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ENGINEERING ECONOMICS OF GEOTHERMAL HEATING APPLICATIONS

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PREFACE

From the start of the UNU Geothermal Training Programme in 1979, it has been customary each year to invite a geothermal expert to Reykjavík as a Visiting Lecturer. The lecturers have stayed at the Geothermal Training Programme from two to eight weeks. During this time they give a one-week lecture series on their speciality, and have discussion sessions with the Fellows attending the Training Programme. The lecture series are open to the geothermal community in Iceland.

The Visiting Lecturers have added an extra dimension to what the UNU Geothermal Training Programme can offer to its Fellows. It has also been an important opportunity for the Training Programme to contribute new understanding to the geothermal engineers and scientists in Iceland, through the lecture series and discussions with a distinguished expert from another country. The following geothermalists have been Visiting Lectures at the UNU Geothermal Training Programme:

1979	Donald E. White	United States
1980	H. Christopher H. Armstead	United Kingdom
1981	Derek H. Freeston	New Zealand
1982	Stanley H. Ward	United States
1983	Patrick Browne	New Zealand
1984	Enrico Barbier	Italy
1985	Bernardo S. Tolentino	Philippines
1986	C. Russell James	New Zealand
1987	Robert Harrison	United Kingdom

This year's Visiting Lecturer was Dr. Robert Harrison, Energy Workshop, Sunderland Polytechnic. The present report consists of an Introduction and five papers that formed the basis of Dr. Harrison's lecture series in Reykjavík, September 14-18, 1987. The UNU Geothermal Training Programme thanks Dr. Harrison for preparing the written-up lectures published in this report.

Jón-Steinar Gudmundsson
Director
Geothermal Training Programme

C O N T E N T S

Chapter 1 Introduction

In general terms, scheme economics are determined by the relationship between capital and running costs on the one hand and upon earning capacity on the other. Figure 1.1 illustrates, in outline, the make-up of the costs and earnings of a typical geothermal district heating scheme. Capital costs are strongly dependent upon the physical characteristics of the resource depth for example, and upon layout of the heat load which is being served. Earning capacity depends upon the fluid temperature and flow, the size and temperatures of the heat load and, through the price of the competing fuels, upon the condition of the local heating fuel market. A number of general observations can be made in relation to the effect of resource and heating market conditions upon viability. Thus schemes which have high subsurface costs will only be viable if a nearby, large, heat load can be served, giving high earnings. Or to put this in another way; in areas with large numbers of blocks of flats situated close together heating networks which serve large heat loads can be constructed at reasonable cost and deep drilling to obtain fluids may be justified. In settings where the thermal gradients are high the possibilities will be different. Subsurface costs will tend to be low and small schemes may be viable. Or it may be economic to transmit the fluids over significant distances to the heat loads. The local prices of heating fuels will also have a fundamental effect on viability. High prices will improve the economics of all schemes and low prices will have the reverse effect.

The optimal design of geothermal heating schemes is a techno-economic problem of some complexity requiring an understanding of the physical system and its engineering and of the commercial environment of the development. This pamphlet contains five chapters which examine particular topics relating to these issues. A wide variety of geothermal heating schemes have been investigated by consulting engineers and by others in many different countries and many different geological settings. In the course of these studies, the principles of optimal design, the methods for forecasting the performance of schemes and methods of assessing schemes are becoming well established. However, this information is not well described in the open literature. The author has carried out several research studies in this area under contract to the EEC Commission. As part of this work, the design and the economics of

Figure 1.1 Outline of Costs and Earnings of Geothermal Heating Schemes

Costs

Surface System

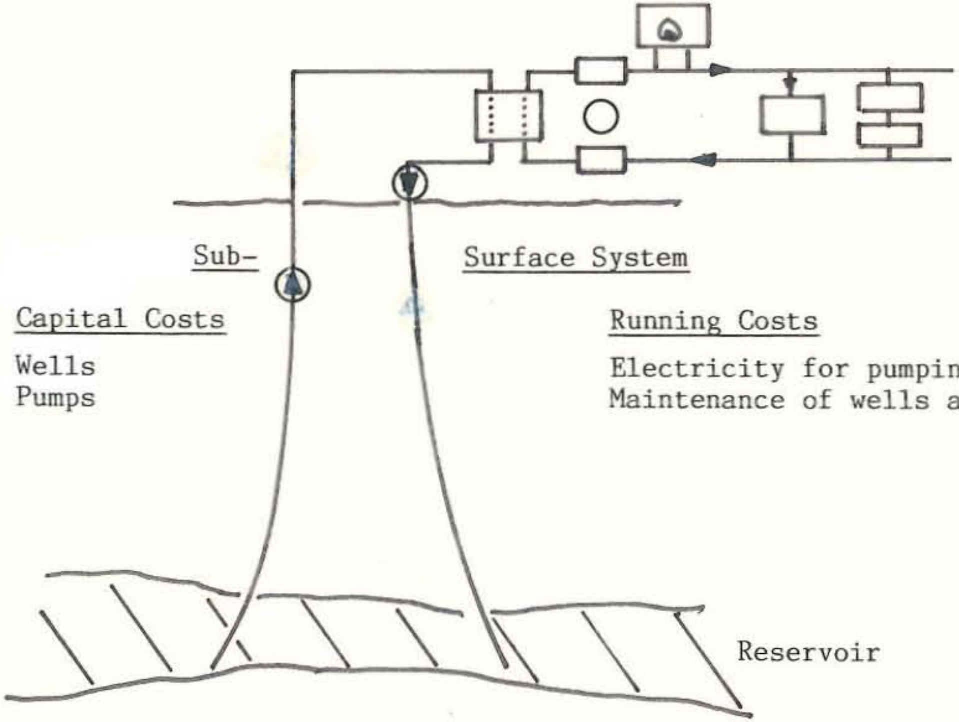
Capital Costs	Running Costs
Transmission Pipeline	Back-up Fuel
Heat Exchangers	Maintenance
Heat Pumps	Heat Pump Fuel
Surface Network	

Earnings

Depend upon size of heat load, fluid conditions and value of the fuel in the local heating fuel market

- savings on running costs
  = fuel saved x price of fuel

- capital savings
  = any capital expenditure avoided in developing the scheme



Sub-Surface System

Capital Costs	Running Costs
Wells	Electricity for pumping
Pumps	Maintenance of wells and pumps

over forty proposed and operating geothermal heating schemes were studied. Also, mathematical models were formulated which relate the economics of schemes to the design parameters of the surface system and the physical parameters of the subsurface system. It is this research which forms the basis of these chapters. The topics have been chosen in an attempt to cover some of the issues which are not well covered in the literature and at the same time to indicate the principles which govern the economics of schemes and to illustrate the methods of analysis and of scheme assessment which are now available. District heating and space heating in general dominate geothermal heat developments and this is reflected in the contents of these chapters.

Chapter 2 Performance of Geothermal Heating Schemes with Direct Heat Exchange

2.1 Introduction

When geothermal fluid temperatures are higher than the supply temperatures in the heating application it is possible to supply all of the heating demands of some group of users. However, because of the fluctuating nature of heating demands this tends to be an inefficient way of employing the wells. Einarsson (Ref. 2.1) and others have shown that the amount of geothermal heat which is delivered from the wells can be increased if they are used to meet the base heating loads of a larger group of users. The data on geothermal heating schemes clearly illustrates that two classes of scheme occur. Figure 2.1 shows a plot of theoretical well powers versus the peak heating demands for both the U.S. and the French schemes which have been examined. In the U.S. cases the theoretical well powers are typically greater than the peak powers of the heat loads, indicating that peak demands are being 'covered' and that the wells are being under-utilised. In the French schemes the theoretical well powers are significantly less than the peak powers of the heat loads, indicating that base loads only are being covered, with the peaks being met by a back-up supply. The explanation of these two approaches is given, partly, by Figure 2.2 which shows wellhead temperatures plotted against well depths. Typically the U.S. schemes employ high temperature fluids from shallow wells, whereas the French schemes use deeper wells and cooler fluids. Thus, in the U.S. schemes, well power is cheap and its level of utilisation is not so important as in the French schemes.

In schemes where the full demands of the heat load are met by the geothermal fluid the amount of geothermal heat which can be supplied is limited by the size of the heat load and the cost of additional connections. Performance cannot be improved by careful design. In schemes where the geothermal fluid covers the base loads only, the design process is more complex. These schemes tend to be closer to the margin of economic viability and it is important to maximise the geothermal heat delivered. This dominates the design of these schemes and it is this which is discussed in this chapter. The main sources for the analysis which follows have been studies of

Figure 2.1 **Theoretical Well Power and Scheme Peak Heat Load**

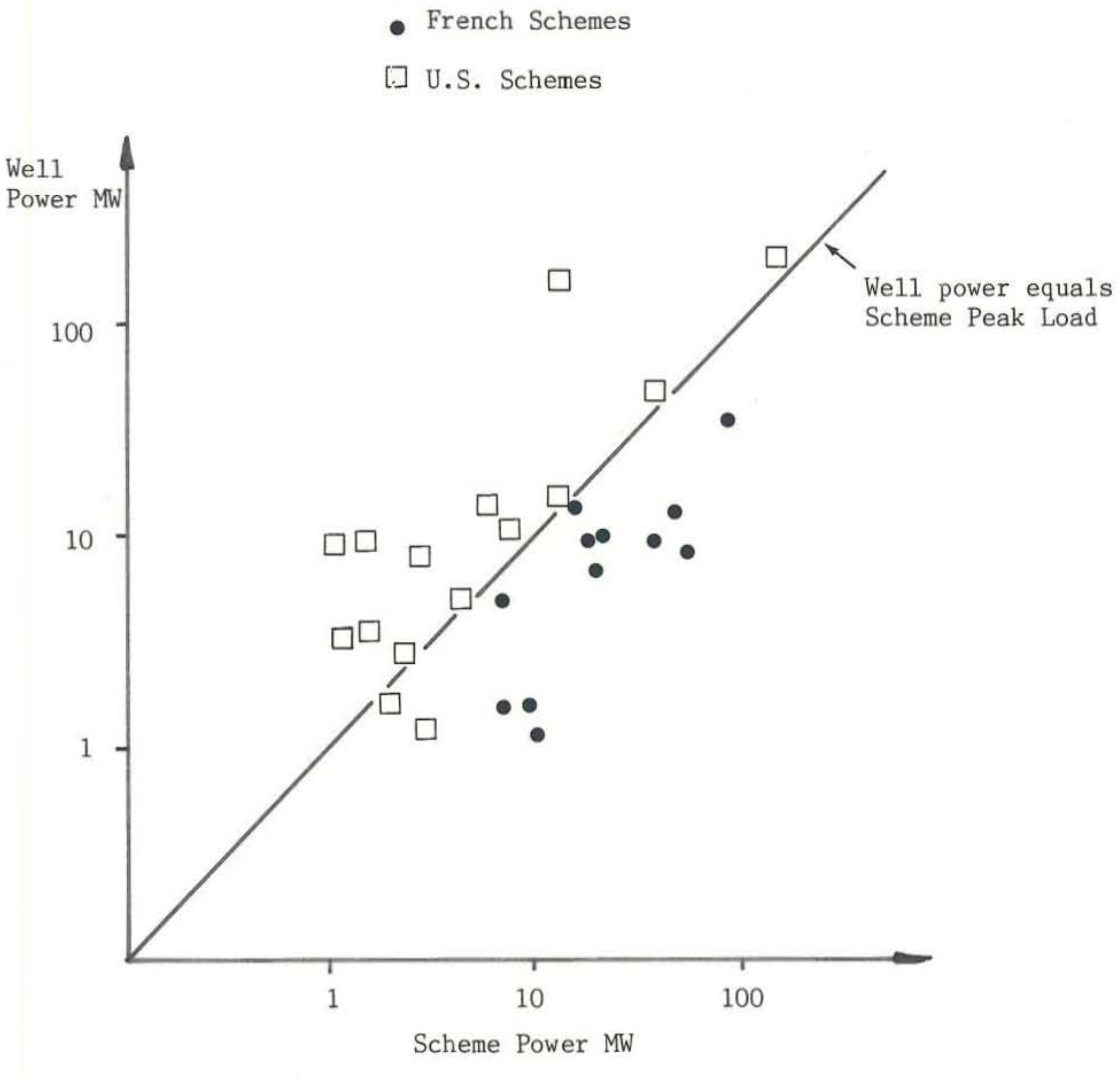
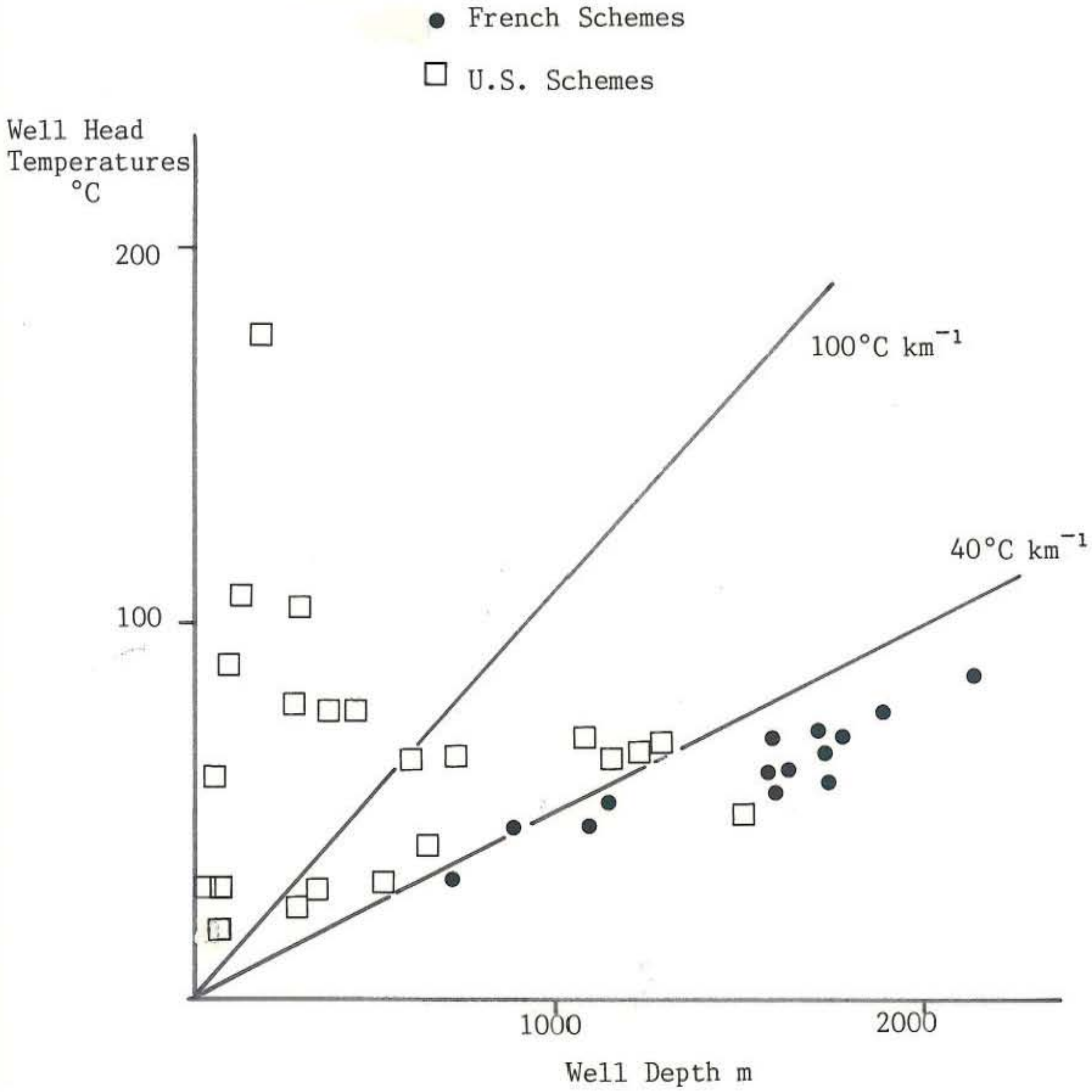


Figure 2.2 <u>**Well Head Temperatures and Well Depths for Geothermal Heating Schemes**</u>



French geothermal district heating schemes. The examples which are used are mainly French.

2.2 Principles of Design

The basic scheme arrangement is as shown in Figure 2.3. Normally the geothermal temperature and the flow will remain fixed while the return temperatures and the flows from the heating network fluctuate as the heat demands of the users change. The thermal behaviour is dominated by the primary heat exchanger and the geothermal heat transfer is given by

$$P_g = M_s E \, (T_{gi} - T_{no})$$

This is an important equation, it governs the design of this type of scheme. The basic aim is to design and operate the scheme so that the values of M_s, E and T_{no} which are obtained give the highest feasible values of P_g. Counter plate heat exchangers are usually used in French geothermal schemes and the effectiveness 'E' is given by

$$E - \frac{[1 - \exp\{ - N(1 - R)\}]}{[1 - R \exp\{ - N(1 - R\}]}$$

where R = ratio of the smallest to the largest heat flow capacity across the heat exchanger

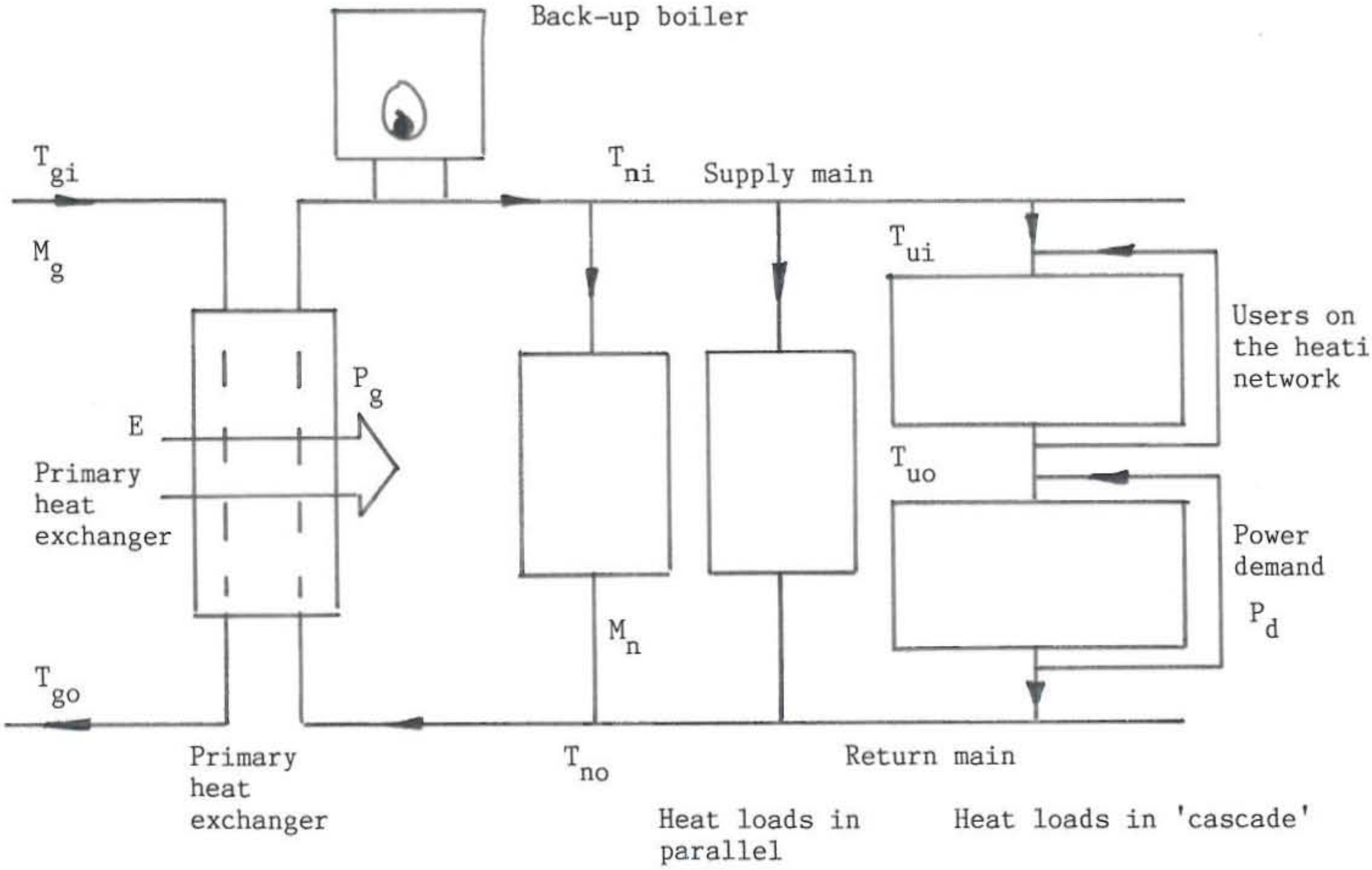
$N = \frac{U\ A}{M_s}$ = number of transfer units (NTU)

U = overall heat transfer coefficient of the heat exchanger $W\ m^{-2}\ {}^{\circ}C^{-1}$

A = surface area of the heat exchanger m^2

Figure 2.4 shows the effect of 'N' and flow ratio 'R' on the effectiveness. 'R' can vary between zero and one; as 'R' increases 'E' falls. 'R' is determined by the size of the heating scheme in relation to the goethermal flow. 'N' is a design variable; increasing 'N' increases 'E'. Villaume (Ref. 2.2) has studied the optimal choice of 'N' in French geothermal schemes; a figure of 5 NTU is often taken.

Figure 2.3 **Geothermal Heating Scheme Employing Direct Heat Exchange - Basic Arrangement**



$$P_g = M_s E(T_{gi} - T_{no})$$

P_g = geothermal heat transfer W

M_s = smallest flow capacity W °C^{-1}

E = exchanger effectiveness

T_{gi} = geothermal supply temp. °C

T_{go} = geothermal return temp. °C

T_{ni} = network supply temp. °C

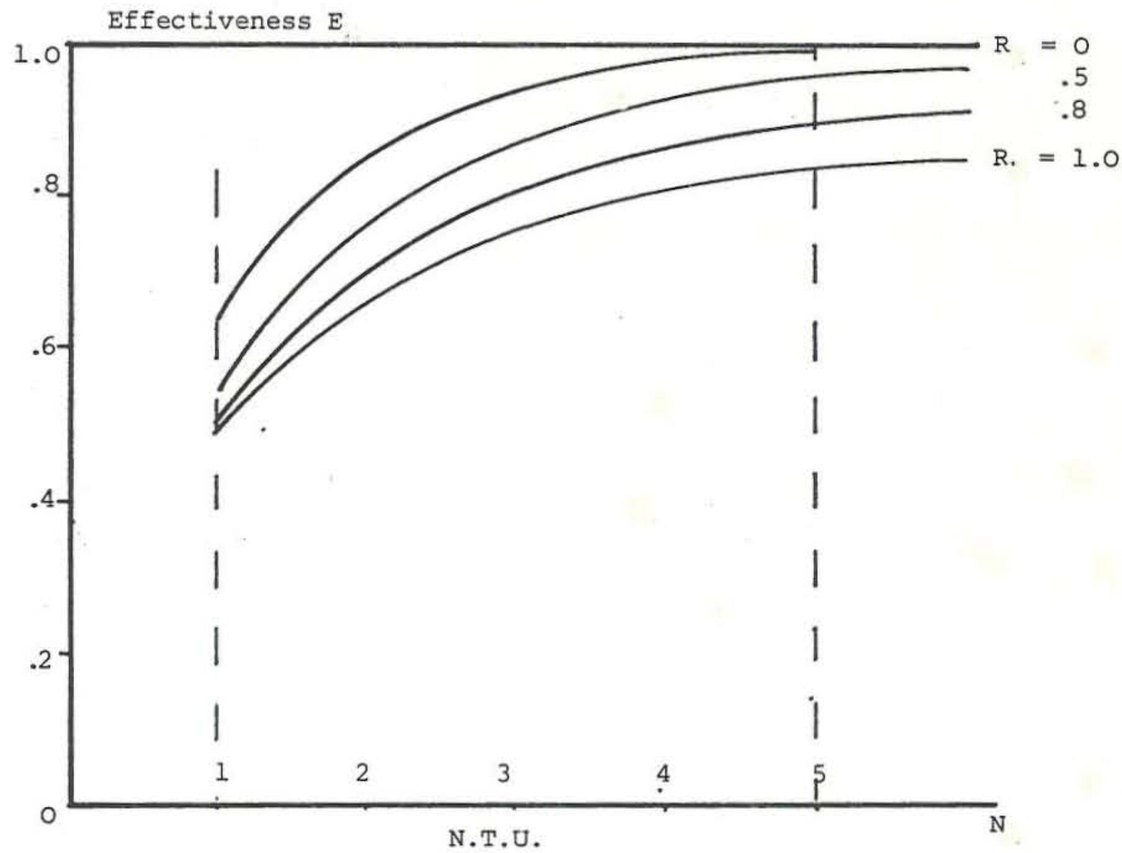
T_{no} = network return temp. °C

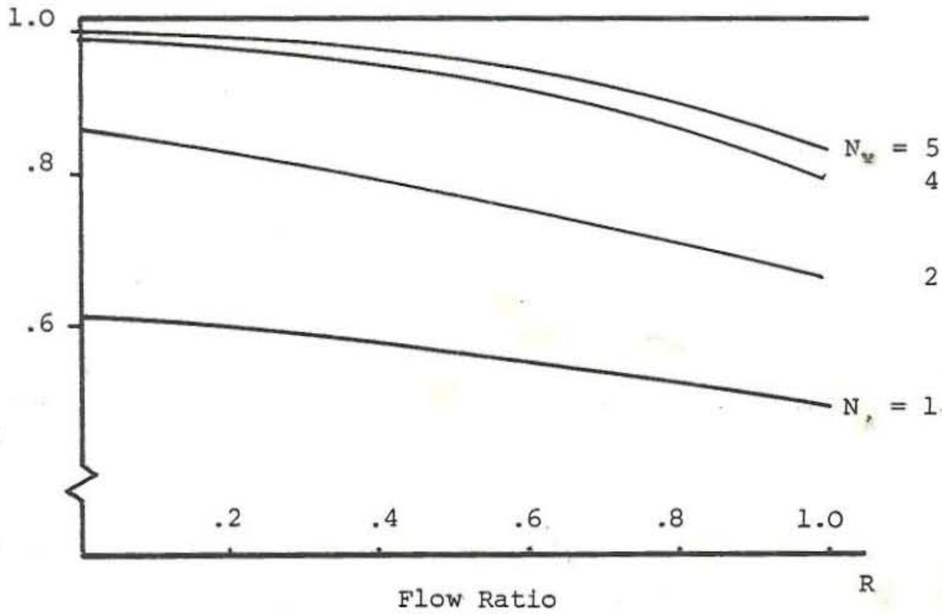
M_g = heat capacity of geo-fluid W °C^{-1}

M_n = heat capacity of network fluid W °C^{-1}

Heat capacity = mass flow (kg s^{-1}) x specific heat (Jkg^{-1} °C^{-1})

Figure 2.4 Effect of N.T.U. and Flow Balance on Effectiveness of Heat Exchange





The way in which the geothermal heat transfer depends upon the network flow is important. Fig. 2.5 shows the variation in a typical case. At low flows the network flow is the smallest flow through the heat exchanger

$$M_s = M_n$$

and $$P_g = M_n\ E\ (T_{gi} - T_{no})$$

Therefore, the geothermal heat supply is limited by the network flow and is very sensitive to any changes in it. As the network flow rises the flow ratio 'R' rises and the heat exchanger effectiveness falls, reaching a minimum when R = 1 and the network flow equals the geothermal flow. At high flows when the network flow is greater than the geothermal flow

$$M_s = M_g$$

and $$P_g = M_g\ E\ (T_{gi} - T_{no}) \qquad (1)$$

Now the heat exchange is limited by the geothermal flow and it is no longer sensitive to changes in network flow. In the type of scheme which is being considered here the geothermal flow is expensive to produce and it is not sensible to operate the scheme in the region where the network flow is less than the geothermal flow. In this region the network flow is not large enough to absorb all of the heat which is available from the geothermal fluid. This is wasteful, the geothermal flow could be reduced without significantly affecting performance.

In general, any conditions in which the network flow falls below the geothermal flow are detrimental to the performance of the scheme. This leads to the first basic principle of the design and operation of these schemes. For best performance the scheme must be designed and operated so that

network flow > geothermal flow

Then equation (1) gives the geothermal heat transfer.

Clearly, the geothermal heat transfer given by equation (1) is very sensitive to the network return temperature T_{no}. In order to obtain the maximum heat transfer T_{no} must be kept as low as possible at all times. This is the second basic principle of the design and operation of these schemes.

