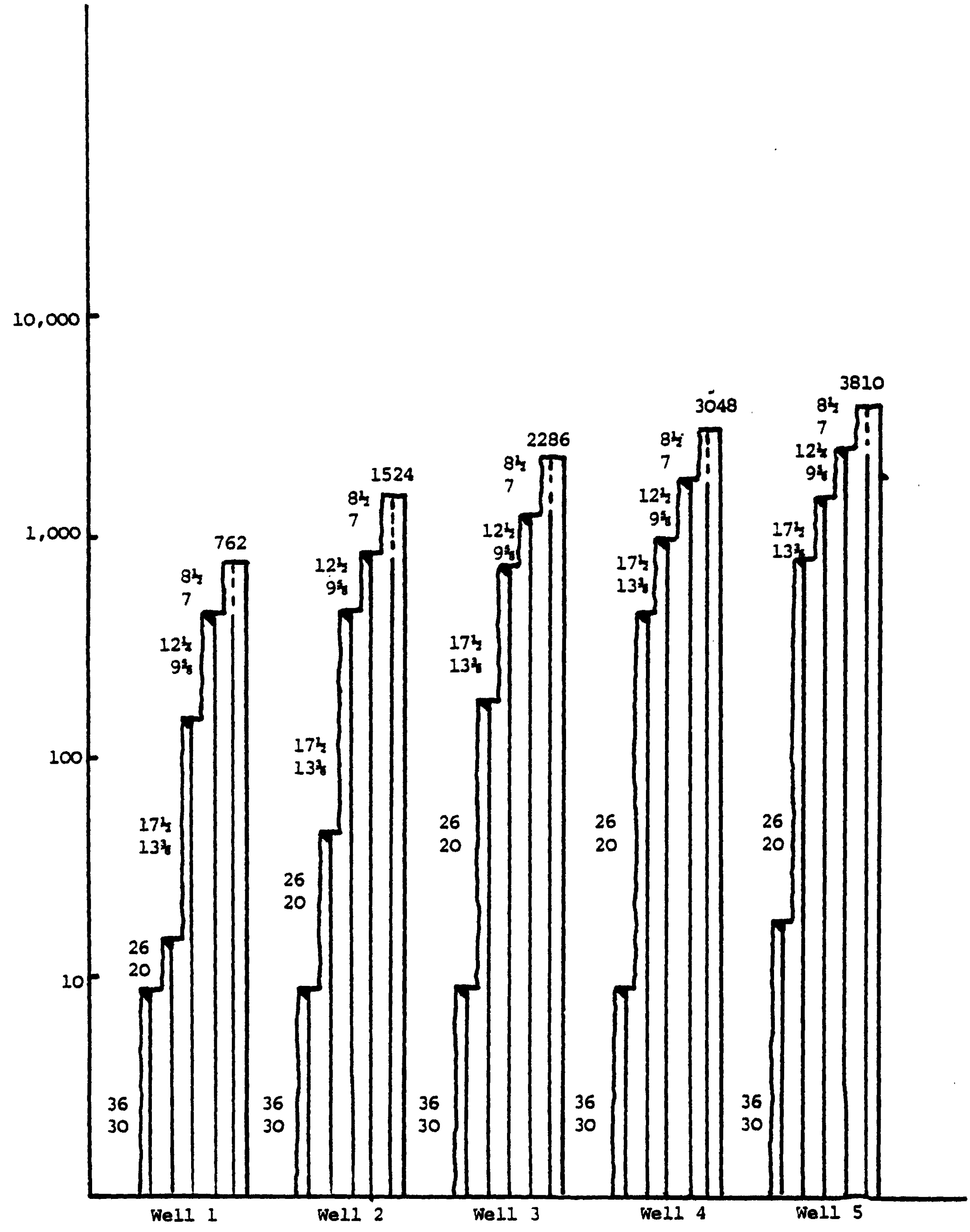


Figure 12a Estimated Total Well Costs for Softer Formations

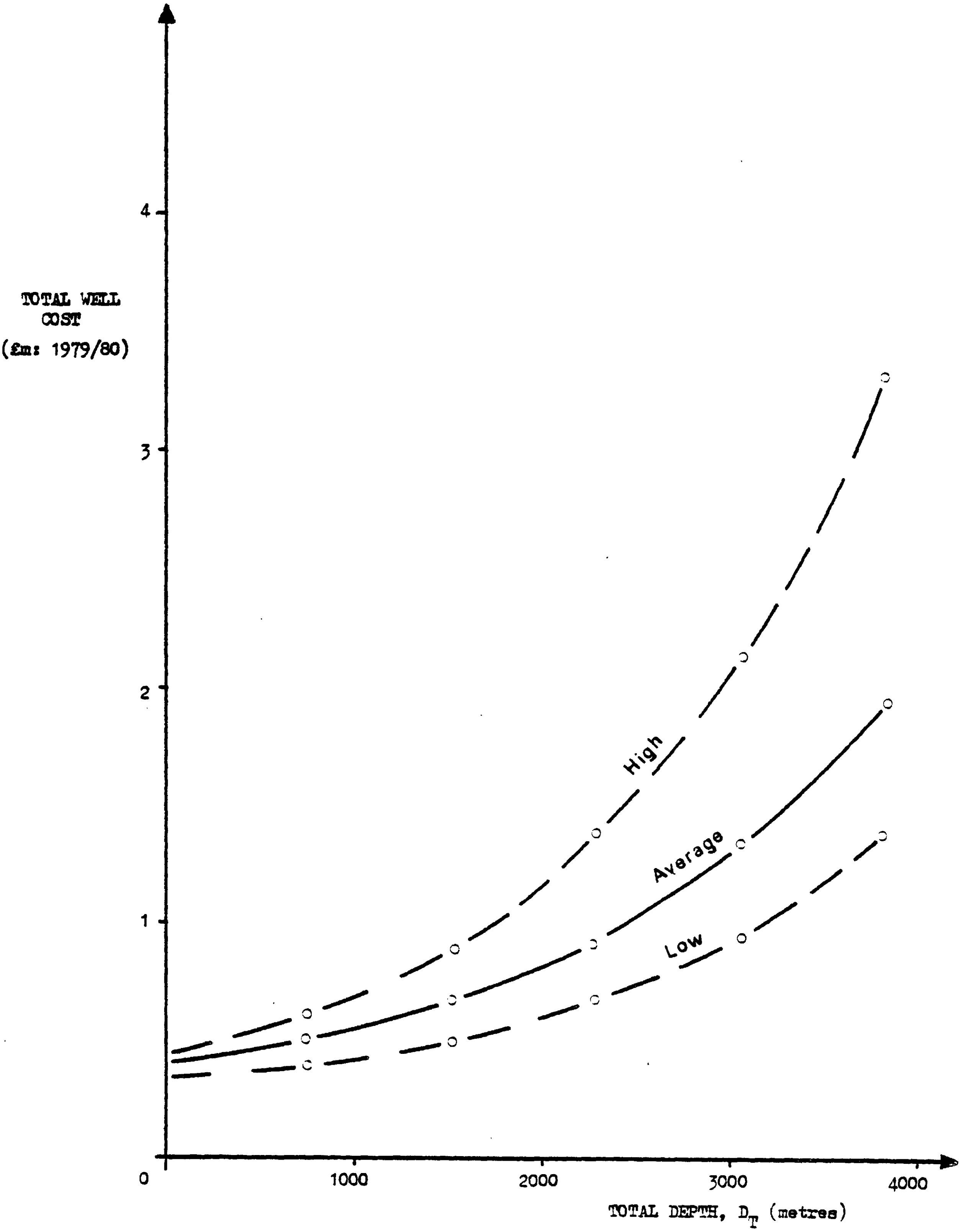
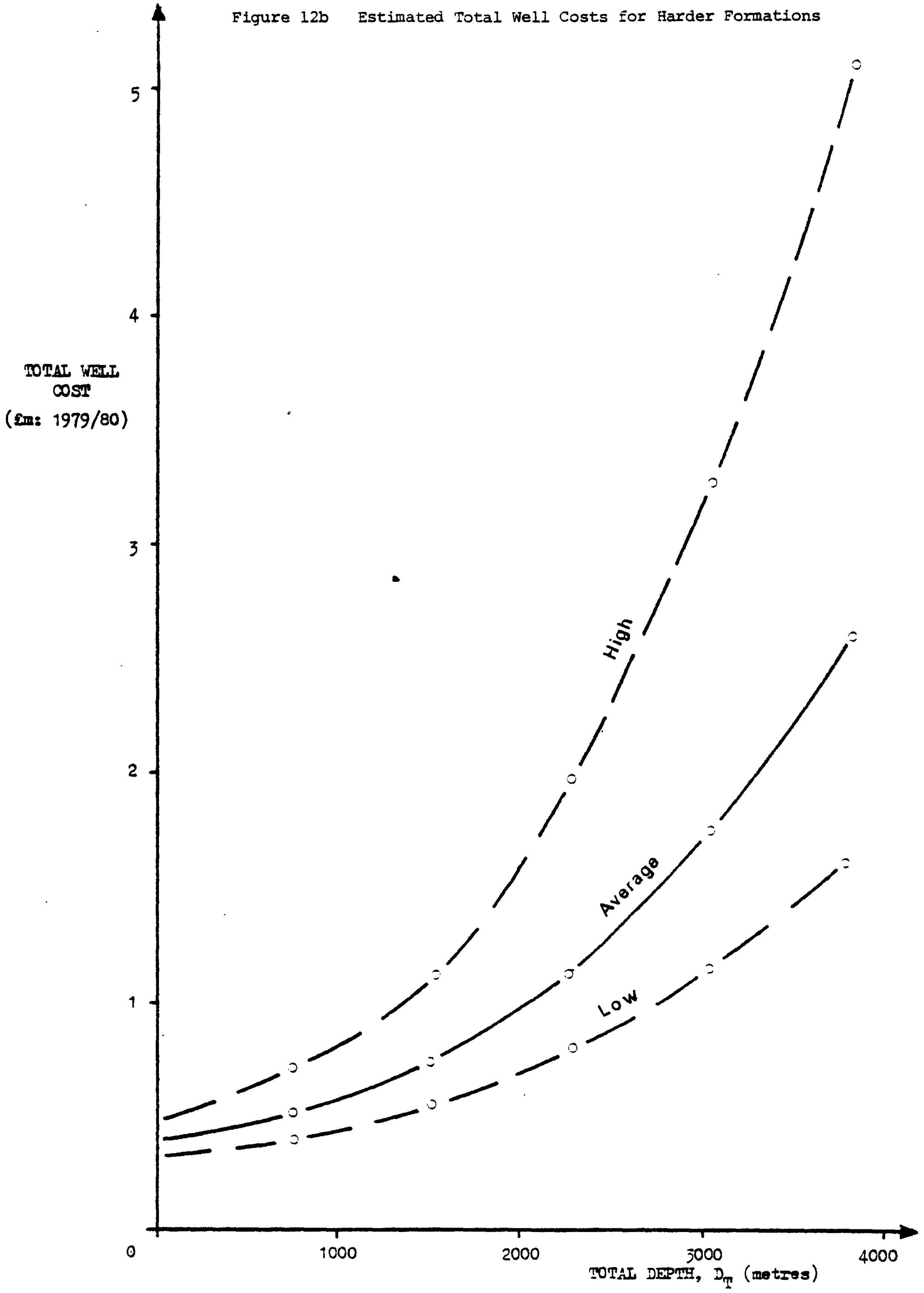


Figure 12b Estimated Total Well Costs for Harder Formations



that as drilling activity increases onland in the U.K. it may be possible that rig rates and costs in general will fall closer to the levels observed in the U.S.

A comparison between a collection of 1980 U.K. well costs and U.S. cost statistics taken from the 1978 Joint Association survey is shown in Figure 13 which is taken from Working Paper No. 12. In order to make the comparison between 1980 U.K. costs in sterling and 1978 U.S. costs in dollars, an index must be found to deflate the 1980 cost back to 1978. Chappell (Ref.7) has published an inflation index which applies to geothermal drilling in the U.S. This gives a figure of 1.25 to convert 1980 costs to 1978 costs in the U.S. Mortimer, in a study of U.K. and U.S. drilling cost inflation derives figures of 1.2 for the deflation of U.K. costs and 1.36 for the deflation of U.S. costs, (see Working Paper No. 8). This is a difficult area in which to construct inflation indices, particularly for U.K. drilling where the activity is so low. A figure of 1.25 was taken here as being reasonably consistent with all the estimates available.

It now remains to choose an appropriate exchange rate to convert '78 sterling costs to '78 dollar costs. U.K. - U.S. official exchange rates are determined by relative interest rates and movements of currency by national governments and by multinational companies with large money holdings. The exchange rate is not determined by the 'hidden hand' of commercial transactions involving large exchanges of goods and services. Particularly in the U.S. case the size of the traded sector of the economy is small. It is not surprising then if there are anomalies when prices of equivalent U.S. and U.K. goods and services are compared using the official excange rate. The official exchange rate does not reflect the relative purchasing powers of the currencies.

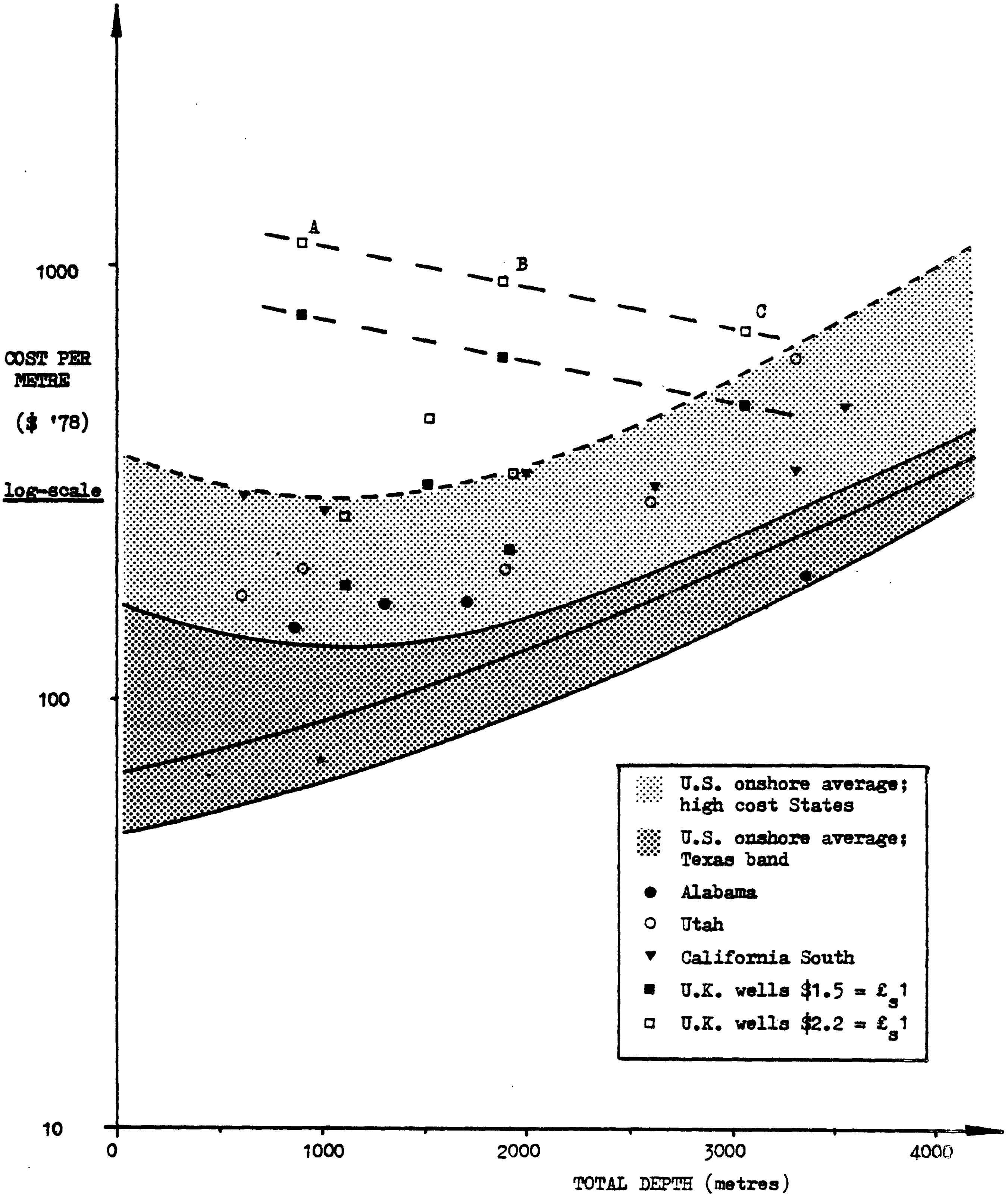
From a study of purchasing power parities (Kravis et al Ref. 8) it is possible by correcting for national inflation to derive appropriate purchasing power parities for industries similar to drilling for 1978 (see Working Paper No. 12). This indicates a parity level of between 1.5 and 2.0 dollars to one pound sterling. These are the conversion rates used to construct Figure 13.

It can be seen from Figure 13 that the U.K. costs are high when compared with the U.S. average. However, this average is dominated by the large number of wells drilled in Texas. These are represented by the Texas 'band' in Figure 13. There are areas of the U.S. where drilling costs are significantly higher than the U.S. average and these costs compare reasonably with the U.K. costs. The costs of the wells numbered A and B are anomalous. Wells A, B and C were all drilled by the same rig; this rig was appropriately powered for well C but was oversized for wells A and B resulting in their high costs.

It is often suggested that because of the low level of drilling activity onland in the U.K. rig utilization rates are low resulting in drilling contractors charging high day rates to keep rigs active in the U.K. market. A survey was carried out of U.K. and U.S. drilling contractors, to determine 1981 day rates, depth ratings and activity rates of rigs. The U.S. data was supplemented by figures taken from Belew (Ref. 9). It is difficult to choose an appropriate exchange parity by which to compare the rates; in this case a figure of 2 $/£ was taken which may be higher than the relevant purchasing power parity and may exaggerate U.K. costs. Figure 14 (taken from Working Paper No. 12) shows a plot of the day rates in 1981 £ against ultimate depth rating of the rig.

In the depth range below 10,000 ft. U.K. and U.S. rig rates appear to be broadly comparable. However, for rigs rated between 10,000 and 15,000 ft. the U.K. rates appear to be marginally higher.

Figure 13 Comparison of Cost of U.S. and U.K. Oil and Gas Wells



There may be a number of reasons for this. It may be that U.K. rigs in this range are all sound proofed while the U.S. rigs are not. One contractor estimated an extra 15% on day rate for a sound proofed rig and this could account for the higher rates. Also it may be that U.K. rigs rated between 10,000 and 15,000 ft. tend to be new rigs with high financing charges which again could result in high rates. There was no general indication that utilization rates were affecting day rates. Contrary to expectations U.K. contractors reported utilization rates in the main between 80% and 100%. However, the National 80 UE rated at 15,000 ft. and costing £5200/day (Point 1 Figure 14) only worked 25% of the time in the last year and it was estimated by the contractors that on yearly contract the day rate could come down to £4500 which would make it consistent with the U.S. costs. On the other hand another National 80 UE rated at 14,000 ft (Point 2 Figure 14) by another contractor charging in the region of £5500/day worked continuously in the previous year.

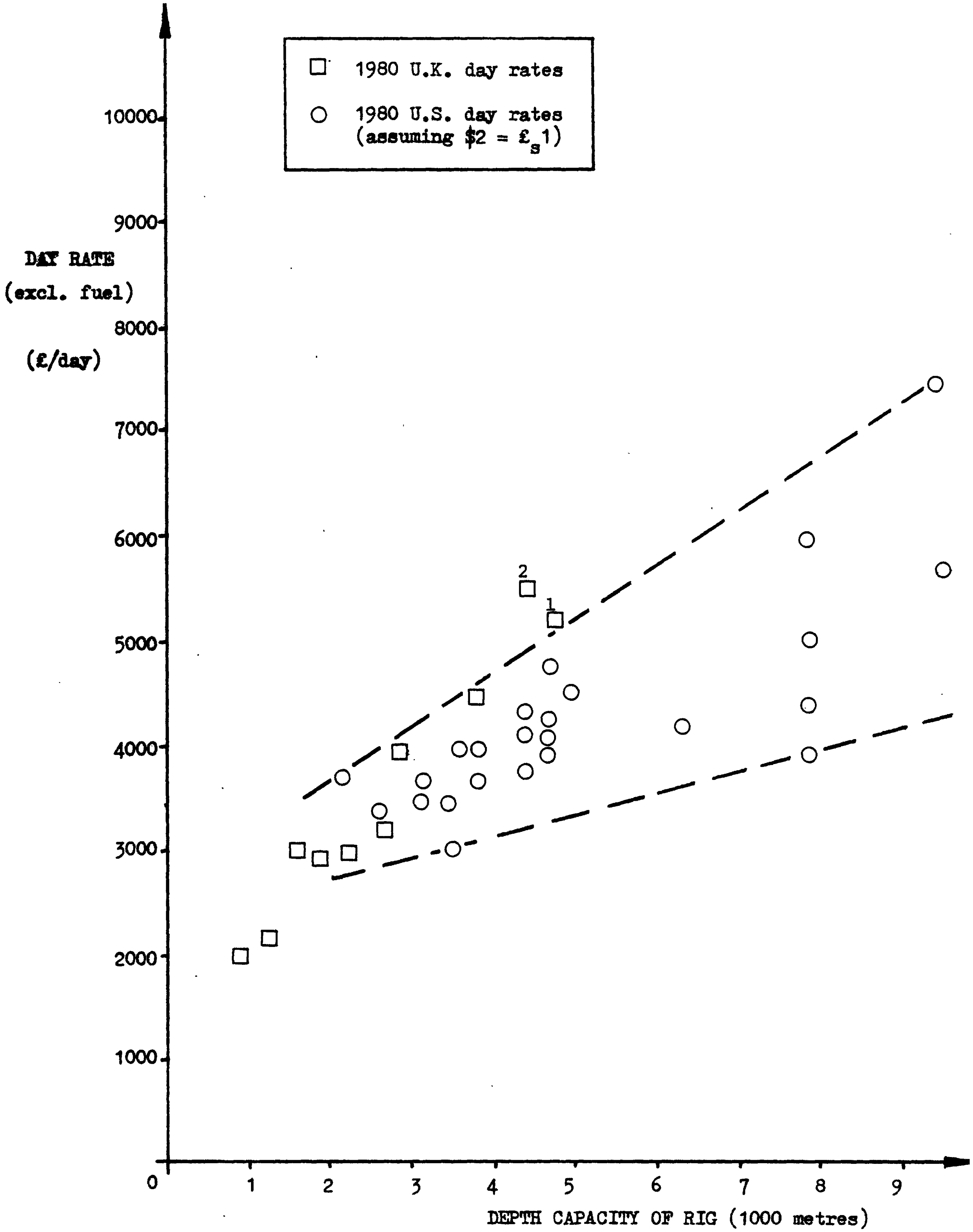
4.1.4 Drilling Cost Inflation in the U.K. and in the U.S.

Chapell (Ref. 7) has shown that geothermal drilling costs in the U.S. have inflated at a rate which is higher than the general level of U.S. inflation. This was studied in both the U.S. and the U.K. contexts (see Working Paper No. 8) and it was found that a major feature of drilling cost inflation was that different elements of cost e.g. rig hire and casing, inflate at different rates. Thus because these represent a different proportion of the costs of wells of different depths the total costs of wells of different depths will inflate at different rates. However, to obtain an index a particular case of a 5000 ft. well was taken. It was found in the U.S. case that the rate of inflation of total cost per foot

$$y = 1.1 \; x + 3.4 \; \%$$

where x is the general rate of wholesale inflation.

Figure 14 Comparison of U.K. and U.S. Day Rates



Because of the low activity of the U.K. drilling market and because of the importance of items purchased directly from the U.S. the U.K. pattern is more complex. It is affected by rising prices in the U.K. and in the U.S. and also by the fluctuating sterling to dollar official exchange rate. Because of the scarcity of data it was not possible to calculate a reliable index which could be applied to U.K. wells.

4.2 Costs for Production and Heating Systems

4.2.1 Cost Categories

For the purposes of the economic appraisal (in Section 7.1 below) the costs of a geothermal heating scheme are divided into:

- Capital costs
- Operating maintenance costs
- Operating energy costs for pumping and back-up heating

since each group of costs varies in a different way over time under changing price conditions.

4.2.2 Capital Costs

Capital costs are dominated by well drilling and completion, outlined above in Section 4.1. The remaining investment costs for a geothermal scheme are modelled in a simpler way, each based on one or more physical parameters. The forms of the cost equations used are developed from those of various U.S. and French models (References 3,4,10,11) with coefficients adapted to 1980 U.K. data.

All the major cost items are expected to last at least 25 years before having to be replaced entirely, except production well pumps which are assumed to have a useful life of only 5 years. Costs are in £ sterling for 1980.

Production Pumps

A submersible downhole electric pump is considered. The cost is estimated for the complete pumping set including the downhole unit, cable, and surface electrical control gear, and is represented as a function of its electrical power rating W:

$$C_{pp} = 601\ W^{0.7},$$

where C_{pp} is in £ and W in KW,
for a U.S. manufacturered pump purchased in the U.K.

Reinjection Pumps

An electric pump, situated on the surface at the well-head is assumed. The total cost is based on both power W' and geothermal flow Q_g:

$$C_{rp} = 22W' + 5.5Q_g,$$

where W' is in KW and Q_g in m^3/h,
again for a U.S. made pump bought in the U.K.

Heat Exchanger

Costs are for a titanium plate heat exchanger manufactured in the U.K. and as a first estimate they are assumed to vary with its 'power potential' KS, given above in Section 3.4.3.

$$C_{he} = .079 \text{ KS}$$

where KS is in W/°C.

Supplementary Equipment

The cost of supplementary and control equipment for the geothermal loop and the main heating circuit is related to the flows Q_g and Q_h in the geothermal and heating loops. Flow in the heating main is assumed to be 1.25 times that in the geothermal loop so the overall equipment cost can be represented as

$$C_s = 112.5 \ Q_g$$

where Q_g is in m^3/h

Transmission Main

The cost of a transmission main is represented by an overall cost per metre for trenching, and supply and return piping. This cost is related to pipe diameter which in turn is tied to volume flow rate, to maintain an average flow velocity (between a faster supply and slower return) of 2.4 m/s in the heating loop (whose volume flow rate Q_h is slightly the higher than that of the geothermal loop). Allowing for these factors, the transmission cost can be approximated as:

$$C_t = 68 + 7.4 \sqrt{(Q_g)} \quad L$$

where Q_g is in m^3/h and L in m.

Back-up Boiler

As a first estimate, the cost of a fossil fuelled boiler plant is assumed to be proportional to the minimum back-up power required $\hat{F}_b$

$$C_b = 24 \ \hat{F}_b$$

where $\hat{F}_b$ is in kW

and is assumed to be the same for coal, gas or oil fired plants.

Omissions

Only the major cost items are included. The cost of piping for the geothermal loop is neglected, since a deviated doublet with adjacent well-heads is assumed. Similarly the cost of a distribution network is ignored by considering only a concentrated load.

4.2.3 Maintenance Costs

Maintenance forms a small part of total costs, so is modelled only approximately. To maintain the wells themselves, an allowance of £1000 per well per year is made, to cover anti-corrosion treatment of casing and tubing.

For the production pump, high maintenance costs are taken, and represented as an average annual charge K based on pump power W.

$$K_{mp} = 36\ W$$

with K in £/yr and W in KW.

This allows for the fact that preventive maintenance is difficult and the pump has to be pulled each time to inspect it, irrespective of whether it is then repaired at the wellhead, sent to the factory for reconditioning, or replaced completely.

The reinjection pump is more accessible and the annual cost of maintaining it is estimated as 1.5% of its initial capital cost

$$K_{mr} = .015\ C_{rp}$$

For general maintenance of other items an annual cost of £5000/yr is assumed.

4.2.4 Operating Energy Costs

The cost of the energy consumed in operating a geothermal scheme consists of electricity for pumping and fuel for back-up heating.

Prices

Prices are for units of useful energy delivered: electricity and heat and refer to 1980. For pumping an industrial electricity tariff of £0.023/kWh is taken and applied directly to the electrical consumption of the well and heating circuit pumps. For back-up heating a range of possible fossil fuels is considered: coal, gas and oil.

. Coal: industrial rather than domestic prices are taken as these are probably closer to those which could be negotiated for a heating scheme. An average value of £1.75/GJ is taken, although there is a regional variation of about 16% within the U.K. A combustion efficiency of 75% is allowed for in this figure.

. Gas: a lowest domestic tariff is used. U.K. industrial tariffs are not appropriate since they relate to interruptable supply and the price data tends to be distorted by old low price long term contracts. A figure of £3.0/GJ is used, allowing for a 75% combusion efficiency. There is very little regional variation in these prices.

. Oil: domestic prices for burning oil are used since industrial heavy fuel oil is not likely to be appropriate and gas oil and kerosene are minor fuels. This gives a price of £5.8/GJ allowing for a 75% combustion efficiency. Regional price variations are small.

Net Energy Price Rises

This study isolates net energy price changes above or below a general price trend. For this study it is assumed that prices of both electricity and the fossil fuels all rise at a 'real' rate of 5% a year above general inflation. This is reasonably consistent with trends over the period 1974 to 79 and with future prospects of dwindling supplies of fossil fuels.

U.K. gas prices are the main exception since prices actually fell at a rate of 3% a year in real terms over this period. More recently, however, government policy has been to increase gas prices at a net-rate of about 10% per year, so 5% may represent a reasonable estimate of their long term trend.

Annual Consumption Costs

Pumping powers refer to electrical consumption, allowing for pump and motor efficiencies, so electricity costs are the product of the unit price of electricity in £/kWh, electrical power in kW and opeating time in h. Back-up heating costs are the product of the price per GJ of useful heat transfer and the total heat transfer in GJ.

5. Energy Analysis

5.1 Introduction

Energy analysis attempts to determine the total amount of energy required to provide a given product or service. By definition, the total amount of energy used in any activity consists of both direct and indirect energy inputs. Direct energy inputs result from the consumption of fuels by the given activity itself. Indirect energy inputs are introduced by the use of fuels elsewhere to supply raw materials, manufacture machinery, etc., needed by the particular activity in question. As a consequence of this definition of energy inputs, energy analysis measures the total amount of energy needed to obtain finished goods and services from basic resources.

A number of energy analysis studies have been performed in the past and quite a few of these have examined energy technologies in particular. These studies have attempted to calculate the total energy required to build and operate energy producing systems, such as a nuclear power station with its associated fuel cycle. Such studies usually obtain values of the net energy requirement for the system, which, in the case of nuclear technology, equals the total amount of energy needed to obtain one unit of electricity from uranium ore. Such a net energy requirement, by definition, excludes the energy content of the uranium itself.

Most energy analysis studies measure energy use in terms of primary energy, which simply equals the energy available as the calorific value of coal, oil and natural gas, the heat released in nuclear reactors and the electrical energy generated by hydro-power schemes. Analysis based on primary energy not only determines the demand for energy resources, it can also indicate total fuel requirements. The difference between resources and fuels is that energy contained in the former may only be available theoretically whilst energy provided by the latter is usually available for direct practical use. This is an important point since it means that energy analysis can be used to examine the total impact of fuel price inflation on energy projects. Standard financial studies can evaluate the effect of rises in the price of fuels consumed directly, i.e. gas for heating. However, energy analysis is required to estimate the result of rises in the price of energy used indirectly, i.e. energy required to build and operate a gas pipeline, boiler, etc. The relative impact of price inflation through direct and indirect energy inputs depends on the magnitude of the net energy requirement; the larger this value, the greater the effect of inflation.

5.2 Energy Analysis of Geothermal Heating

At least three energy analyses of geothermal projects have already been completed by other researchers. However, the most detailed work has concentrated on geothermal-electric schemes (Refs. 12, and 13) and only one energy analysis of a geothermal heating system has been reported (Ref. 14). This particular study was prepared by the Office of the Governor for the State of Oregon, U.S.A., and it describes the energy analysis for a district heating scheme in Reykjavik, Iceland. Although details of the analysis are not clear, the net energy requirement of the scheme appears to be 0.189 joules per joule, i.e. 0.189 joules of primary energy (from non-geothermal sources) are required to supply 1 joule of heat from the scheme. This suggested that, provided the result is typical, fuel price rises can have a significant impact on the cost of geothermal heat. Consequently, it became necessary to perform an independent energy analysis of European schemes to examine this further.

Two particular cases were chosen for preliminary investigation; the existing Creil 4 doublet scheme in France and a proposed single well scheme at Marchwood in the U.K. To simplify the work the energy analyses were only performed up to, and including, the heat exchanger. This meant that it was only necessary to determine the energy input of drilling fuel, well casing manufacture, pump fabrication, heat exchanger construction, and pump operation and maintenance. Also for simplicity, it was decided that as a basic exercise total energy inputs would be compared with the total heat output assuming a 20-25 year life, full geothermal coverage and a 100% load factor for the scheme. Although this assumption overestimates the heat output from the scheme, such a basic energy analysis will still indicate the major energy inputs. More realistic assumptions are used with the results of energy analysis incorporated in Section 7.

The energy inputs to different parts of the schemes were calculated by various methods. The direct energy input of drilling fuel was obtained from estimates of rig fuel consumption derived in Working Paper No. 5, and an energy requirement of about 175 x 10^6 joules per U.S. gallon (Ref. 15). The indirect energy input resulting from well casing was calculated using estimates of casing quantities derived in Working Paper No. 7 and an energy requirement for steel pipes of about 36 x 10^9 joules per tonne (Ref. 16). The indirect energy inputs of other drilling consumables were ignored in this analysis as they are expected to be much lower than the inputs from rig fuel and well casing. The indirect energy input to pump manufacure was determined from estimated costs and an energy intensity of 51 x 10^6 joules per £ sterling; 1980 (Ref. 16). Pump costs were derived, as shown in Section 4.2, from estimates of pump power rating obtained through Working Paper No. 9. Submersible pumps were assumed to have a working life of 5 years, whilst the life of surface pumps was taken as equal to the life of the scheme which was 20-25 years. The indirect energy input to heat exchanger construction was calculated by combining estimated costs, again from Section 4.2, with an energy intensity of 46 x 10^6 joules per £ sterling; 1980 (Ref. 16). The direct energy input to pump operation was obtained from the pumping power rating equations given in Working Paper No. 9 and selected resource parameters. Electricity consumption of the pumps was converted to primary energy using a value of 4 joules of primary energy per joule of electricity. Indirect energy inputs to maintenance were obtained from costs and an energy intensity equal to 10% of that forpump manufacture.

5.3 Results

The results of these brief energy analyses are shown in Tables 4 and 5. Average estimates were obtained by the methods discussed above. A possible range of estimates was calculated for each scheme to demonstrate the relative reliability of the results. The variation in energy inputs from drilling fuel and well casing is a consequence of using the well cost estimating procedure described in Working Papers No. 5 and No. 7. The ranges of direct energy inputs to well pumping are based on an assumed accuracy of ±10% for actual electricity consumption. Variations in the energy inputs to pump and heat exchanger manufacture and maintenance are caused by the relatively large uncertainty associated with using energy intensities; which in this case was assumed to be ±75%.

Total energy inputs derived in Table 4 and 5 can be compared with the expected heat output from each scheme. Both schemes were assumed to operate at a 100% load factor and give full geothermal coverage. The Marchwood scheme had a working life of 25 years and the Creil 4 scheme was based on a life of 20 years. Comparison of input with output gives an average net energy requirement for the Marchwood project of 0.33 joules per joule, and a figure of 0.15 joules per joule for the Creil 4 doublet. Analysis for Creil 4 gives a lower net energy requirement than Marchwood largely because of the better geothermal resource characteristics experienced in the Paris basin. These reduce pumping energy requirements in relation to total heat output so that even using double wells at Creil produces a better energy balance than the single well at Marchwood.

Although the results obtained from this brief energy analysis incorporate over-optimistic assumptions about heat output from the scheme and thus underestimate subsequent net energy requirements, they can still be used to indicate conclusions for actual schemes. In general, choosing a realistic load factor and coverage will

Table 4 Basic Energy Analysis of the Marchwood Scheme

Energy Flows	Range (joules)	Average (joules)
Direct Input		
Drilling Fuel	$1.1 \times 10^{12} - 2.4 \times 10^{12}$	1.5×10^{12}
Pump Operation	$7.8 \times 10^{14} - 9.6 \times 10^{14}$	8.7×10^{14}
Indirect Input		
Well Casing	$4.5 \times 10^{12} - 8.1 \times 10^{12}$	6.0×10^{12}
Well Pumps	$2.0 \times 10^{12} - 1.4 \times 10^{13}$	8.0×10^{12}
Heat Exchanger	$5.2 \times 10^{11} - 3.6 \times 10^{12}$	2.0×10^{12}
Maintenance	$3.2 \times 10^{11} - 2.2 \times 10^{12}$	1.3×10^{12}
Total Input	$7.9 \times 10^{14} - 9.9 \times 10^{14}$	8.9×10^{14}
Total Output	2.7×10^{15}	2.7×10^{15}
Net Energy Requirement	0.29 - 0.37	0.33

Table 5 Basic Energy Analysis of the Creil 4 Scheme

Energy Input	Range (joules)	Average (joules)
Direct Input		
Drilling Fuel	$2.2 \times 10^{12} - 5.1 \times 10^{12}$	3.1×10^{12}
Pump Operation	$4.8 \times 10^{14} - 5.9 \times 10^{14}$	5.3×10^{14}
Indirect Input		
Well Casing	$1.0 \times 10^{13} - 1.9 \times 10^{13}$	1.4×10^{13}
Well Pumps	$7.0 \times 10^{11} - 4.9 \times 10^{12}$	2.8×10^{12}
Heat Exchanger	$7.8 \times 10^{11} - 5.5 \times 10^{12}$	3.1×10^{12}
Maintenance	$5.3 \times 10^{10} - 3.7 \times 10^{11}$	2.1×10^{11}
Total Input	$4.9 \times 10^{14} - 6.2 \times 10^{14}$	5.5×10^{14}
Total Output	3.7×10^{15}	3.7×10^{15}
Net Energy Requirement	0.13 - 0.17	0.15

reduce heat output and pumping energy consumption. Since Tables 4 and 5 show that the direct energy input to pump operation is by far the greatest single input in either scheme, then the reduction in heat output may well be balanced almost totally by the decrease in energy input. Hence the results derived here should give a reasonable indication for the complete energy analysis of actual schemes. This present analysis also provides an important result for the cost estimating procedure described in this report; namely, the direct energy consumption of pumping dominates the energy input to geothermal heating schemes. Consequently, the effects of other energy inputs on total costs through fuel price inflation were ignored in the remainder of this study. Instead, the impact of fuel price rises on pumping costs and the costs of back-up fuel is emphasised here (see Section 7).

6. Unit Costs at the Wellhead

6.1 Introduction

The aim of this section is to bring together some of the diverse modelling procedures introduced previously and examine their features in relation to practical geothermal data. For this exercise the drilling cost procedure (Section 4.1) will be combined with the geothermal reservoir equations and certain information on well operation. As such this modelling exercise enables unit costs to be calculated for heat available from geothermal sources at the heat exchanger. For convenience, these results will be referred to as 'unit costs at the wellhead'. These unit costs include the costs of well drilling and completion, the costs of well maintenance, capital costs for production and re-injection pumps and the heat exchanger, and pump operating and maintenance costs. The exercise provides annualised costs, which make no account of general and fuel price inflation, measured in terms of 1980 £ sterling per 10^9 joules (GJ) of heat delivered by the heat exchanger of the geothermal project. These unit costs do not include the costs and direct effects of operating the subsequent heating scheme (Section 4.2) attached to the geothermal heat exchanger. For simplicity, the output from the heat exchanger is assumed to cover the full working life, i.e. without significant interruption. Although this results in an overestimate of practical heat output and, hence, an optimistic view of unit costs, this exercise provides a brief test of the validity of some of the modelling procedures incorporated in the ultimate part of this study.

6.2 Estimating Procedure

The methods of calculating capital, operating and maintenance costs have been introduced mainly in the form of general equations and routines based on basic parameters. These parameters describe the features of the geothermal resource, the operating characteristics of the geothermal scheme and the economic criteria applied to the project's assessment (see Table 6). Since there are a large number of these basic parameters, it is necessary to specify their values so that unit costs can be estimated and examined. Resource, operating and economic parameters were obtained from details of actual and proposed geothermal projects. In particular, four sets of parameters were taken for initial investigation; the Creil 4 and the Villeneuve-la-Garenne doublets in France, and a proposed scheme with single and double wells at Marchwood in the U.K. These four cases were chosen because they seem to cover a fairly wide range of resources and economic conditions. However, in order to study a wider range, individual parameters were varied separately for a base case incorporating information for the Marchwood scheme.

The main parameters for the four initial cases were obtained from various sources (Refs. 5, 17 and 18) and these are listed in Table 7. Some parameters, such as formation fluid density, were derived from given information, such as formation fluid temperature and salinity, using standard tables. The important points to note in Table 7 are that Creil has probably the best combination of resource parameters whilst Villeneuve-la-Garenne has the worst, and both French schemes are operated under better economic conditions (interest rate = 9%) than the U.K. scheme (interest rate = 15%). This is reflected in the basic derived results illustrated in Table 8. These derived results, which are used to determine total unit costs for each case, were obtained using the following procedure:

Step 1 Resource data is taken and the doublet spacing is determined using Working Paper No. 9. Assuming both wells are deviated by equal amounts from ground level the length of each well is estimated. This information is used to calculate the capital costs of deviated wells and pump power ratings - see below (this part of the procedure is not required in the case of a single well).

Step 2 The power rating of both the production and re-injection pumps are estimated using resource data and the equations provided by <u>Working Paper No. 9</u>. Results are used to determine capital, operating and maintenance costs of the pumps.

Step 3 By specifying the total vertical well depth the capital cost of one or two vertical wells is obtained using the estimating procedure outlined in <u>Working Paper No. 7</u>. These costs are adjusted for deviated wells using the ratio of well length to vertical depth determined in Step 1. Applying a chosen interest rate and scheme life enables the annual capital charges for the wells to be found.

Step 4 The capital costs of the production and re-injection pumps are evaluated using the equations given in Section 4.2.1, the geothermal flow rate and the estimates of pumping power derived in Step 2. Annual capital charges for the pumps are obtained using the chosen interest rate and the given lifetime for the relevant pump.

Step 5 Taking a chosen value of geothermal flow rate, the capital costs of the heat exchanger are calculated using the equation in Section 4.2.1. Annual capital charges are obtained as described above.

Step 6 The electricity consumption of the well pumps is estimated from pump power ratings assuming operation for 8760 hours per year. Operating costs are calculated using a 1980 average industrial rate of 2.3 pence per kilowatt-hour.

Step 7 Well maintenance costs are set at about £1,000 per well per year (Ref. 10).

Step 8 Pump maintenance costs are derived from equations in Section 4.2.2 using the power rating of the production pump calculated in Step 2 and the capital cost of the re-injection pump derived in Step 4 (maintenance costs for the heat exchanger are disregarded in this exercise).

Step 9 The maximum annual heat output from the scheme is obtained from the values of the flow rate, production and re-injection fluid temperatures and the specific heat capacity of the production fluid. A 100% load factor is assumed with 8760 hours per year geothermal coverage.

Step 10 The separate annual costs derived in steps 3 to 8 are added together to obtain an estimated total annual cost which is then divided by the maximum annual heat output calculated in Step 9 to produce an estimate of total unit costs of heat at the wellhead.

The results for this procedure for each case considered here are shown in Table 9. These costs can be compared with the costs of providing heat from conventional fuels. Taking into account heat losses in the heating system, the 1980 U.K. prices per unit of useful heat delivered are £1.5 to £2.0 per GJ for house coal, £3.0 per GJ for natural gas, £5.5 per GJ for burning oil and £8.8 to £9.7 per GJ for domestic electricity. It can be seen that all four cases provide heat cheaper than electricity or oil, whilst only the geothermal heat from the Creil 4 doublet is consistently cheaper than any competing fuel. These conclusions must be treated with caution, however, since this initial exercise underestimates total costs as a result of; (a) using very optimistic assumptions about heating load which may, in practice, reduce by about 50%, (b) ignoring the capital, operating and maintenance costs of the rest of the heating system from the heat exchanger onwards, and (c) omitting the effects of fuel and general price inflation over the life of the scheme. However, all these factors are incorporated in the next stage of this study described in Section 7.

Returning to the results obtained here, it can be seen that some important broad implications can be identified from the basic approach adopted here. First, the test cases can be compared using the unit costs shown in Table 9. The cost of heat from the Creil 4 doublet is estimated as cheaper than the other schemes because of its particular combination of resource parameters; namely a relatively high value of effective reservoir thickness, H', which reduces doublet spacing and, hence, well capital costs; and a

Table 6 List of Parameters

Parameters	Units	Selected Range
Resource Parameters		
Rock hardness	-	soft to hard
Total vertical depth, D_T	m	762 to 3810
Reservoir porosity, ϕ	-	0.05 to 0.50
Reservoir permeability, K	Darcy	0.25 to 1.50
Effective reservoir thickness, H'	m	1 to 100
Production well skin factor, S	-	-10 to +10
Re-injection well skin factor, S'	-	-10 to +10
Production well static formation pressure, P_o	bars	-20 to +20
Re-injection well static formation pressure, P_o	bars	-20 to +20
Production fluid temperature, T_o	^oC	57 to 70
Viscosity of formation fluid, μ_o	centipoise	0.50 to 0.53
Viscosity of re-injection fluid, μ_i	centipoise	0.80 to 1.05
Density of formation fluid, ρ_o	kg/m^3	1009 to 1056
Density of re-injection fluid, ρ_i	kg/m^3	1015 to 1074
Density of formation rock, ρ_s	kg/m^3	2000
Specific heat capacity of formation fluid, γ_o	$J/kg/^oC$	3900
Specific heat capacity of formation rock, γ_s	$J/kg/^oC$	3000
Scheme Parameters		
Well radius at total depth, r_w	m	0.078 to 0.108
Flow rate, Q	m^3/hr	50 to 250
Re-injection temperature, Ti	^oC	20 to 60
Load factor, l_f	-	0.25 to 1.00
Scheme lifetime, t_s	years	20 to 25
Submersible pump lifetime, t_p	years	5
Economic Parameters		
Interest rate, i	%	5 to 20

Table 7 Parameters for Test Cases

Parameters	Creil 4	Villeneuve-la-Garenne	Marchwood
Rock hardness	soft	soft	soft
Total vertical depth, D_T	1725m	1630m	1690m
Reservoir porosity, ϕ	0.17	0.11	0.20
Reservoir permability, K	0.48 Darcy	0.45 Darcy	0.67 Darcy
Effective reservoir thickness, H'	91m	15m	6m
Production well skin factor, S	0	-3.4	0
Re-injection well skin factor, S'	0	-4.4	0
Production well static formation pressure, P_o	+2.65 bars	+16.00 bars	+9.00 bars
Re-injection well static formation pressure, P_o'	+2.65	+12.50 bars	+9.00 bars
Production fluid temperature, T_o	57°C	57°C	70°C
Viscosity of formation fluid, μ_o	0.53 centip.	0.50 centip.	0.50 centip.
Viscosity of re-injection fluid, μ_i	1.05 centip.	0.70 centip.	0.80 centip.
Density of formation fluid, ρ_o	1005 Kg/m^3	1009 Kg/m^3	1056 Kg/m^3
Density of re-injection fluid, ρ_i	1015 Kg/m^3	1017 Kg/m^3	1074 Kg/m^3
Density of formation rock, ρ_s	2000 Kg/m^3	2000 Kg/m^3	2000 Kg/m^3
Specific heat capacity of formation fluid, γo	3900 J/Kg/°C	3900 J/Kg/°C	3900 J/Kg/°C
Specific heat capacity of formation rock, γ_s	3000 J/Kg/°C	3000 J/Kg/°C	3000 J/Kg/°C
Well radius at total depth, r_w	0.078 m	0.075 m	0.108 m
Flow rate, Q	150 m^3/hr	185 m^3/hr	100 m^3/hr
Re-injection fluid temperature, T_i	21°C	30°C	40°C
Load factor, l_f	1.00	1.00	1.00
Scheme lifetime, t_s	20 years	20 years	25 years
Submersible pump lifetime, t_p	5 years	5 years	5 years
Interest rate	9%	9%	15%

Table 8 Derived Results for Test Cases

Results	Creil 4 doublet	Villeneuve-la-Garenne doublet	Marchwood singlet	Marchwood doublet
Doublet spacing	490m	1448m	-	1598m
Well length	1756m	1784m	-	1869m
Production pump power	56Kw	213Kw	280Kw	176Kw
Re-injection pump power	156Kw	625Kw	-	474Kw
Average capital cost of wells (1980)	£1.004m	£1.007m	£0.644m	£1.292m
Capital cost of production pump (1980)	£0.010m	£0.025m	£0.031m	£0.022m
Capital cost of re-injection pump (1980)	£0.004m	£0.015m	-	£0.011m
Capital cost of heat exchanger (1980)	£0.068m	£0.084	£0.045m	£0.045m
Annual costs of:				
Well capital	£109,839/yr	£110,267/yr	£99,627/yr	£199,872/yr
Prod. pump capital	£ 2,586/yr	£ 6,589/yr	£ 9,258/yr	£ 6,689/yr
Reinj. pump capital	£ 466/yr	£ 1,617/yr	-	£ 1,698/yr
Heat exch. capital	£ 7,422/yr	£ 9,198/yr	£ 6,991/yr	£ 6,991/yr
Prod. pump operation	£ 11,282/yr	£ 42,915/yr	£56,332/yr	£ 35,447/yr
Reinj. pump operation	£ 31,431/yr	£125,925/yr	-	£ 95,502/yr
Well maintenance	£ 2,000/yr	£ 2,000/yr	£ 1,000/yr	£ 2,000/yr
Prod. pump maintenance	£ 2,016/yr	£ 7,668/yr	£10,080/yr	£ 6,336/yr
Reinj. pump maintenance	£ 64/yr	£ 222/yr	-	£ 165/yr
Total	£167,205/yr	£306,401/yr	£183,288/yr	£354,700/yr
Maximum annual heat output	185,400GJ/yr	175,000 GJ/yr	108,000 GJ/yr	108,000 GJ/yr

Table 9 Unit Costs for Test Cases

Scheme	Unit Costs at Wellhead (£/GJ)		
	Low	Average	High
Creil 4 doublet	0.805	0.902	1.348
Villeneuve-la-Garenne doublet	1.519	1.751	2.214
Marchwood singlet	1.439	1.697	2.055
Marchwood doublet	2.711	3.284	4.079

relatively high value of effective transmissivity (permeability x thickness) which reduces pumping power ratings and, hence, pump capital, operating and maintenance costs. Both the French projects show a relative advantage over the Marchwood doublet scheme partly because lower interest rates decrease the effect of capital charges. However, the total unit cost of geothermal heat from the Marchwood singlet proposal is marginally lower than that for the Villeneuve-la-Garenne doublet due to obvious savings in drilling a single vertical well instead of two deviated wells. However, such savings are only possible where re-injection of geothermal fluids can be avoided in an acceptable manner.