The implications of these principles will now be considered.

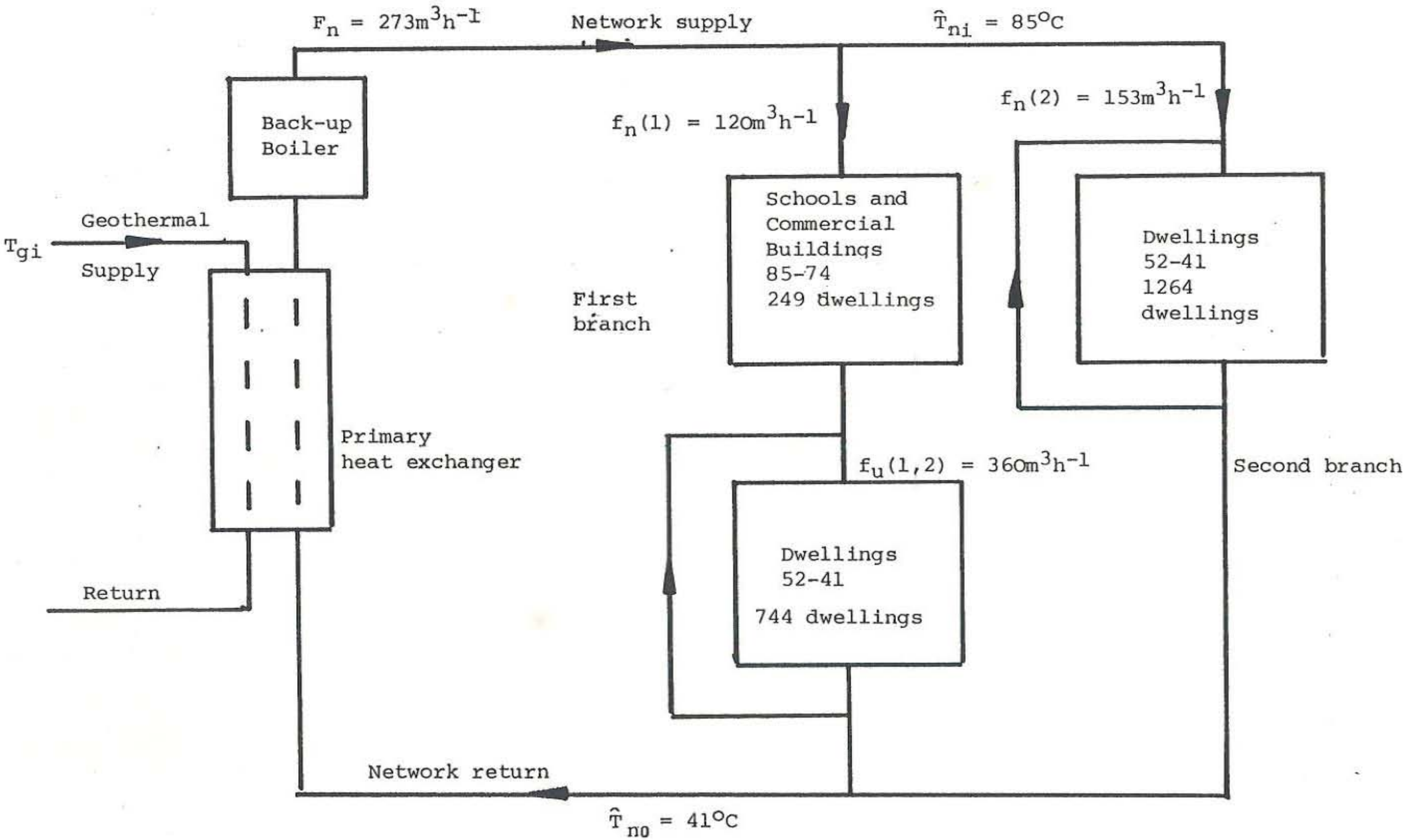
2.3 Layout and Regulation of Geothermal District Heating Networks General Principles

In a geothermal district heating scheme the main heat load is space heating and this may be supplied by a variety of heaters of different types with different temperature characteristics. Domestic water heating may be an additional, minor component of the heating load, and, occasionally, applications such as the heating of swimming pools may also be included. The network flow returned to the heat exchanger is a mixture of the return flows from all of these applications. In the main the return temperatures and flows at the heat exchanger depend upon

- the arrangement of the different types of heater on the network
- the regulation of the heaters to match fluctuating demands caused by changes in temperature
- the response of the network to users turning off their heating systems.

A wide range of different heating elements are in use in geothermal heating schemes. Many users employ conventional radiators. At full load these operate with supply temperatures of 90°C and return temperatures of 70°C. There are also significant numbers of users who employ low temperature floor heaters. These operate with supply temperatures of about 55°C and return temperatures of 45°C at full load. A variety of other heaters are also encountered which have operating temperatures somewhere between these extremes. In a scheme which has both high and low temperature users connected in significant numbers on the same network an advantage can be gained by connecting them in series so that the low temperature users are supplied by the returns from the high temperature users. Figure 2.6 shows schematically the Garges Nord network (Ref. 2.3) where this approach is used. By connecting some of the low temper-

Figure 2.6 Garges Nord Schematic Diagram of the Network



ature users in series with the high temperature users the return temperature from the first branch is reduced from 74°C to 41°C at peak load. The result is that the overall network flows and the return temperatures are both reduced.

2.3.1 Temperature Regulation

Heater regulation is an important aspect of the operation of geothermal schemes. An example of the normally adopted regime is shown in Figure 2.7. As the external temperatures rise, and the heat demands fall, the heater supply temperatures are reduced. If the flows through the heaters are kept constant the return temperatures also fall. Heating demands can be measured by the effective temperature difference across the building fabric ΔT. This is the simultaneous temperature difference adjusted to take account of incidental gains (see below). It is called the demand intensity here.

The actual behaviour of a heater is complex, it can be simplified by assuming that is behaves as counterflow water to air heat exchanger. The mathematics of the analysis can also be simplified by assuming that the log-mean-temperature-difference across the heater is equal to the mean temperature difference and that the overall heat transfer coefficient is constant. Then it can be shown that heaters which have constant fluid flows and linear temperature characteristics such as those shown in Figure 2.7 where

$$T_{ui} = \check{T}_u + S_{ui}\,\Delta T$$

$$T_{uo} = \check{T}_u + S_{uo}\,\Delta T$$

and capable of meeting the full heat demands given the appropriate values of $\check{T}_u$ S_{ui} and S_{uo} where

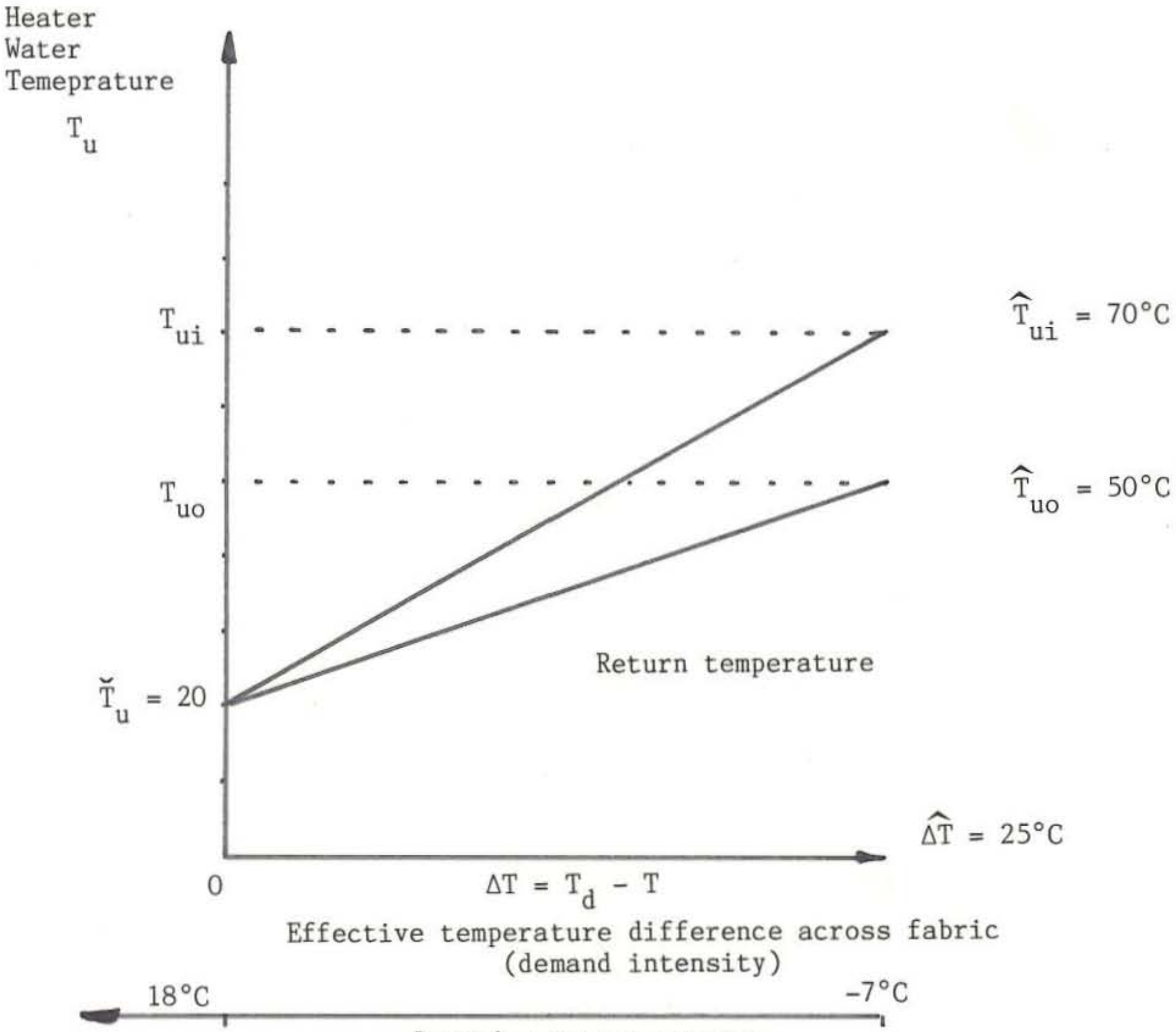
T_{ui} = heater supply temperature at demand intensity ΔT

T_{uo} = heater return temperature at demand intensity ΔT.

Figure 2.7 Typical Linear Control Characteristic for Room Heaters

$$T_{ui} = \check{T}_u + S_{ui}\ \Delta T$$

$$T_{uo} = \check{T}_u + S_{uo}\ \Delta T$$



$\hat{T}_{ui}$ = 'design' heater supply temperature °C

$\hat{T}_{uo}$ = 'design' heater return temperature °C

$\hat{\Delta T}$ = 'design' effective temperature difference across fabric °C

$\check{T}_u$ = heater 'base' temperature °C

2.3.2 Flow Control

It is important that the return temperatures of the heaters, which are the lowest temperatures on the network, should determine the return temperature of the network main. This requirement governs the way in which the network must be operated to respond to users shutting down their heating systems. In conventional fossil fuel fired district networks it is common practice to operate the network with essentially constant network flow. The users are fitted with bypass connections and when they shut down the redundant flow passes directly to the return main. This increases the return temperature and while this is of little significance in a fossil fuel fired heating network it would be detrimental to the performance of a geothermal supply. Clearly this bypassing must be avoided in heating networks which include geothermal heat exchangers. The network flow must be reduced when users shut down their heating systems so that there is no redundant fluid and no requirement for bypassing. Reductions in network flow have only a small effect on the geothermal heat transfer provided that the number of users shutting down at any time are not large enough to reduce the network flow below the geothermal flow. In some networks which include commercial and public buildings a large proportion of the users may be shut down at night, or during weekends, producing low network flows. In these cases it may be feasible to use fluid storage. This is discussed further below.

The general rules which must be observed to obtain best performance from the heating system are that the network must be operated with

- varying temperature in response to changing external temperatures
- varying flow in response to changing numbers of users.

2.4 Heating System Calculations

The main purpose of heating system calculations is to forecast the level of geothermal heat which will be supplied when the scheme is in operation. In some cases, information may be available about the way in which heat demands will fluctuate due to changes in external temperature and due to users turning off their systems. Then it may be possible to carry out an hour by hour simulation of the temperatures and flows in the heating network and hence forecast the geothermal power supplies as a time series. Such information may be available when retrofitting existing buildings or if an existing district heating scheme is being modified. Normally, however, such detailed information is not available and a simpler modelling approach will be used. The model which is described here is adapted from French methods (Ref. 2.4) and it seems to form the basis of French heating scheme calculations. The model relates the important thermal power levels to climatic and system temperatures and for this reason it has been called the 'temperature governed model'. The assumptions upon which it is based are as follows.

2.4.1 Scheme Layout

The calculations are carried out on the basis of a general scheme layout as shown in Figure 2.3. The main features of this are

- the supply facilities are centralised and consist of a geothermal heat exchanger and a back-up boiler. Heat pumps and recuperators are possible options and these are discussed in Chapter 3.

The user network consists mainly of dwellings in which

- heaters are linked by a distribution pipeline. There may be a mixture of different types of heaters and there may be intricate arrangments of feedback and bypass in order to reconcile their different requirements. However, it is assumed that the network consists passive heat transfer devices only with no additional heat supplies.
- The supply facilities are connected to the user network by a single set of supply and return mains. There are no independent network branches connected preferentially to particular heat supply elements.

Thus the geothermal and the supplementary heat are supplied to a single fluid stream which feeds the network as a whole.

In effect the back-up heating is arranged in 'series' between the geothermal supply elements and the heaters on the user network. They ensure that the users' input temperature requirements can be fully met, with the result that the supply main temperature can be set independently of the geothermal supply.

Although, as will be discussed below, there is a significant number of heating networks which are not consistent with these assumptions, the departures from the assumptions have little effect on the network return temperatures. Thus provided that there are no independent branches, this basic layout probably provides a reasonable approximation for the purpose heating calculations.

2.4.2 Model Calculations

Power Demand

It is assumed that the power demand 'P_d' of a single dwelling is determined by its size and its heat loss characteristics and by the effective temperature difference across the building fabric after adjusting for incidental gains.

$$P_d = VG\,\Delta T \qquad (2)$$

V = volume of the dwelling m^3

G = characteristic heat loss coefficient $W\,m^{-3}\,°C^{-1}$

$\Delta T = T_d - T$ °C

T = external air temperature °C

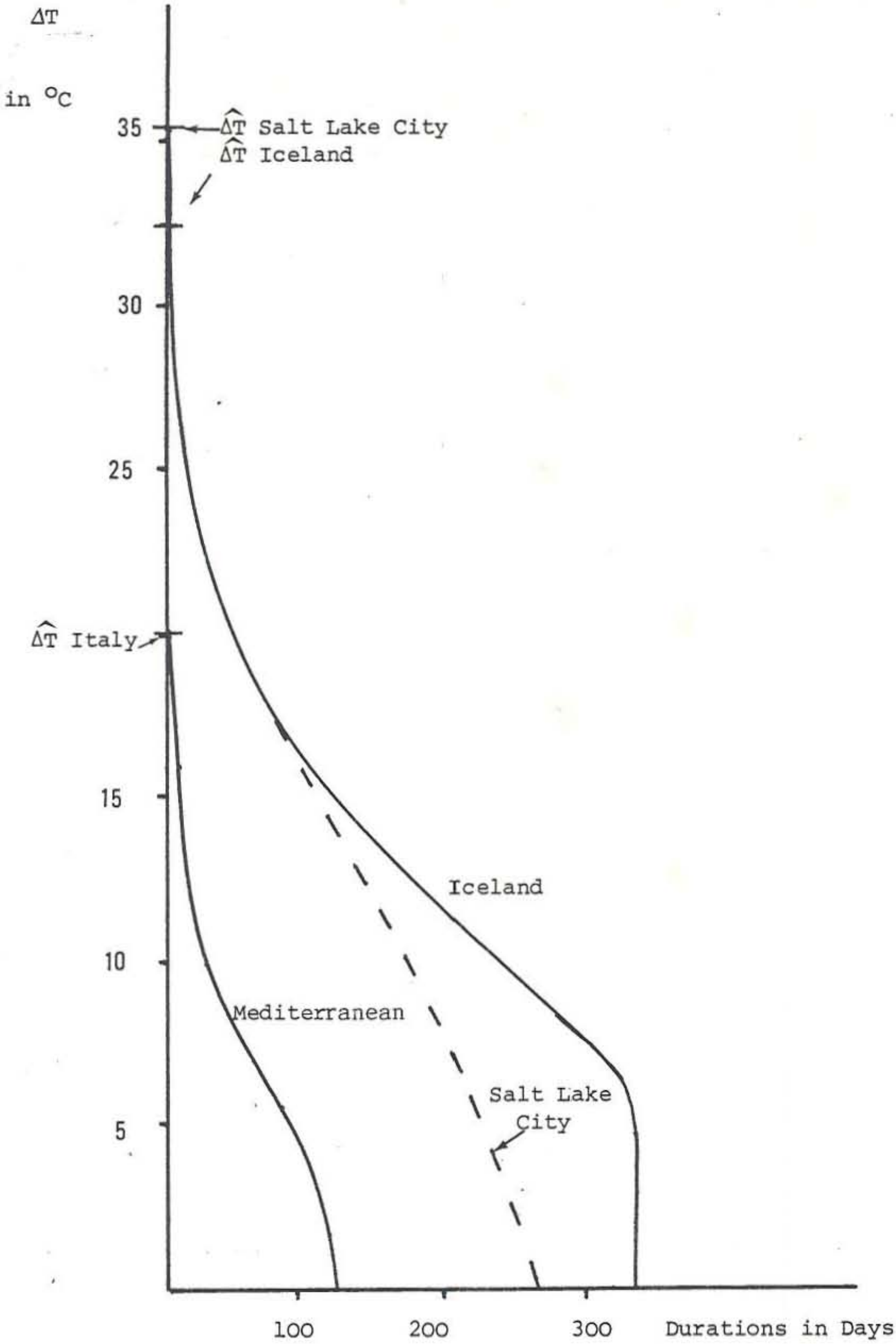
$T_d = T_i - dT$ = demand temperature °C

T_i = required temperature in the dwellings °C

dT = temperature adjustment to account for incidental gains °C

It is further assumed that 'T_i and 'dT' are constant. Then 'P_d' is the function of the external air temperature 'T' only. Statistics of external air temperatures can be used to provide temperature-time duration curves (Figure 2.8), which by using (2) can be converted into thermal power demand-duration curves.

Figure 2.8 Temperature Duration Curves for Different Climates



Iceland $\widehat{\Delta T}$ = 32.5°C
θ = 5700 degree days
Salt Lake City $\widehat{\Delta T}$ = 35°C
θ = 3650 degree days
Mediterranean $\widehat{\Delta T}$ = 20°C
θ = 730 degree days

For 'K', identical dwellings connected together to form a district heat heating system, the total thermal power demand of the whole system

$$P_d = KVG\ \Delta T$$

K will, of course, vary considerably over a heating season but for a large system it may be assumed that users are shutting down at random so that 'K' is constant. Then, by multiplying by 'KVG' the temperature-duration curve can be transformed into the thermal power-duration curve for the whole system.

Heat Supply

It is assumed that the temperature of the network fluid which is supplied to the heaters is regulated so that

$$P_u = P_d$$

where P_u = heat supplied by the heaters, W

$$P_u = M_u\ (T_{ui} - T_{uo})$$

where M_u = the heat capacity of the mass flow through the heaters, W °C^{-1}

$T_{ui} = \breve{T}_u + S_{ui}\ \Delta T$ = supply temp. of the heater, °C

$T_{uo} = \breve{T}_u + S_{uo}\ \Delta T$ = return temperature of the heater, °C.

Thus, the supply and return temperatures are regulated linearly as discussed above, see Figure 2.7.

Then

$$P_u = M_u\ (S_{ui} - S_{uo})\ \Delta T$$

$$P_u = P_d = VG\Delta T = M_u\ (S_{ui} - S_{uo})\ \Delta T$$

$$M_u = \frac{VG}{S_{ui} - S_{uo}}$$

Thus, the heaters carry a constant flow.

Network Temperatures and Flows

In the context of the model assumptions, the entire user network behaves in a similar way to the individual heaters. In the simple case of a network composed of parallel branches of identical users, the network input and return temperatures T_{ni} and T_{no} are identical to the individual heater temperatures:

$$T_{ni} = T_{ui} \qquad T_{no} = T_{uo}$$

and the network flow is the sum of all of the user flows.

A complex arrangement of users with different types of heaters can be analysed at a single condition, e.g. the design temperature, and represented as an equivalent simple heater load, with

$\hat{T}_{ni}$ = water inlet temperature to the entire network under the design conditions

$\hat{T}_{no}$ = water outlet temperature to the entire network under the design conditions

When all of the heaters in the network have the same minimum water temperature

$$\check{T}_n = \check{T}_u$$

Then

$$T_{ni} = \check{T}_n + S_{ni}\ \Delta T$$

$$T_{no} = \check{T}_n + S_{no}\ \Delta T$$

The total network flow

$$M_n = \frac{KVG}{S_{ni} - S_{no}}$$

which is constant when K = constant. This is discussed further below.

Central Heating Supply

The heat demands of the network are met by a combined heat supply comprising, in general,

P_g = geothermal heat supplied by the heat exchanger, W

P_b = supplementary heat from the back-up boiler, W

It is assumed that all of the network flow passes through the secondary side of the heat exchanger, and that

$$M_g < M_n$$

as discussed above. Then

$$P_g = M_g\ E\ (T_{gi} - T_{no}).$$

Substituting for T_{no} gives

$$P_g = M_g\ E\ (T_{gi} - \check{T}_n) - M_g\ E\ S_{no}\ \Delta T \tag{3}$$

Thus, given the assumptions of the model in any scheme P_g is a function of the external temperature only.

Geothermal Coverage

By using equation (3) above, the geothermal supply levels can be plotted on the demand duration curve and quantities of geothermal heat Q_g and back-up heat Q_b can be calculated.

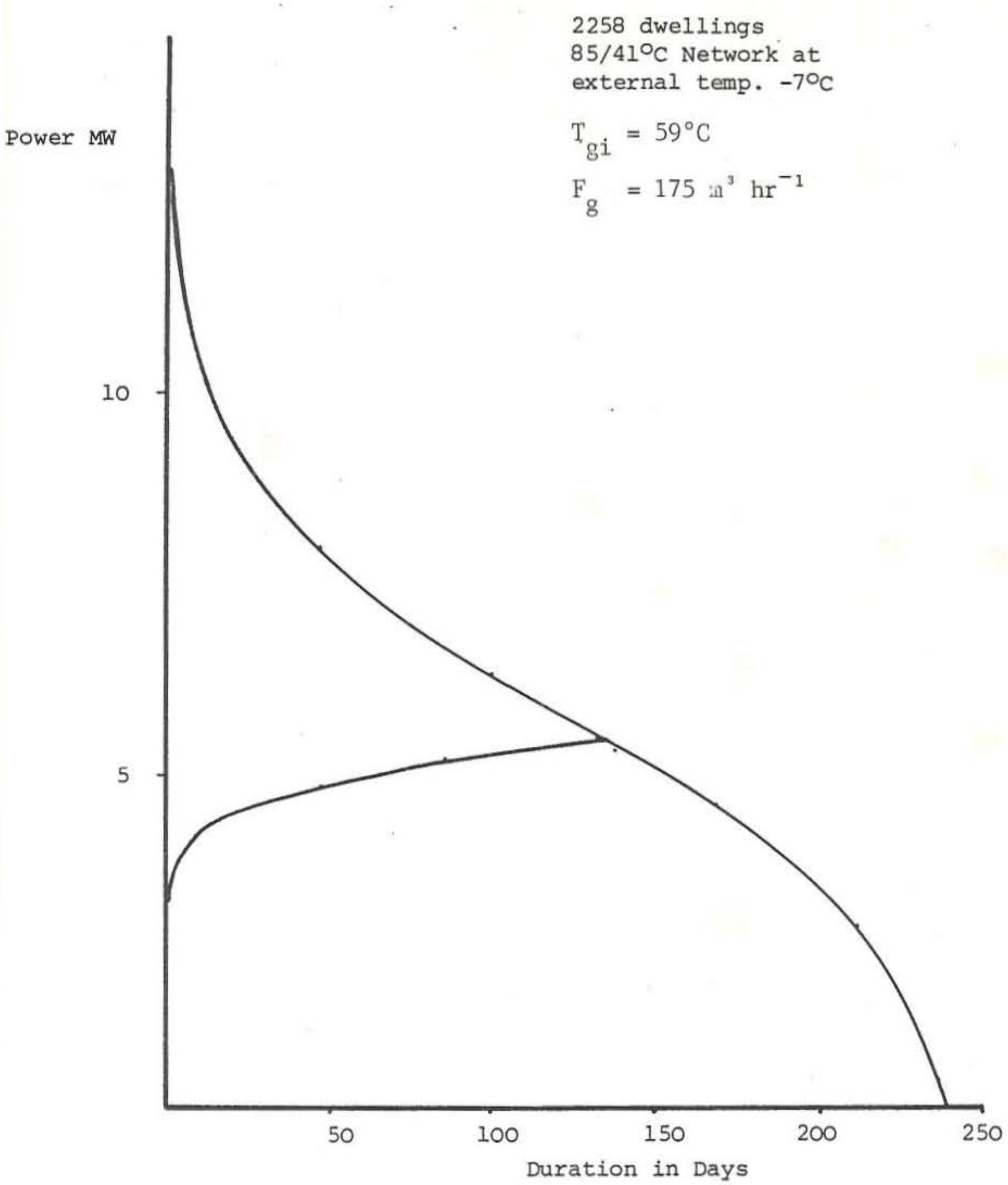
$$\text{Coverage ratio} = \frac{Q_g}{Q_d}$$

Figure 2.9 is an example of an actual curve showing the performance of the Garges Nord scheme.

1.4.3 Network Analysis

In a network which comprises a mixture of users with different characteristics an analysis must be carried out to determine

Figure 2.9 Garges Nord Simple Heat Exchange



Q_d = 34,584 MWhs

Q_g = 24,684 MWhs

Coverage ratio = 71%

$\hat{T}_{ni}$, $\hat{T}_{no}$ and M_n.

The principles of the analysis are simple involving continuity, temperature compatibility and mixing. However, individual cases may be complex if multiple branches and 'cascade' connections are employed. An example of a French network is given in Figure 2.6. This is a relatively simple case, the problem is to calculate the appropriate number of low temperature users that should be connected in 'cascade' with the high temperature users. The requirements of temperature compatibility mean that feedback and mixing is required to moderate the supply temperatures to the low temperature users in the second branch.

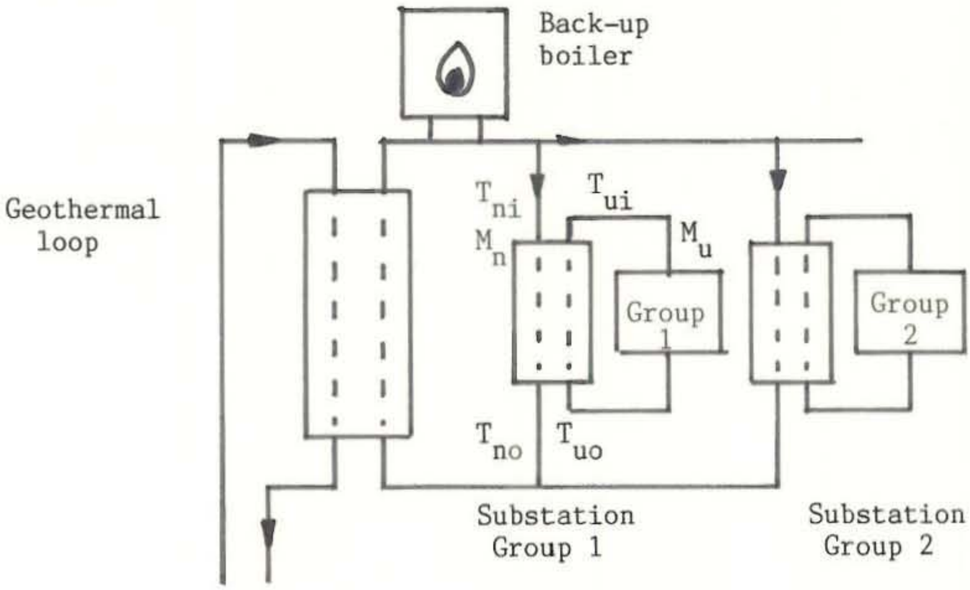
2.5 Characteristics of Actual Schemes

The standard layout assumed in the temperature governed model is representative of many geothermal district heating schemes. But a number of schemes depart from it in a variety of ways.