Comparison of actual costs with those derived here is difficult because of the lack of suitable information. However, from a preliminary assessment it seems that this procedure obtains unit costs of the correct magnitude. Some of the derived results, shown in Table 8, which are used to estimate total unit costs also compare well with actual data. For example, the actual production pumps installed at Creil 4 and Villeneuve-la-Garenne are rated at 60 Kw and 241 Kw, respectively compared with estimated ratings of 56 Kw and 213 Kw. Similarly, the production test pump used at the Marchwood well was 246 Kw, compared with an estimated 280 Kw.

6.3 Sensitivity of Results

In the previous section the results for the chosen test cases demonstrated that unit costs at the wellhead can vary due to changes in the nature of the geothermal resource, the way it is used and the manner in which costs are assessed. For the particular cases examined these factors vary quite independently and it is not easy to determine the specific effects of changes in any given parameter. In order to explore the sensitivity of results to specified changes in basic parameters it was decided to investigate one particular base case in detail. The initial parameters for this case were based on resource data obtained for the Marchwood well in the Wessex basin. The basic operating conditions are fairly typical for a geothermal heating scheme and the economic criteria reflect those currently applied in the U.K. Having specified the base case each parameter can be varied independently and the effect on unit costs can be discovered. The ranges of variation of some of these parameters are shown in Table 6. In addition to varying resource, operating and economic parameters, unit costs were also determined for a scheme with one and two wells. Although singlet schemes are possible in the Marchwood region where disposal of geothermal fluid into the sea can be used, inland sites in the Wessex basin would probably require a re-injection well for suitable disposal.

The particular parameters examined in this exercise are rock hardness, total depth, reservoir porosity, reservoir permeability, effective reservoir thickness, production and re-injection well skin factors, production and re-injection well static formation pressures, flow rate, re-injection fluid temperature, load factor and interest rate. The effects of changes in these parameters are illustrated in Figures 15 to 34. Low, average and high estimates of unit costs of heat at the wellhead are given in nearly every case and these can be compared with the costs of useful heat from coal, natural gas and burning oil. Although it is not possible to discuss all the implications of these results here, certain important points can be identified and examined.

Starting with Figure 15, showing the variation of cost with depth and rock hardness for a doublet scheme, it can be seen that the difference in economics between schemes in 'softer' and 'harder' geological provinces increases quite strongly with depth. This results from greater drilling times encountered in 'harder' provinces which ultimately affect the annual capital charges for the wells. The effect of increasing depth on costs is examined more closely in Figure 16, which shows that heat from the doublet is only marginally competitive with natural gas at relatively shallow depths. At greater depths this margin disappears so that geothermal heat becomes even more expensive than burning oil. Figure 17 shows that reservoir porosity has only a very small effect on costs, because changes in this parameter only affect doublet spacing which, in turn, results in minor increases in well capital costs. In contrast, reservoir permeability and

Figure 15 Unit Costs and Rock Hardness for a Marchwood Doublet

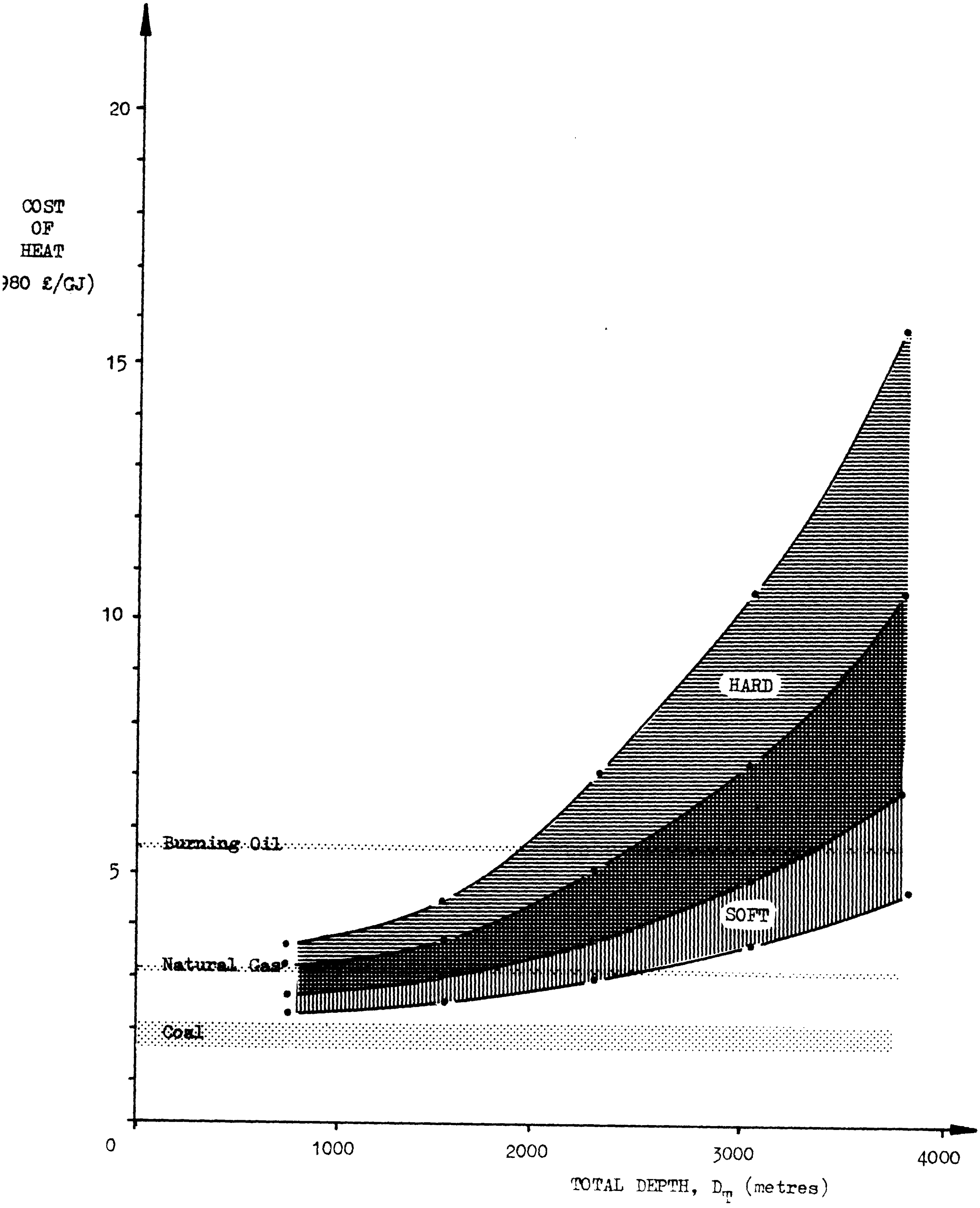


Figure 16 Unit Costs and Total Depth for a Marchwood Doublet

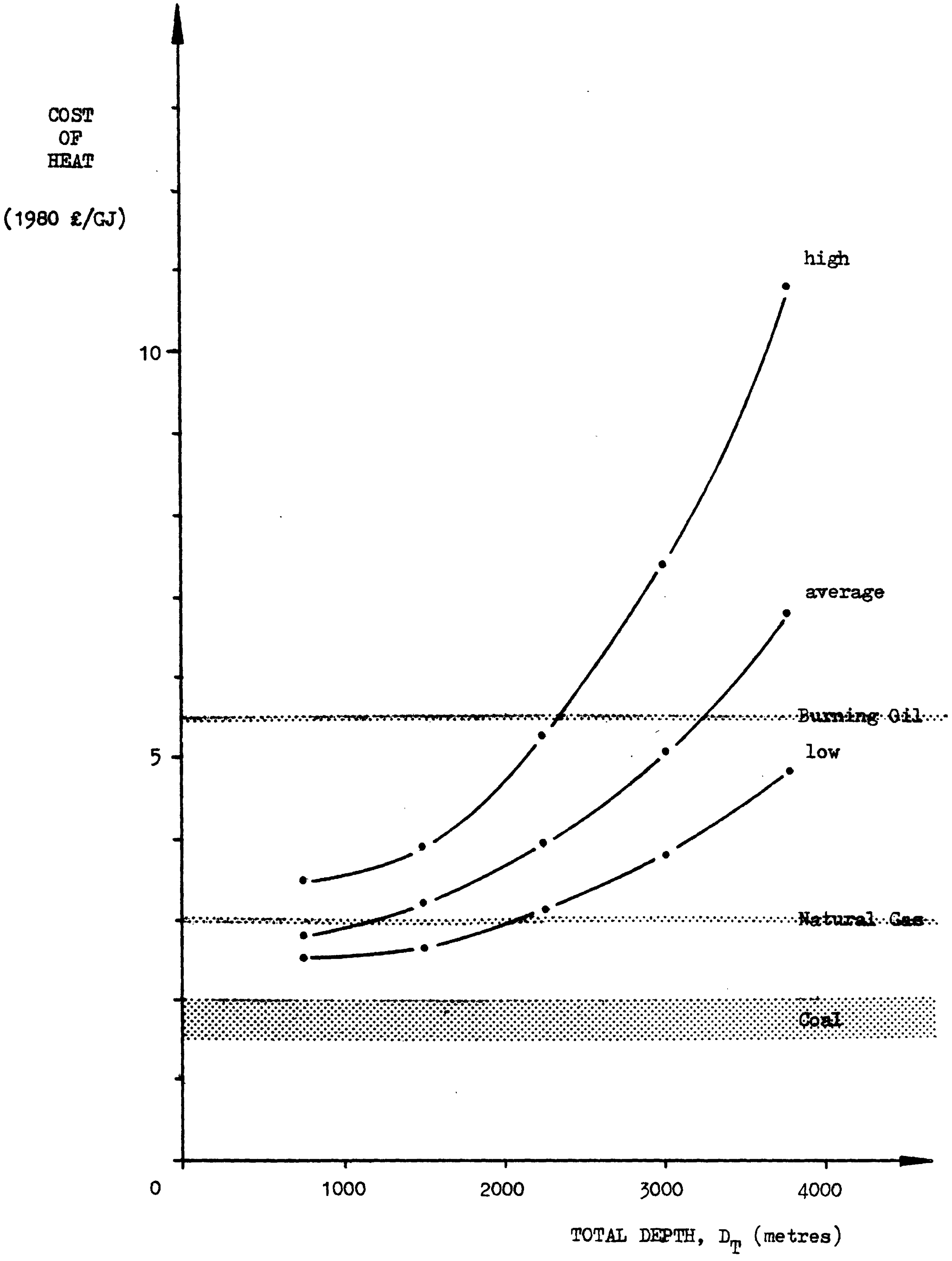
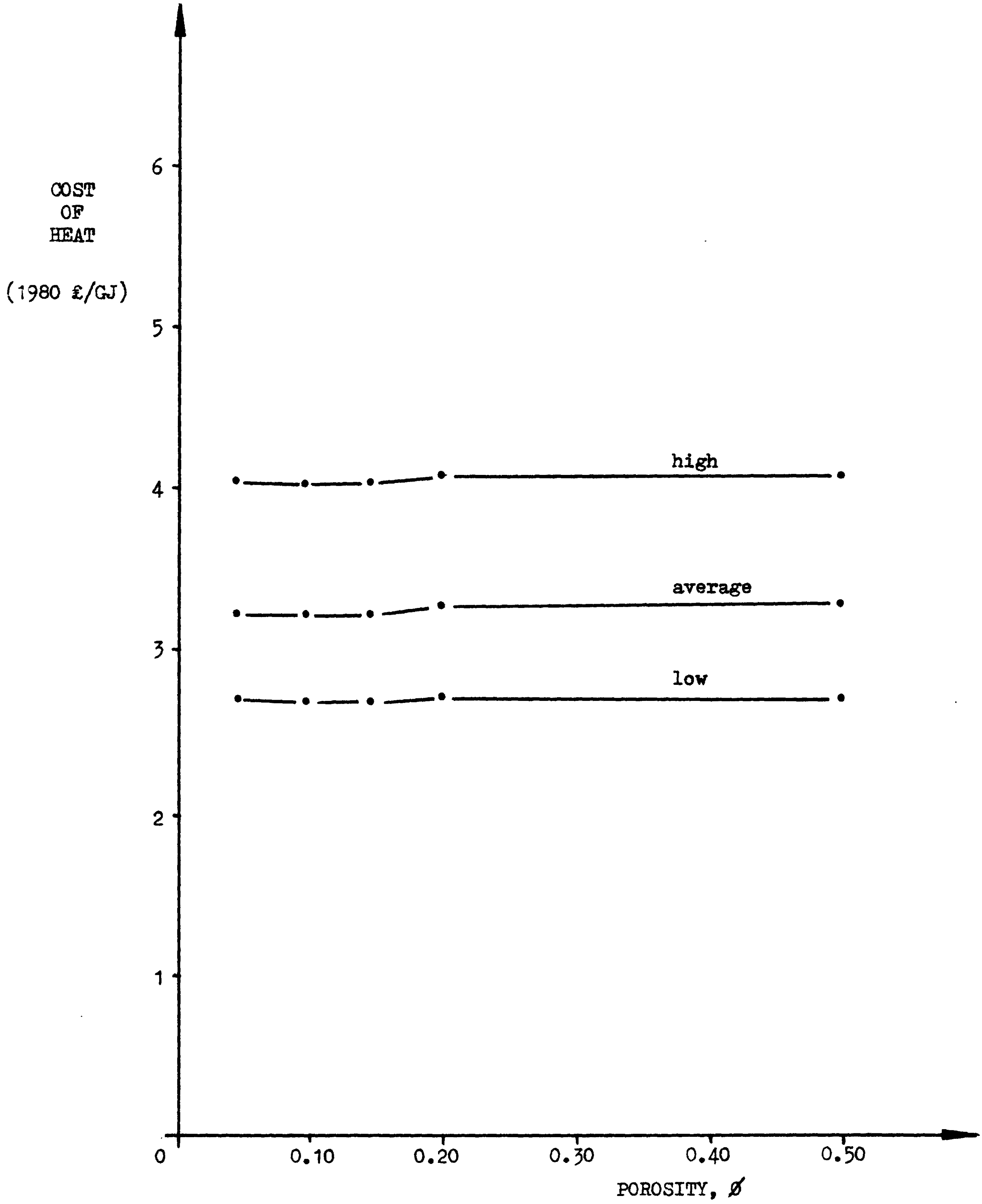


Figure 17 Unit Costs and Porosity for a Marchwood Doublet



effective thickness can have a strong influence on costs as illustrated in Figures 18 and 19. The main reasons for this are that these parameters affect the pump power ratings which determine pump capital, operating and maintenance costs. This aspect is investigated further towards the end of this section. The skin factors also affect costs through pump power ratings as demonstrated in Figure 20. This figure gives the variation of unit costs with both skin factors for the production and re-injection wells together. A positive value for the skin factor means that flow into and out of the well has been stimulated (an improvement over natural flow), whilst a negative value indicates a reduced natural flow due to well damage of some description. For a Marchwood doublet the skin effect in the production well has more influence on costs than the skin effects in the re-injection well. The final resource parameter investigated is static formation pressure, as illustrated in Figure 21. There is virtually no change in unit costs with static formation pressure in the production and re-injection wells. Basically, this is caused by any reduction in production pump power rating, resulting from increasing static formation pressure, being balanced by an almost equivalent increase in re-injection pump power rating.

The next set of parameters to examine for the doublet scheme describe operating and economic conditions. Figure 22 shows the influence of varying flow rate on unit costs at the well head. Unit costs at low flow rates are relatively high because the reduction in costs associated with the well pumps is not balanced by the greater reduction in heat output from the scheme (the capital costs of the wells remain constant). Similarly, unit costs at higher flow rates are high, since increases in pumping costs are greater than the extra heat output from the scheme. A balance is achieved at intermediate flow rates, giving minimum unit costs at about 115 m^3/hour, on average. It should be noted, however, that this value for optimum flow rate will change when the economics of a complete geothermal heating scheme are assessed and the impact of fuel and general price rises is considered (see Section 7.2.2). The influence