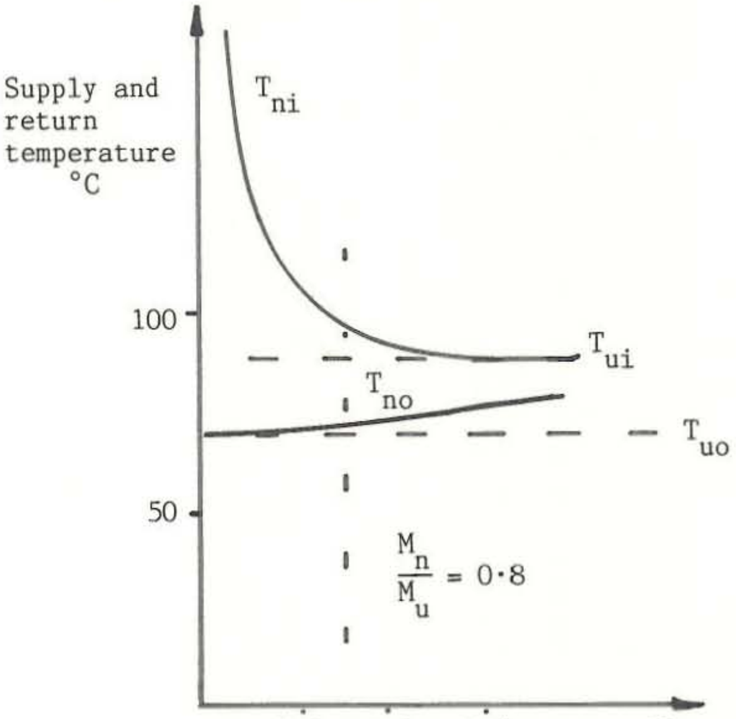
Type of Substation

Groups of users in the same building and using the same types of heater are connected to the network by heating substations. These may be mixing stations in which the users are connected directly to the network through some arrangement of valves and tanks. Because bypassing is not allowed, the return temperatures from these substations will be identical with the return temperatures of the heaters. Mixing may be required to obtain compatible supply temperatures but this depends upon the location of the back-up boilers as described below. In many networks, the substations house secondary heat exchangers and in these cases there is no direct connection between the heating fluids supplying the buildings and the network fluids. Secondary heat exchangers are used to reduce the pressures on the network caused by high rise buildings. However, they also have the effect of increasing the supply temperatures required from the network and the return temperatures to the network. The effect is shown in Figure 2.10 where these temperatures are plotted against the flow ratio across the secondary heat exchanger. If the heat exchanger effectiveness is high (> 90%) and provided

Figure 2.10 **Inclusion of Secondary Heat Exchangers at Substations**



a) Schematic layout



b) Effect of flow ratio at the
secondary heat exchanger on the network
inlet/return temperatures required to meet user demands

that the network flow through the heat exchanger is less than 80% of the user flow, then the return temperature to the network is only about 2°C higher than the user return temperature. This is the only significant effect which secondary heat exchangers have upon scheme performance and so long as the return temperatures are elevated by only 1 or 2°C then it is of secondary importance.

Location of Back-up Boilers

Two basic approaches to the location of back-up boilers are encountered. When an existing district heating system is being adapted to geothermal heating, or, alternatively, where a new network is being built and all existing boilers are being scrapped, the back-up boilers will be centralised close to the geothermal heat exchanger. The French schemes, Garges Nord and Orly are of this type. In these cases the temperature of the network supply main is regulated to meet the demands of the highest temperature users on the network, and feedback and mixing may be required to obtain temperatures which are compatible with any low temperature users. In these networks all of the heat is supplied from the central heating station and there is no way of supplementing at the sub-stations. Then at each substation of what ever type

$$M_n (T_{ni} - T_{no}) = M_u (T_{ui} - T_{uo})$$

The network temperatures and flows are essentially determined by the user temperatures and flows, and because of this, these are the simplest networks to analyse. The main area of flexibility is in the choice of network supply temperature, but it seems to be normal practice to choose the lowest possible supply temperature. This reduces losses and also reduces the possibility of oversupplying heat to the substations, ensuring that elevated return temperatures are avoided. Network flows must also be carefully controlled as any redundant flow at the substations will also lead to elevated return temperatures as described above. This approach is identical with the assumptions of the temperature governed model.

When large existing buildings or a collection of existing group heating schemes are connected together to form a geothermal network then the original boiler houses will be converted to heating substations and the original boilers may be retained as back-up boilers. The Fontainebleau scheme is of this type, Figure 2.11. Thus, in these schemes there is no centralised back-up, the temperature regulation is imposed at the substation and the mains temperatures follow these fluctuations in a natural way. Analysis shows that the network return temperatures faithfully follow the user return temperatures, only being elevated by 1 or 2°C if secondary heat exchangers are used.

Now at the substations

$$M_n (T_{ni} - T_{no}) \neq M_u (T_{ui} - T_{uo})$$

The network flow in the geothermal loop is not uniquely determined but normally it will be chosen so that

$$M_g < M_n < \text{Sum of the user flows } M_u.$$

This has an insignificant effect on performance, and, overall, the location of back-up boilers is of minor significance for the performance of a scheme.

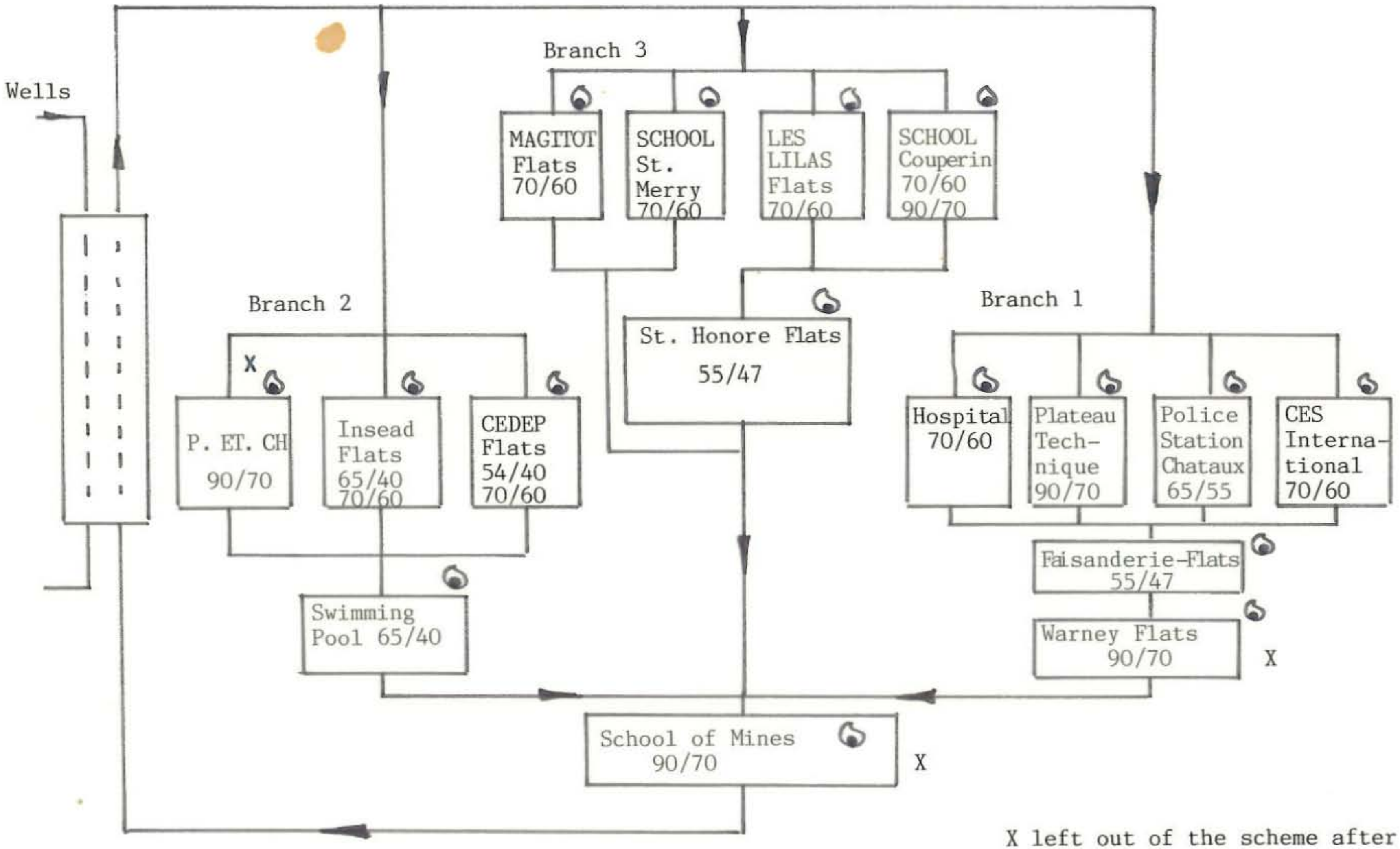
Provision of Domestic Hot Water

Average demands for domestic hot water are about 200 litres per dwelling per day at a temperature of about 50°C. If this is supplied by a heat exchanger, heating the water up from a cold temperature of about 10°C, then low return temperatures are possible and this makes it suitable for geothermal heating. However, it is only a small heating load (about 10% of the space heating load of the dwelling) and when supplied in parallel with space heating loads, as shown in Figure 2.12, the overall effect is to reduce the substation return temperature by only about 1 or 2°C below the space heating return temperatures.

2.6 Using the Temperature Governed Model

The geothermal power supply

Figure 2.11 Schematic Diagram of Fontainebleau Heating Network



X left out of the scheme after an optimisation study

Figure 2.12 Supply of space Heating and Domestic Hot Water from Central Geothermal Heating Station

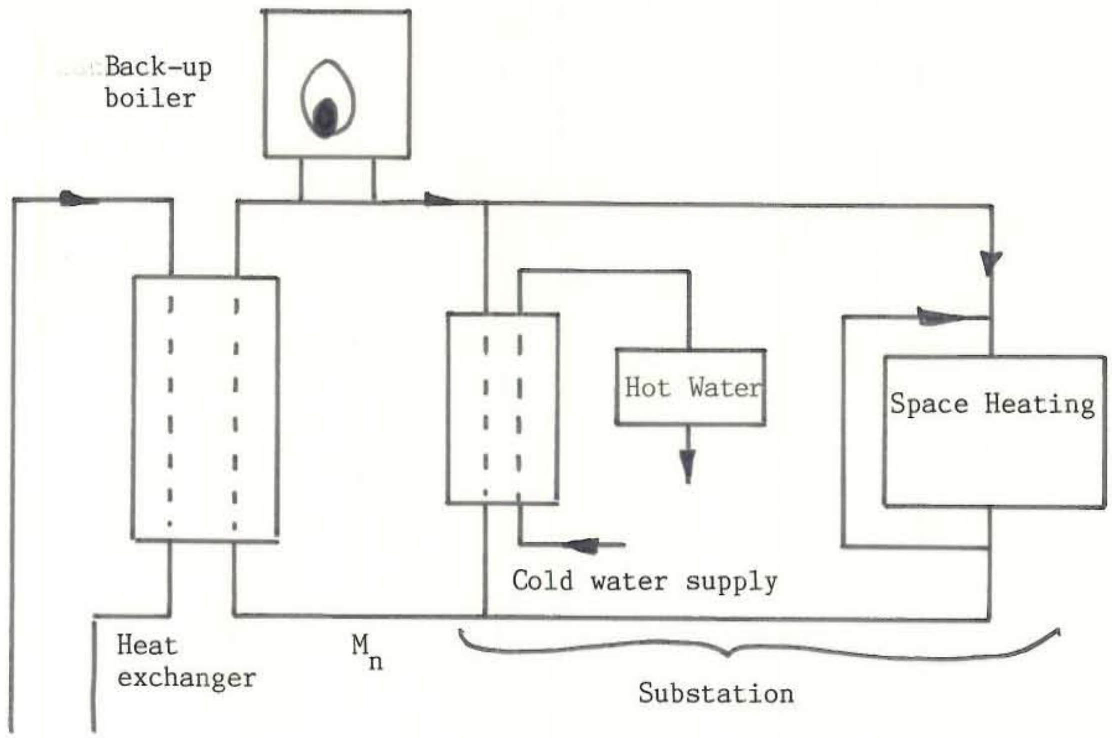
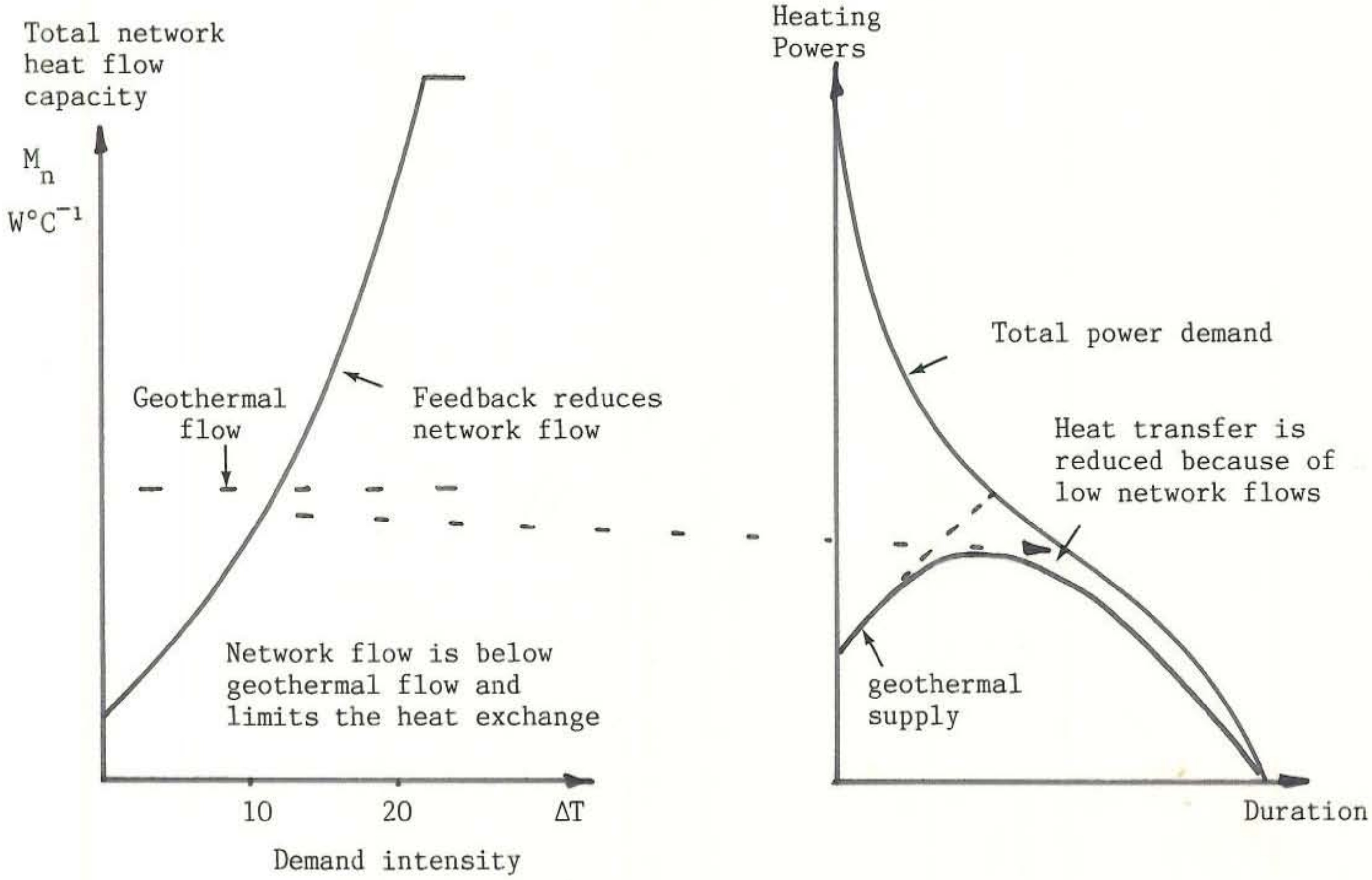


Figure 2.14 Effect of Falling Network Flow on Geothermal Supply in Systems Supplying DHW Centrally



$$P_g = M_g\ E\ (T_{gi} - \breve{T}_n) - M_g\ E\ S_{no}\ \Delta T \tag{3}$$

Provided that the network flow is always greater than the geothermal flow the 'P_g' is not sensitive to network flow. It is sensitive to return temperatures and provided that corrections are made for secondary heat exchangers:-

network return temperature = T_{uo} + 2°C

and corrections are made for the inclusion of domestic hot water:-

network return temperatures = T_{uo} - 2°C.

The model equations probably provide reasonably reliable way of forecasting 'P_g'. The calculations are easy to perform.

- Plot demand duration curve, P_d = KVG ΔT, using climatic data to give ΔT-time durations (ΔT-time exceedence)curve
- Plot P_g using (3) on the same curve.
- Calculate Q_g and coverage from the areas.

Sensitivities to return temperature T_{uo} and to geothermal fluid characteristics are also easy to perform. Figure 2.13 gives an example of the comparison of two different heater return characteristics.

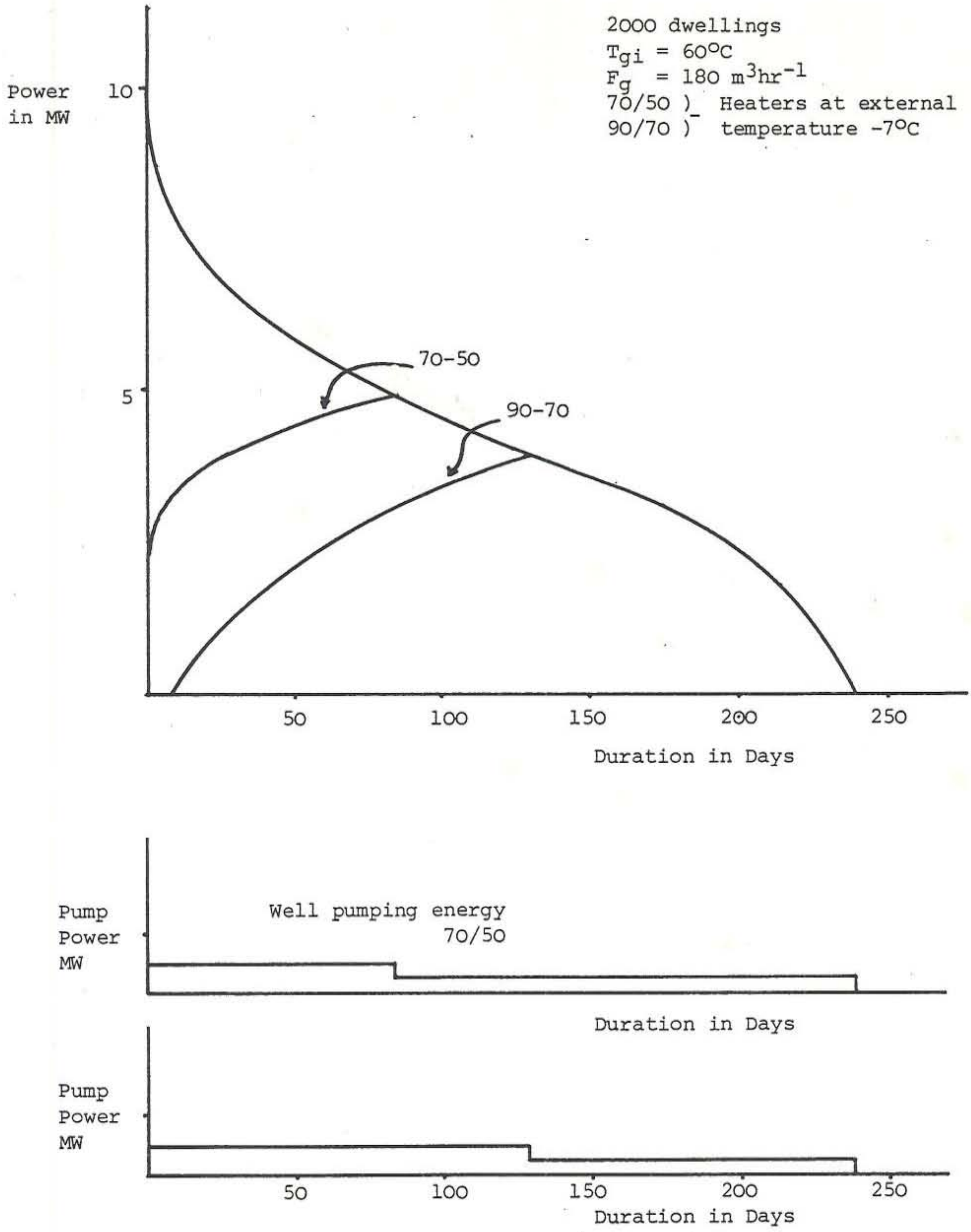
2.7 Schemes Where Network Flows Change by Large Amounts

These require a special analysis which falls outside of the scope of the temperature governed model. Two examples will be considered.

2.7.1 Effect of Domestic Water Heating in Centrally Supplied Networks

The effect of the inclusion of water heating on the overall performance of the scheme depends upon the type of heating network being employed. In particular it can have a detrimental effect on the performance of networks which have centralised back-up boilers and which are therefore centrally regulated as described above. In these cases the regulation regime is modified because the water heating component

Figure 2.13 Simple Example Simple Heat Exchange



Energy Demand Q_d = 24900 MWh

70/50		90/70	
Geothermal Energy	Q_g = 19,950 MWh	Geothermal Energy	Q_g = 14,200 MWh
Coverage Ratio	C = 80%	Coverage Ratio	C = 57%

requires a fixed network supply temperature of about 60°C. So long as T_{ni} is above 60°C there are no problems, the supply temperature is regulated to follow changes in ΔT in the normal way and the supply temperatures to the water heaters is reduced to 60°C by feedback and mixing. The problems arise at low values of ΔT when network supply temperatures of less than 60°C would normally be used. In this region, the network supply temperature must be maintained at 60°C to be compatible with the water heating system and the lower temperatures required for the space heating loads are obtained by feedback and mixing. The result of using feedback in relation to the majority of the heat load is to reduce the overall mains flow, and this can quickly fall below the geothermal flow. As the network flow falls below the geothermal flow the heat transfer at the primary heat exchanger is restricted as described above, and this has a detrimental effect on the geothermal heat supply at low levels of space heating demand. This will be unimportant if T_{gi} > 60°C because the reduction in geothermal heat supply will tend to occur at heating demands which would be oversupplied by the goethermal heat exchanger anyway. However, if T_{gi} < 60°C then the effect can be important and back-up heating could be required over the whole demand range. Figure 2.14 shows schematically the type of behaviour which would occur. This behaviour cannot be analysed using the model described above, the network temperatures and flows and the geothermal supply must be calculated separately at a number of different values of ΔT.

The problem can be overcome by using some form of localised heating in the substation or in the dwellings to back-up the domestic water heating component only. If this approach is feasible then disturbance of the regulation regime can be avoided. Clearly, in networks which already have distributed back-up at substations no problems arise.

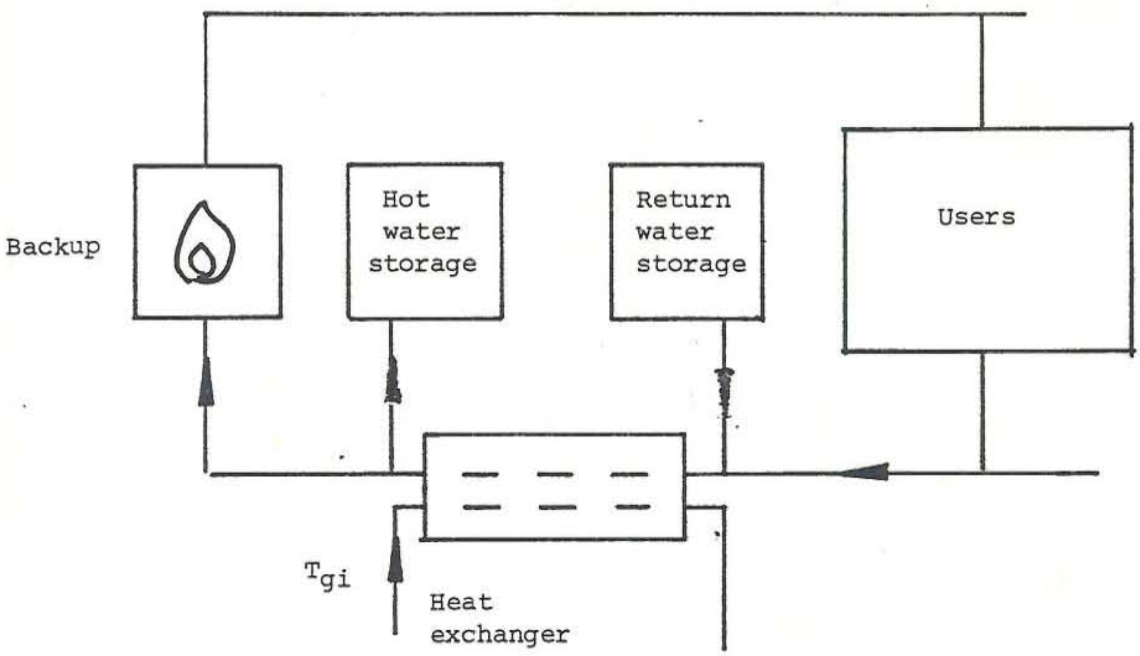
On the face of it domestic water heating seems to offer great improvements in the performance of geothermal schemes. However, on more careful examination the benefits appear to be mixed. As a heating load it is not usually large enough to give greatly enhanced earnings and as has been seen it may conflict with the space heating supply. Water heating demands do continue during the summer months when space heating loads are shut down, but not many networks would be kept in operation just to supply water heating. Although this is done at Melun l'Almont (Ref. 2.4). Finally, the costs of retrofitting a centralised domestic water heating supply into an existing building which is already equipped with water heaters in the individual dwellings can be high. The French do not seem to find this to be justified and it is their practice to include water heating in a scheme only if centralised supplies already exist.

2.7.2 The Effect of Users Shutting Down:- Storage

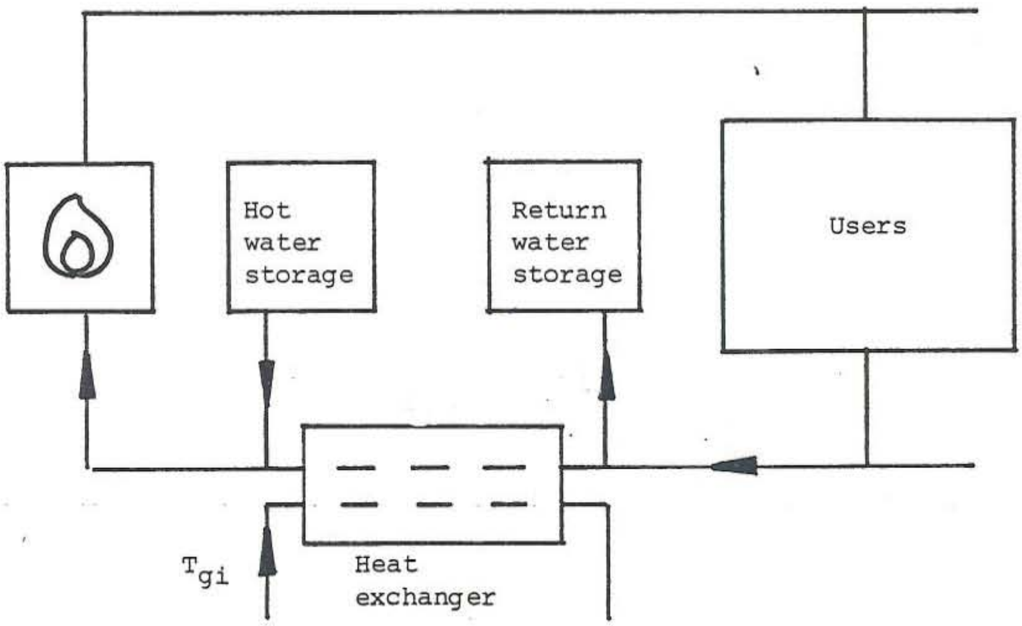
Various types of storage are used in goethermal schemes to smooth domestic water heating loads so that heat exchangers supply a more or less constant load heating water from 10°C to 50°C. However, storage in connection with the space heating loads is often also discussed for schemes where significant fractions of users shut down their heating systems regularly. A possible arrangement is shown in Figure 2.15. The storage tanks enable the flow through the heat exchanger to be kept at a constant level when the network flow changes. In the low demand period the network flow is less than the secondary flow through the heat exchanger and the excess supply fluids are diverted to hot water storage. During high demand periods the network flow is supplemented by adding hot fluid from the storage tank. In order for the flows to balance it is necessary to store return fluids from the network when the network flow is being supplemented. These fluids maintain the flow through the heat exchanger in the low demand periods. The overall result is to increase the supply capacity of the network over and above what would be supplied without storage. This allows more users to be connected to the network. In essence, the geothermal heat which would have been supplied to those users which are shut down during the night is stored and is supplied to the additional users on the network during the day. The viability

Figure 2.15 Heating Networks Incorporating Storage

a) Low Demands - Some Users Shut Down



b) High Demands - All Users Connected



of storage depends upon the numbers of users which regularly shut down their systems. Only if large numbers shut down so that the network flow falls below the geothermal flow for significant periods, thus limiting the heat transfer, is storage a useful option. If the network flow does not fall below the geothermal flow when users shut down then the geothermal heat transfer will not fall significantly in low demand periods. In this case the system is automatically transferring the geothermal heat supply which would have gone to the users which have shut down to the users which are still connected, and there is no need for expensive storage facilities. The author knows of no scheme where storage has been installed to smooth space heating loads.

If the numbers of users shutting down are relatively small so that the network flow does not fall below the geothermal flow then the model should forecast the geothermal heat supply reasonably well. It would be interesting to perform the calculation to determine the usefulness of the model in situations where storage is included because of periods when the network flow falls below the geothermal flow.

References **Chapter 2**

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Chapter 3 Heat Pumps in Geothermal Heating Schemes

3.1 Introduction

Heat pumps are machines that use a compressor to do work driving a cycle in which heat is absorbed at a low temperature and rejected at a higher temperature. They can be used in low-temperature geothermal heating schemes to increase the heat extracted from the fluid, but their particular role in any specific scheme depends upon the temperature of the fluid which is being used. Thus, with moderate temperature fluids in the range of 50°C to 70°C the heat extraction is dominated by the primary heat exchanger and the heat pumps are usually connected in a way which extracts additional heat from the geothermal fluid. However, with fluid temperatures of less than 40°C direct heat exchange becomes almost impossible and the heat pump is connected so that it accomplishes all of the heat transfer.

Which ever way heat pumps are used the economics of their operation depends upon the relationship between the following quantities:

- The heat which the heat pump transfers. This includes waste heat from the compressors and also heat recovered from the engines, if diesel-fired or gas-fired engines are used to drive the compressors.
- The fuel or electricity used to drive the compressor.
- The capital cost of the heat pump and of the engines, if present.

In order to be able to assess the economics of schemes which include heat pumps, it is essential to be able to calculate the heat transfers and the associated compressor work. This is the main aim of this chapter.

The theory and performance of heat pumps are considered first so that a model of the heat pump as an active heat transfer device can be defined. This leads on to the formulation of methods which can be used to analyse heat pump performance under varying demand conditions and in a number of the different configurations which are encountered in geothermal schemes.

3.2 Basic Principles of Heat Pump Operation

Normally, heat pumps in geothermal schemes interact with the rest of the heating system in such a way that their performance must be analysed as part of the overall system. However, before this analysis can be attempted it is necessary to consider how heat pumps operate in general so that an appropriate model can be formulated. The basic physical principles of heat pumps are well established and can be found in standard texts (Ref. 3.1 to 3.4) so only a brief description is given here.

From a basic thermodynamic point of view a heat pump cycle is an engine power cycle in reverse. The heat pump uses a work imput to provide a heat transfer accompanied by a rise in temperature while the heat engine uses a heat transfer and a fall temperature to provide a work output. The basic relationships which govern heat pump and heat engine operation follow from the first and second laws of thermodynamics and are independent of the details of the working fluid, the type of cycle or the form of the heat transfer.

Thus, following the first law, the sum of the heat and work transfers must be zero.

$$P_h + P_c - w = 0$$

where P_h = the heat transfer to or from the fluid at the high temperature.

P_c = the heat transfer to or from the fluid at the low temperature.

w = the mechanical work done by or done upon the fluid

In this expression the sign convention is:

- heat input is positive
- work output is positive

So, for the heat engine

$$w = P_h - P_c$$

and for the heat pump

$$P_h = w + P_c$$

A coefficient of heating performance of the heat pump can be defined as

$$C_h = \frac{P_h}{w} = \frac{P_h}{(P_h - P_c)}$$

and a coefficient of cooling performance (COP) can be defined as

$$C_c = \frac{P_c}{w} = \frac{P_c}{(P_h - P_c)}$$

It is easy to show that

$$C_c = C_h - 1$$

For a heat pump operating in a perfect Carnot cycle with perfect heat exchange between a high-temperature reservoir at T_h (°K) and a low-temperature reservoir at T_c (°K) the COP is given by

$$C_c = \frac{T_c}{T_h - T_c}$$

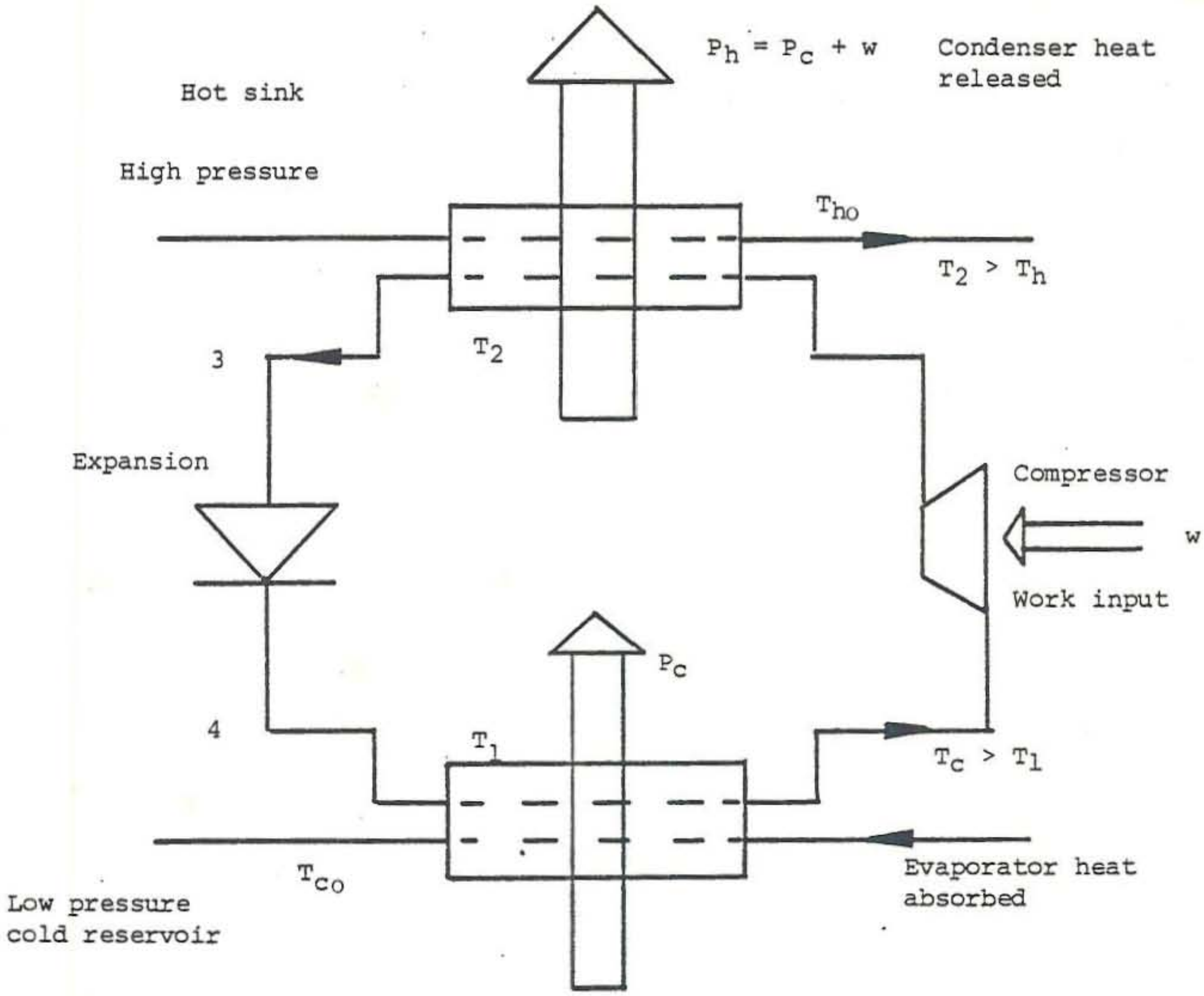
It is inversely proportional to the temperature stretch: $T_h - T_c$.

3.3 Practical Heat Pump Cycles

Heat pumps used in geothermal heating schemes work by evaporation. Heat is absorbed by the working fluid converting it from a liquid to a vapour at a low temperature. The vapour is compressed and the latent heat is released at a higher temperature. The cycle is shown schematically in Figure 3.1. It consists of the following stages.

- Evaporation heat is absorbed by the fluid by conduction from the cold reservoir and the liquid, which is at a low pressure, evaporates.
- Compression the vapour is compressed adiabatically, its temperature rises, and it passes to the condenser as a high pressure, high

Figure 3.1   Practical Heat Pump Vapour Compression Cycle



temperature, saturated or superheated vapour.

- Condenser in the condenser the liquid condenses at this higher temperature with the latent heat being conducted away to the high temperature reservoir.
- Throttling the liquid is returned to the low pressure part of the cycle by passing through an expansion valve. Here the pressure is reduced and there is partial evaporation accompanied by cooling.

Finally, the cooled liquid passes back to the evaporator.

The performance of practical heat pump cycles is always poorer than the performance of the equivalent Carnot cycle for the following reasons.

- Finite heat exchange

  The evaporators and condensers are heat exchangers of a finite size and hence significant temperature differences are required between the working fluid and the reservoirs. Thus, when the working fluid is in the evaporator it has to be cooler than the cold reservoir and when it is in the condenser it must be warmer than the hot reservoir. The result is that the cycle temperature stretch of the working fluid must always be larger than the temperature difference between the hot and cold reservoirs. This reduces the heat pumps COP significantly in practice.

- Finite reservoirs

  In practical applications, the hot and cold reservoirs are flows of hot and cold water with limited thermal capacities. Hence, the temperatures of these flows can change significantly in the evaporator and the condenser. This effect results in even larger differences between evaporating and condensing temperatures being required. To alleviate this problem, heat pumps are often arranged in batteries with their evaporators and condensers connected in series.

- Work losses

  The pressure reduction is usually achieved by the gas expanding through a single throttling valve. Work is done in this process which is not used and this results in a loss in performance.

These factors can have significant effects in reducing COP's in practice. For instance, consider the effects of the heat exchange efficiency at the condenser and evaporator. Typical French practice in estimating COP's (Refs. 3.5 and 3.6) is to assume that:

- The working fluid evaporation temperature has to be 4°C lower than the outlet temperature of the water stream passing through the evaporator, T_{co}.
- The working fluid condensation temperature has to be 4°C higher than the outlet temperature of the water stream passing through the condenser, T_{ho}.

Then the theoretical Carnot COP is modified to become

$$C_c = \frac{(T_{co} - 4)}{(T_{ho} - T_{co} + 8)}$$

It is also often assumed that the other thermal and mechanical losses reduce the COP to about 70% of this adjusted value. Hence,

$$C_c = 0{\cdot}7 \frac{(T_{co} - 4)}{(T_{ho} - T_{co} + 8)}$$

COP data is often difficult to obtain, Table 3.1 gives some figures for a range of evaporator and condenser outlet temperatures. It is clear from this that COP is a strong inverse function of $T_{ho} - T_{co}$ and a weak function of T_{co}.

Writing $\theta = T_{ho} - T_{co}$ and, ignoring the dependence upon T_{co}, this data is represented reasonably well by the expression

$$C_c = 9{\cdot}376 - 0{\cdot}24\ \theta + 1{\cdot}87 \times 10^{-3}\ \theta^2$$

In real heat pump cycles there are physical limits beyond which heat pumps will not operate effectively. These constraints arise because of the thermal properties of the heat pump working fluid which must evaporate and condense within a reasonable band of temperatures and pressures and also because of the mechanical limitations of the compressor.

The main physical constraints are:-

- Maximum condenser water outlet temperature. This depends upon

Table 3.1 Coefficient of Cooling for a Heat Pump in a Geothermal Scheme

$$\theta = T_{ho} - T_{co}$$

Condenser Outlet Temperature T_{ho}	Evaporator Outlet Temperature T_{co}						
	5	10	15	20	25	30	35
65	2.61	2.84	3.12	3.46	3.86	4.36	4.99
60	2.83	3.10	3.44	3.84	4.34	4.97	5.75
55	3.08	3.41	3.82	4.32	4.94	5.72	
50	3.39	3.79	4.29	4.91	5.69		
45	3.77	4.26	4.88	5.65			
40	4.23	4.85	5.62				
35	4.81	5.58					

The heat pump cannot operate with T_{ho} and T_{co} in this region

Taken from Ref. 8c.

Coefficient of cooling is strongly dependent upon θ and less strongly dependent upon level of T_{co}. For instance, for all of the heavily squared boxes, θ is constant at 30°C and the COP varies only slightly with T_{co}.

the type of working fluid and the compressor. Normal condensation temperatures are around 70°C for R12 and 55°C for R22, but they may vary by about 25°C around these levels (Ref. 3.8). The high temperature limit at high pressure can be taken to be 85°C (Ref. 3.6).

- Minimum evaporator water outlet temperature. This is set at a level of about 5°C in geothermal applications in order to avoid freezing in the evaporators.
- Maximum evaporator water outlet temperature. This depends upon the working fluid and the compressor type and is around 35°C for screw compressors (Ref. 3.8).
- Minimum temperature difference between the evaporator and condenser water outlets. This must be large enough for the cycle to work effectively and Figures of 18 to 22°C are used (see Refs. 3.6 and 3.7).
- Minimum temperature difference between the working fluids and the water outlers. There must be in the region of 4°C to enable heat transfers to take place (see Ref. 3.6).

3.4 Geothermal Applications

Heat pumps are not single elements like primary heat exchangers or back-up boilers. The evaporators and condensers are located in different parts of the system and also bypass connections of various types are possible. Consequently, a wide variety of different layouts are possible in geothermal schemes all of which can, in general, perform differently. If attention is focussed on the way in which the heat pump supplies heat in any scheme then two basic classes of configuration can be identified.

- The heat pump assists the primary heat exchanger, supplying additional heat from the geothermal fluid. This is called the heat pump assisted (HPA) approach in this chapter.
- The heat pump dominates the geothermal supply and no heat is transferred if the the pump is not operating. This is called the heat pump only (HPO) approach in this chapter.

The choice between these different approaches is dependent upon the temperature of the fluid which is available to any scheme. It will be shown later, using an example, that, with higher temperature fluids the heat pump assisted approach is the most efficient. As the fluid temperature falls the advantage shifts to the heat pump only approach.

3.4.1 Heat pump assisted heat transfer

In these arrangements the heat pumps are connected in ways which produce additional geothermal heat over and above what would be obtained from simple heat exchange above. The geothermal heat transfer is still dominated by the primary heat exchanger and significant heat transfers would be obtained with the heat pump switched off. The basic arrangements are given in Figure 3.2 which shows alternative direct and indirect evaporator connections.

Heat pump assisted - direct evaporator

This is the simplest arrangement. The evaporators are located on the geothermal return and extract residual heat directly from the brine leaving the primary heat exchanger. The action of the heat pump does not affect the operating conditions of the primary heat exchanger but the reverse is not true.

In this situation there are clear and distinct heat transfer paths.

- Heat is transferred by simple heat exchange and the heat flows are unaffected by the action of the heat pump.
- The residual heat extracted from the brine is transferred by the heat pump to the heating system supply.

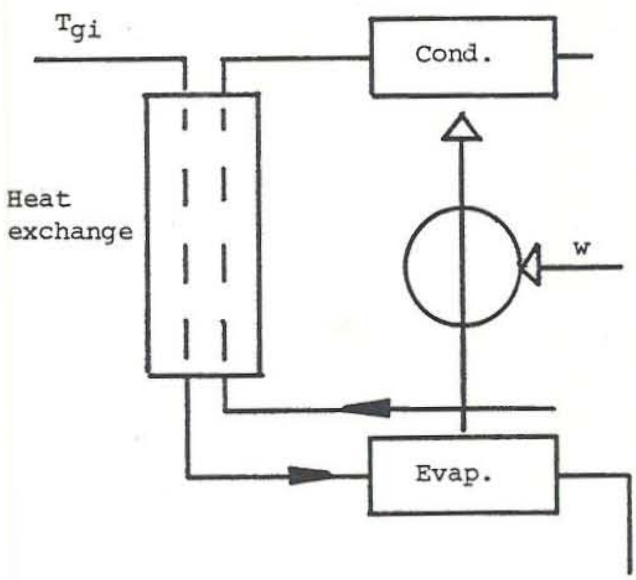
The additional geothermal heat transfer δP_g is equal to the cooling effect of the evaporator.

Thus: $$\delta P_g = P_c$$

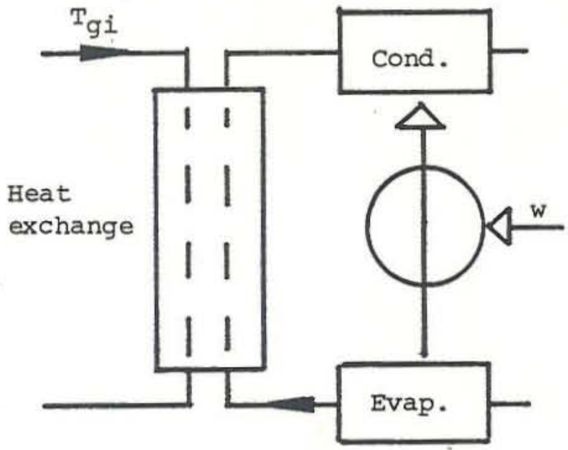
Although this arrangement has the advantage of simplicity there can be problems of corrosion if saline fluids pass through the evaporators. One solution is to use an ancillary heat exchanger as is done at Chateauroux (Ref. 3.7) see Figure 3.2c. However, this involves additional costs and reduces performance.

Figure 3.2 Heat Pump Assisted Heat Exchange Layouts

a) Direct Evaporator

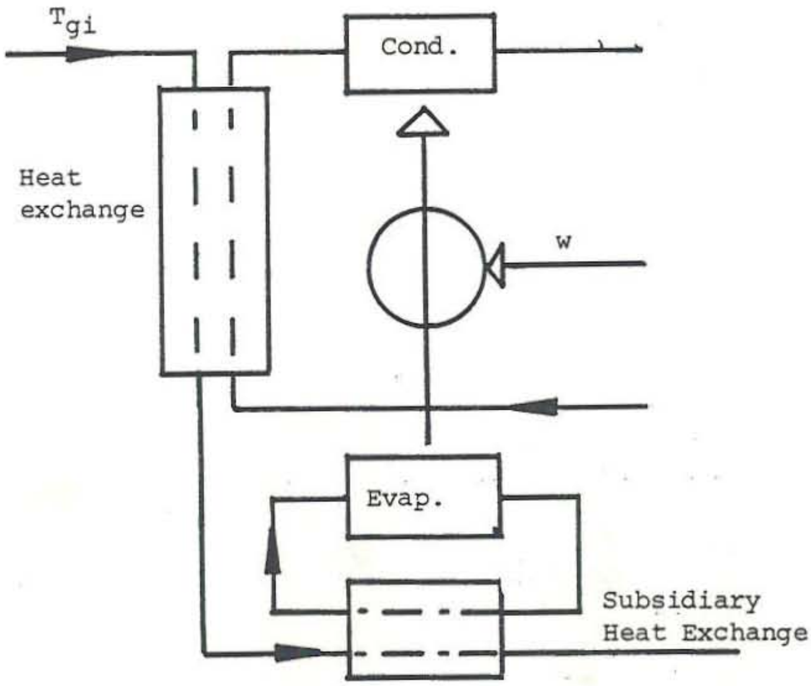


b) Indirect Evaporator



e.g. Creil

c) Direct Evaporator and Subsidiary Heat Exchanger



e.g. Chateauroux French Case No. 5

Heat pump assisted - indirect evaporator

This arrangement is a little more complex. The evaporators are located on the heating system return main. Heat is extracted from the return fluids, this reduces the return temperature to the heat exchanger, increases the geothermal heat exchange and reduces the brine outlet temperature. The effect of the heat pump is the same as it is in the direct evaporator arrangement in that residual heat is extracted from the brine, but in this case the action is indirect. All of the geothermal heat is transferred by a single route across the primary heat exchanger which is being assisted by the heat pump.

In this arrangement the heat pump and the heat exchanger influence each other. The extra heat which is transferred due to the cooling action of the heat pump is proportional to but less than the amount of heat absorbed by the evaporator. It can be shown that the additional heat transfer δP_g is slightly less than the cooling effect of the evaporator. It is reduced by the heat exchanger effectiveness E and the ratio of the flows across the heat exchanger R.

$$\delta P_g = R\ E\ P_c$$

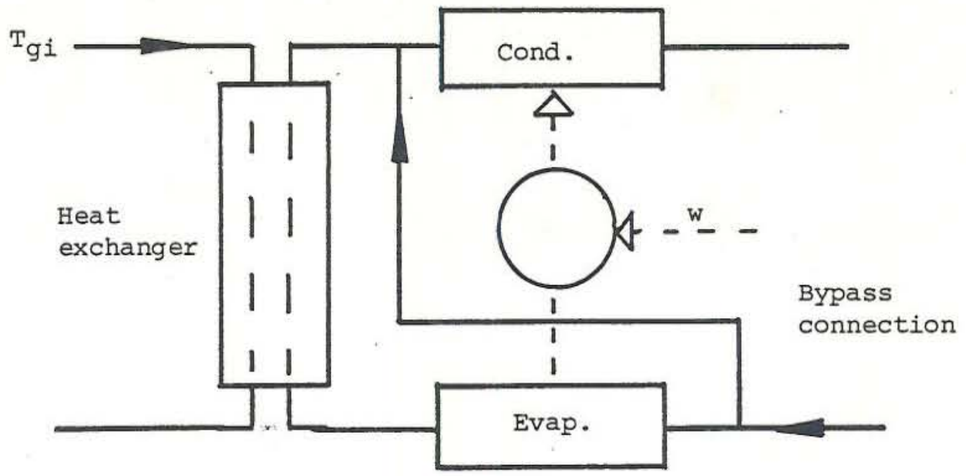
R E is always less than 1 so the performance can never be as good as the direct evaporator arrangement. The attraction of this indirect evaporator arrangement over the direct evaporator is that corrosion in the evaporator is avoided without resorting to the expense of an additional heat exchanger.

Optimisation of operating conditions

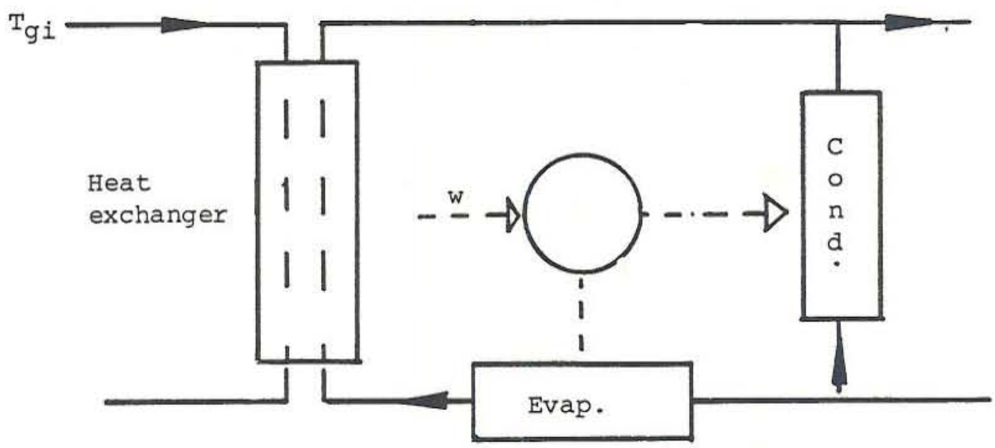
There are many variants on these basic layouts which may have special advantages in the context of the details of particular schemes. Also a variety of devices may be employed to optimise the performance of the heat pump. One important modification is shown in Figure 3.3a. Here the network return flow is divided at the evaporator inlet and one stream bypasses both the evaporator and the heat exchanger to be mixed back with

Figure 3.3 Bypass Arrangements to Improve Operating Conditions

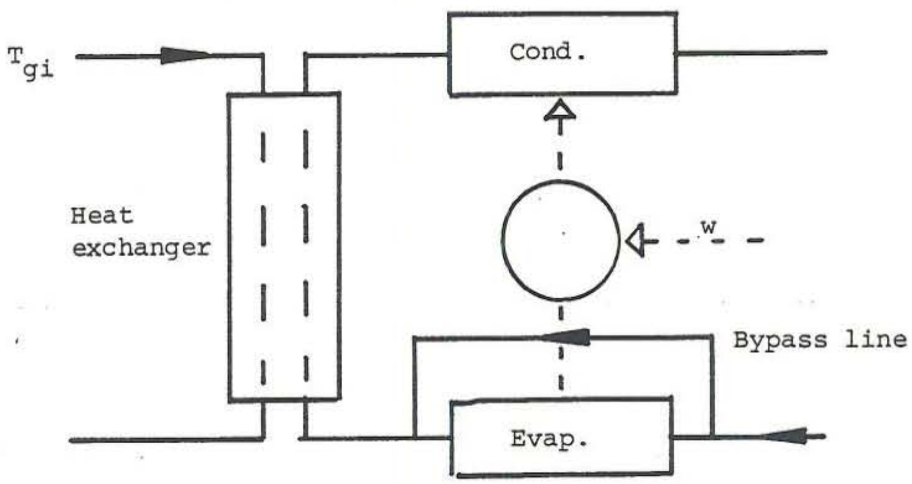
a) Evaporator/heat exchanger bypass



b) Parallel Condenser



c) Evaporator Bypass



the main stream at the condenser inlet. This arrangement has two advantages. The flow through the evaporator and the heat exchanger can be controlled so that the product:

R E

is a maximum and hence the additional heat transfer is as large as possible. In addition to this, the condenser input temperature and hence the output temperature may be reduced. This will reduce the temperature stretch and increase the COP.

In some cases it may be advantageous to actually locate the condenser on the bypass line, as is shown in Figure 3.3b. This arrangement should reduce the condenser output temperature and the temperature stretch yet further thus increasing COP's.

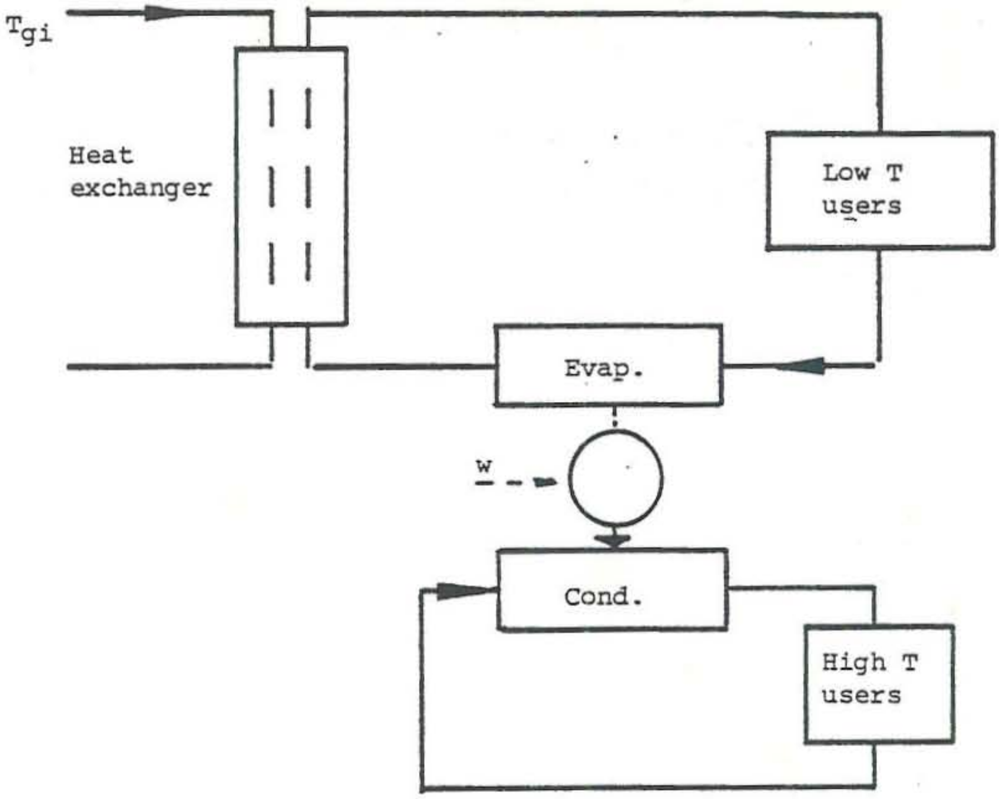
In some conditions, when the temperature levels in the system are such that the temperature stretch would be too low for the heat pump to operate, then an evaporator bypass may be used, see Figure 3.3c. This allows the evaporator temperature to fall and re-establish the minimum temperature stretch required for operation. A similar result could be achieved by a condenser bypass which increases condenser outlet temperature.