Figure 18 Unit Costs and Permeability for a Marchwood Doublet

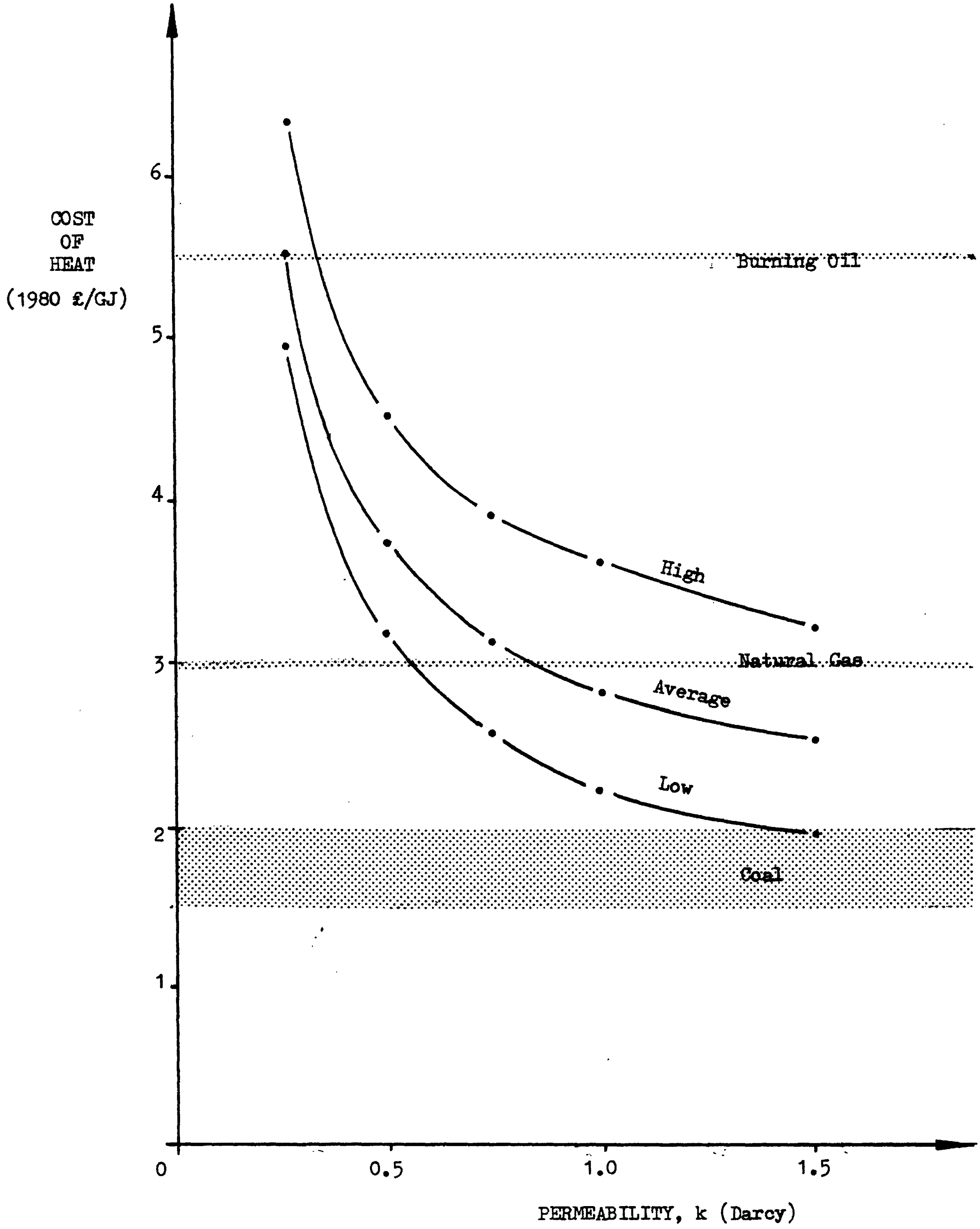


Figure 19 Unit Costs and Effective Thickness for a Marchwood Doublet

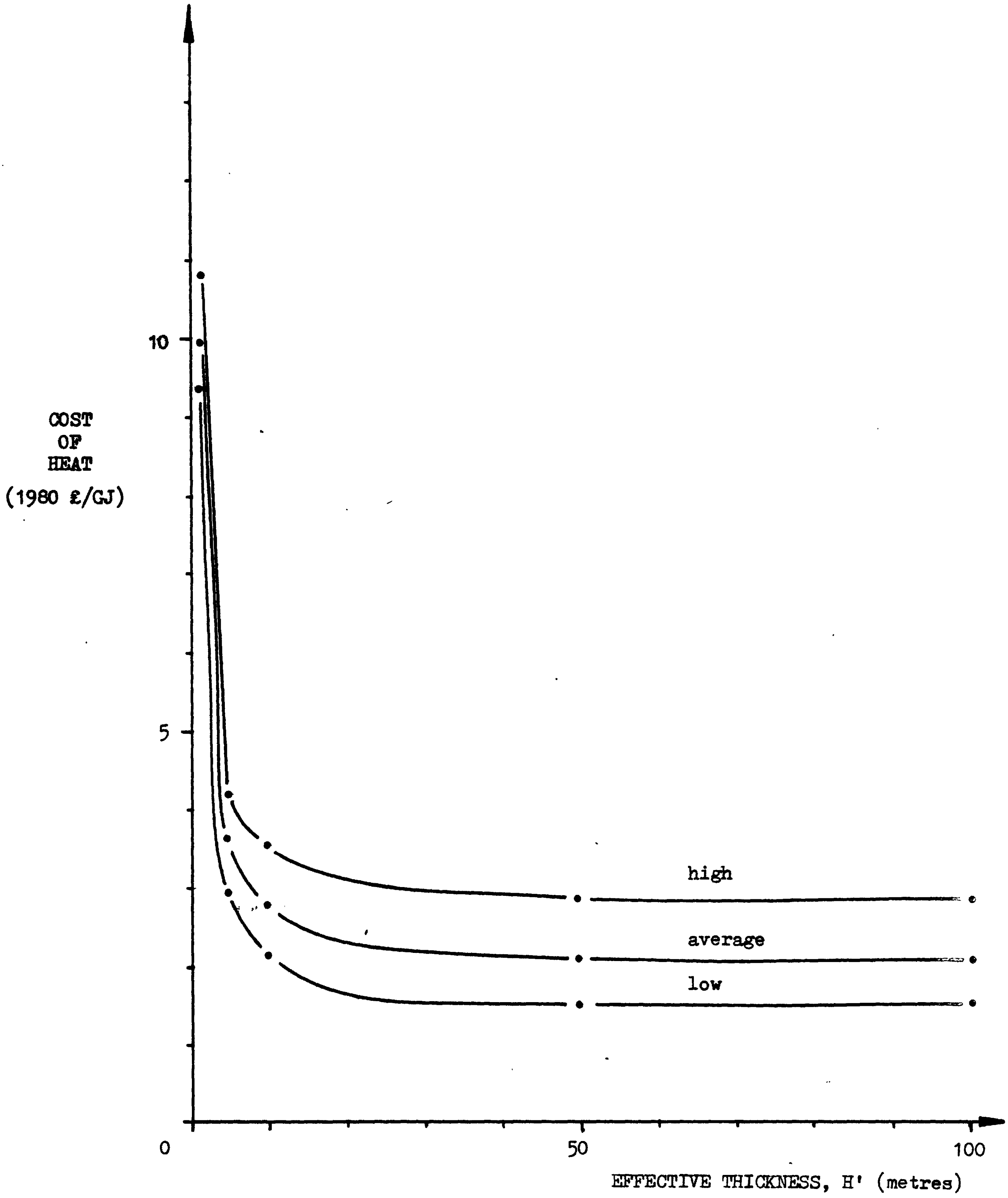


Figure 20 Unit Costs and Skin Factors for a Marchwood Doublet

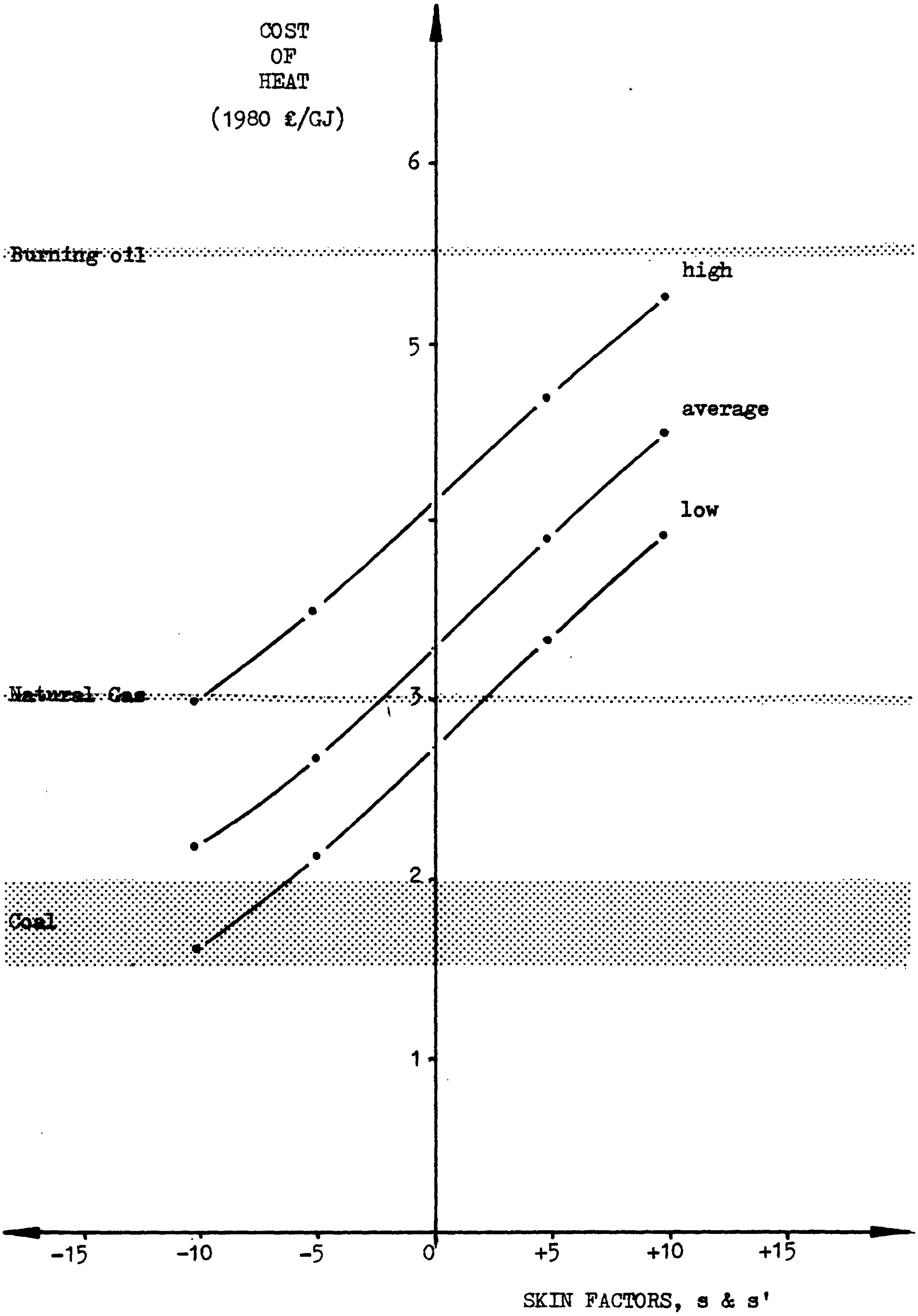


Figure 21 Unit Costs and Static Formation Pressure for a Marchwood Doublet and Singlet

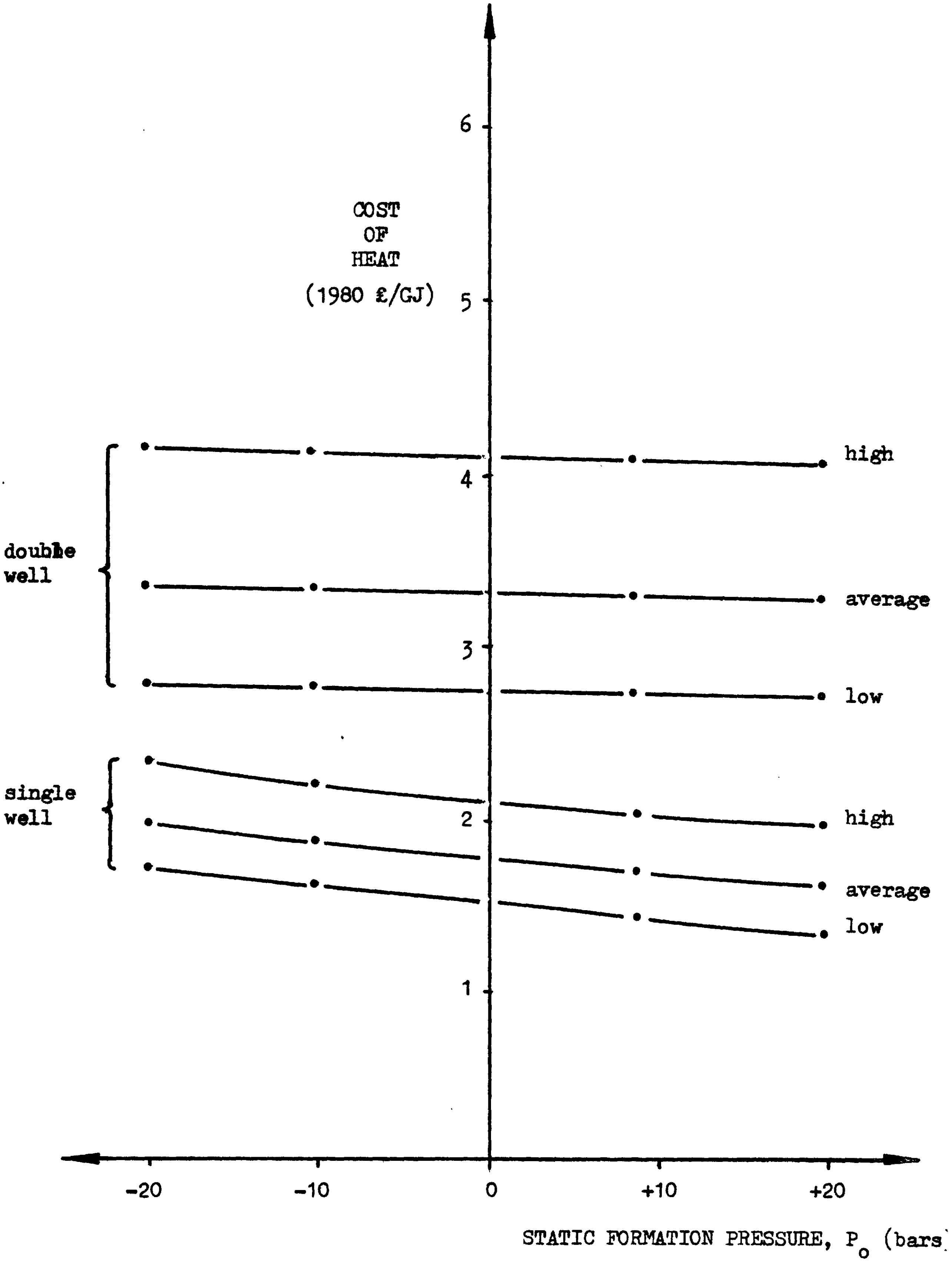
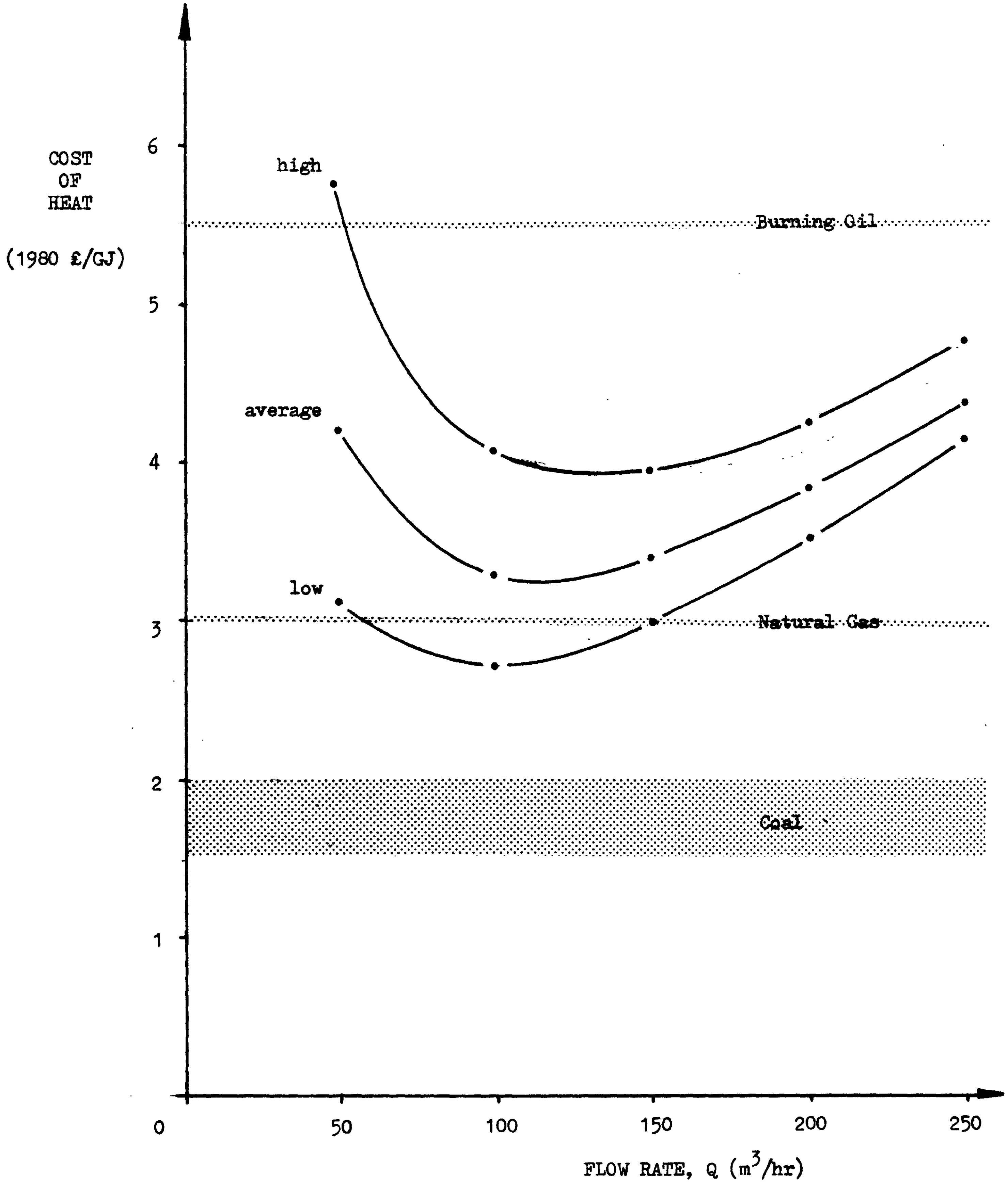


Figure 22 Unit Costs and Flow Rate for a Marchwood Doublet



of re-injection fluid temperature on unit costs is demonstrated in Figure 23, which shows that unit costs rise rapidly as the re-injection temperature approaches the production temperature. This occurs for the obvious reason that heat output decreases as the relative temperature difference between production and re-injection fluid falls. Figure 24 describes the effect of load factor on unit costs. As shown unit costs increase as the load factor decreases, largely because fixed capital costs must be spread over a smaller heat output. Falling pump operating costs cannot compensate for this rise in unit costs. Finally, for the doublet scheme, the impact of difference interest rates on unit costs are illustrated in Figure 25. The variation is almost linear, with lower interest rates reducing unit costs quite significantly.

The investigation of parameters is repeated for a single well geothermal scheme in the Wessex basin in Figures 26 to 34. This re-examination is not as trivial as it might first appear since the use of one well instead of two does not simply halve well capital costs. Figure 26 shows that the difference in unit costs due to rock hardness for all depths become less distinct because of a reduction in well capital costs. Similarly, unit costs are reduced in Figure 27 which gives the variation of costs with depth for a singlet scheme (compare with Figure 16). Although these changes are relatively obvious, the effect on well pumping is less simple as demonstrated in Figures 21 and 28 to 30. Figure 28 illustrates the variation of unit costs with reservoir permeability, Figure 29 gives the variation with effective reservoir thickness, Figure 30 examines the skin factor and Figure 21 investigates static formation pressure. Differences between these variations for the double and single well schemes are most pronounced for the skin factor and static formation pressure because, the compensating factors of operating a re-injection well do not occur in the case of a singlet scheme. Similar comments given previously for the doublet scheme are applicable to the remaining figures which show the effect on costs of flow rate (Figure 31), re-injection fluid temperature (Figure 32), load factor (Figure 33) and interest rate (Figure 34).