<u>Heat pumps serving only part of the heat load</u>

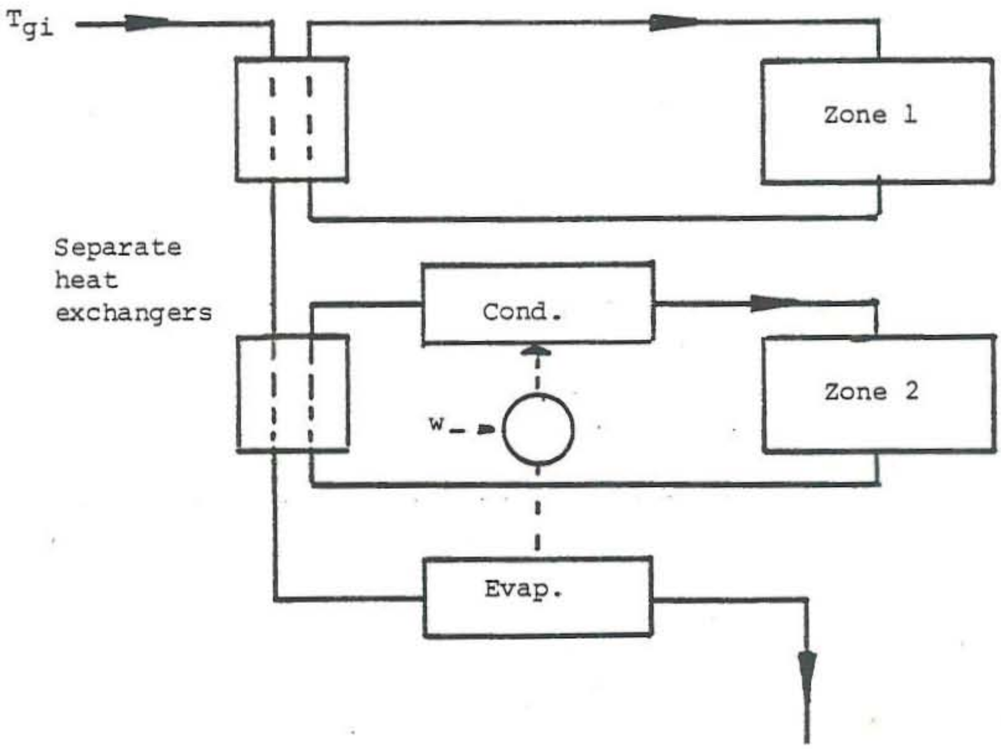
When the heat load consists of a mixture of high and low temperature users, schemes may be designed so that the low temperature users are supplied by direct heat exchange while the heat pump is used to boost the supplies to the high temperature user. Figure 3.4 shows schematic diagrams of schemes of this type. At Creil the evaporators cool the returns from the low temperature users and the increased heat exchange compensates for this. The additional heat which is extracted by the heat pumps is transferred to a separate branch of the network supplying the high temperature users. The Acheres scheme is a variant of the direct evaporator arrangement. In this scheme the production and reinjection wells are widely separated and there are two main heat

Figure 3.4 Networks Where Heat Pumps Serve Only Part of the Load

a) Creil Heating Network.
(heat pump assisted)



b) Acheres Heating Network.
(direct evaporator)



exchangers. These are connected in series and they serve completely independent groups of users. The heat pump evaporator is located directly on the geothermal return and it serves to boost the heat supply to the second group of users.

It is a common practice to use heat pumps to supply only part of the heat load in a geothermal scheme. However, it makes the analysis of the heat supply difficult.

3.4.2 <u>Heat pump only heat transfer (HPO)</u>

This arrangement tends to be used when the temperature of the supply fluids, aquifer brines or ground waters, are so low that only insignificantly small heat transfers would be obtained by simple heat exchange alone. The basic arrangement is shown in Figure 3.5. The heat is extracted by the evaporator from the geothermal supply fluid either directly or across an auxilliary heat exchanger. The heat is released to the heating system by the condenser. The only heat transfer path is through the heat pump and no heat is delivered unless the heat pump is working. In this arrangement the heat pump operates in a way which is closest to the simple 'text book' arrangement and indeed, if the flows on the geothermal side are large enough, this will act as a 'text book' infinite, constant temperature reservoir. The heat pump upgrades the heat extracted so that the condenser outlet temperature is higher than the geothermal supply temperature.

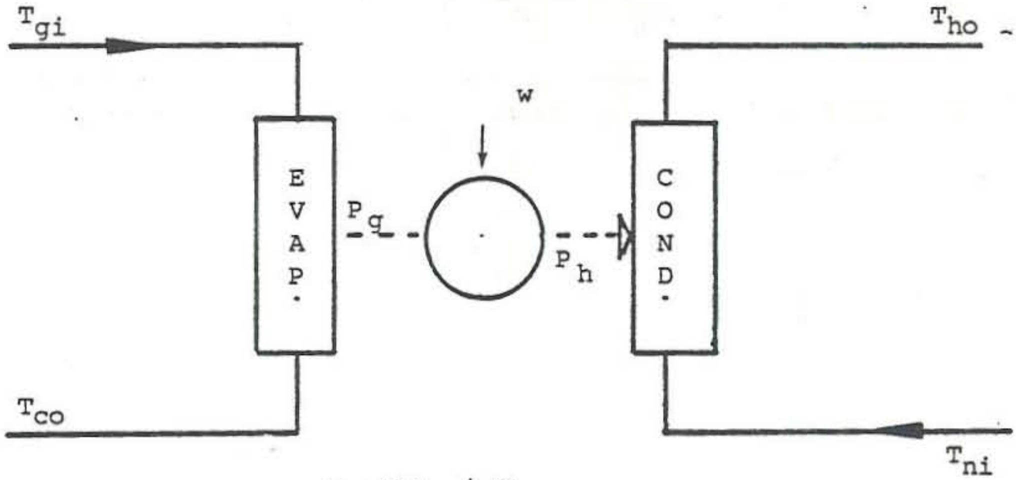
$$T_{ho} > T_{gi}$$

Bypass connections may also be used in this arrangement. Thus, in those situations where the temperature stretch is too low for the heat pump to operate, condenser bypass can be used to raise the condenser output temperature and restore normal operating conditions.

As with the heat pump assisted arrangement, there are many variants on the heat pump only layout where the heat pumps are used to supply special groups of users in the heating network. Figure 3.6 shows the layout of the Beauvais heating

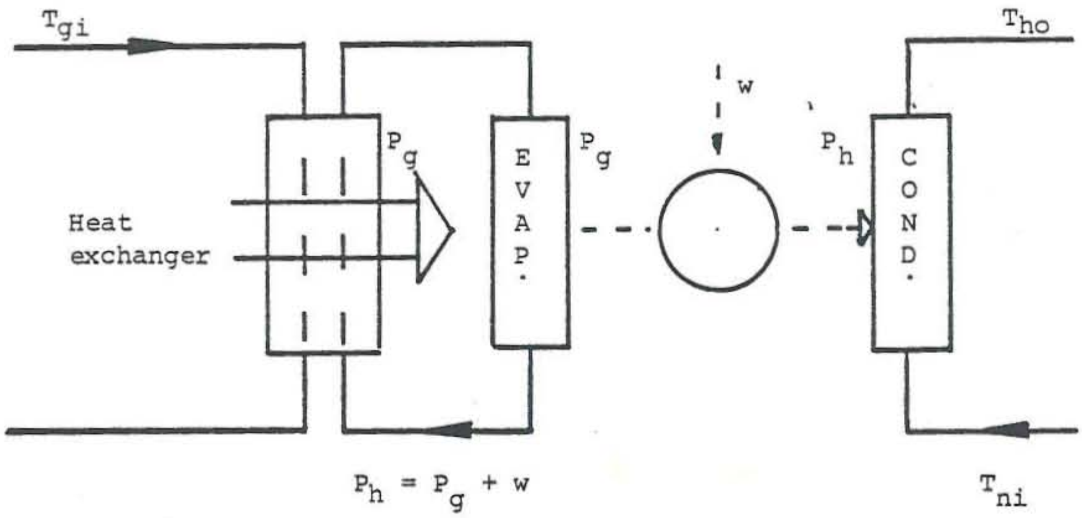
Figure 3.5 Heat Transfer by Heat Pump Only

a) Basic Layout



$P_h = P_g + w$

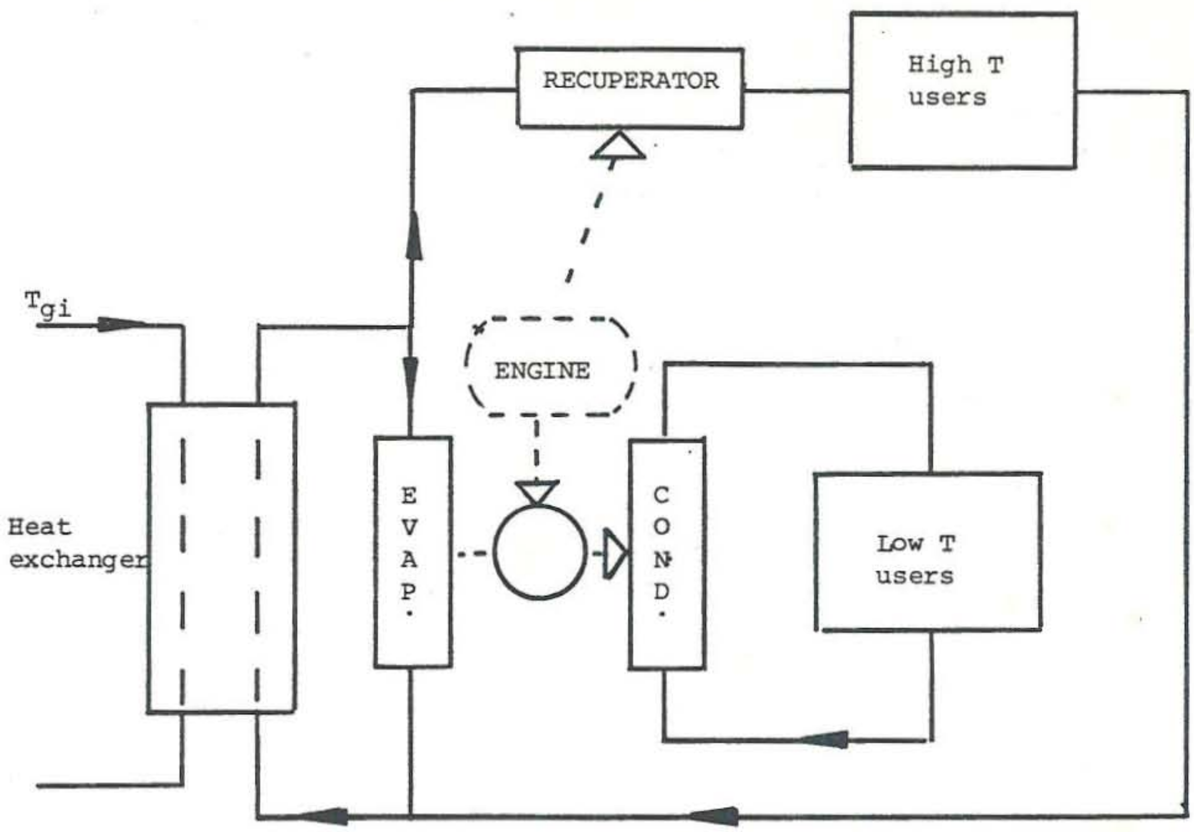
b) Layout with Ancillary Heat Exchanger



$P_h = P_g + w$

Figure 3.6   Heat Pump Supplying Only Part of the Load

Beauvais French Case No. 6.



scheme in Northern France. In this scheme the heat pumps, which are driven by gas engines, dominate the heat transfer to one group of users. A second group of users is supplied directly from the heat exchangers and is additionally supplied by the recuperators which recover heat from the gas engines.

3.5 Analysis of Heat Pump Performance

It is necessary to extend the analysis developed in Chapter 2 so that geothermal power levels and compressor work can be calculated with the heat pump operating under different demand conditions. The analysis is complicated by the fact that it cannot be assumed that the heat pump operates at a fixed COP delivering a constant level of additional heat. This can be understood by considering the standard layout in Figure 3.7. The return fluids from the network are cooled by the evaporator from T_{no} to T_{co}. The heat exchanger transfers additional heat due to the improved conditions. The fluid temperature rises from T_{co} to T_{xo}. The fluid is further heated by the condenser from T_{xo} to T_{ho}. The heat pump temperature stretch $T_{ho} - T_{co}$ which determines the COP is in part determined by the action of the heat pump itself. The analysis has two basic aspects.

- Interaction. The heat pump and the heat exchanger interact and affect the mutual operating conditions. In general, the operation of the heat pump cannot be analysed independently of the heat exchanger.
- Variability. The overall operating conditions of the heat pump-heat exchanger combination depend upon the inlet conditions. T_{no}, M_n, T_{gi} and M_g. T_{no} and M_n will change and power levels must be recalculated over the whole demand range in order to give a complete assessment of the heat pumps contribution.

It is possible to define a basic approach to the heat pump calculations. This consists of formulating sets of equations which give the temperatures and power levels at evaporator, heat exchanger and condenser. The equations must be solved simultaneously. The detailed form of these equations are different for different layouts. Two cases will be considered here.

3.5.1 Analysis of the heat pump assisted layout

The basic layout is shown in Figure 3.8 which incorporates

Figure 3.7 Heat Pump Assisted Heat Exchange Operating Temperatures

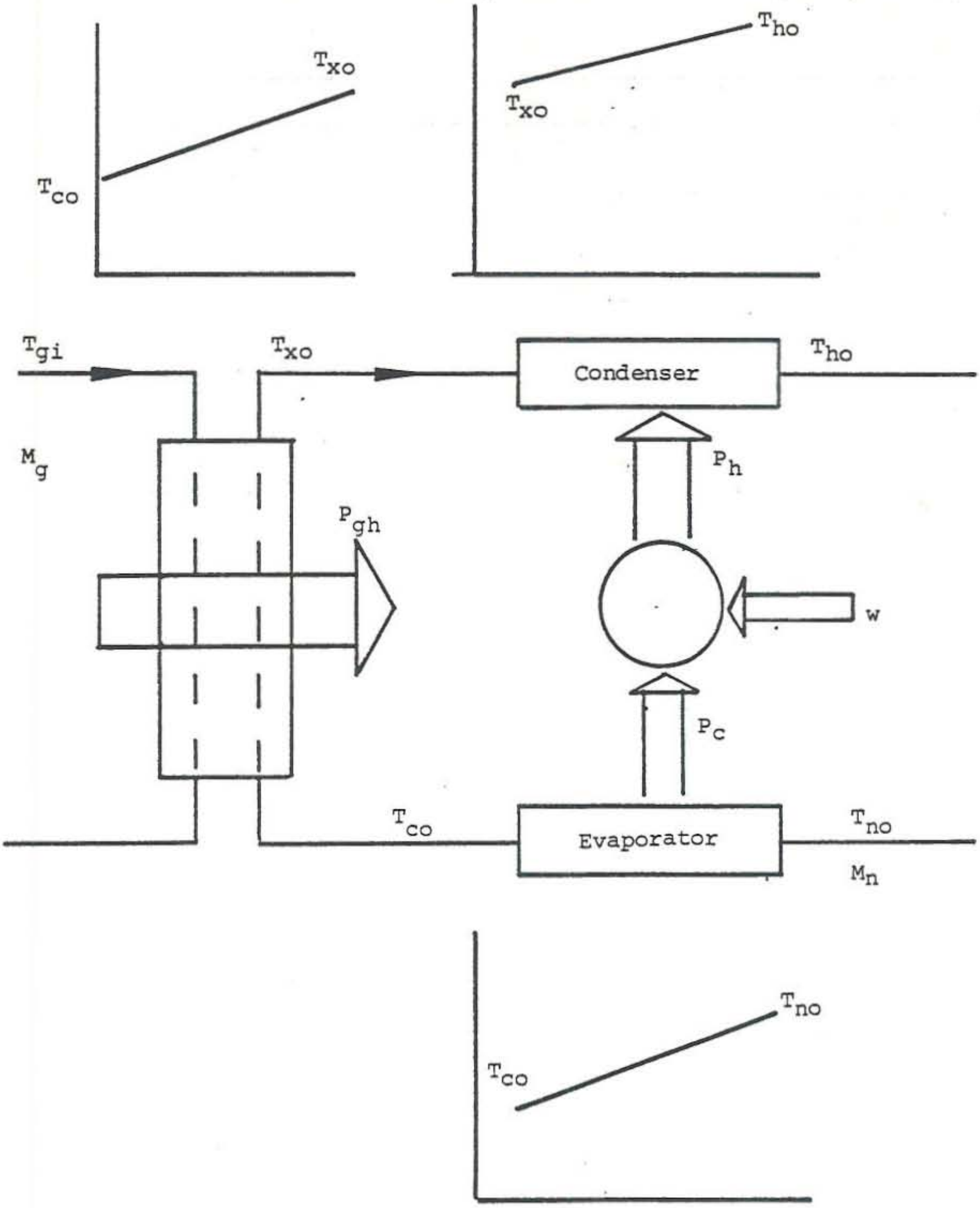
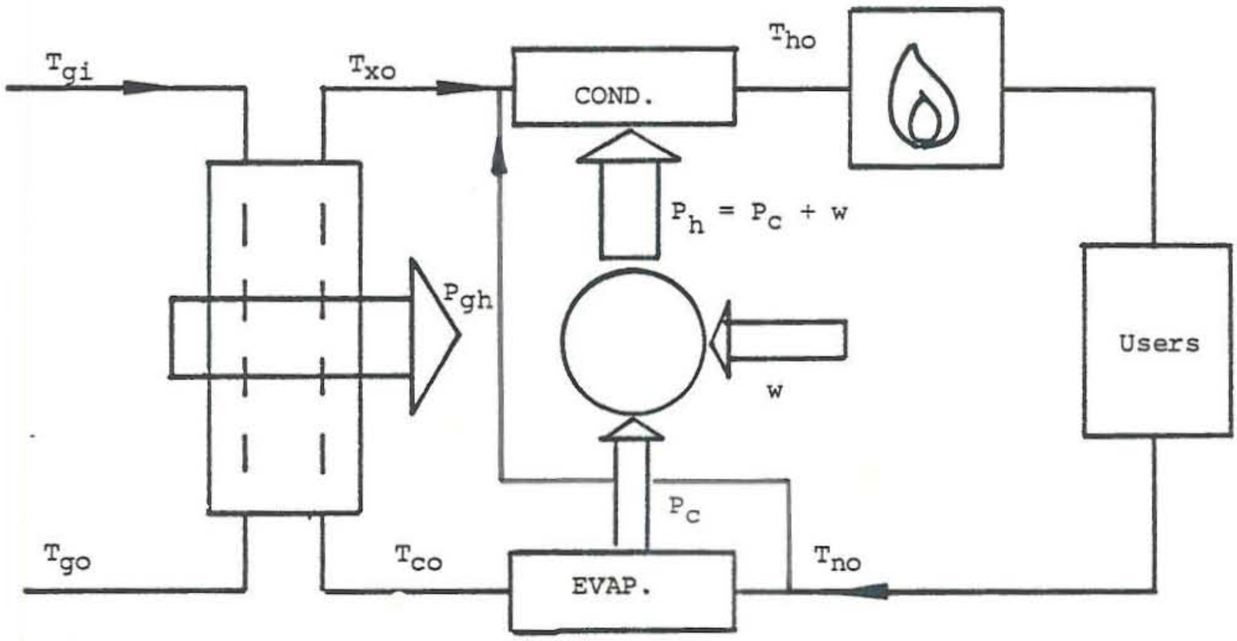


Figure 3.8 Heat Pump Assisted-Indirect Evaporator Layout



the bypass connection discussed above.

(i) Powers and temperatures at the evaporator

Heat absorbed $P_c = C_c\ w$ (1)

Outlet temperature $T_{co} = T_{no} - \left(\frac{P_c}{M_x}\right)$ (2)

$$M_x = M_n - M_b \qquad (3)$$

$$T_{no}\ T_u + S_{no}\ \Delta T \qquad (4)$$

(ii) Powers and temperatures at the heat exchanger

Heat transferred $P_{gh} = M_g\ E\ (T_{gi} - T_{co})$ (5)

Outlet temperature $T_{xo} = T_{co} + \frac{P_{gh}}{M_x}$ (6)

(iii) Powers and temperature at the condenser

Heat released $P_h = P_c + W = (C_c + 1)\ w$ (7)

Inlet temperature $T_{hi} = \frac{(T_{no}\ M_b + T_{xo}\ M_x)}{M_n}$ (8)

Outlet temperature $T_{ho} = T_{hi} + \frac{P_h}{M_n}$ (9)

(iv) Heat pump performance

Temperature stretch $\theta = T_{ho} - T_{co}$ (10)

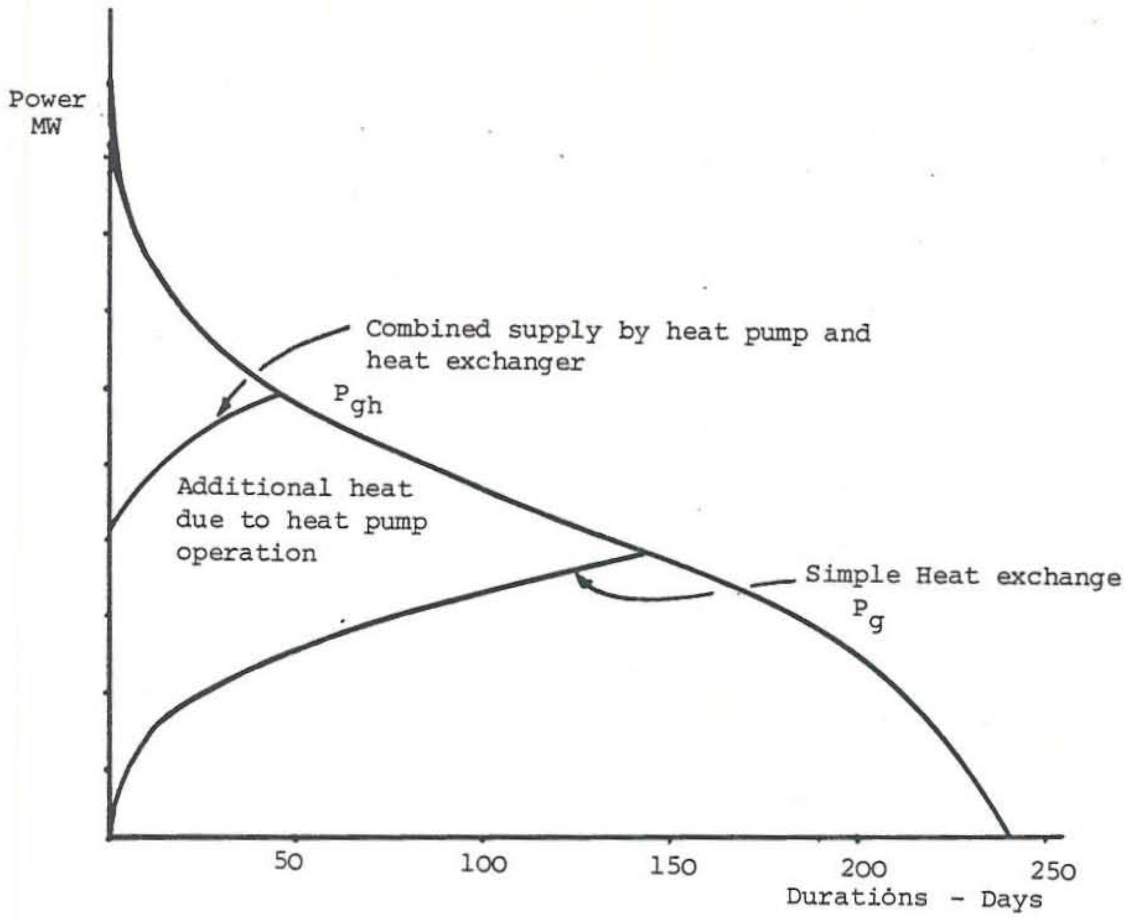
COP $C_c = 9{\cdot}376 - 0{\cdot}24\theta + 1{\cdot}87 \times 10^{3}\theta^{2}$ (11)

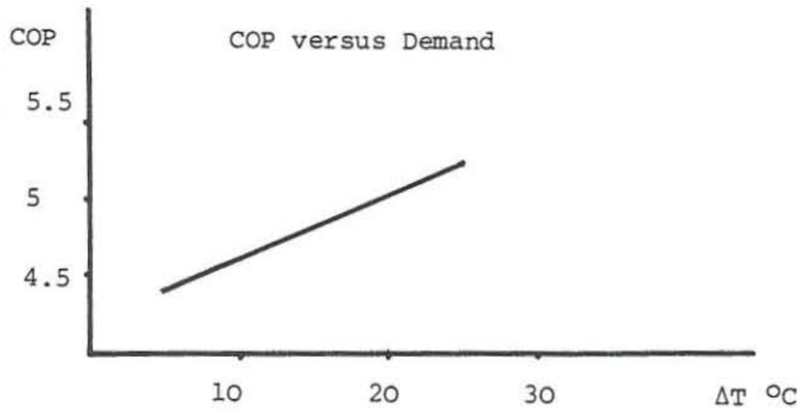
There are 11 equations in 11 unknowns, they must be solved simultaneously in order to determine the combined supply, by heat pump and heat exchanger at different demand levels ΔT. This is easy to do using an iterative approach. Figure 3.9 illustrates some typical results for a hyperthetical scheme (in this case there is no bypass connection).

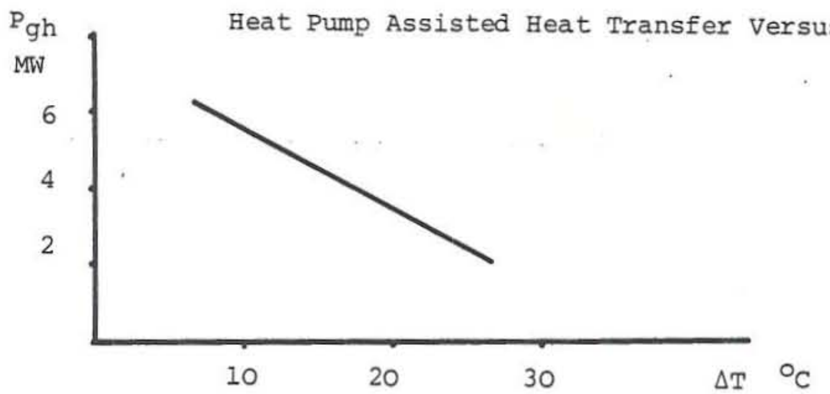
At the highest demand level $\Delta T = 25°C$, $T_{no} = 50°C$, the the temperature stretch is a minimum, the COP is at a maximum but heat pump assisted heat transfer is at a minimum. As ΔT falls T_{no} falls, the heat pump COP falls but the heat pump assisted heat transfer rises.

The bypass has an important effect on the performance of this arrangement. The additional heat transfer due to the heat pump is given by

Figure 3.9 Heat Pump Assisted-Indirect Evaporator Example of Results







$$\delta P_g = \frac{M_g}{M_x} E\ C_c\ w$$

The effect of varying M_x is shown schematically in Figure 3.10. As $\frac{M_g}{M_x}$ approaches unity the unassisted heat transfer falls because the heat exchanger effectiveness falls, but this is more than offset due to improvements brought about by reductions in T_{co}.

The effect on the overall performance is shown in Figure 3.11. The combined heat supply is increased by about 7%.

3.5.2 Analysis of the heat pump only layout

The basic layout is as shown in Figure 3.5b above, the evaporation is located in the primary position and heat is supplied from the geothermal fluid via a heat exchanger interface. The geothermal heat supply is determined by and limited by the compressor power and the level of the COP.