Figure 23 Unit Costs and Re-injection Temperature for a Marchwood Doublet

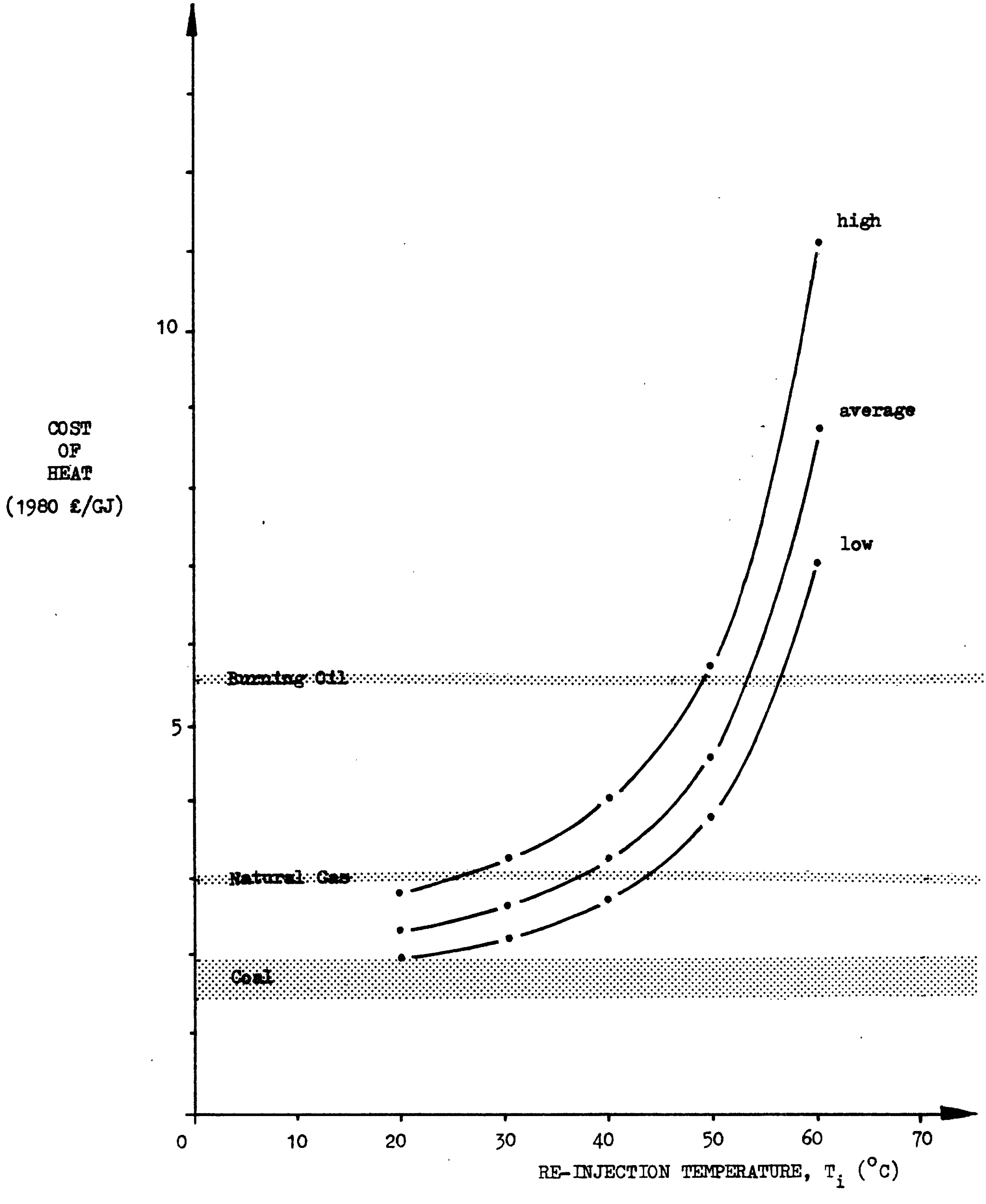


Figure 24 Unit Costs and Load Factor for a Marchwood Doublet

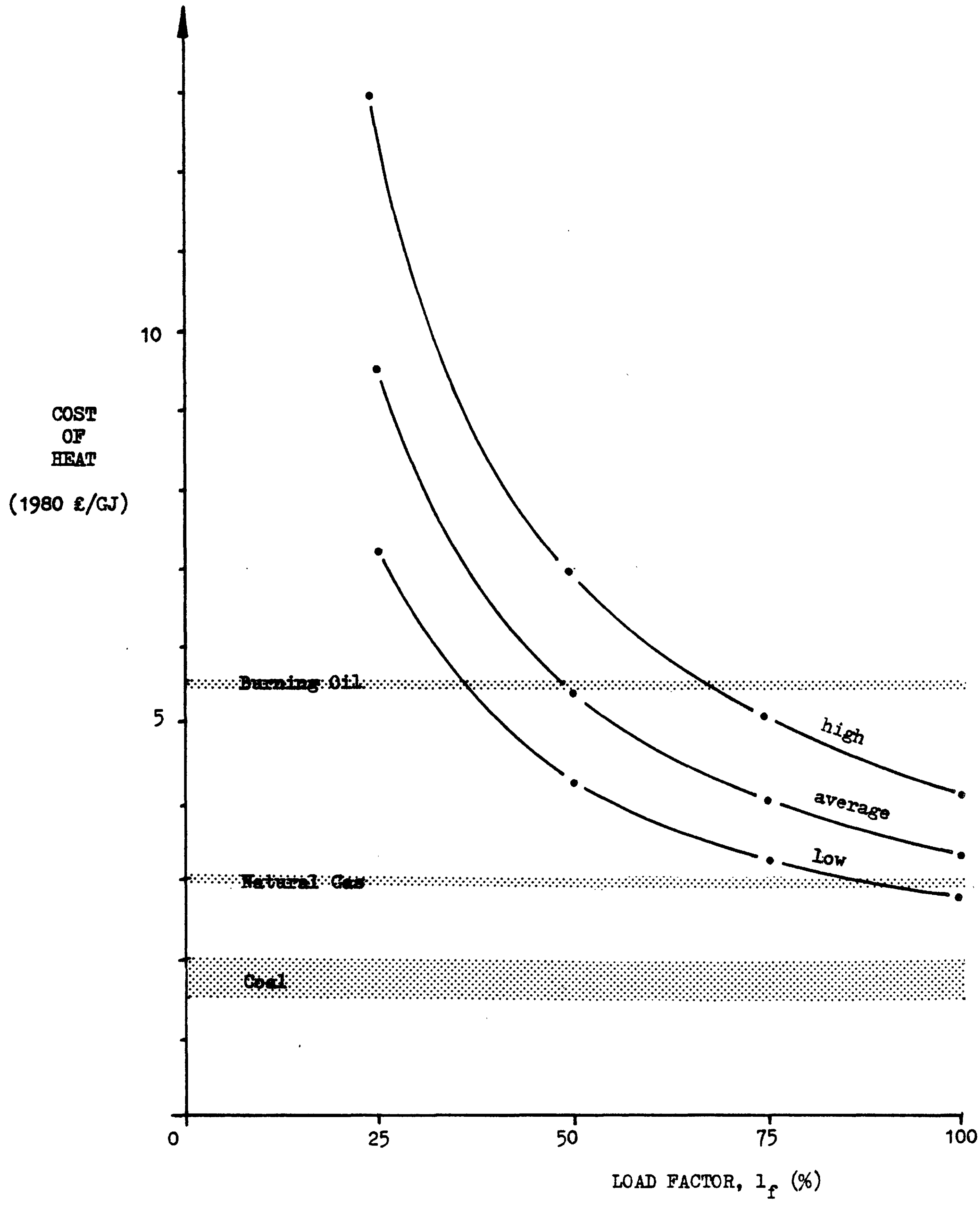


Figure 25 Unit Costs and Interest Rate for a Marchwood Doublet

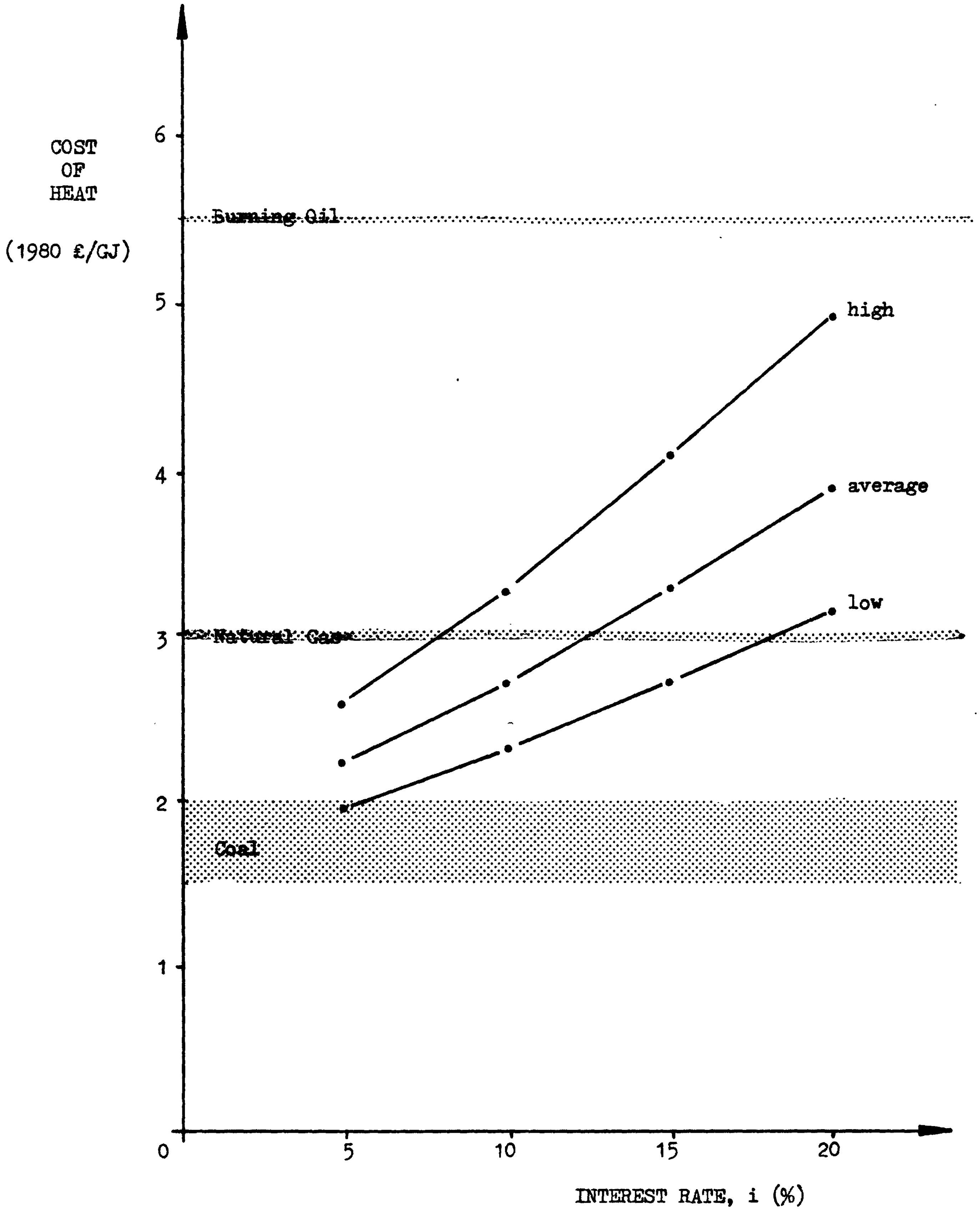


Figure 26 Unit Costs and Rock Hardness for a Marchwood Singlet

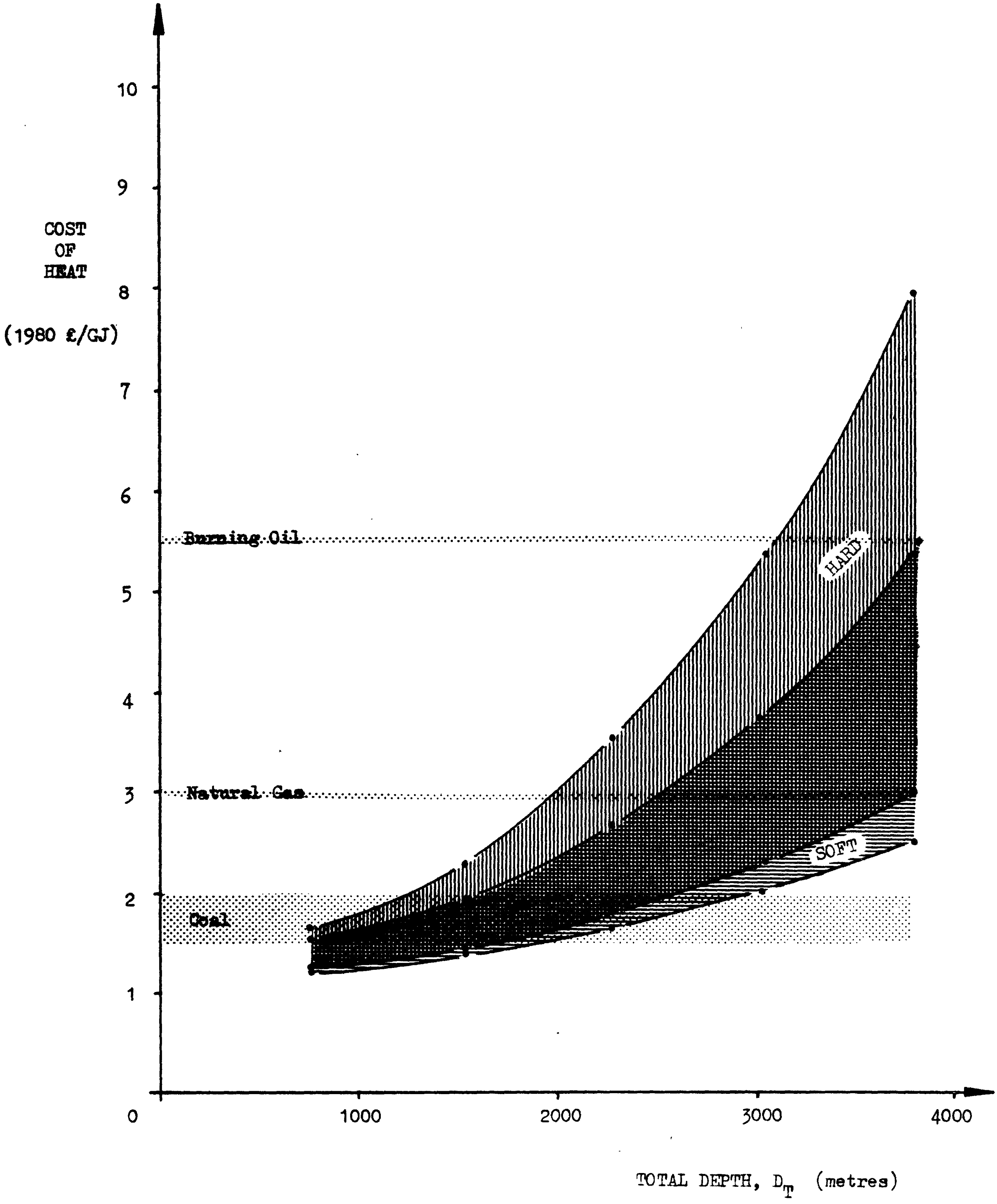


Figure 27 Unit Costs and Total Depth for a Marchwood Singlet

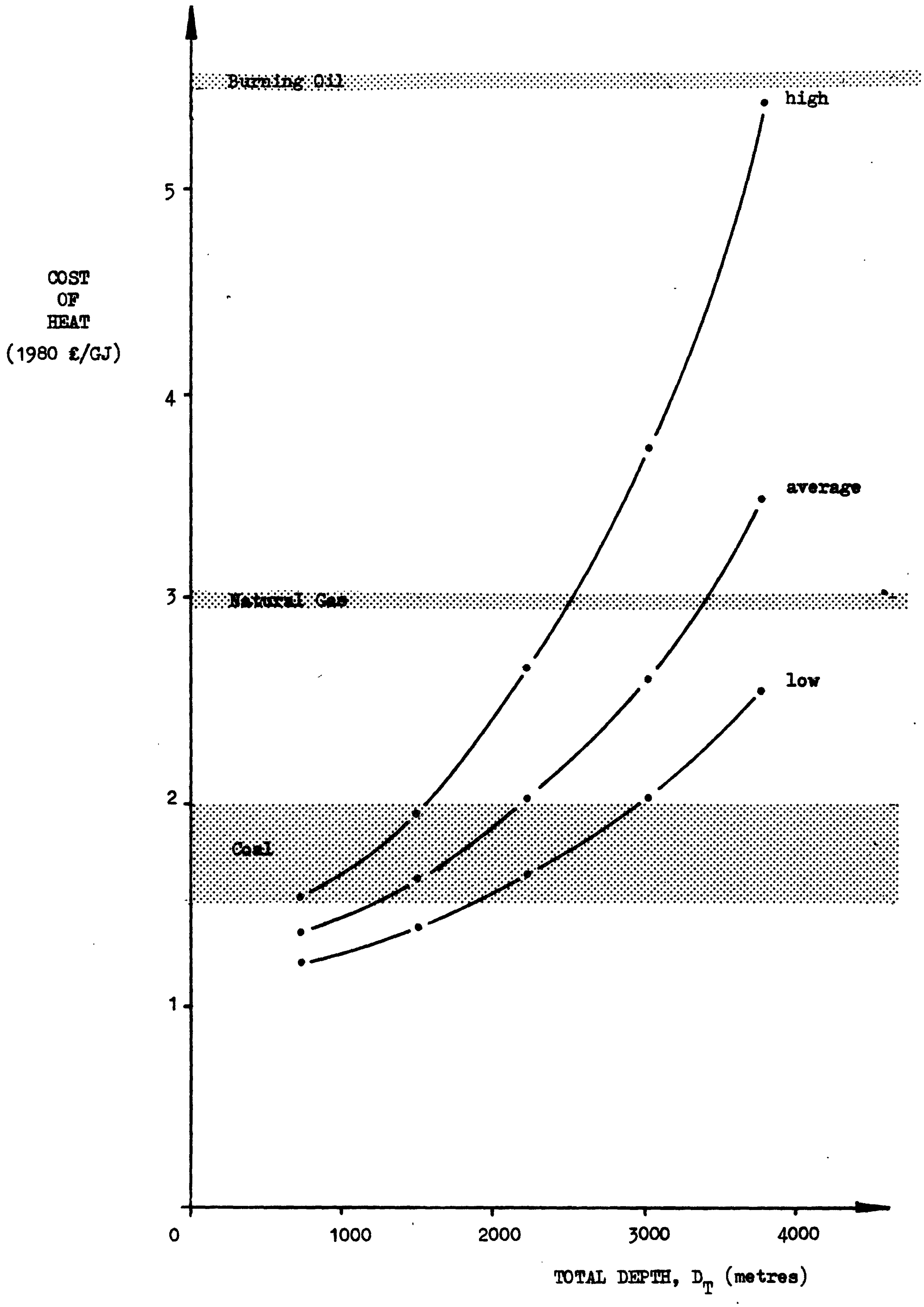


Figure 28 Unit Costs and Permeability for a Marchwood Singlet

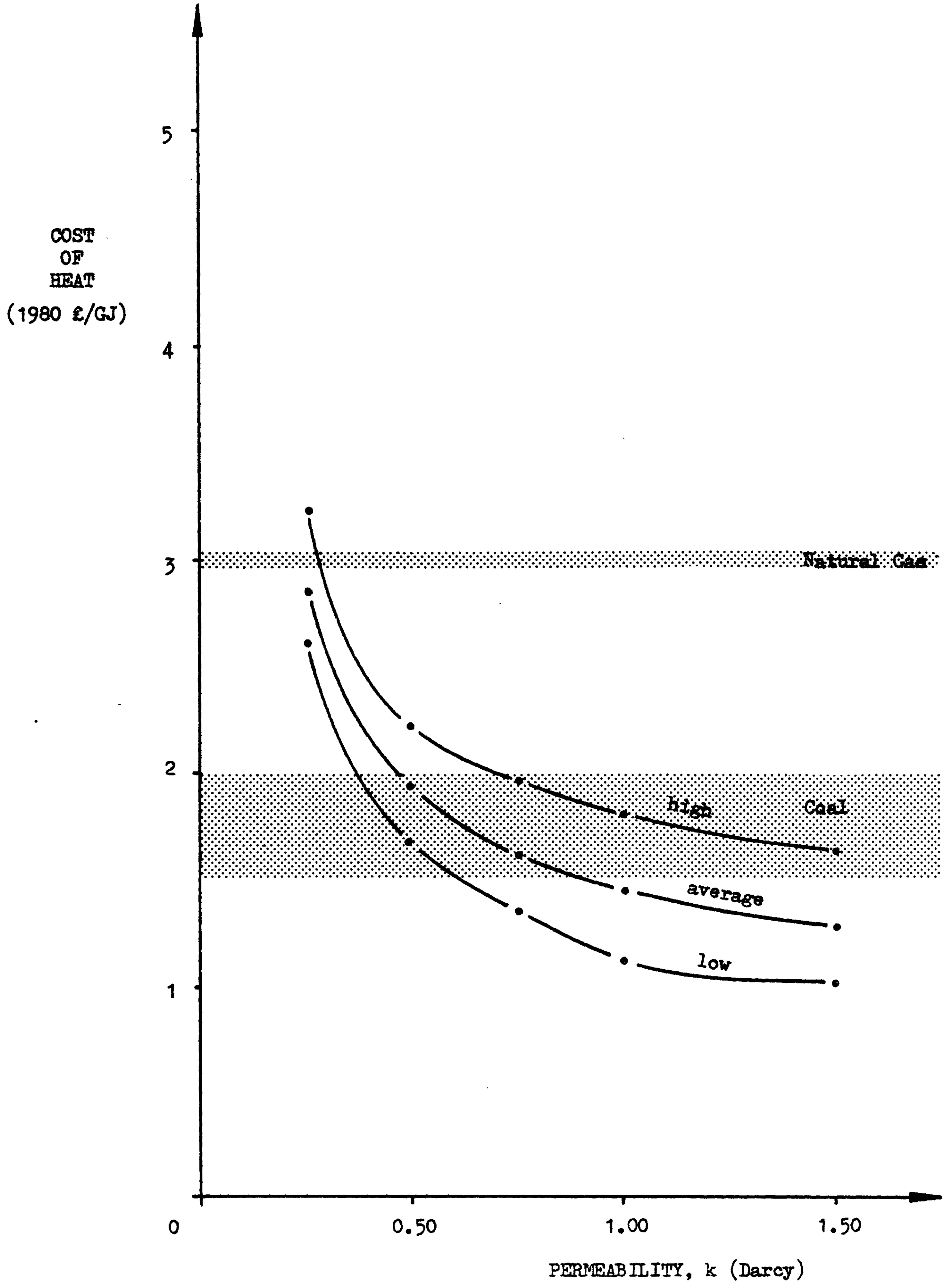


Figure 29 Unit Costs and Effective Thickness for a Marchwood Singlet

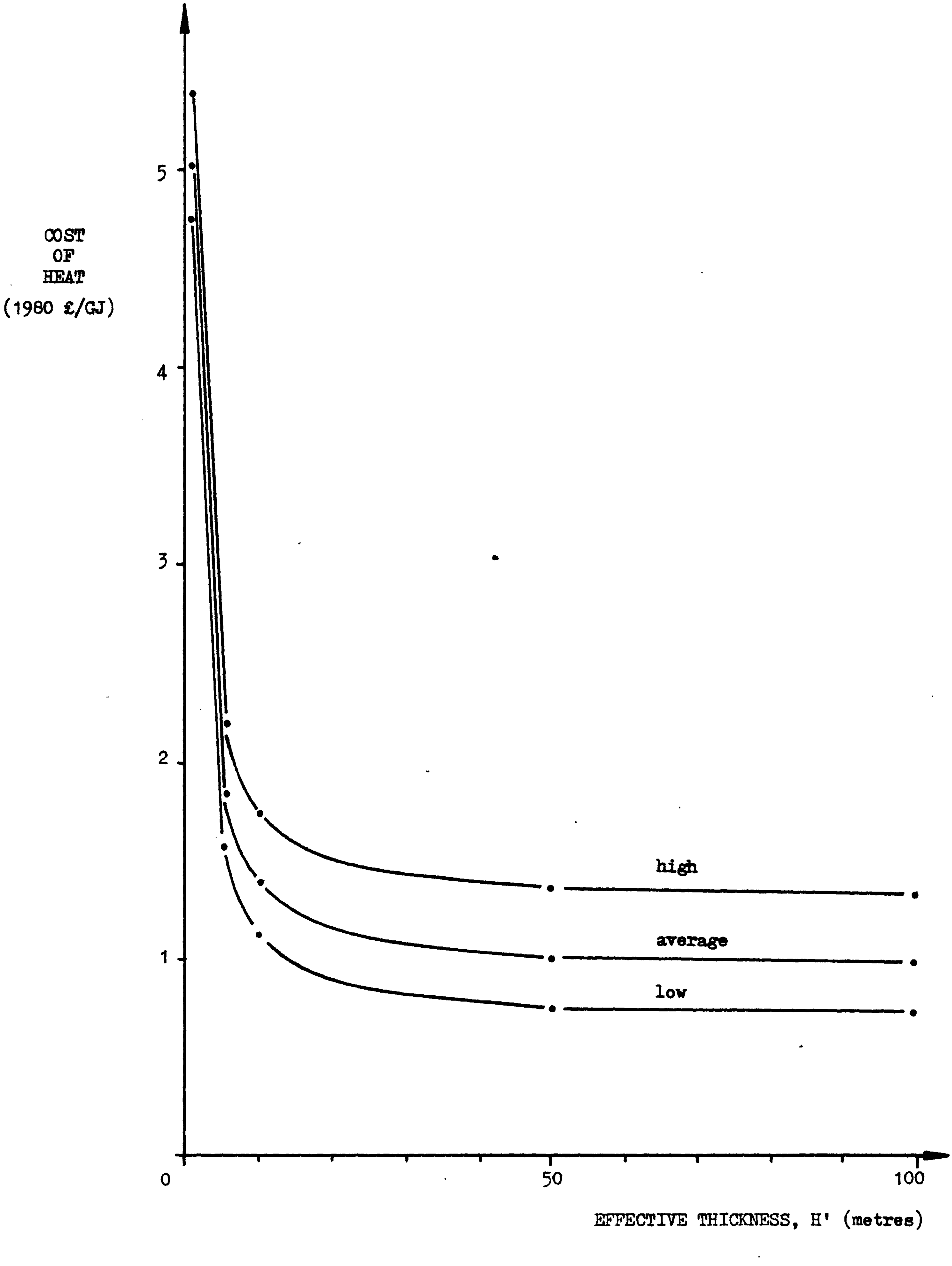


Figure 30 Unit Costs and Skin Factor for a Marchwood Singlet

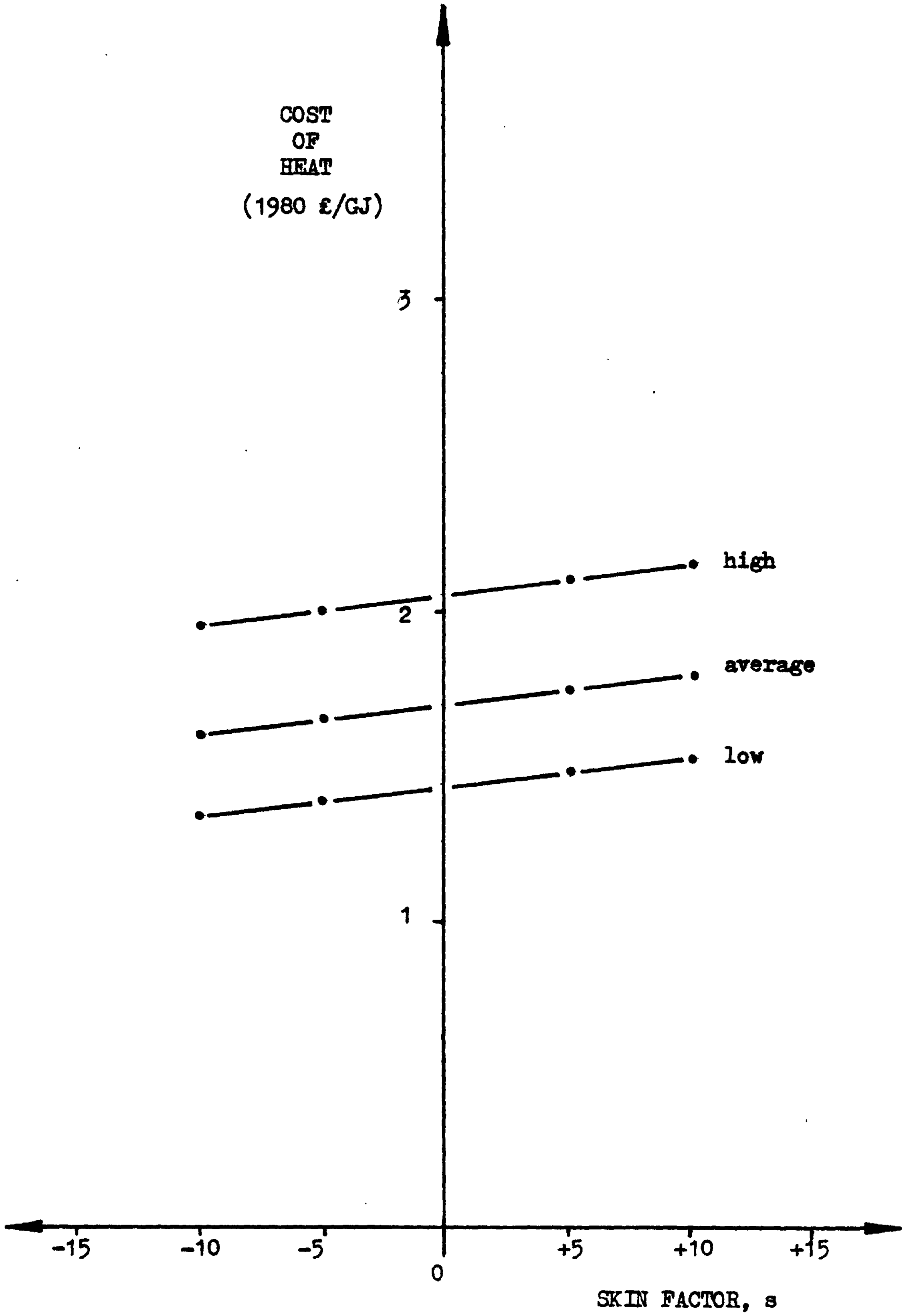


Figure 31 Unit Costs and Flow Rate for a Marchwood Singlet

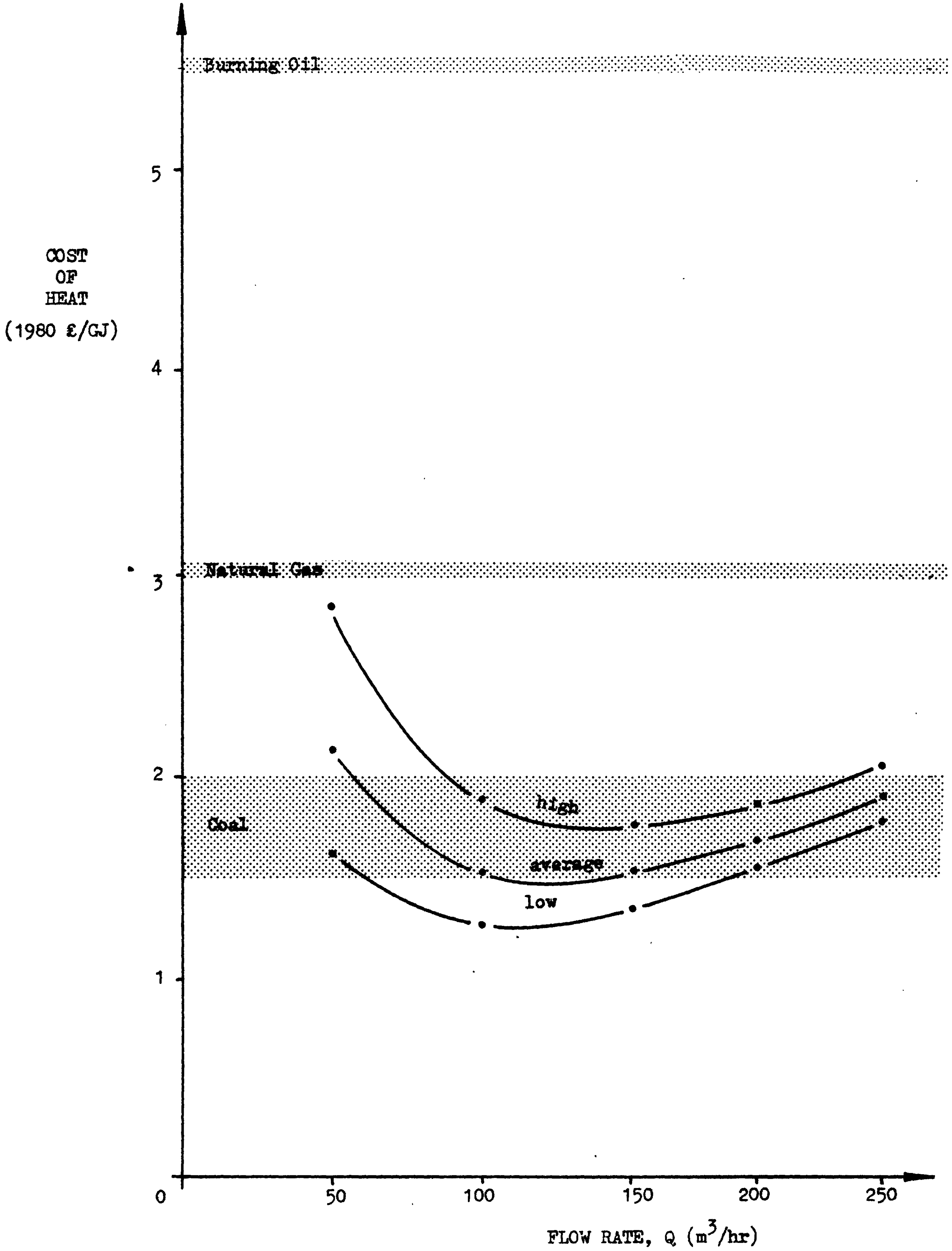


Figure 32 Unit Costs and Re-injection Temperature for a Marchwood Singlet

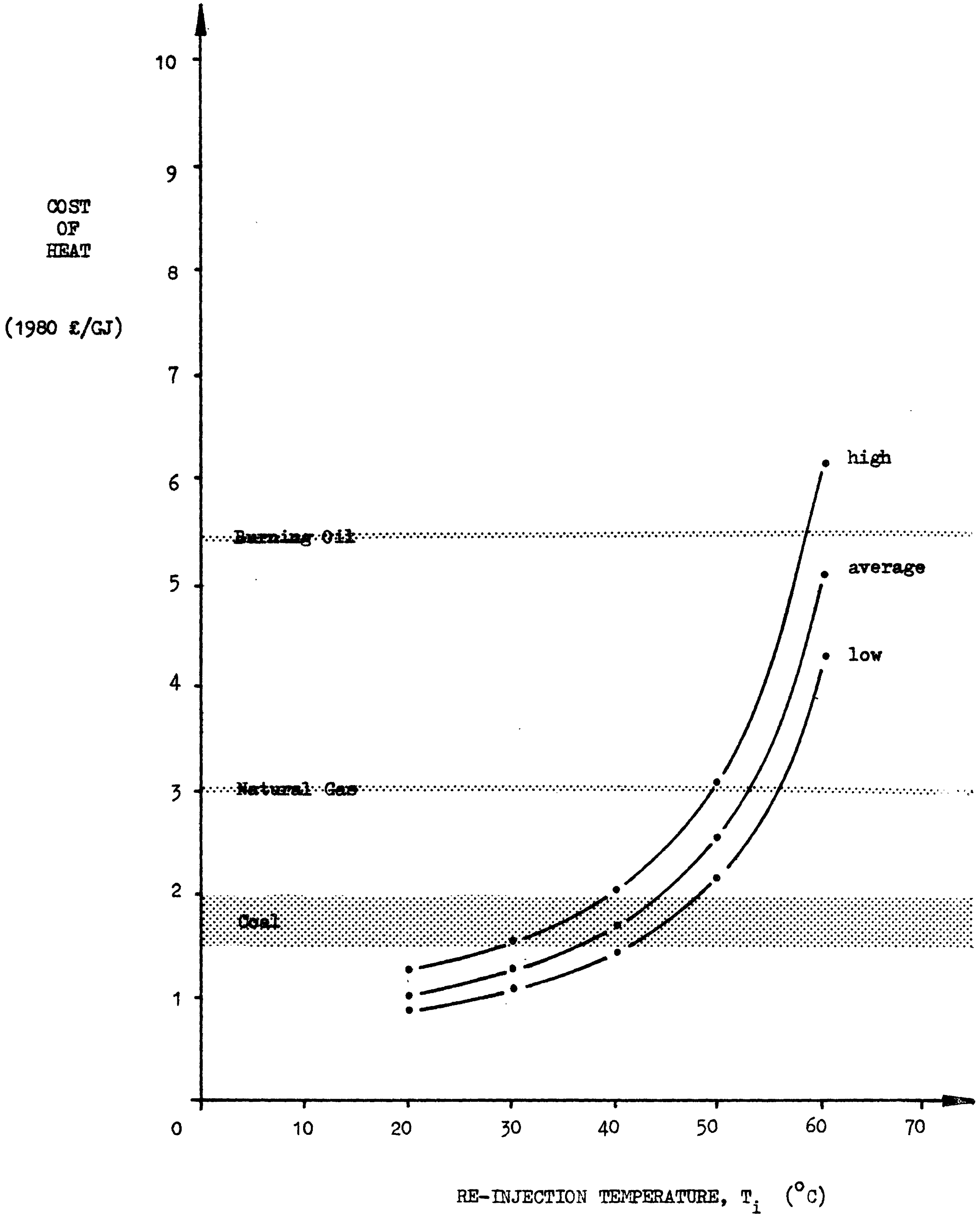


Figure 33 Unit Costs and Load Factor for a Marchwood Singlet

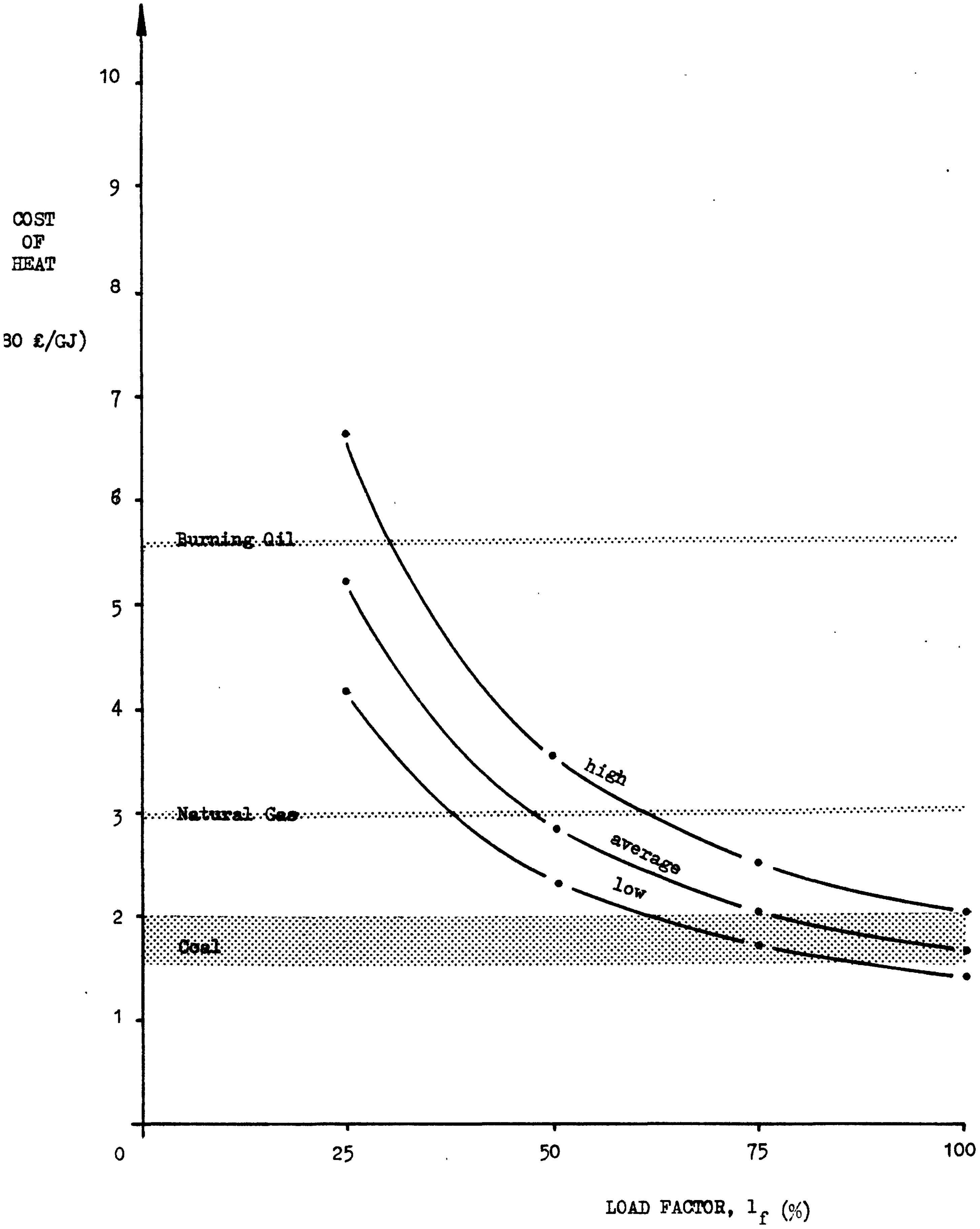
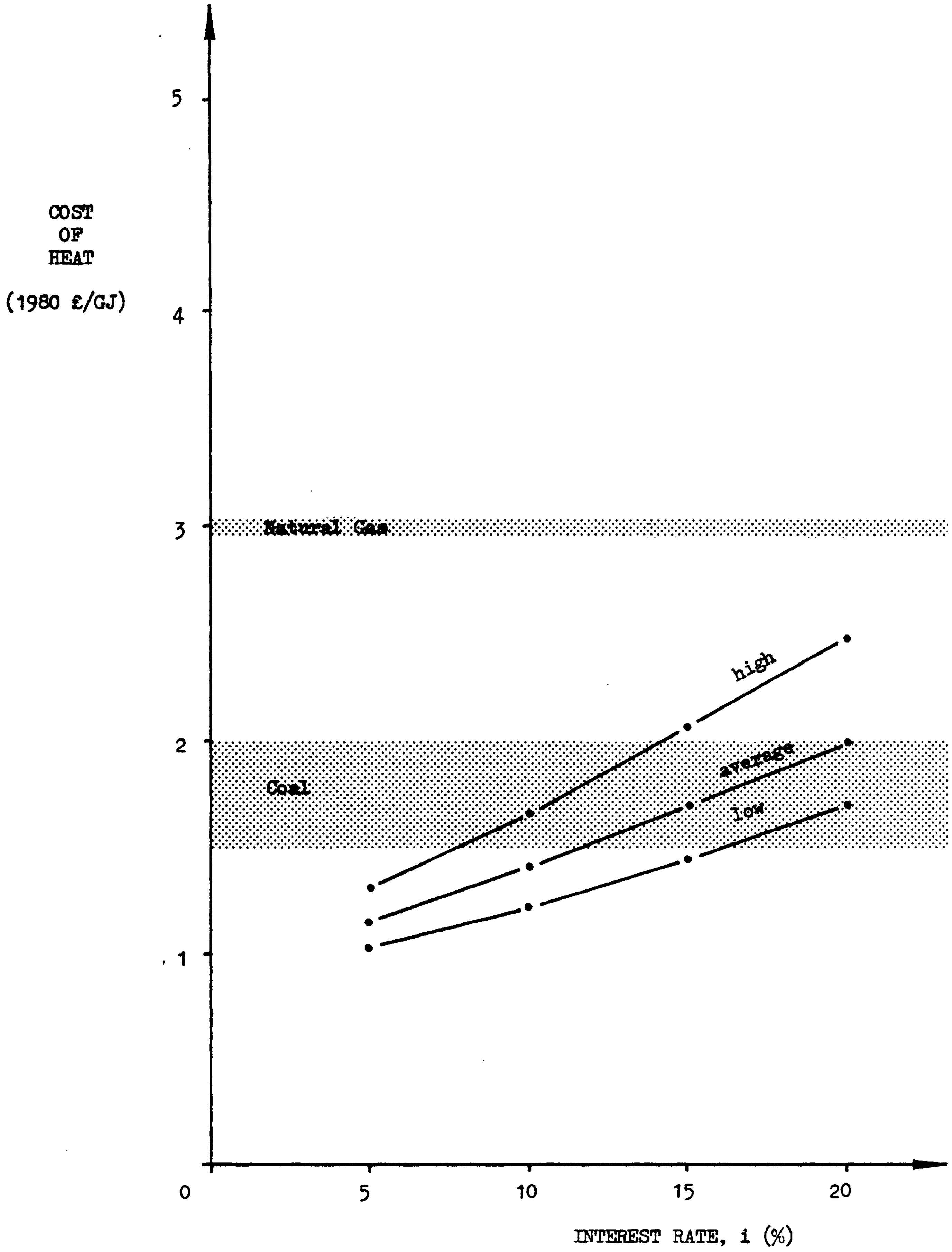


Figure 34 Unit Costs and Interest Rate for a Marchwood Singlet



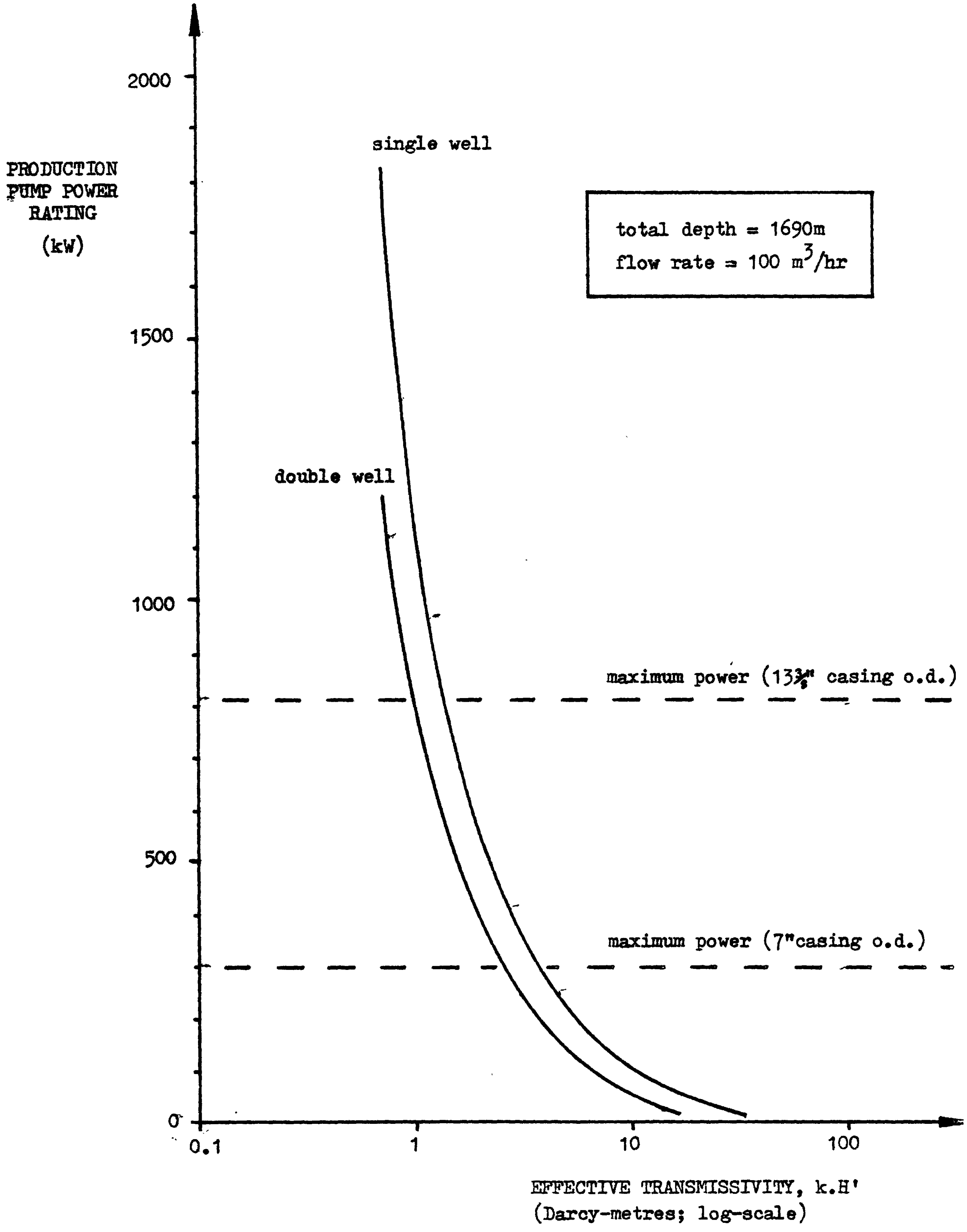
Before concluding this section, the effects of reservoir permeability and effective reservoir thickness on the geothermal scheme must be examined in slightly more detail. Preceding figures suggest that the unit costs at the wellhead are strongly dependent on reservoir permeability and thickness, especially at low values of these parameters. The reason for this is that permeability and reservoir thickness determine the resistance to fluid flow within the reservoir and this affects production and re-injection pump power ratings, which in turn influence pump capital, operation and maintenance costs. Equations given in Working Paper No. 9 suggest that pumping power is inversely proportional to the effective reservoir transmissivity which is the product of permeability and effective reservoir thickness. Consequently, at low values of transmissivity the required pumping power can be very high and this may set a practical physical limit on using the geothermal resource. The problem affects the rating of the submersible pump in the production well in particular since the power of this pump can be limited by the size of casing into which it must be placed. Examination of manufacturer's catalogues (Ref. 19 and 20) suggests that the maximum power capacity of a standard submersible pump fitting a 7 inch outside diameter casing (which is the size of the production casing used in this study) is about 300 KW. The maximum power rating of all standard submersible pumps was found to be about 800 KW (fitting a normal 13⅜ inch outside diameter casing). These maximum values can be compared with the required production pump power ratings for a Marchwood type singlet and doublet scheme, varying with effective transmissivity in Figure 35. This implies that the practical, lower limit to transmissivity is between 1.0 and 4.0 Darcy-metres.

6.4 Conclusions

Using Marchwood data represented as a base case this study suggests that:

a) The most important resource parameters for a doublet scheme are rock hardness, depth, permeability, effective reservoir thickness, skin factor and production fluid temperature.

Figure 35 Effect of Transmissivity on Production Pump Power Rating



b) The most important resource parameters for a singlet scheme are depth, permeability, effective reservoir thickness and production fluid temperature.

c) The minium practical value of transmissivity for both doublet and singlet schemes is between 1.0 and 4.0 Darcy-metres.

d) An optimum flow rate exists for any scheme which results in minimum costs of heat at the wellhead.

7. Unit Costs of Complete Schemes

7.1 Method of Economic Appraisal

7.1.1 Unit Costs

To assess the broad economic feasibility of a geothermal scheme under changing conditions, the cost of producing a gigajoule unit of useful heat from the full scheme is estimated for each year of its life. To do this the different behaviour of the three main groups of costs under rising prices is tracked, for the lifetime of the project, namely:

- Capital costs, whose annual repayments decline over time in effective money terms.
- Maintenance whose real costs remain substantially constant.
- Energy costs, which may rise in real terms, over and above general inflation.

All these costs are calculated for each year of operation in £/year, and divided by the total annual heat output from the scheme in GJ/year, to give the cost per unit of useful heat in £/GJ for that year.

7.1.2 Interest Rate

It is assumed that all capital costs are met through debt (external loans) and all operating costs through earnings (internal funds). This enables interest on loans to be treated separately from any extra return expected by the geothermal organisation itself - which may be nil.