The heat transferred across the heat exchanger is identical with the heat extracted by the evaporator

$$P_g = P_c = C_c w = M_g\ E\ (T_{gi} - T_{co})\ *$$

The simultaneous equations which determine the power levels and the temperatures of operation are as follows.

Powers and temperatures in the heat exchanger/evaporator loop

$$P_c = C_c w \tag{1}$$

$$P_g = P_c \tag{2}$$

evaporator output temperature

From * $$T_{co} = T_{gi} - P_g/(M_g\ E) \tag{3}$$

Powers and temperatures at the condenser

$$P_h = (C_c + 1)\ w \tag{4}$$

condenser output temperature

$$T_{ho} = T_{no} + P_h/M_n \tag{5}$$

$$T_{no} = T_u + S_{no}\ \Delta T \tag{6}$$

Figure 3.10 Effect of Flow Ratio R on the Performance of the Bypass Layout

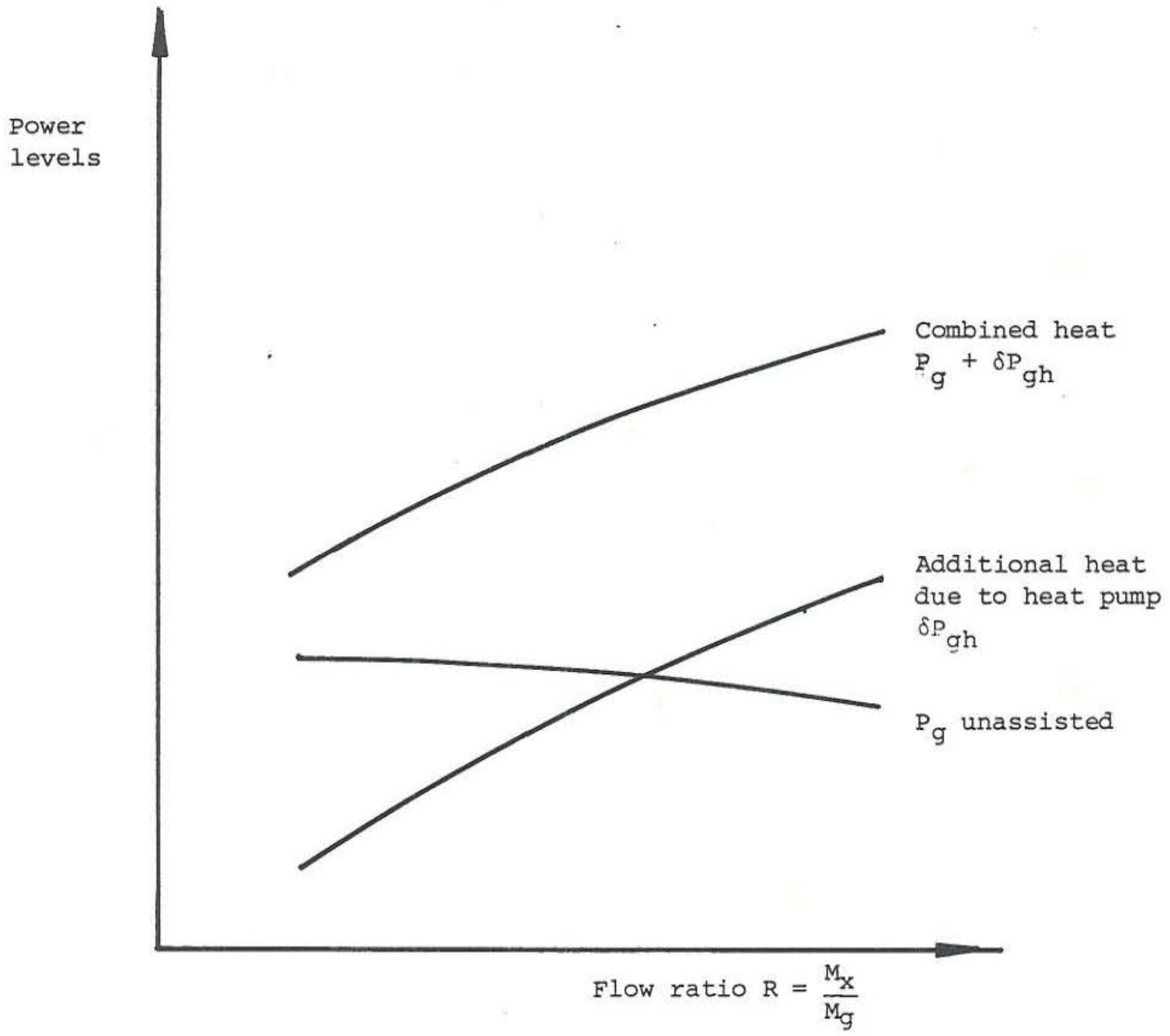
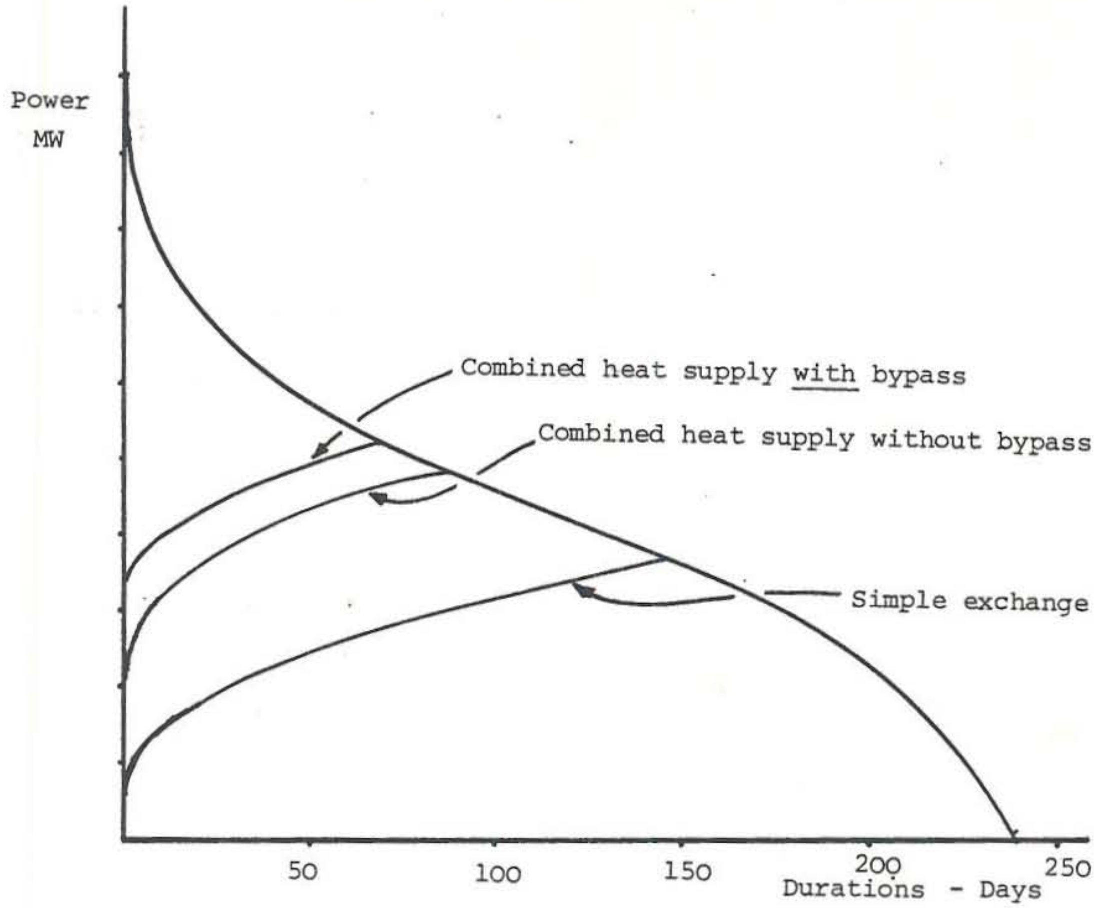
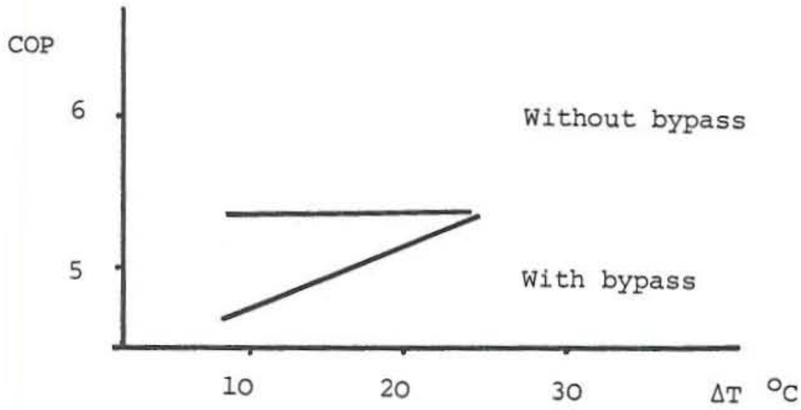


Figure 3.11 Effect of Bypass Connection on Heat Pump Assisted Layout



COP variations with demand



Total demand 24900 MWh

Q_{gh} without bypass = 19600 MWh
coverage = 78.7%
Q_{gh} with bypass = 21000 MWh
coverage = 84.3%

Heat pump performance

Temperature 'stretch'

$$\theta = T_{ho} - T_{co} \tag{7}$$

$$C_c = \text{function } \{\theta\} \tag{8}$$

These are 8 equations in 8 unknowns and can be solved iteratively.

It should be noticed that it is not necessary to specify the flow in the intermediate loop M_I in order to carry out the calculation of the power levels.

Figures 3.12 and 3.13 show the results of a set of calculations for a hyperthetical case. These show that as ΔT and T_{no} fall T_{co} falls slowly and T_{ho} falls quickly. Hence, the COP quickly rises to the maximum value and a condenser bypass must be operated to maintain the temperature 'stretch' at the minimum level required for effective operation. In this case the heat pump operates at constant and high COP's over the majority of the demand range.

3.6 Relative Advantages of Different Heat Pump Layouts

Figures 3.13 - 3.15 show the results of a series of calculations of heat pump power levels with the heat pump in both the 'Heat Pump Assisted' and the 'Heat Pump Only' layouts. Three different geothermal fluid temperatures have been taken 50, 40 and 35°C in order to investigate the way in which the relative advantages of the alternative arrangements depend upon fluid temperature.

The behaviour is very clear. Thus, at the higher fluid temperatures a significant energy transfer would be achieved by direct heat exchange alone. In these cases the advantage lies with the 'Heat Pump Assisted' arrangement. If the 'Heat Pump Only' arrangement is used with these temperatures then the amount of heat delivered cannot exceed $C_c w$ and this acts as a restriction on the level of heat transfer which is possible. With the lowest temperature fluid the heat transfer by simple exchange alone would be negligible. In this case, the advantage shifts to the 'Heat Pump Only' layout.

Figure 3.12 Heat Pump Only Layout
Variation of Operating Temperatures with Demand

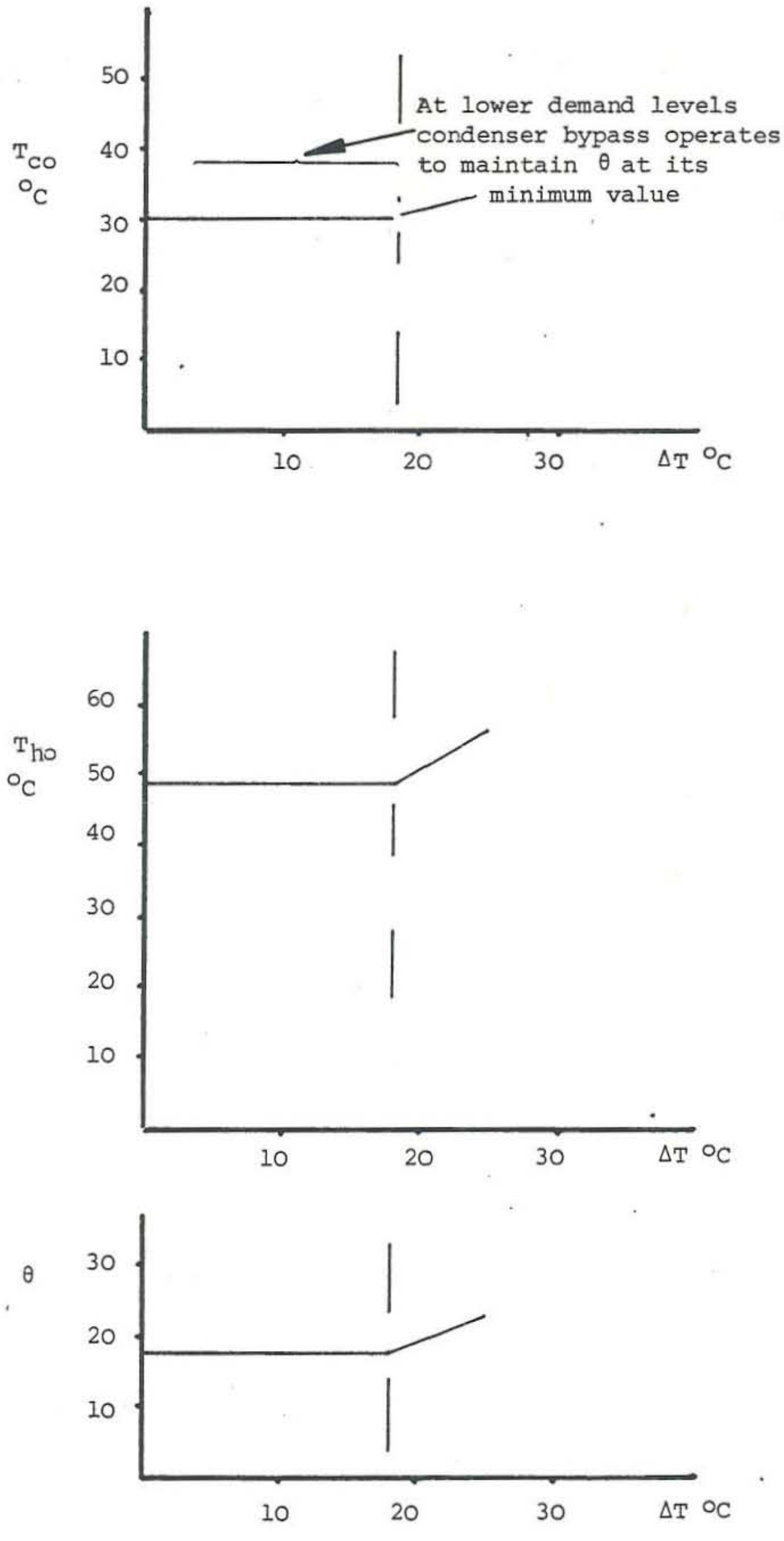
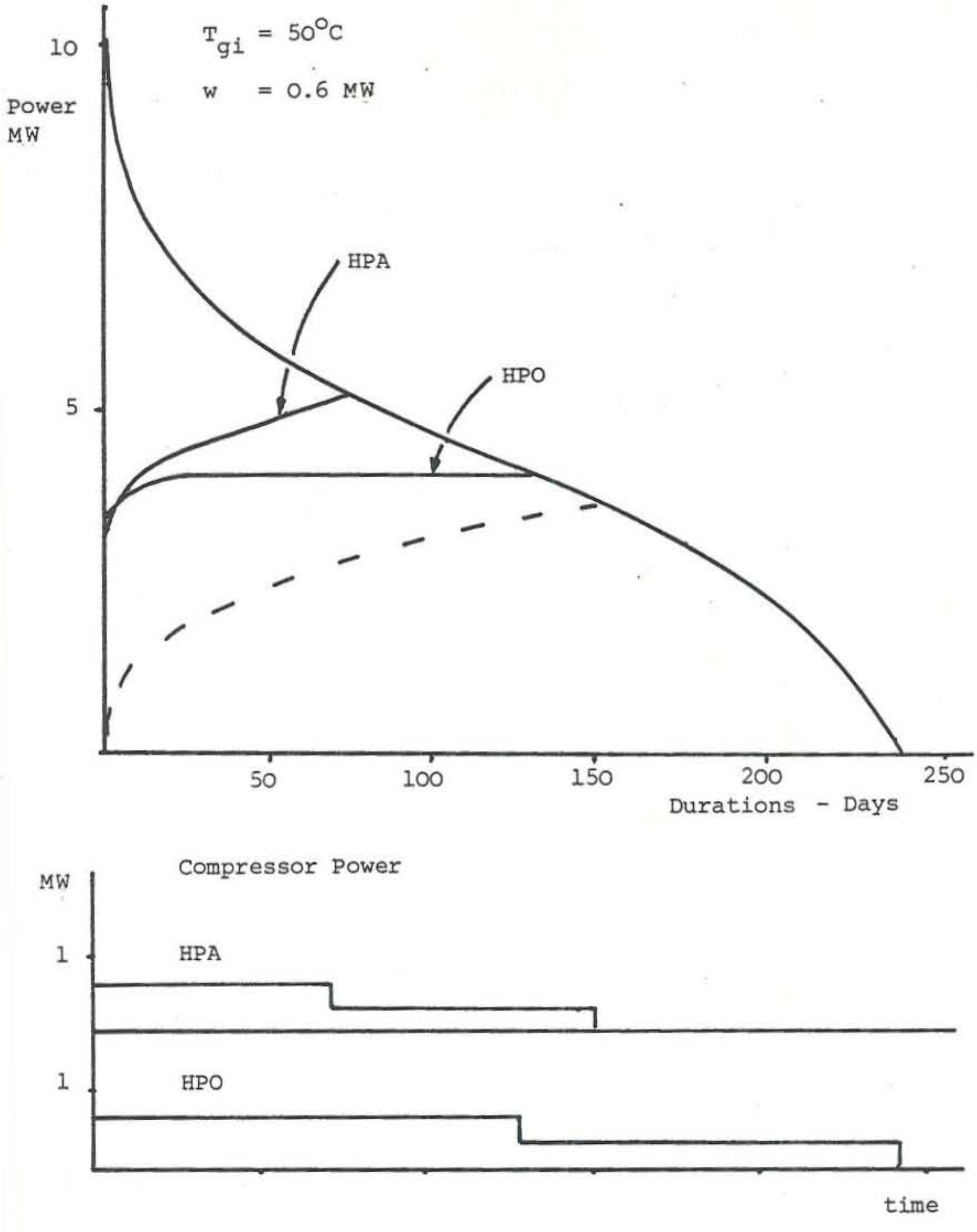


Figure 3.13 Comparison of Heat Pump Assisted HPA and Heat Pump Only HPO Layouts



Energy Balances

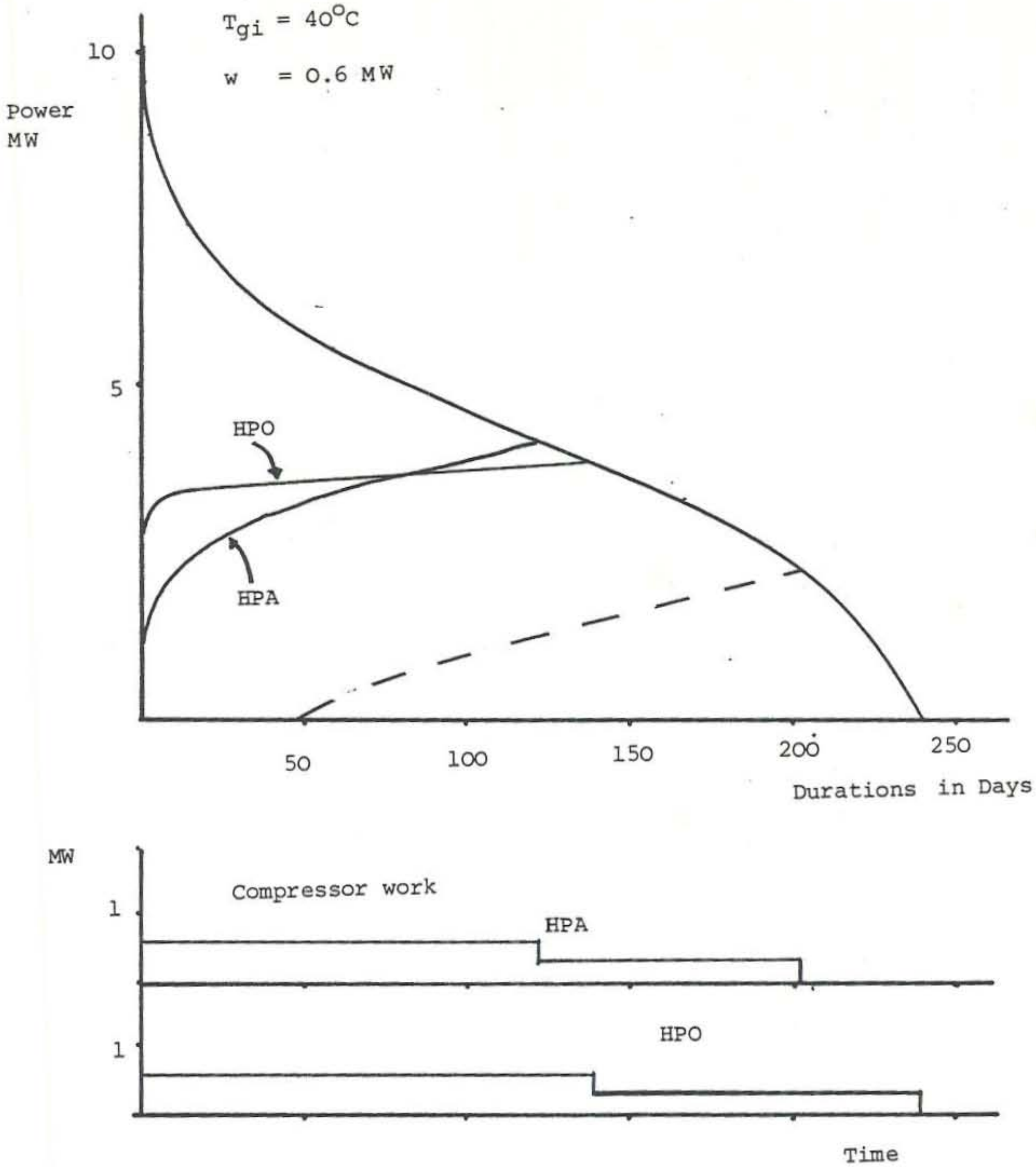
Q_g = 14550 MWh Simple exchange

Q_{gh}(HPA) = 20952 MWh) Heat pumps

Q_{gh}(HPO) = 19176 MWh)

The heat pump assisted layout delivers more heat and requires less compressor work.

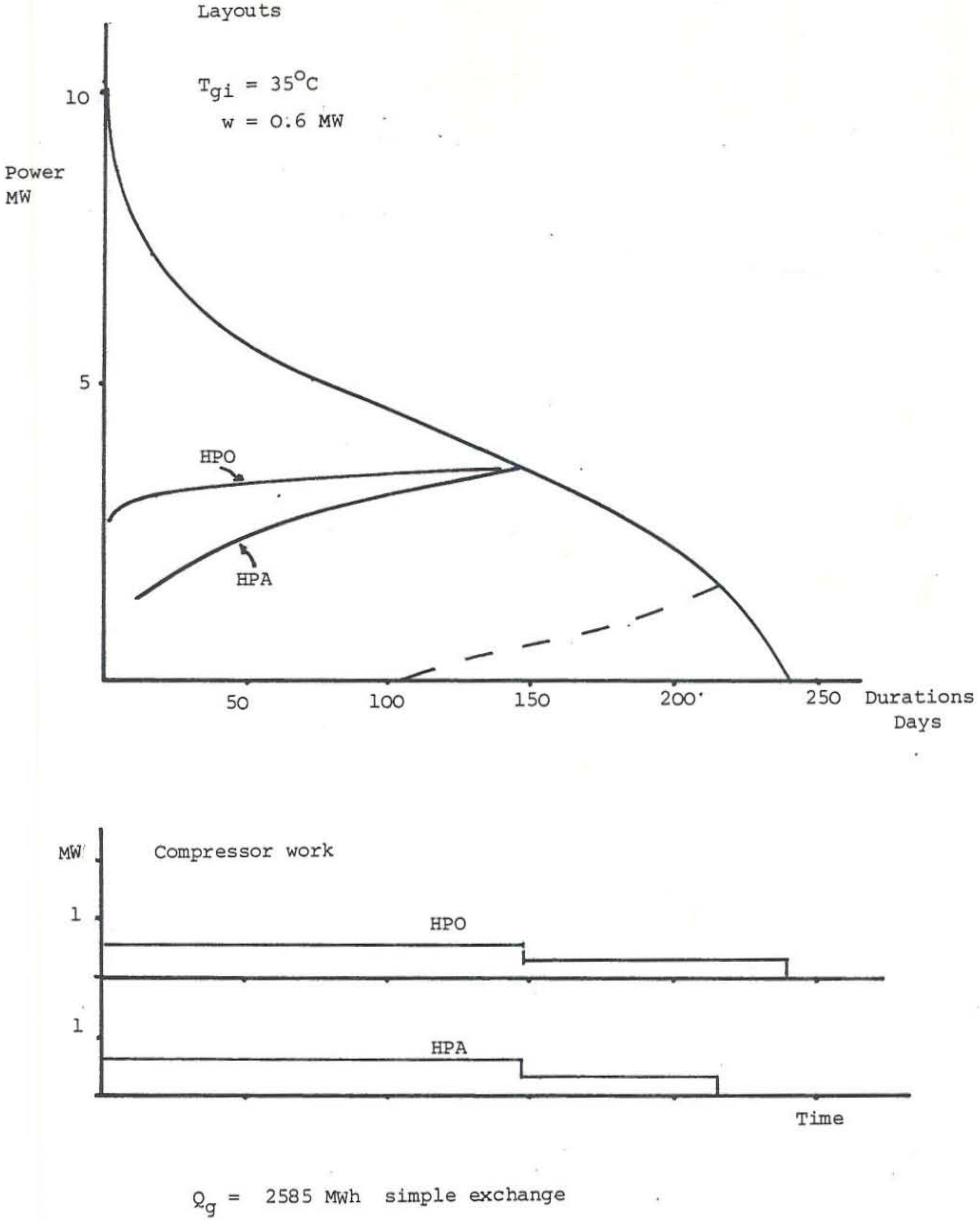
Figure 3.14 Comparison of Heat Pump Assisted HPA and Heat Pump Only HPO Layout



Q_g = 5664 MWh simple exchanger
Q_g(HPA) = 16890 MWh)
Q_g(HPO) = 17808 MWh) heat pumps

The heat pump only layout delivers more heat

Figure 3.15 Comparison of Heat Pump Assisted HPA and Heat Pump Only HPO Layouts



Q_g = 2585 MWh simple exchange

Q_{gh}(HPO) = 17232 MWh) Heat pumps

Q_{gh}(HPA) = 14472 MWh)

The HPO arrangement delivers more heat

Under the assumptions which have been used in these calculations the dividing line is at about $T_{gi} \simeq 40°C$.

Thus:-

Above $T_{gi} = 40°C$ 'Heat Pump Assisted' layouts give better performance.

Below $T_{gi} = 40°C$ 'Heat Pump Only' layouts are better.

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Chapter 4 Economic Methods and Markets

4.1 Introduction

There are two areas of economic theory which are necessary to the understanding of the engineering economics of geothermal energy. These are the methods of assessment or methods of investment appraisal on the one hand and the economics of the markets for heating fuels on the other.

Any examination of published accounts of the (capitalist) economics of geothermal heating schemes shows that a confusing variety of different methods seem to be employed in different contexts. In fact, the methods of analysis, which simply rely on discounting to adjust for differences in the timing of payments, are universally applied in capitalist assessments. However, many different organisational contexts are possible which affect the way in which costs and earnings are accounted. For instance, if the organisation which is developing the project is subject to tax this will affect its cash 'flows'. Tax regulations are different in different countries and indeed frequently change. Hence it is not possible to set out a universal approach in this case. It is from institutional aspects such as these that the confusions mainly arise.

The earnings of a geothermal heating scheme depend upon the quantities of conventional fuel which are saved and also upon the value of this fuel. The value of the fuel saved depends upon the prices in the local market for heating fuels. These market aspects tend to be overlooked by geothermal engineers, however, they can be as important as reservoir conditions or scheme design in determining scheme economics. In particular, forecasts of the way in which fuel prices will develop over the lifetime of the scheme can be very important.

This chapter will examine these various aspects of applied economics and describe ways in which they can be used consistently to analyse the economics of geothermal heating schemes.

4.2 Methods of Investment Appraisal (Capitalist)

4.2.1 Basic Principles of Discounting

The value of money which may be paid to us in the future is not equal to the value of money which we hold today for two main reasons.

- Opportunity: delay in receiving the money means that we miss opportunities to spend and obtain the value of the money.
- Risk: the future is uncertain money which is expected in the future may not materialise.

These effects can be taken into account by adjusting the size of the payments to allow for different timings.

The simplest case is of an individual investing a sum of money 'P' today ('P' is the present worth or value) in the expectation that it will increase in value to 'F' in the future ('F' is the future worth or value). This is commonly taken into account by the payment of <u>interest</u>.

The future value after one year $F_1 = P(1 + r)$

after 'n' years $F_n = P(1 + r)^n$

The present worth $P = \dfrac{F_n}{(1 + r)^n}$

the payment 'F_n' expected in 'n' years time has been discounted by $\dfrac{1}{1 + r}$ 'n' times. 'r' is the discount rate (equivalent to the interest rate).

This is the basic mathematical calculation in discounted cash flow analysis. The term $\dfrac{1}{(1 + r)^n}$ is the <u>discount</u> factor.

When analysing the economics of energy investments a common calculation is the discounting of a series of payments. If F_1, F_2, F_3, ... F_n is a series of payments which are made at the end of each year for a total of n years, then the total present worth of these payments

$$P = \frac{F_1}{(1 + r)} + \frac{F_2}{(1 + r)^2} + \ldots\ldots \frac{F_n}{(1 + r)^n}$$

$$= \sum_{j=1}^{n} \frac{F_j}{(1 + r)^j}$$

In the simplest case, when the payments are all equal to a constant annuity A,

$$P = A \sum_{j=1}^{n} \frac{1}{(1 + r)^j}$$

$\sum_{j=1}^{n} \frac{1}{(1 + r)^j}$ is the inverse of the capital recovery factor CRF(n, r).

A = P x CRF (n, r).

The capital recovery factory is an important quantity in capitalist investment appraisal. If an amount 'P' is invested today then earnings of the amount P x CRF (n, r) are required every year for 'n' years to recover the capital and earn interest at the rate 'r'. Or, consequently, constant annual payments 'A' can be converted to a present worth 'P' by dividing by the capital recovery factor 'CRF (n, r)'. Tables of capital recovery factors for different values of 'n and r' are published in standard texts (Ref. 4.1). Values can be calculated using

$$\text{CRF } (n, r) = \frac{r(1 + r)^n}{\{(1 + r)^n - 1\}}$$

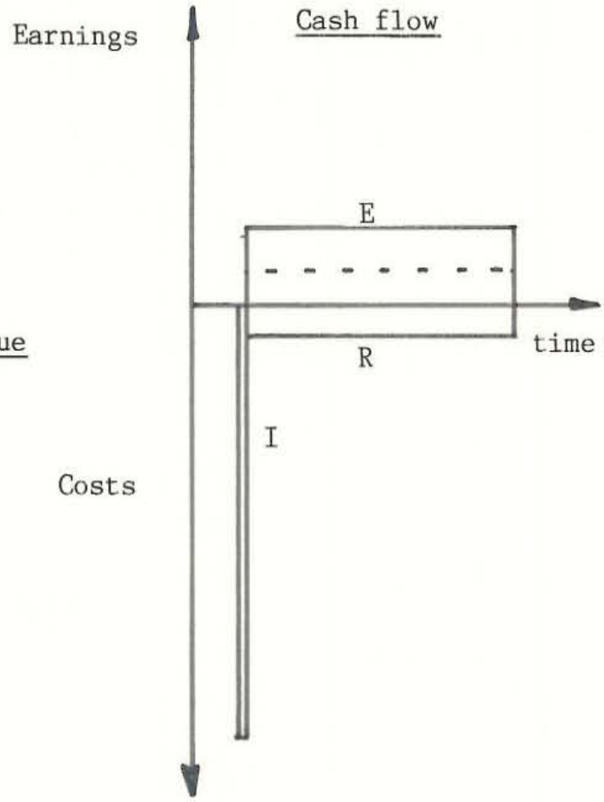
4.2.2 Comparison of Costs and Earnings

The 'cash flows' of any project consist of a series of earnings (positive payments) and costs (negative payments) over the lifetime of the project. The basic problem of investment appraisal is to adjust these cash flows to some equivalent basis so that they can be compared with each other or with those of alternative projects. There are a number of ways in which this can be done and a variety of indices can be formulated which measure aspects of the economic performance of the project. Consider a scheme which requires an initial investment 'I', produces 'q' units of heat per annum, has constant annual running costs 'K' and constant earnings 'E' over n years, see Figure 4.1. Then methods of comparison are:-

Figure 4.1 Investment Appraisal Indices

Financial details

Discount rate (r) 6%
Scheme life (n) 25 years
Investment (I) £1.6 x 10^6
Earnings (E) £0·28 x 10^6/year
Running costs (R) £0·12 x 10^6/year
Units produced (q) 70,000 GJ
CRF(n, r) 0·0782



a) Calculation of Net Present Value

$$NPV = \frac{E - R}{CRF\ (n,\ r)} - I$$

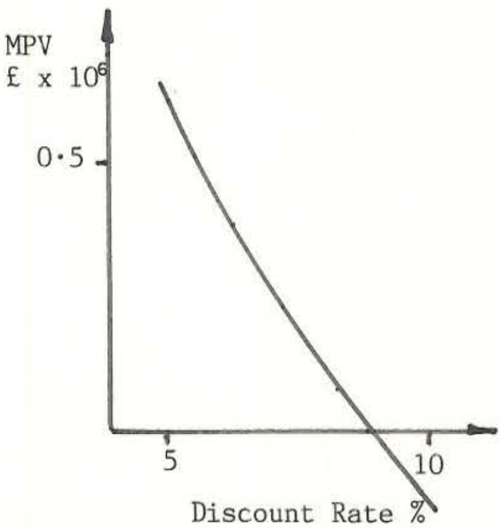
$$= 0{\cdot}45 \times 10^6$$

b) Discounted Unit Cost

$$DUC = \frac{R + CRF\ (n,\ r)I}{q}$$

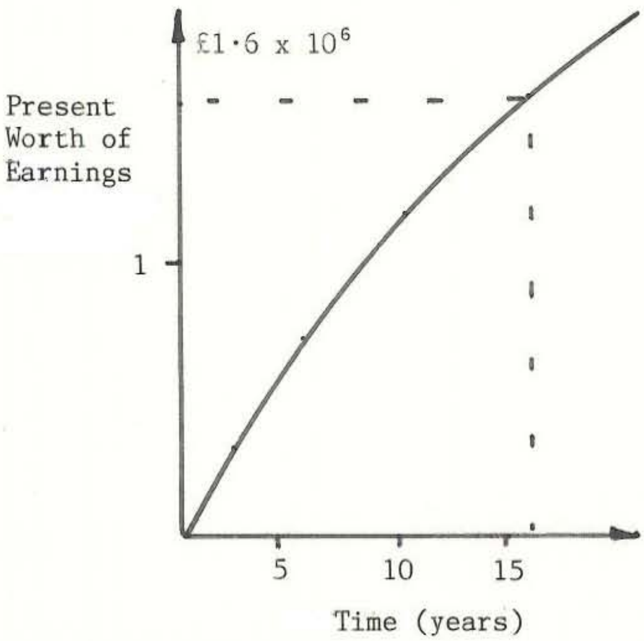
$$= 3{\cdot}5\ £GJ^{-1}$$

c) Internal Rate of Return



IRR = 8·9%

d) Discounted Payback Time



DPT = 16·75 years

Net present value (NPV) at discount rate r

Present value of earnings $= \frac{E}{CRF(n, r)}$

Present value of running costs $= \frac{K}{CRF(n, r)}$

Net present value NPV $= \frac{(E - K)}{CRF(n, r)} - I$

Discounted unit costs (DUC) at discount rate r.

Present value of all costs $= \frac{K}{CRF(n, r)} + I.$

If the heat is sold at price 'P' then E = Pq and the present value of earnings $= \frac{Pq}{CRF(n, r)}$.

When the present value of earnings equals the present value of costs the price 'P' is equal to the discounted unit cost 'DUC'.

$$DUC = \frac{K + I \times CRF\ (n, r)}{q}$$

This is also called the minimum revenue requirement approach. It is equivalent to the calculation of the level of revenue which gives zero net present value.

Internal rate of return (IRR)

This is the calculation of the discount rate which adjusts the costs and the earnings so that the net present value is zero. There is no analytical way of calculating this rate. Normally, increasing the discount rate will reduce the net present value of a project. Hence, by progressively increasing the discount rate and recalculating the net present value the discount rate for which NPV = 0 can be determined numerically.

i.e. by plotting a graph of $\frac{(E - K)}{CRF(n, r)} - I$ for different values of r.

Discounted payback time (DPT)

The time required to pay back the initial investment can be determined numerically by calculating the year by year increase in present value of the net earnings.

The accummulated present value of net earnings after year T

$$= \frac{E - K}{CRF(T, r)}$$

$$\text{if } \frac{E - K}{CRF(T, r)} < I < \frac{E - K}{CRF(T + 1, r)}$$

then the discounted payback time lies between T and T + 1.

None of these indices alone gives the correct way of appraising a project. They each highlight different aspects of the financing. They will be given different weightings by different organisations. Major corporations may accept internal rates of return of 15%, whereas smaller operators will require 25% and above. Small operators will be interested in schemes with small net present values - $\$5 \times 10^6$ while large corporations prefer investments which have net present values in the region of $\$50 \times 10^6$ (Ref. 4.2).

4.2.3 Investment Appraisal in Different Contexts

The cost and earning streams of a project may be formulated in different ways depending upon the nature of the appraisal or the type of organisation involved in the project. Three general approaches can be identified in the literature. The simplest approach is a strictly economic approach which considers the whole project. There are also two approaches which consider details of project financing rather than overall economics. All three are illustrated in Figure 4.2.

The economic or 'whole project' approach

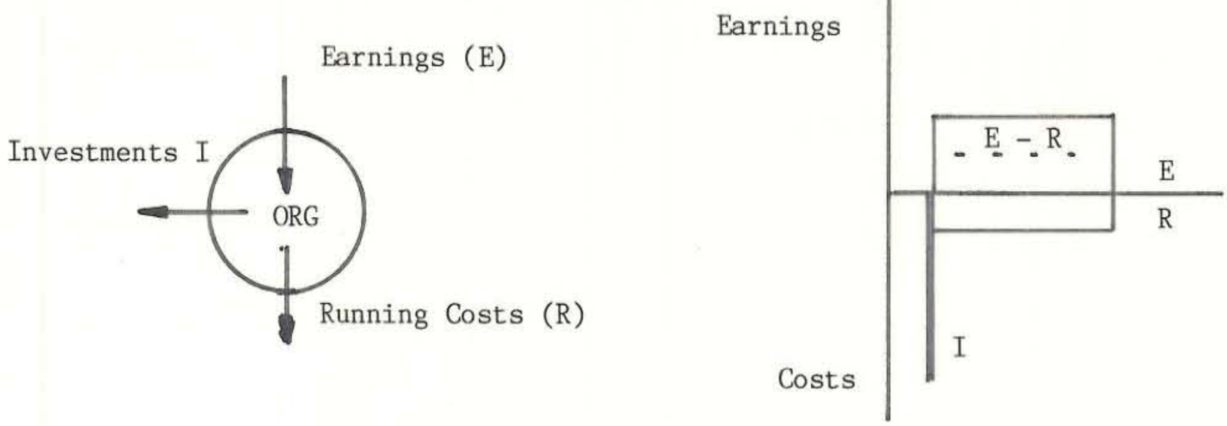
This is the simplest approach. No distinction is made between the organisations involved in the scheme. Hence there is no division of investment costs or of the earnings. Although this is a theoretical case, the results give an indication of the overall economics of the whole project unclouded by the effects of financing provisions: Some results for a hyperthetical example are given in Table 4.1.

Financial case (1) - non-taxable organisation

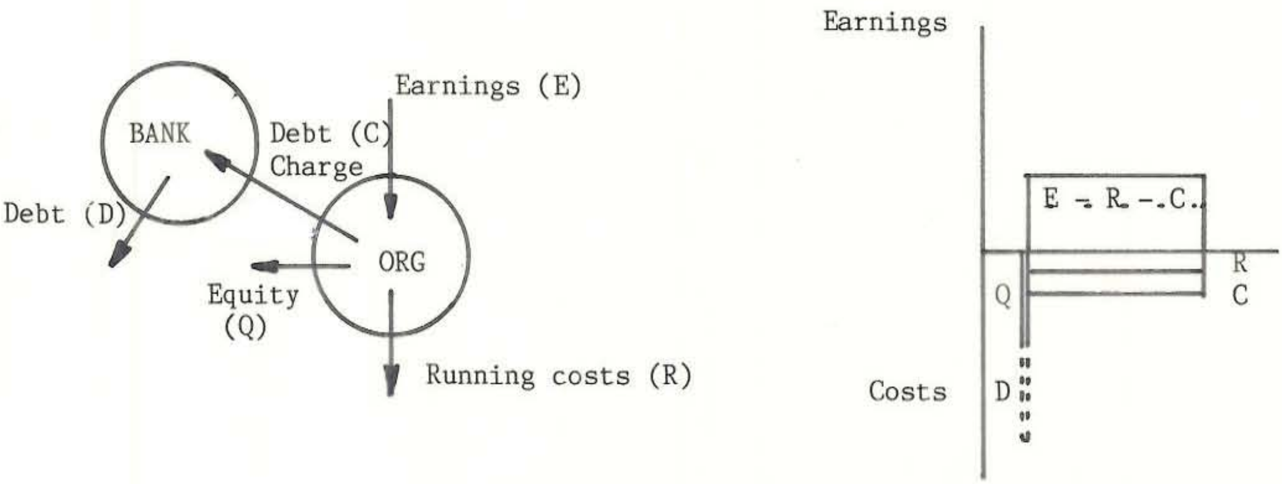
In this case the assessment is carried out from point of

Figure 4.2 <u>**Investment Appraisal in Different Contexts**</u>

a) <u>Economic/Whole Project Approach</u>



b) <u>Financial Case (1) Non-taxable Organisation</u>



c) <u>Financial Case (2) Taxable Organisation</u>

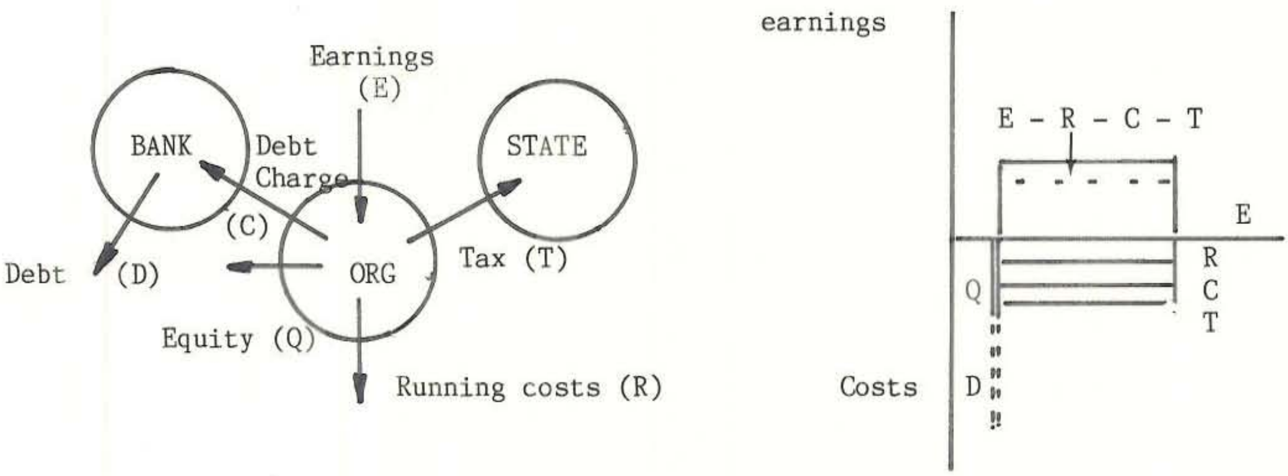


Table 4.1 **Effects of Financing Context on Scheme Appraisal**

Financial Details	Whole Project	Financing Cases	
		(1) Non-Taxable	(2) Taxable
Discount Rate (%) r	6	6	6
Debt Interest Rate (%) i	-	5	5
Scheme Life	25	25	25
Capital Recovery Factor CRF(n,r)	0·0782	0·0782	0·0782
CRF (n,i)	-	0·0709	0·0709
Tax Rate (%) τ	-	-	0·3
Investment (£) I_o	$1{\cdot}6 \times 10^6$	$1{\cdot}6 \times 10^6$	$1{\cdot}6 \times 10^6$
Debt (£) D	-	$0{\cdot}8 \times 10^6$	$0{\cdot}8 \times 10^6$
Equity (£) Q	-	$0{\cdot}8 \times 10^6$	$0{\cdot}8 \times 10^6$
Running Costs (£) R	$0{\cdot}12 \times 10^6$	$0{\cdot}12 \times 10^6$	$0{\cdot}12 \times 10^6$
Debt Charges (£) CRF (n,i) D	-	$0{\cdot}057 \times 10^6$	$0{\cdot}057 \times 10^6$
Annual Tax (£) T	-	-	$0{\cdot}0264 \times 10^6$
Number of Units produced (GJ) q	70,000	70,000	70,000
Gross Earnings (£) E	$0{\cdot}28 \times 10^6$	$0{\cdot}28 \times 10^6$	$0{\cdot}28 \times 10^6$
Indices			
Net Present Value NPV (t)	$0{\cdot}45 \times 10^6$	$0{\cdot}52 \times 10^6$	$0{\cdot}18 \times 10^6$
Discounted Unit Cost DUC (£GJ^{-1})	3·5	3·42	3·8
Internal Rate of Return IRR %	8·9	12·1	8·3
Discounted Pay-back Time DPT yrs	16.75	10·9	16·5

view of the organisation responsible for the management of the project. This organisation finances the investment partially from its own capital resources (the equity contribution) and partially from a fixed interest loan (the debt). This loan may be raised from the banks and/or by the sale of bonds. Figure 4.2 indicates the organisations cash flows. These differ from the whole project case in that the organisations investment is reduced but its running costs are increased because it is required by repay the loan with interest (the debt charges). The viability of the investment from the point of view of the organisation is assessed by comparing the net revenue, after subtracting the debt charges, with the equity investment. The effect on the indices is shown in Table 4.1. It is assumed that the investment has been divided equally between debt and equity and that the interest rate on the debt - which is secured against the oranisations assets - is lower than the discount rate for the equity. The equity contribution is unsecured and hence is at 'risk'. The indices are improved. In effect, the organisation is increasing its earnings by being able to borrow money at low interest. Some public authorities may be able to finance all of the investment in this way and this is highly advantageous.

Financial case (2) - organisation subject to tax

This case differs from the second case in that the state participates by taxing the net revenues which remain after allowable running costs and debt interest have been deducted from gross earnings, and after allowance has been made for the depreciation of equity assets. Normally, even with constant running costs and earnings, tax liabilities will vary from year to year because the proportions of debt interest may change from year to year and depreciation regulations may give varying allowances. These calculations can be very complex and may dominate the assessment in these cases. Figure 4.2 shows how the cash flows may change by applying simple rules which give constant allowances and a constant tax liability. Table 4.1 shows how the indices change. Taxation represents an additional cost and the result is to reduce the net earnings from the equity investment.

Partnerships between two operators can complicate the assessment further. An example of this is the Boise City geothermal heating scheme in the U.S.A. Here, the wells are owned by a drilling partnership which sells the fluid to the operators of the district heating network (the City) at an agreed price. The City have also guaranteed the drilling partnership a minimum volume of sales. The two operators are each responsible for about half the costs but the agreements divide the earnings unequally. 57% go to the drilling partnership and 43% to Boise City. Hence, the NPV and the IRR of the drilling partnerships investment are higher than those of the City's investment. Thus, a scheme can appear differently to the individual participants depending upon their respective costs on earnings, and therefore, in this case their skill in negotiating agreements.

State support

The state can also participate by supporting geothermal developments with grants and cheap loans. In France, the state operates a scheme which indemnifies developers against risks of dry wells or wells which are poor producers of fluid. This removes the major risk from the developers and enables them to proceed with projects with IRRs which are lower than those that they would require if they were to bear all of the risks. Also, many French geothermal developments are carried out by public housing authorities and in these cases the improvements attract significant grants. For twelve French schemes on which data was available, grant entitlements ranged between 3% and 30% with an average of 20% of the investment. These grants have the simple effect of reducing the organisations investments.

In the U.S.A. the government has for some periods of time employed a policy of supporting some renewable energy developments with the tax credits. This is very attractive for higher tax paying organisations and individuals. The result is to reduce the real cost of any investments which they make in qualifying projects.

Clearly, the complexity of the calculations in scheme assessments increases markedly in going from the simple whole project or economic approach to the detailed consideration of financing. Government support in the form of grants, cheap loans or tax allowances makes the calculations much more complex still and also can completely alter the assessment of the scheme. In these cases, the results of the scheme assessment may depend more upon the financial details than upon the engineering optimisation of the scheme. The whole project/economic approach on the other hand takes no account of the details of financing and the results will strongly reflect the engineering optimisation of the scheme. For engineering economic studies, the use of the whole project/economic approach is strongly recommended for the main optimisation studies. Financing details should only be included at a later stage when actual commercial implementation is being considered. The whole project/economic approach has been followed to produce the assessments given in this pamphlet.

4.3 Markets for Geothermal Heat

4.3.1 General Considerations

The size of actual markets for geothermal heat can only be determined by carrying out assessments with a knowledge of particular resource conditions and in relation to the heating loads which exist in specific areas. Such studies have indeed been carried out, (Ref. 4.3). Market potential on the other hand can be assessed from a knowledge of the nature and structure of the existing market for heating fuels and from some knowledge of the expected levels of geothermal costs.

There are two aspects of the existing market which must be defined before the geothermal potential can be specifically determined.

Market size

Because of the low temperature nature of many geothermal resources, which makes it uneconomic to transport the fluids over significant distances, the size and nature of the accessible heating loads can constitute a major limiting factor on market potential. Temperature compatibility between the geothermal resource and the heat load is always important and the lack of compatible heat loads in the vicinity of a resource will effectively sterilise the resource.

There have been many studies of the nature of heating loads to determine the characteristics of different applications. The 'Lindal' diagram which lists heating applications arranged in order of increasing temperature is well known. It shows that the temperatures required for space heating, greenhouse heating and fish farming are characteristically low. Figure 4.3, which is taken from (Ref. 4.4), shows the size of heating energy demands in the United States divided into a series of temperature bands. It is obvious from these figures that because of its size and temperature characteristics, space heating represents an important market for geothermal heating. In addition to general studies of this type, ther have been a number of specific studies of the heating loads which exist in particular areas. For instance, Johns Hopkins University (Ref. 4.5) have investigated the residential, commercial and agricultural energy demands and the industrial process heat demands of the North Atlantic Coastal Plain in the U.S. in order to define markets for geoethermal energy. Also, Techint (Ref. 4.6) have carried out a similar study of Sardinia.

In summary, only a particular portion of the existing heating market in any region is suitable for geothermal heating. This consists of those heat loads which have the following characteristics:

- low temperature
- high density
- close proximity to the resources.

The critical conditions governing these characteristics will depend upon the details of the resource conditions and upon the costs in various locations.

Prices of fuels and costs of delivered heat

A major aspect of existing heating markets which determines geothermal potential relates to the price levels of the competing fuels. These determine the costs of delivered heat and it is these costs

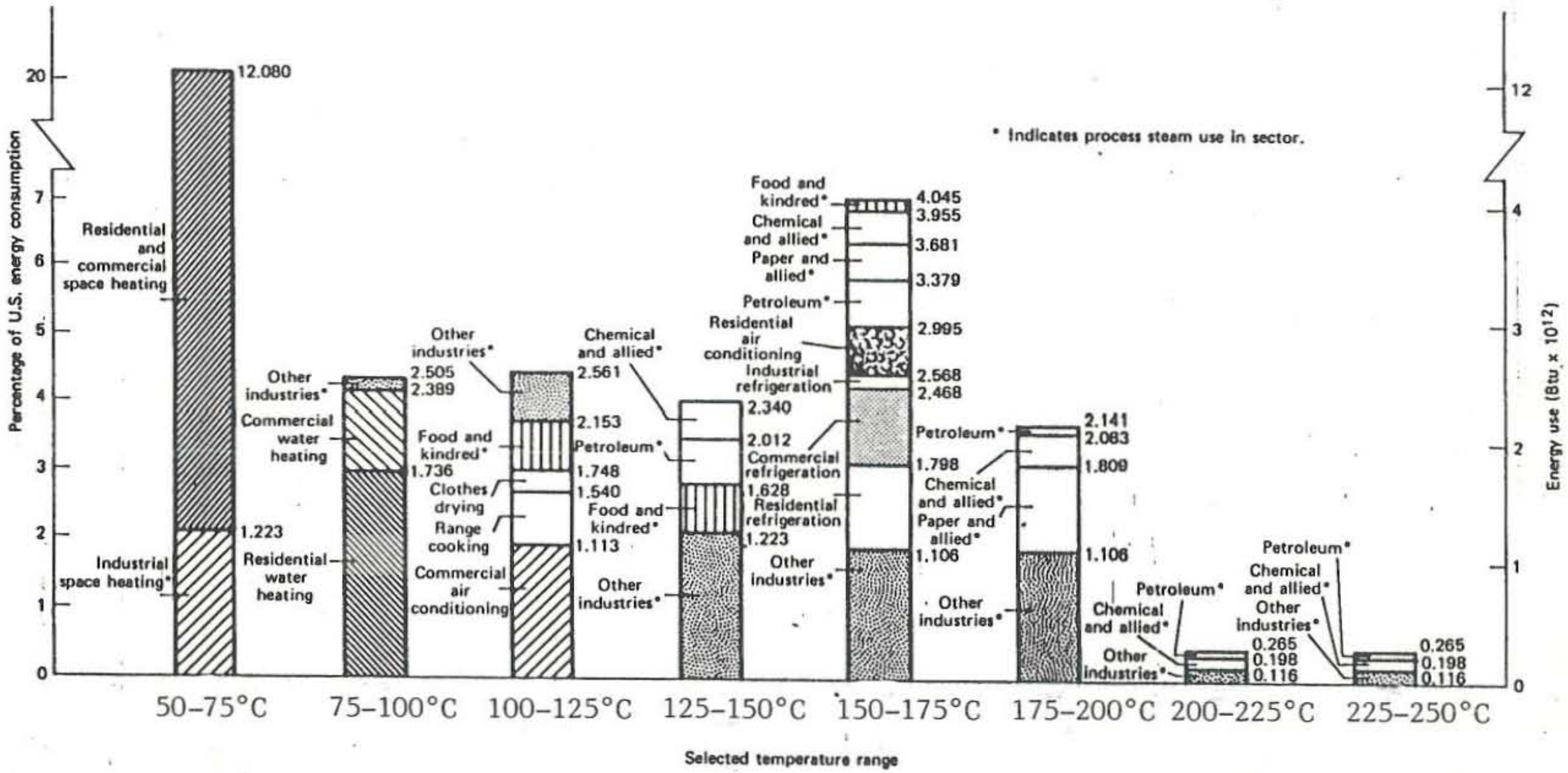


Figure 4.3 U.S. Estimated heating energy use by temperature range.

which are avoided by using geothermal heat and which consequently determine the earnings of the development. Obviously, to be economically viable the costs of the heat supplied by the geothermal facilities must be lower than the costs of the cheapest alternative heating method. This may be an existing heating system or it may be some proposed, newly built, system.

In broad terms, there are two contexts in which this comparison can be made:

- retrofit
- newbuilt or refurbishment.

In the retrofit situation, an existing and otherwise satisfactory heating system is being assessed to determine whether modification to include a geothermal component would give lower costs. The alternative to geothermal heating is to leave the system alone and to continue to consume the existing fuel. The only costs which would be avoided by the geothermal scheme are the fuel costs and the unit costs which can be compared with the geothermal unit costs are simply calculated from the price of the fuel, its calorific value and the burning efficiency of the boiler which is being used. When an entirely new heating system is being installed in a new building or an antiquated heating system is being replaced in an existing building, geothermal heating would be considered along with a number of alternative systems using a variety of alternative fuels. The costs which would be avoided by the geothermal development would include, in this case, some capital costs associated with the new alternative systems as well as the fuel costs.

In general, the economics of new build/refurbishment situation are more favourable than those of the retrofit situation because additional capital costs are avoided. Also, in the newbuild situation, there is greater flexibility to design the heating system to make best use of the geothermal fluid. However, the newbuild or refurbishment situation offers greater competitive alternatives and while the geothermal scheme may be cheaper than some options it may not be the cheapest of all. For example, consider refurbishing the individual heating systems of some existing buildings by installing a geothermal district heating scheme. The geothermal heating scheme may be cheaper than the existing heating scheme but it might not be cheaper than a fossil fuel fired district heating scheme which uses a different, cheaper fuel.