Capital costs are converted into their equivalent annual payments, needed to pay back the loan with interest over the items lifetime. This is done by multiplying each capital cost by a Capital Recovery Factor:

$$CRF = \frac{i(1 + i)^n}{(1 + i)^n - 1}$$

where i is the annual interest rate and n is the number of years over which the loan is repayed.

The unit costs are set out year by year in this study, and represent a first stage of appraisal. They can be incorporated into an overall financial assessment of the project over its whole lifetime by discounting these costs, together with corresponding earnings, only at the incremental rate required by the organisation itself, since interest has already been allowed for.

For the cases studied here the same compound interest rate i is assumed on all capital costs. It is a gross rate, as actually charged by a bank, so it includes a component for inflation, g, as well as for risk, r, and a basic time preference for money, p:

$$(1 + i) = (1 + p)\ (1 + r)\ (1 + g)$$

7.1.3 General Inflation

All costs, for capital, maintenance and operating energy consumptions are adjusted to allow for the effect of general price rises, and are presented in 'real' or constant money value terms.

General price rises progressively reduce the real value of capital repayments in later years, by eroding the purchasing power of each £ borrowed. To represent this decline, the gross interest rate i is used in the Capital Recovery Factor (to make the first year's repayment K_o correct) and the annual repayments K are then reduced year by year at the general rate of inflation g:

$$K = \frac{K_o}{(1 + g)^n}$$

n = 0, 1, 2, ... project lifetime

The gross interest rate i sets the inital level of repayments, and the general inflation rate g determines their subsequent decline in real value.

Costs of maintenace and of any capital items replaced during the scheme's lifetime (only production pumps in this exercise) are assumed to rise with general inflation, so they remain constant in real money terms.

7.1.4 Fuel Price Rises

Net fuel price rises above general inflation are taken, as indicated in Section 4.2.3, so they represent a rise in real terms, relative to other commodities.

7.2 Unit Cost Trends for Delivered Heat

7.2.1 Presentation

The results of the economic appraisal are presented in the form of cost profiles which show how the unit cost of final delivered heat for a complete scheme changes over time in real terms under changing price conditions.

All the results presented refer to a full geothermal heating scheme based on a hypothetical Wessex Basin resource, with geothermal properties similar to those of the Marchwood well. To assess the economic impact of different possible ways of exploiting the resource, and of different economic and financial conditions, a wide, though selective, range of cases is analysed by varying:

- Geothermal flow rates: from 50 to 250 m^3/h in steps of 50 m^3/h
- Coverage of energy demand by the geothermal source: 70,80, 90%.
- Well configuration: single well and doublet.

By varying flow or coverage, the size of the heating scheme is effectively altered since the total heat supply changes.

These cases are compared to find relatively favourable geothermal schemes, which are then judged against reference heating systems fuelled by coal, oil or gas only, comparing like with like (e.g. geothermal with gas back-up against a totally gas-fired system). To provide a fair basis for comparison, capital costs for fossil-fuelled schemes are included, assuming a central boiler plant as for adjacent blocks of flats or for a small district heating scheme.

Economic and financial assumptions are also varied to indicate the sensitivity of a scheme to:

- Net fuel price rises: 0 and 5% per year.
- Inflation and interest rates: 15% gross interest coupled with 10% inflation, 10% interest with 5% inflation.

7.2.2 Discussion of Results

Base Case

A reference case is taken of a geothermal doublet in the Wessex Basin with a flow of 100 m^3/h, linked to a heating system outlined in Section 3, and covering 80% of its annual energy demands, the rest being provided by a gas-fired back-up plant. Figure 36 shows how the relative importance of capital and operating costs for such a scheme changes dramatically over its lifetime. In early years capital repayments form most of the total, but in later years operating costs dominate, as fuel prices rise and capital repayments decline in real terms.

This basic case is systematically varied, one parameter at a time, in the following examples.

Geothermal Flow

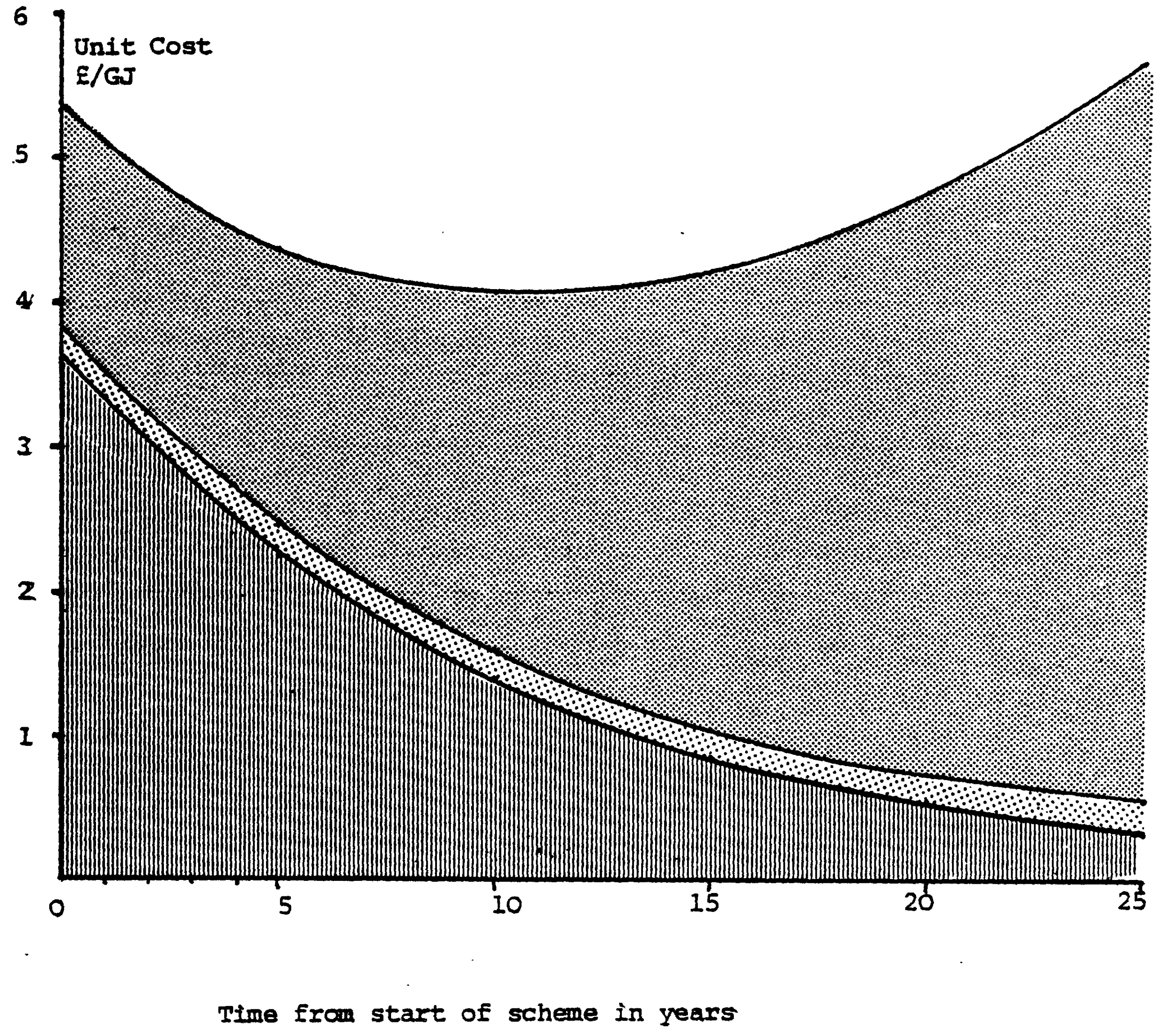
Increasing flow rate has two opposing effects on the unit cost of delivered heat. Costs are increased, particularly for pumping, but they are spread over a larger heat output. The net effect of this trade-off gives a distinct minimum cost at a moderate flow rate, above and particularly below which costs for a complete scheme rise significantly, Figure 39, as do costs at the wellhead (see Figure 22, Section 6).

Where this occurs, however, is affected by linking the wells to a complete scheme, with a variable heating load, and extra capital and operating costs. This optimum flow also depends crucially on both fuel and general price trends, so that progressively lower flow rates become the most economic as fuel and other prices rise, Figures 37, 38.

Since the flow cannot be grossly reduced during the life of the scheme without disrupting it, a compromise flow and scheme size has to be chosen. If average unit costs for the lifetime of different schemes are plotted against flow, Figure 39, the lowest overall cost occurs at around 85 m^3/h. This represents the cheapest option if no extra return on top of interest repayments is required,

Figure 36 Unit Cost Profiles for Lifetimes of Complete Geothermal Schemes

Wessex Basin Doublet, Base Case



Cost Components

▨ Operating Energy

░ Maintenance

▥ Capital

Scheme Features

Flow	100	m^3/h
Temperature	70	^oC
Total demand	69 500	GJ
equivalent to	1 540	dwellings
Geothermal coverage	80	%
Back-up	gas	
Gross interest	15	%
General inflation	10	%
Net fuel price rise	5	%

Figure 37 Capital and Total Cost Profiles for High and Low Flow Rates

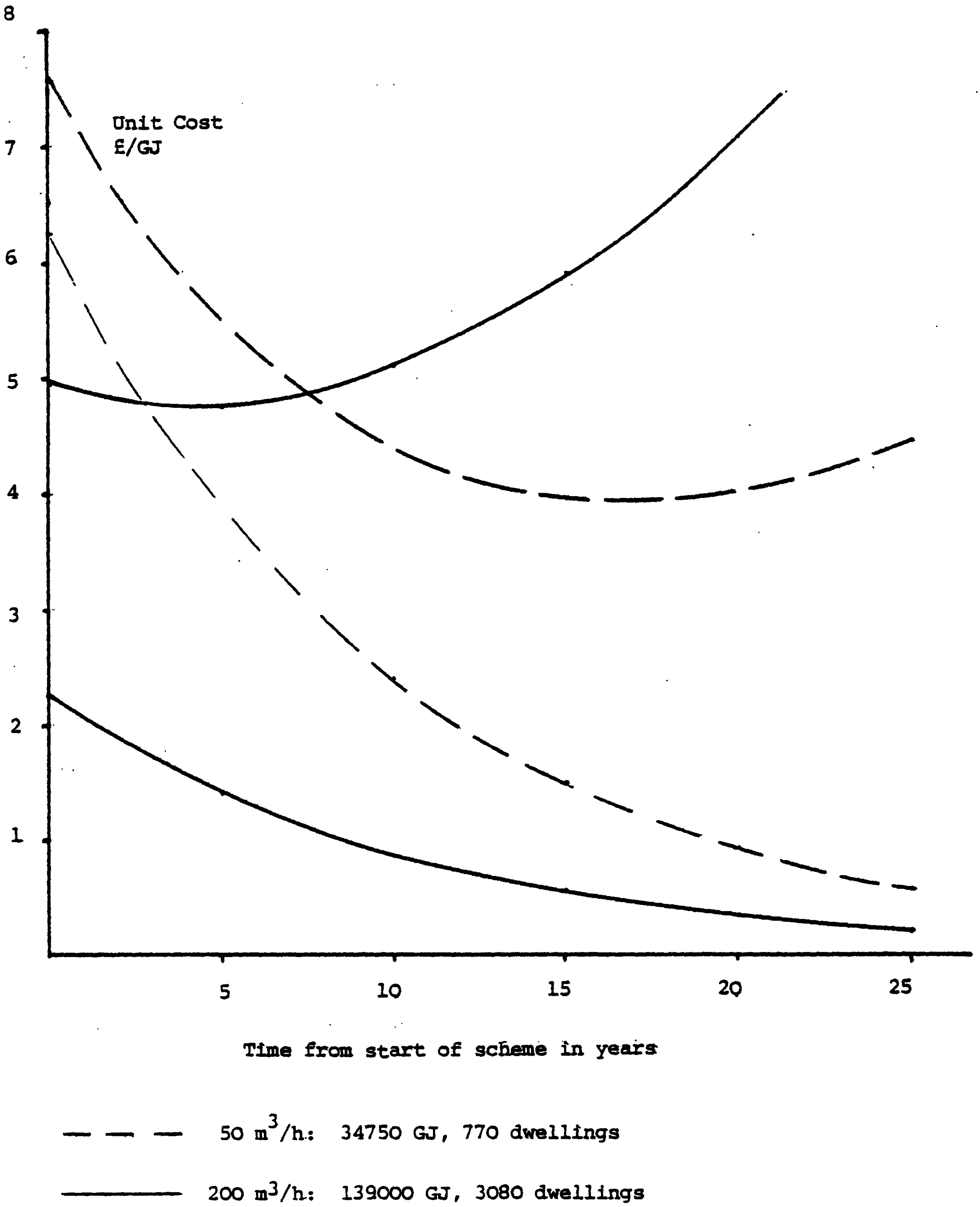


Figure 38 Effect of Flow Eate on Unit Cost Profiles

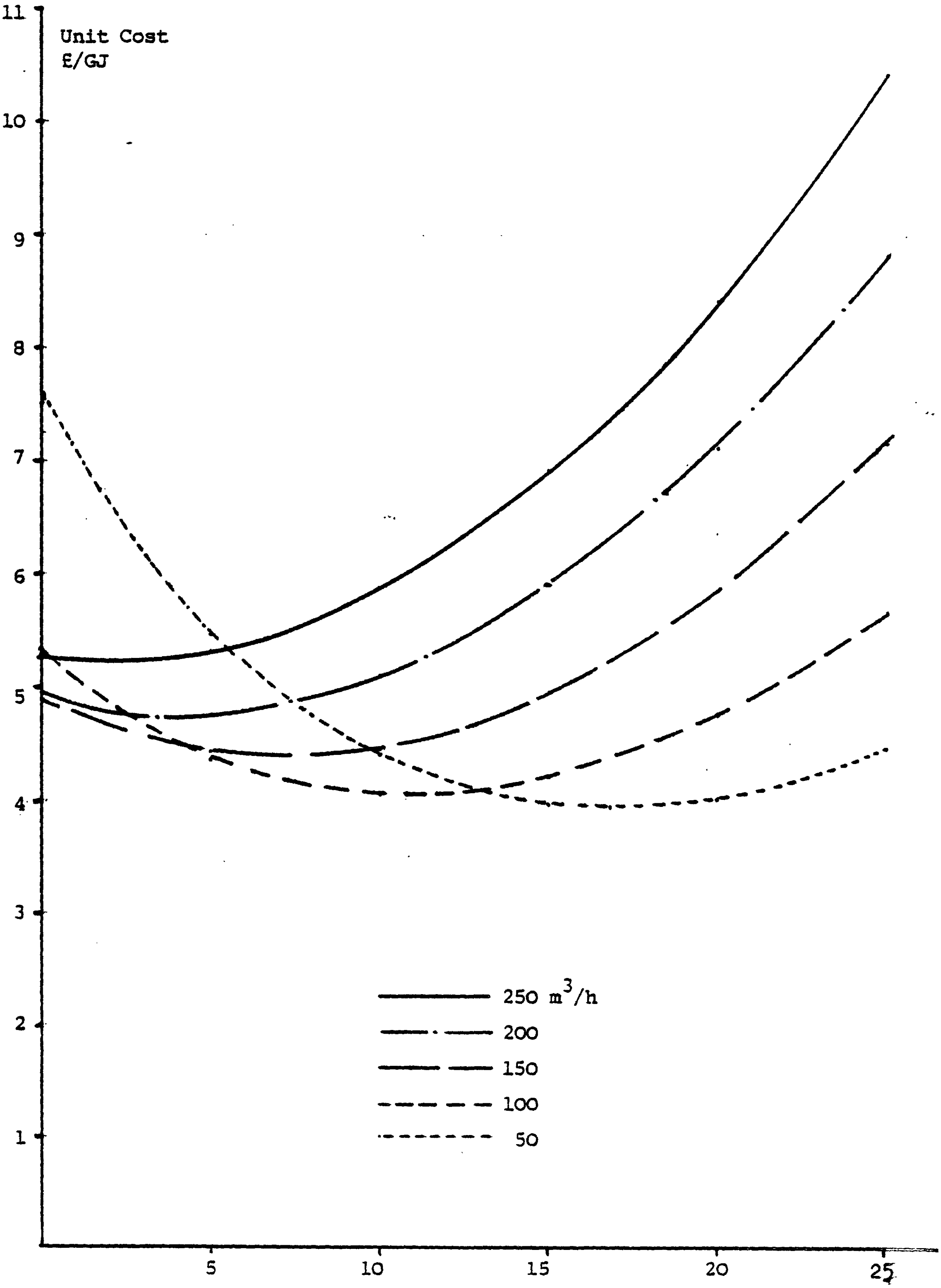
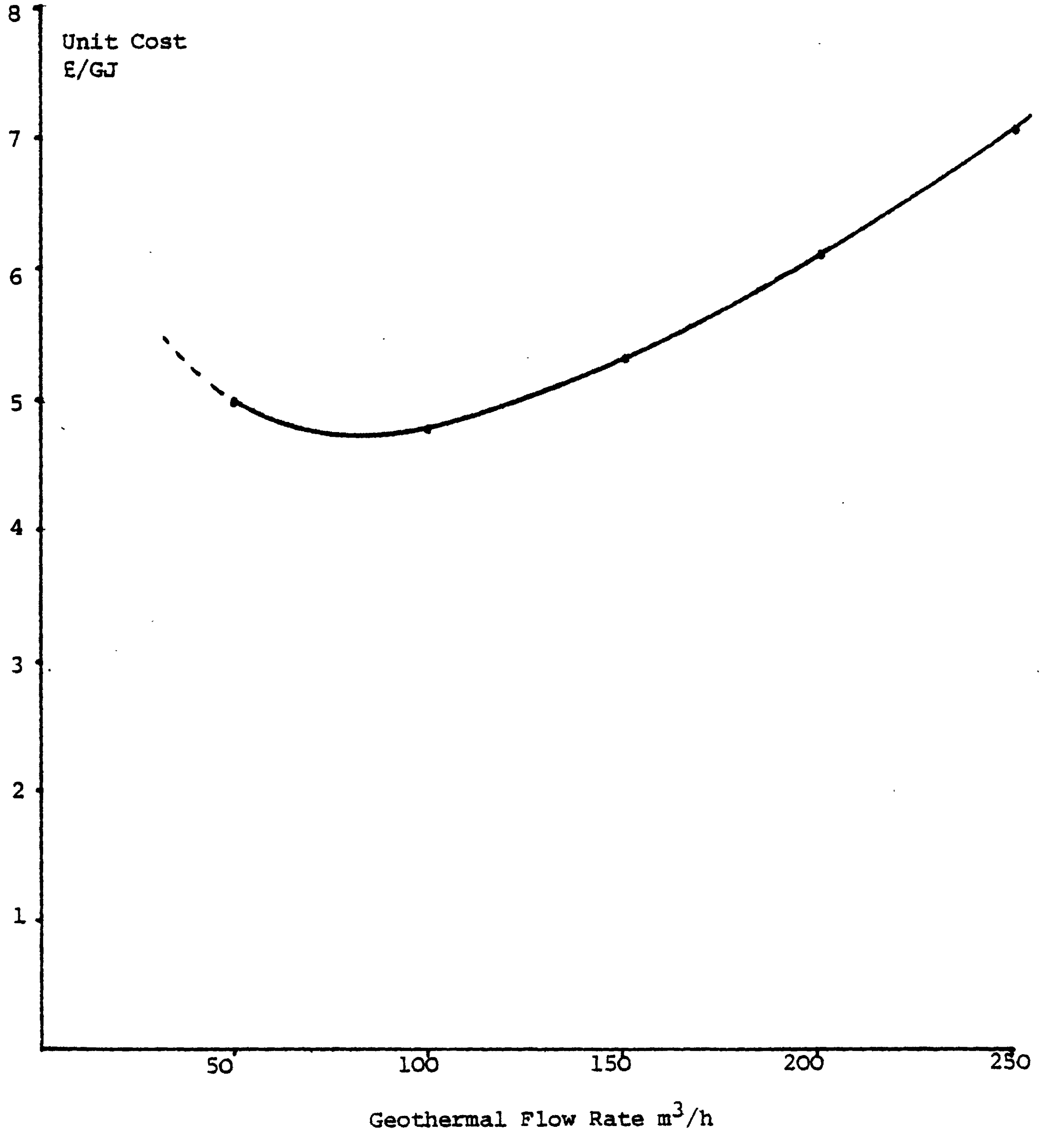


Figure 39 Effect of Flow Rate on Average Unit Costs



so that later cash flows do not have to be discounted any further.

Coverage

Optimum coverage depends on prevailing fuel prices, Figure 40. Increased coverage tends to increase unit capital costs, since the reduction in the total heat load covered tends to outweigh the reduced cost of the back-up plant. It has a mixed effect however, on unit operating costs: the reduced total heat output is offset to a varying degree by reduced back-up fuel requirements, so the net effect depends on fuel price trends.

For a very high geothermal contribution like 90% with consequently only 10% of the total heat produced by fossil fuel, even a three-fold increase in fuel prices does not have sufficient impact to compensate for reduced output, so schemes giving such high coverage are unlikely to be economic. On the other hand a lower coverage like 70% is only economic at low fuel prices, and a midway coverage of around 80% becomes and remains most economic after about 7 years of fuel price rises.

Climatic Conditions

Changing the temperature and demand distribution, within the same total 'temperature demand' of 2500 degree days, has negligible effect. If a flatter temperature distribution, characteristic of the Western U.K. is assumed (together with a 1°C higher minimum temperature of -6°C and a 1.5°C lower effective demand temperature of 16.5°C), capital costs are reduced by about 1% because of a 10% lower peak power demand and back-up boiler cost. This is offset by marginally increased operating costs (1% higher initially) since the wells are pumped continuously at full power for about 5% longer.

Single and Doublet Wells

Unit costs for a single well scheme without reinjection, Figure 41 are consistently lower than for a doublet, because of lower capital costs without a reinjection well (and pump) and lower operating costs without reinjection pumping, despite increased drawdown and pump and pumping costs for the production well. But the surface disposal entailed by a single well scheme may not be acceptable and the cost of such disposal is not included in this example.

Figure 40 Effect of Energy Coverage

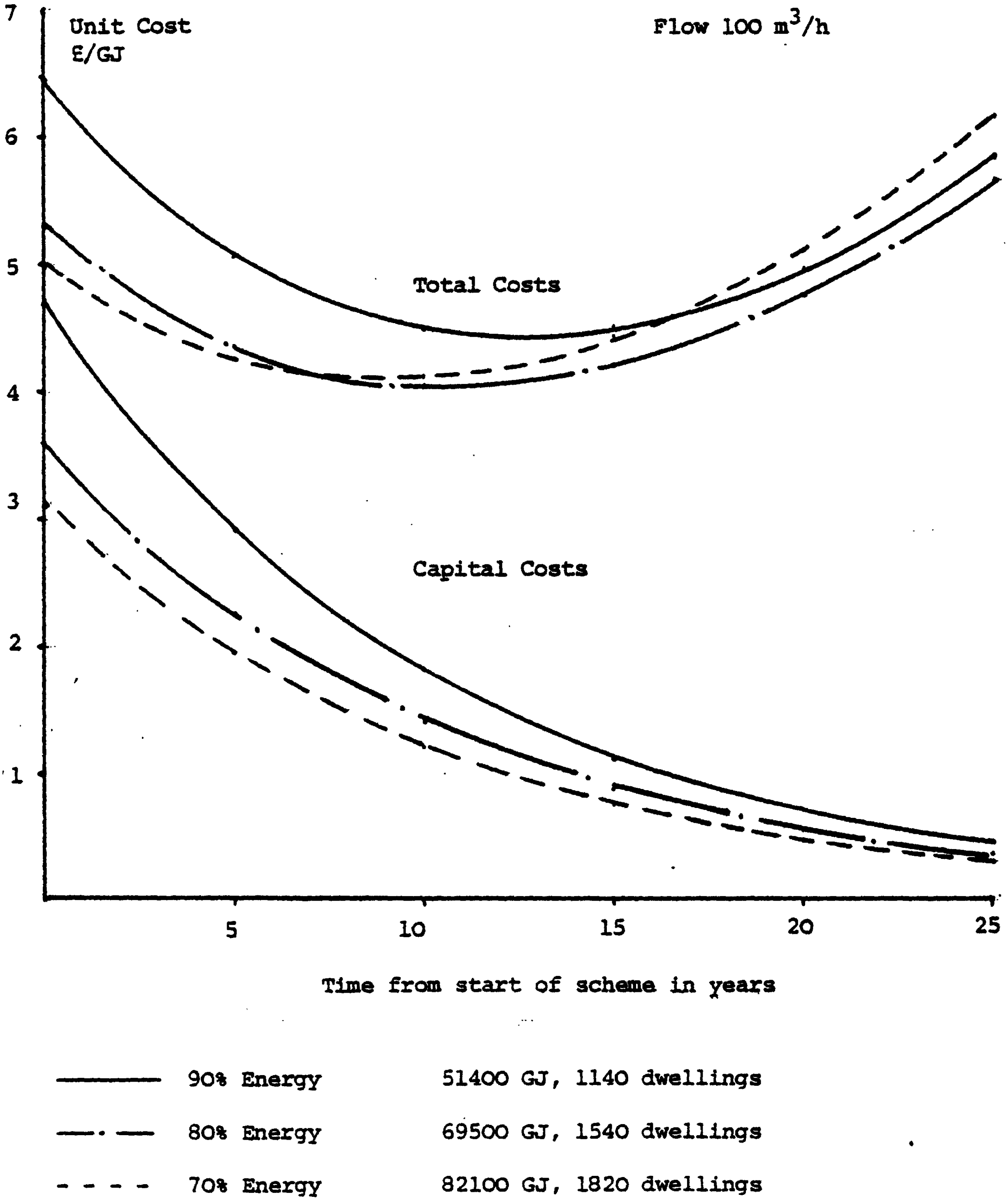


Figure 41 Comparison of Single Well and Doublet Scheme

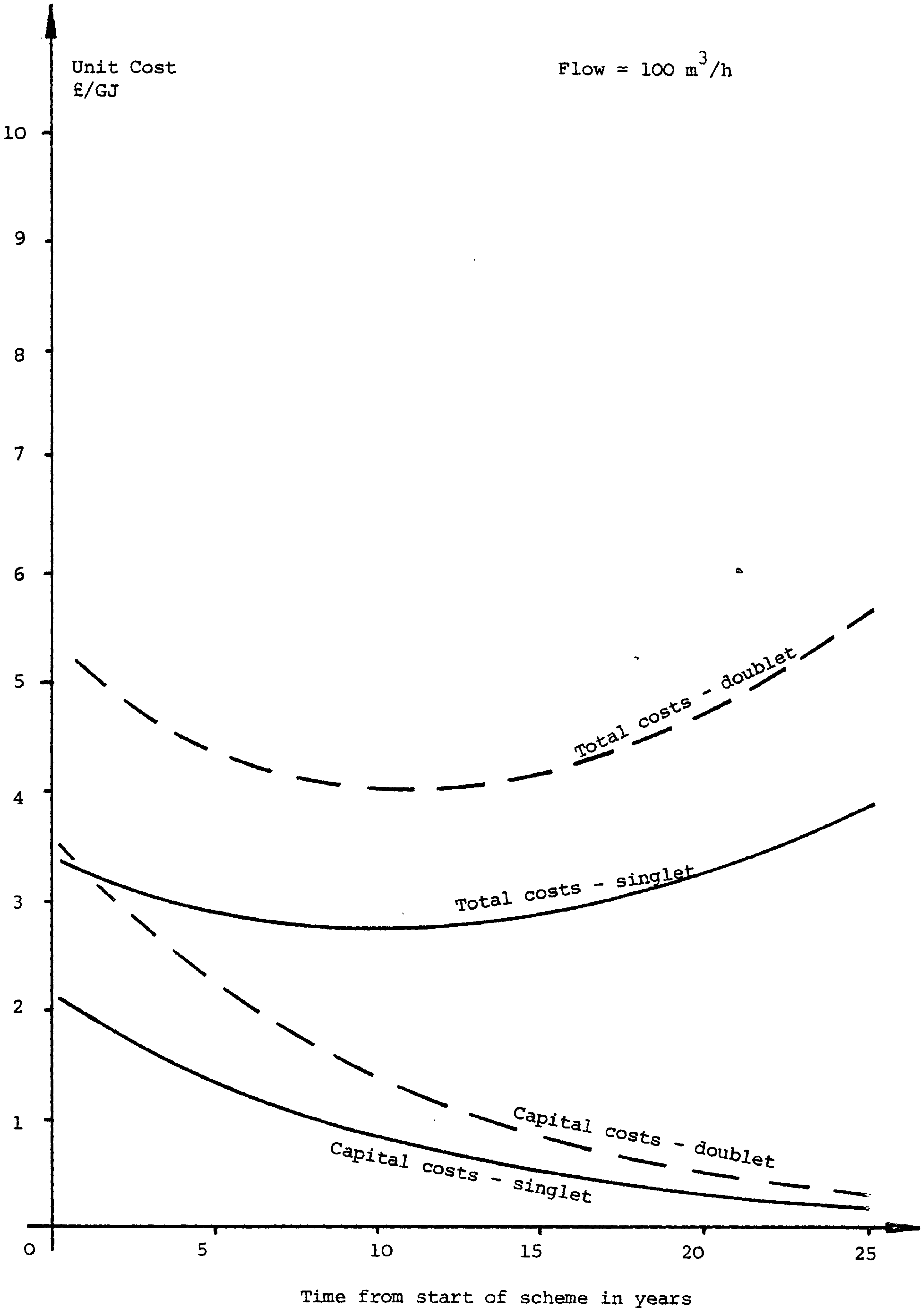
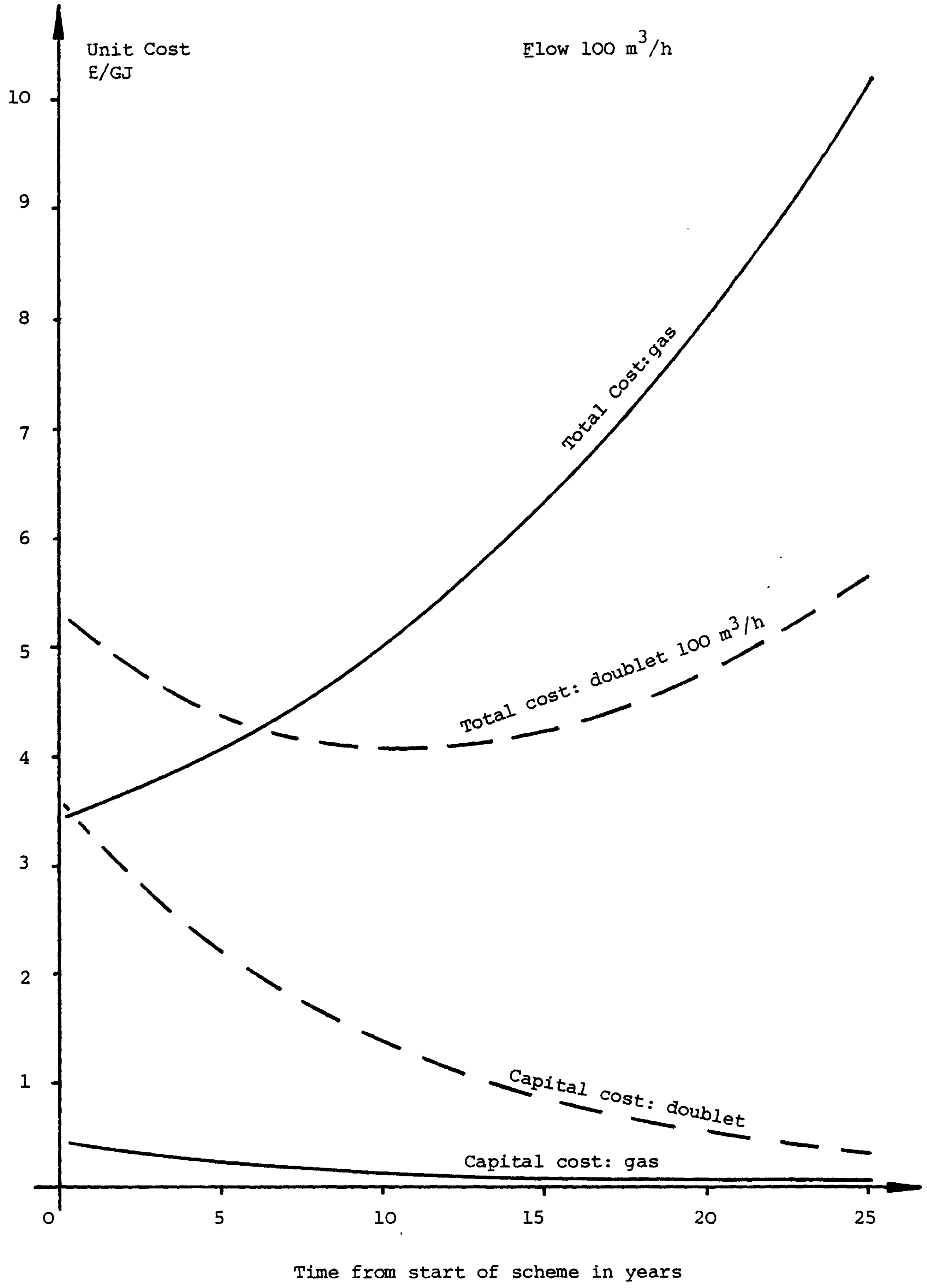


Figure 42 Comparison of Geothermal Doublet with Gas-fired Scheme



Back-Up Fuels

The choice of back-up fuel has an increasing effect on total unit costs, as fuel prices rise. Total unit costs forgeothermal with oil back-up systems are initially 15% higher than for coal fired back-up but eventually 50% higher after 25 years of fuel price rises, by the end of the projects lifetime. Similarly gas back-up gives total unit costs initially 5% but finally 16% higher than coal back-up.

Competitiveness with Fossil Fuelled Systems

In assessing how economic a geothermal system is compared with one which is fossil fuelled only, a similar fuel is assumed for the geothermal scheme's back-up as for the reference fossil fuel system. A favourable or relatively economic geothermal scheme is taken in each case: represented by a single well or doublet with a flow of 100 m^3/h and an energy coverage of 80%. hence a 20% coal, gas or oil-fired back-up supply.

Such a geothermal scheme appears consistently and progressively more economic than an oil-fired scheme, a doublet being marginally cheaper, even at current oil prices, Figure 43.

A geothermal doublet scheme is intially more expensive than its all-gas fired counterparts, Figure 42, but becomes cheaper after about 6 years of fuel price rises (to about 34% above their 1980 level).

A geothermal doublet only becomes competitive with a coal fired-system after about 15 years when fuel prices have doubled, Figure 43.

Fuel Price Trends

All the foregoing results are extrapolations based on highly uncertain future price trends, so their sensitivity to different assumptions is assessed.

Fuel price trends have a significant effect on when geothermal schemes become competitive with fossil-fuelled ones, Figure 44. If fuel prices were to rise at only the same rate as prices in general, rather than 5% faster, then it would take a geothermal doublet almost twice as long to become competitive with gas: 10 years instead of 6, and a geothermal doublet would not compete

Figure 43 Comparison of Geothermal Doublets with Oil- and Gas Fired Schemes

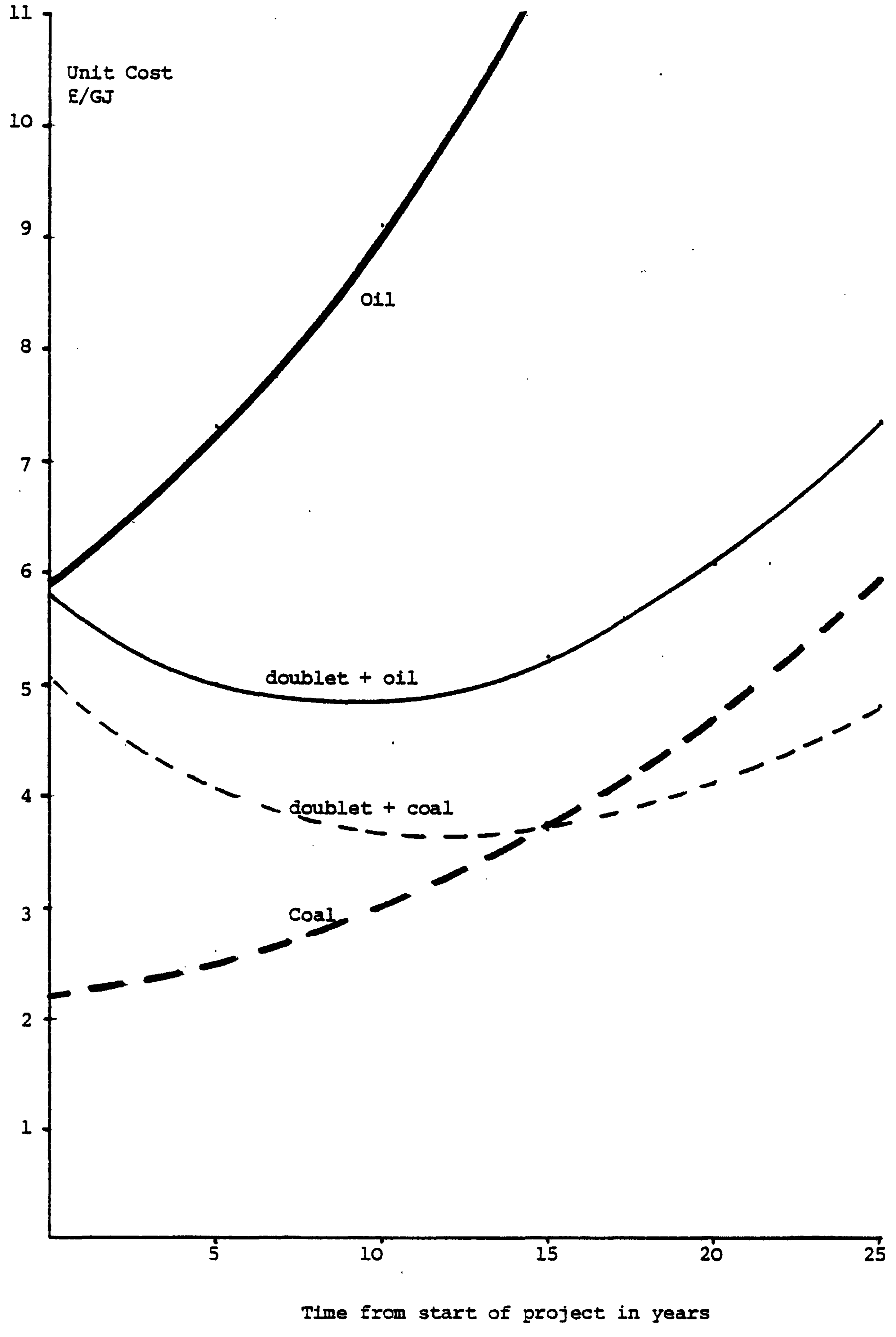
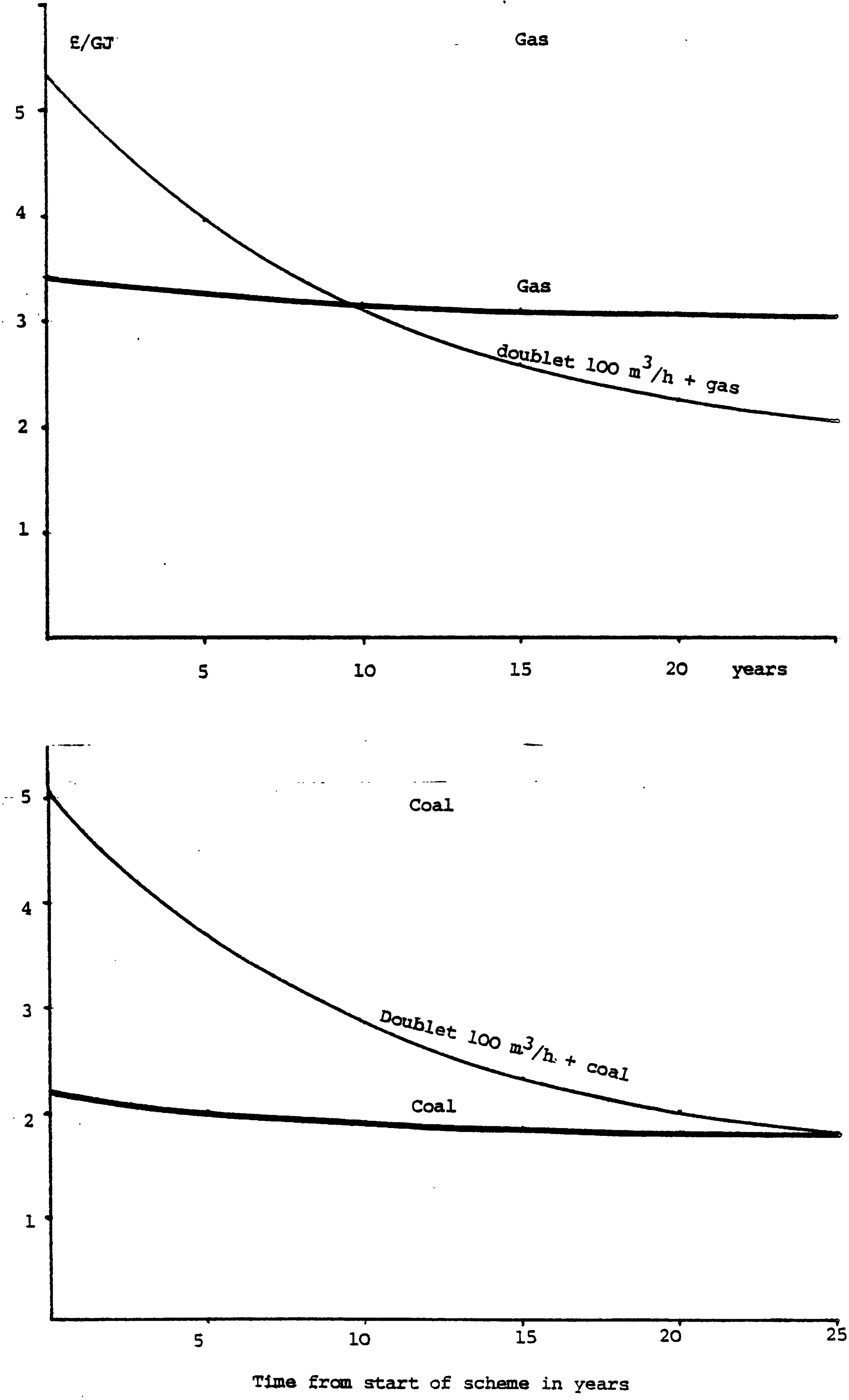


Figure 44 No. Net Fuel Price Rises



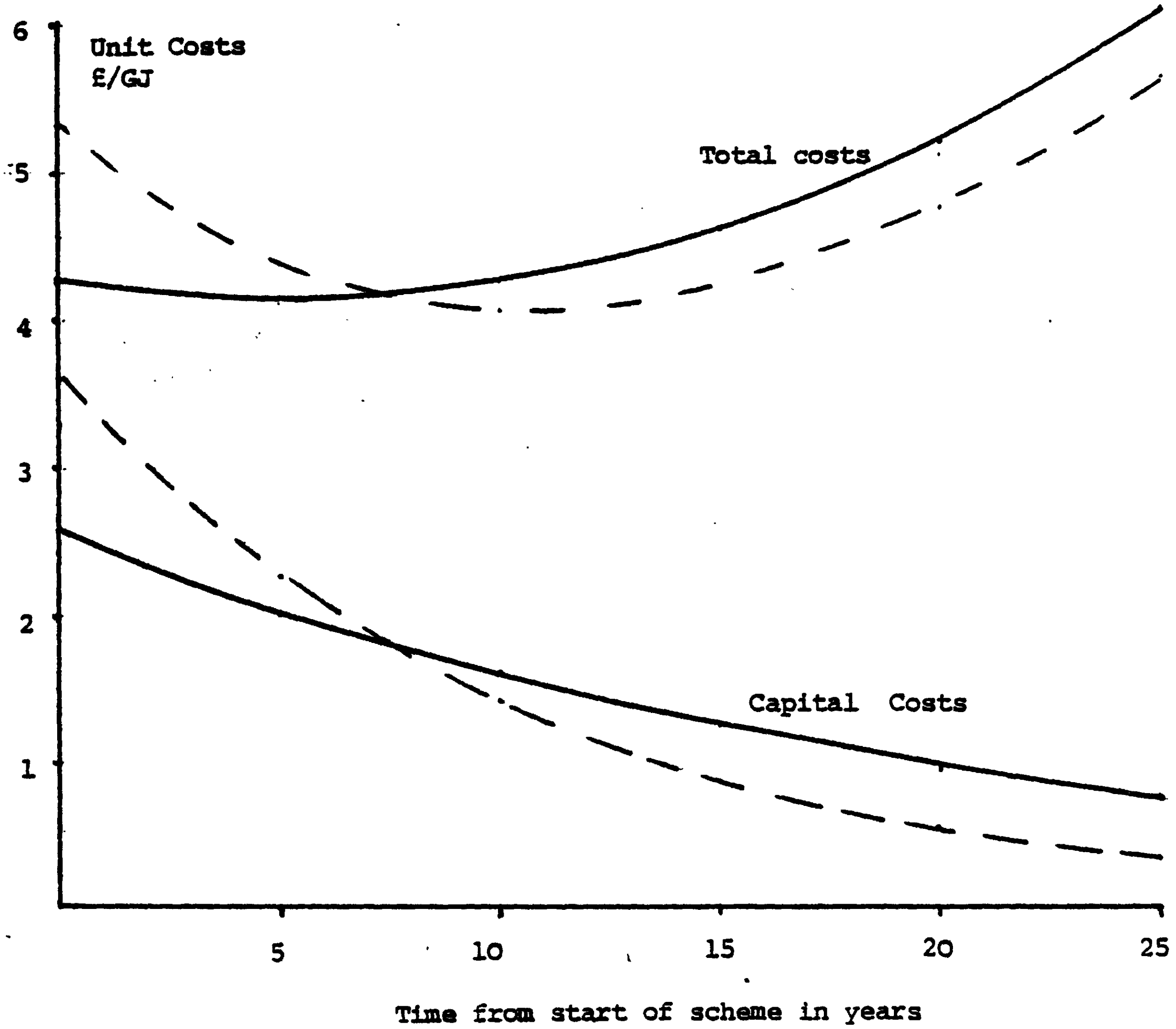
in price with coal until the end of its life.

General Economic and Financial Assumptions

To give an indication of the effect of different general price and financing assumptions, a lower general inflation rate of 5% is taken, together with a lower gross interest rate of 10%. The gross interest rate sets the initial level of capital repayments and general inflation their subsequent decline in real value. They are varied together since the gross interest rate is affected by prevailing inflation (see Section 7.1 above).

Given this coupling of interest and inflation rates, the net effect of different general price trends may not be particularly pronounced. With lower inflation and interest rates a geothermal scheme will tend to be cheaper in early years but more expensive later in real terms, Figure 45, although it may only break even with a fossil-fuelled scheme slightly quicker.

Figure 45 Reduced Rates of Interest and General Inflation



——— Reduced 10% interest, 5% inflation

- - - - Base case 15% interest, 10% inflation

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    M.J. Lockwood Sept 1982

APPENDIX I

Reservoir Equations

Summary of Important Equations for a Well Doublet

Doublet spacing, d:

$$d \sim 91.5 \left[\frac{Q\ t_s\ \rho_o \gamma_o}{H'\{\rho_o \gamma_o \emptyset + (1 - \emptyset)\ \rho_s \gamma_s\}} \right]^{\frac{1}{2}}$$

Production well pressure drop, P_w:

$$P_w = P_p - P_o + \Delta P_d + \Delta P_{se} + \Delta P_f$$

$$\Delta P_d = \frac{Q.\mu_o}{K.H'} \cdot \log_{10} \left(\frac{d}{r_w}\right)$$

$$\Delta P_{se} = 0.44 \frac{Q.\mu_o.S}{K.H'}$$

$$\Delta P_f = (1.6 \times 10^{-12}).\frac{(\mu_o)^{0.21}\ (Q)^{1.79}\ L}{(r_w)^{4.79}}$$

Re-injection well pressure rise, P_w':

$$P_w' = P_o' - P_t + \Delta P_d' + \Delta P_{se}' + \Delta P_f'$$

$$P_t = (9.8 \times 10^{-5}).L'.(\rho_i - \rho_o)$$

$$\Delta P_d' = \frac{Q.\mu_i}{K.H'} \cdot \log_{10} \left(\frac{d}{r_w}\right)$$

$$\Delta P_{se}' = 0.51 \frac{Q.\mu_i}{K.H'} . \left\{ 0.87S' + 2 \left(1 - \frac{\mu_o}{\mu_i}\right) \log_{10} \left(\frac{d}{2r_w}\right) \right\}$$

$$\Delta P_f' = (1.6 \times 10^{-12}).\ \frac{(\mu_i)^{0.21}\ (Q)^{1.79}\ L'}{(r_w)^{4.79}}$$

Production well pump power rating, W;

$$W = (2.78 \times 10^{-2})\ .\ \frac{P_w \cdot Q}{\eta}$$

Reinjection well pump power rating, W';

$$W' = (2.78 \times 10^{-2})\ .\ \frac{P_w'\ Q}{\eta}$$

Summary of Parameters for a Well Doublet

d = doublet spacing (m)

H' = effective reservoir thickness (m)

K = reservoir permeability (Darcy)

L = length of production well casing (m)

L' = length of re-injection well casing (m)

P_w = total pressure drop in production well (bars)

P_w' = total pressure rise in re-injection well (bars)

P_o = static formation pressure expressed at the production well head (bars)

P_p = surface over-pressure (bars)

P_t = thermo-siphon pressure (bars)

ΔP_d = dynamic pressure drop of fluid flowing from reservoir (bars)

$\Delta P_d'$ = dynamic pressure rise of fluid flowing into reservoir (bars)

ΔP_{se} = pressure drop of skin effect in production well (bars)

$\Delta P_{se}'$ = pressure rise of skin effect in re-injection well (bars)

ΔP_f = pressure drop of friction in production well (bars)

$\Delta P_f'$ = pressure rise of friction in re-injection well (bars)

Q = production/re-injection flow rate (m^3/hour)

$\bar{Q}$ = average annual flow rate (m^3/hour)

r_w = well radius at total depth (m)

S = skin factor for production well (dimensionless)

S' = skin factor for re-injection well (dimensionless)

t_s = lifetime of doublet (years)

W = production well pump power rating (KW)

W' = re-injection well pump power rating (KW)

μ_o = dynamic viscosity of formation fluid (centipoise)

μ_i = dynamic viscosity of re-injection fluid (centipoise)

ρ_o = density of formation fluid (Kg/m^3)

ρ_i = density of re-injection fluid (Kg/m^3)

ρ_s = density of formation rock (Kg/m^3)

γ_o = specific heat capacity of formation fluid (J/Kg/^oK)

γ_s = specific heat capacity of formation rock (J/Kg/^oK)

ϕ = porosity of reservoir (dimensionless)

η = net efficiency of well pump (dimensionless)

Summary of Important Equations for a Single Well

Maximum total pressure drop in well, $\hat{P}_w$;

$$\hat{P}_w = P_p - P_o + \Delta\hat{P}_d + \Delta P_{se} + P_f$$

$$\Delta P_d = 0.51 \frac{Q.\mu_o}{K.H'} \log_{10}\left\{\frac{7096\ K.t_s}{\phi\mu_o\ c\ r_w^{\ 2}}\right\}$$

$$\Delta P_{se} = 0.44 \frac{Q.\mu_o.S}{K.H'}$$

$$\Delta P_f = (1.6 \times 10^{-12}) \frac{(\mu_o)^{0.21} (Q)^{1.79}\ L}{(r_w)^{4.79}}$$

Maximum well pump power rating, $\hat{W}$;

$$\hat{W} = (2.78 \times 10^{-2}) \frac{\hat{P}_w Q}{\eta}$$

Total energy consumption of pumps over life of scheme. ΣE_p;

$$\Sigma E_p = 8760.t_s \left\{ \frac{6.1 \times 10^{-3}\ Q^2\mu_o}{\eta K'H} . \log_e \left(\frac{7096\ Kt_s}{\phi\mu_o \hat{c} r_w^{\ 2}}\right) \ldots\right.$$

$$\left. \ldots + \frac{2.78 \times 10^{-2}\ Q}{\eta} (P_p - P_o + \Delta P_{se} + \Delta P_f) - 1\right\}$$

Summary of Parameters for a Single Well

c = compressibility of formation fluid (bars^{-1})

ΣE_p = total energy consumption over life of scheme (KWh)

H' = effective reservoir thickness (m)

K = reservoir permeability (Darcy)

L = length of well casing (m)

P_w = total pressure drop in well at time t (bars)

$\hat{P}_w$ = maximum total pressure drop in well (bars)

P_o = static formation pressure expressed at the wellhead

P_p = surface over-pressure (bars)

ΔP_d = dynamic pressure drop in fluid flowing from reservoir at time t (bars)

$\Delta\hat{P}_d$ = maximum dynamic pressure drop in fluid flowing from reservoir (bars)

ΔP_{se} = pressure drop of skin effect in well (bars)

ΔP_f = pressure drop of friction in well (bars)

Q = production flow rate (m^3/hour)

r_w = well radius at total depth (m)

S = skin factor (dimensionless)

t_s = lifetime of well (years)

$\hat{W}$ = maximum pump power rating (KW)

μ_o = dynamic viscosity of formation fluid (centipoise)

ϕ = porosity of reservoir (dimensionless)

η = net efficiency of well pump (dimensionless)

European Communities — Commission

EUR 8584 — An investigation of the sensitivity of the economic appraisal of geothermal energy resources to energy price rises

R. Harrison, N.D. Mortimer, M.J. Lockwood

Luxembourg: Office for Official Publications of the European Communities

1983 - VI, 99 pp. - 21.0 x 29.7 cm

Energy series

EN

ISBN 92-825-3961-X

Catalogue number: CD-ND-83-120-EN-C

Price (excluding VAT) in Luxembourg:
ECU 6.57 BFR 300 IRL 4.80 UKL 3.80 USD 6

A procedure has been developed to assess the prospects for using low-temperature geothermal resources in the United Kingdom and Europe, for domestic heating under changing economic conditions. This report describes the procedure which consists of routines for investigating reservoir characteristics, well drilling costs, heating system operation and costs, and techniques of financial appraisal for the complete project. Sample data are used to test and validate the procedure. The basic sensitivity of costs to fuel price rises is examined by using energy analysis to determine the relative importance of energy inputs. Both unit costs of heat produced at the wellhead and of heat finally delivered to dwellings in a complete scheme are calculated. These results are used to examine the effect of resource parameters, operating conditions and economic factors, including fuel and general price inflation, on the economics of geothermal heating schemes. Total unit costs for complete schemes are also compared with those of competing fossil-fuelled heating systems.