Geothermal developments will proceed only slowly if the special circumstances of newbuild developments are required to offer opportunities for viable schemes. Significant geothermal developments will only be possible by retrofitting. Thus, in order for there to be chances of significant market penetration the geothermal heat must be cheaper than the heat produced by the dominant fuel in existing applications.

Heating markets vary significantly from country to country and also within countries in a number of ways.

- The prices of the fuels can vary
- Different fuels will dominate different markets
- Tariff structures can be very different, affecting the prices which are charged to different types of user
- Prices will develop over time in different ways.

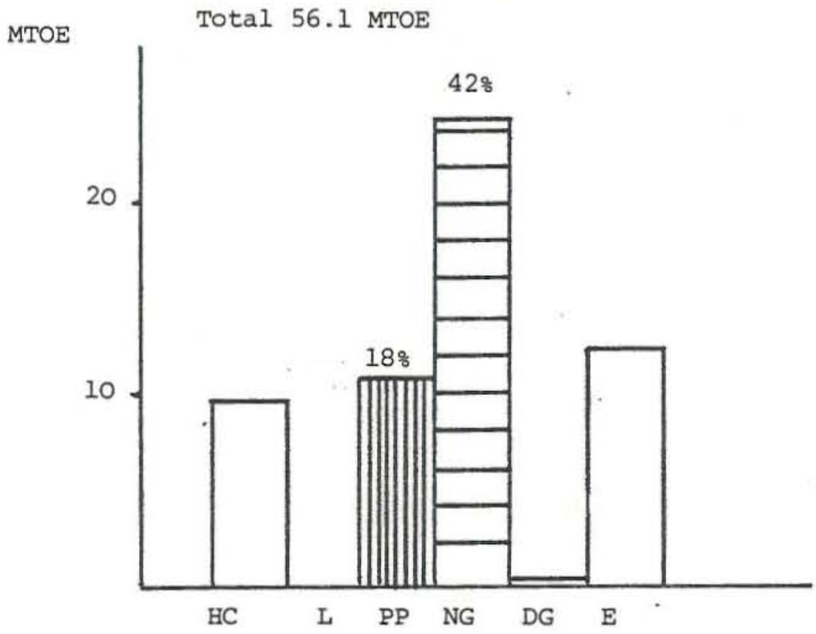
There are no simple general guides which can be given to market conditions and errors can be made if it is assumed that the market conditions which exist in one location will also pertain in another. This is certainly true in moving from one European country to another and also when considering different locations in the United States.

4.3.2 Comparison of Domestic Heating Fuel Markets U.K. and France

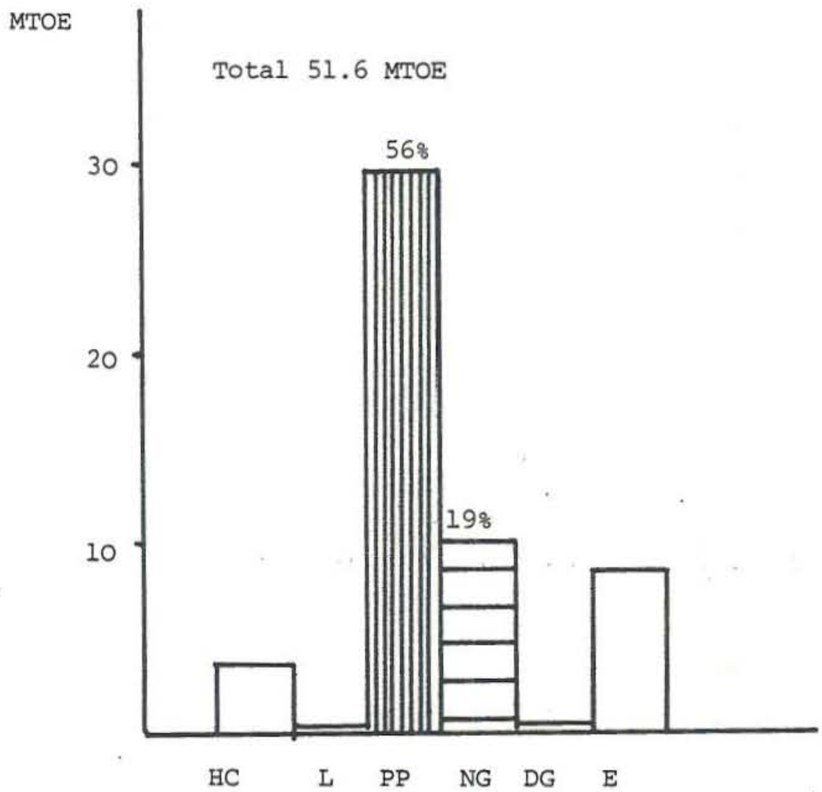
Figure 4.4 shows the shares which different fuels have of the U.K. and the French markets for domestic/residential heating fuels. Clearly, there are major differences. The French markets are dominated by petroleum products with natural gas playing a minor role. In the U.K. the markets are dominated by natural gas and petroleum products are less important than electricity. Developments in a range of French and U.K. fuel prices over the last decade or so are shown in Figures 4.5 and 4.6 respectively. In order to be able to compare the prices these have been expressed in terms of a price per unit of useful heat delivered. The French prices indicate that industrial natural gas prices are comparable with heavy fuel oil and coal, while domestic gas prices

Figure 4.4 Domestic Heat Markets - Shares by Fuel Type

a) United Kingdom



b) France



HC = house coal, L = lignite, PP = Petroleum Products, NG = natural gas, DG = derived gas, E = Electricity

Figure 4.5 <u>Unit Costs of Heat Delivered (FF Current) in France</u>

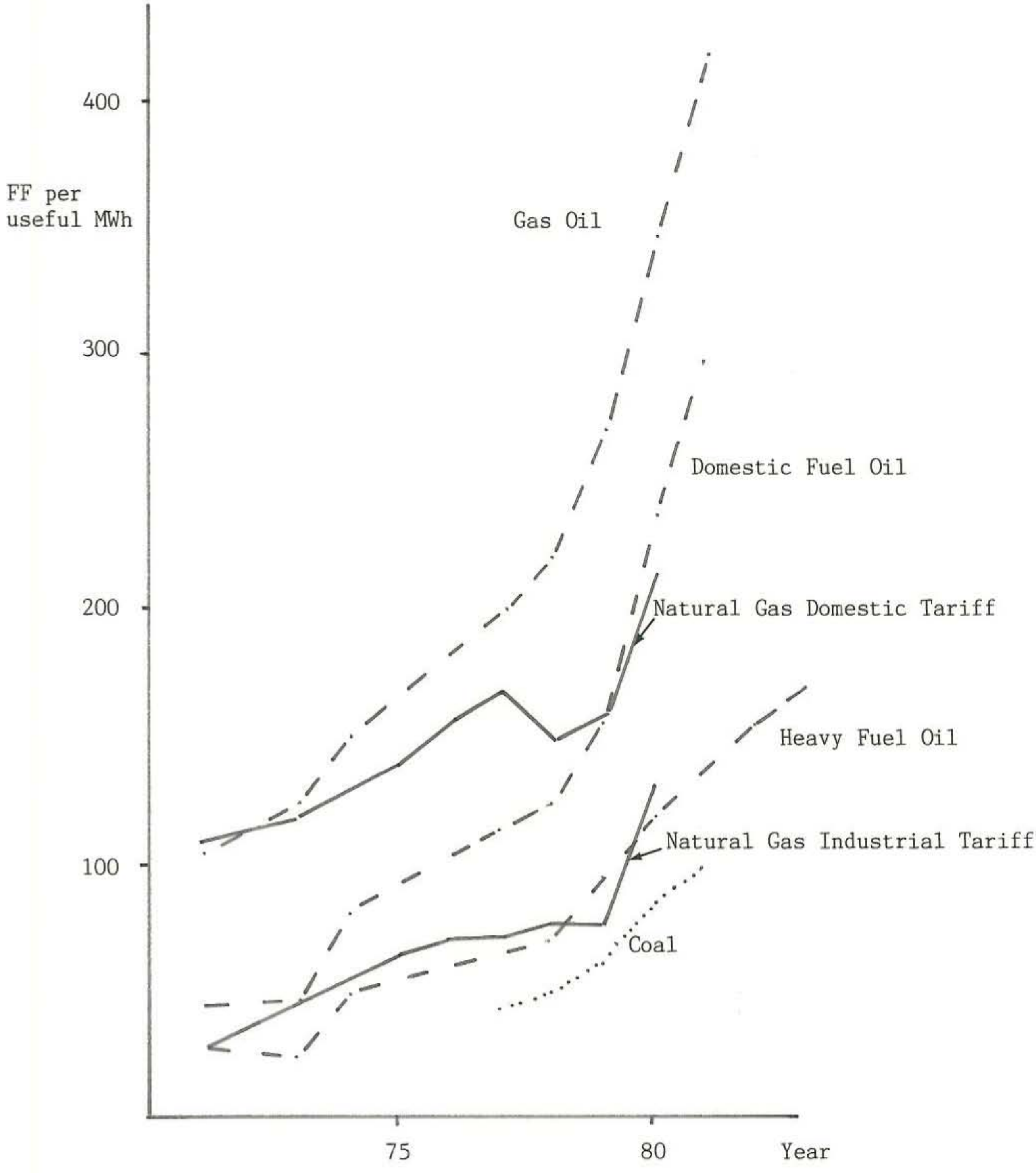
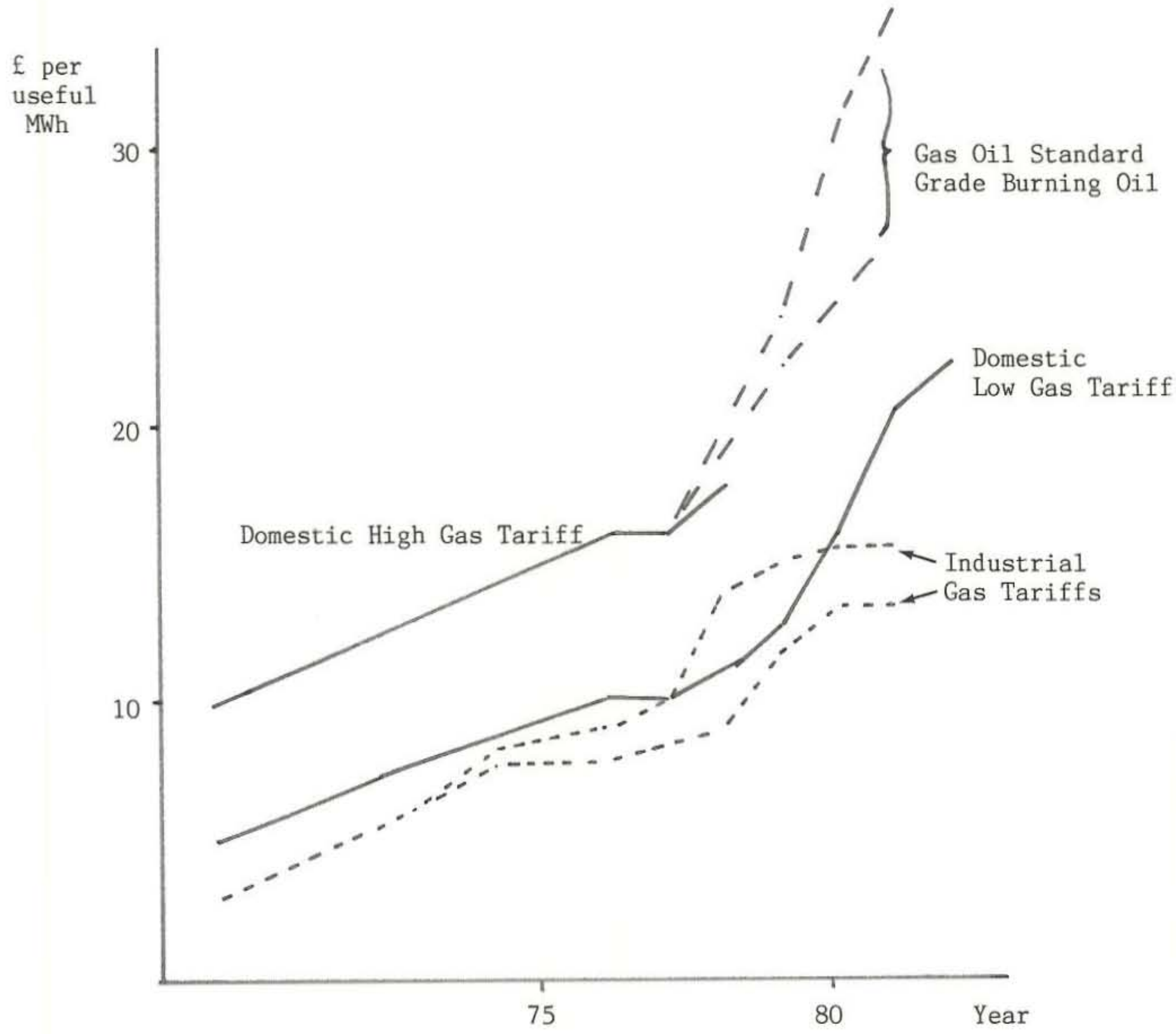


Figure 4.6 <u>**U.K. Delivered Heat Costs £ per Useful MWh (Current £)**</u>

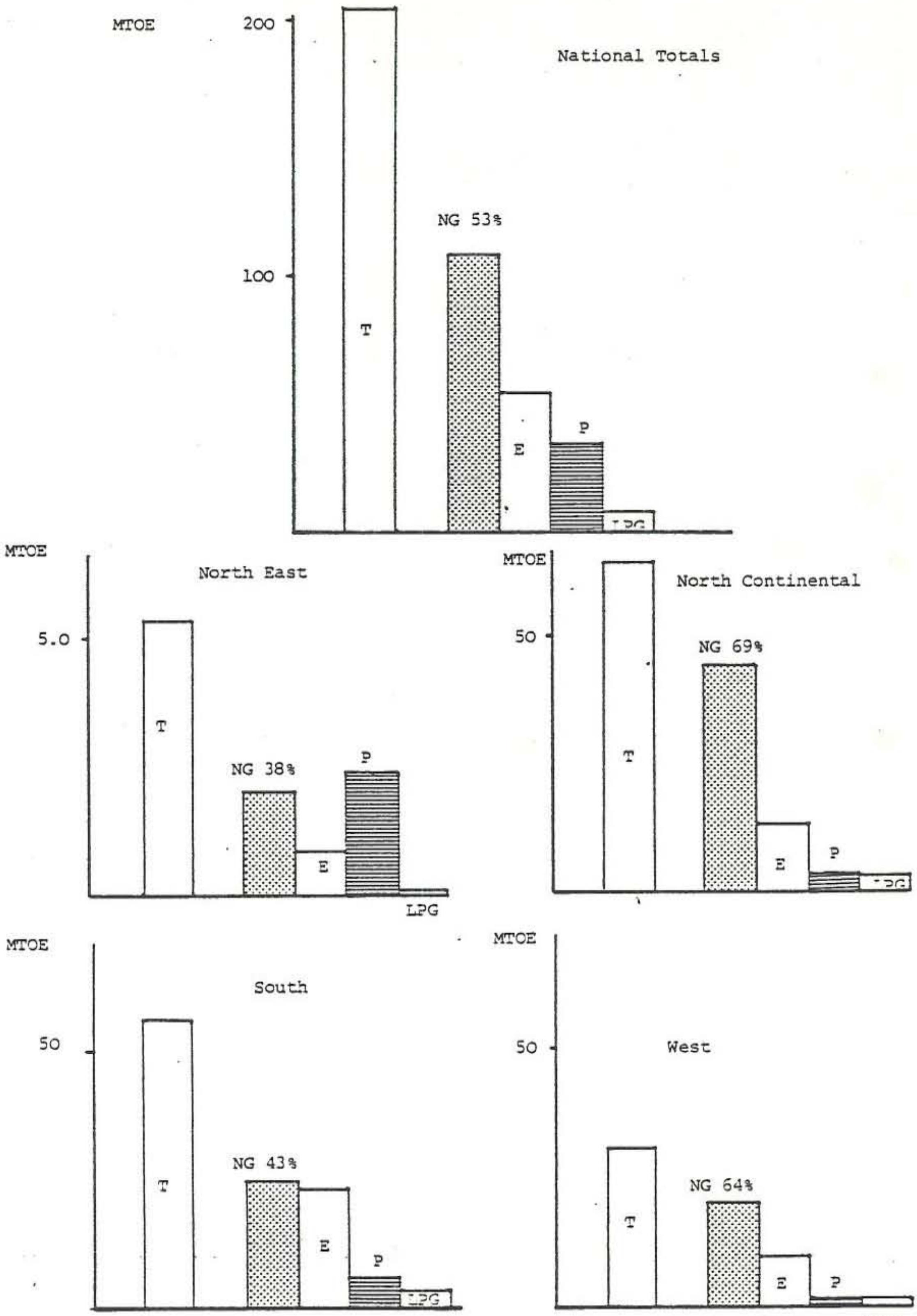


are comparable with the prices of domestic fuel oil. These price levels indicate no likelihood of increased penetration of natural gas into the domestic markets. In the U.K. the situation is very different. The U.K. gas supply network is much more extensive than the French network and also natural gas is priced differently. Thus, industrial gas prices have been broadly comparable with heavy fuel oil as in France, but domestic prices are significantly lower than those of domestic heating oils. Comparing U.K. and French domestic gas prices directly, using conventional currency exchange rates, indicates that U.K. domestic gas prices are significantly lower than French prices. These differences are very important for the prospects of geothermal heating applications in the two countries. In France average heating fuel prices are high and natural gas supplies are restricted; a market situation conclusive to geothermal development. In the U.K. average heating fuel prices are dominated by natural gas which is widely available. Average prices tend to be lower giving a market situation which is unfavourable to geothermal developments.

U.S.A.

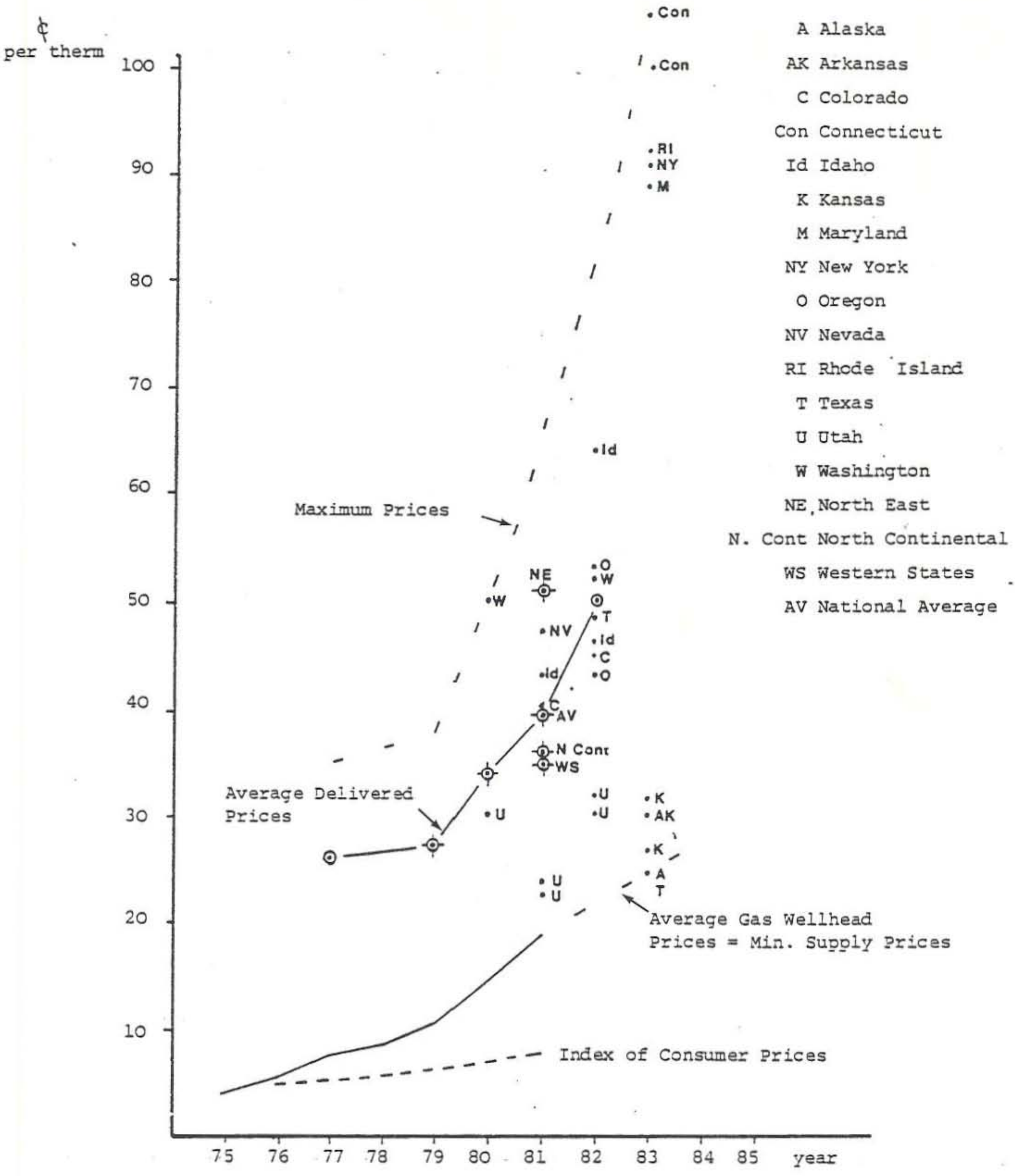
Figure 4.7 shows how the shares of different residential heating fuels vary across different regions of the U.S.A. The national totals are dominated by natural gas but there are large vaiations. Petroleum products dominate in the North Eastern States which are remote from natural gas fields. All other areas are dominated by natural gas with electricity also being important in the Southern States. Figure 4.8 shows a scatter of U.S. natural gas prices taken from a variety of sources. The North Eastern States of Connecticut, New York and Maryland have the highest prices and the major producing States of Alaska, Texas, Kansas and Arkansas have the lowest. Some of the Western States, for instance Washington and Utah, also have high prices. This variation in prices is important for the assessment of geothermal economics in the U.S.A. Schemes with good resource conditions may be uneconomic in Southern States because of low gas prices. On the other hand, in the North Eastern States,

Figure 4.7 U.S. Residential Energy Market



T = Total, NG = Natural Gas, E = Electricity (joule effect)
P = Petroleum, LPG = LPG

Figure 4.8 Residential Natural Gas Prices U.S. ¢ Current Per Therm



Average Figs. from U.S. Stats ⌖

Other Average Figs. ⊙

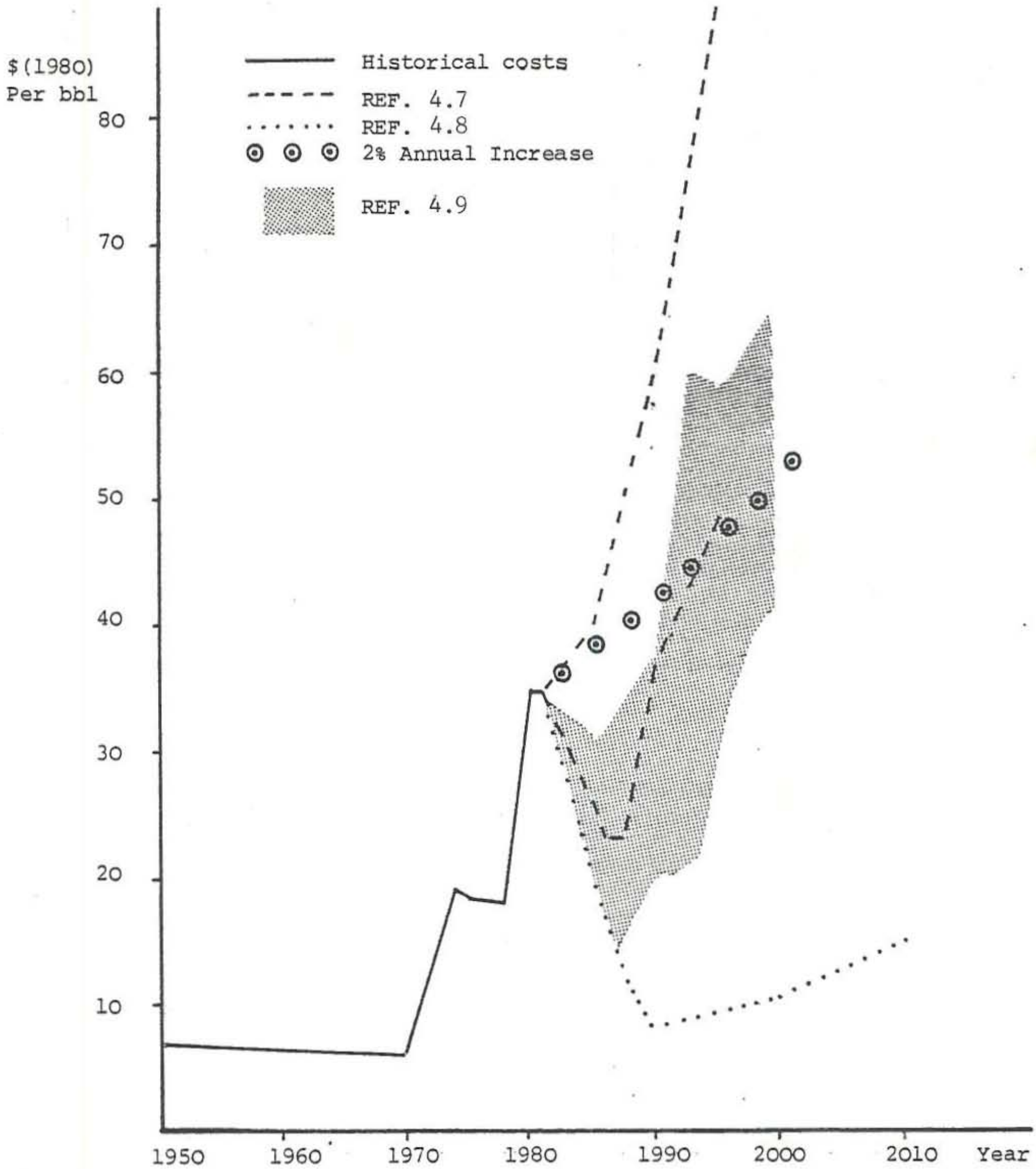
because of high fuel prices, geothermal schemes with poor resource conditions could be economically viable. This will be returned to later when discussing the economics of geothermal heating in the U.S.A.

4.3.3 Forecasts of Fuel Price Developments

Long-term national forecasts of fuel prices are usually based upon forecasts of world crude oil prices. It is usually assumed that the prices of petroleum products will be directly related to crude oil prices. The prices of other fuels are related to crude oil prices in secondary way. Thus, natural gas and coal, for example, can substitute for petroleum produces in many applications and an increase in the price of petroleum products will affect the market for the fuels and will have the general effects of driving up their prices.

Our understanding of the world oil market is very incomplete and forecasts regarding its development tend to be unreliable. Figure 4.9 shows a collection of forecasts of world oil prices each of which has been made in recent authoritative studies. During the mid and late 70's the dominant view was that physical depletion of reserves combined with growing demands would raise perceptions of the value of oil into the medium term future. As late as 1982 the U.S. Department of Energy were predicting (Ref. 4.7) that prices would rise steadily through the 80's and 90's. In France during the late 70's and early 80's the government required geothermal developers to assume a 2% annual increase in fuel prices in the assessment of all schemes submitted for support. While these views were widely held they were not unchallenged. Odell (Ref. 4.8) has consistently argued that estimates of crude oil reserves are systematically underrated by the oil companies and he maintains that with vigorous exploration and improved recovery physical depletion can be delayed until the 21st century. Consequently, in Odell's view, oil prices need not rise in the medium term. He forecasts low real prices for the remainder of the century. The falling prices of recent years provide us with clear evidence that the economic recessions of the 70's and intervention of new oil

Figure 4.9 Forecasts of World Oil Prices



producers has severely weakened the OPEC cartel. Forecasters now usually include these effects and indicate a short-term weakening of prices. However, eventual price recovery is also still a feature of most forecasts. Forecasts of fuel price changes can have marked effects on the assessments of a geothermal scheme.

Scheme assessment under changing fuel price conditions

Consider the simple example which has been analysed above. If the earnings are increasing at a compound rate of 'f' then the total present value of the earnings, 'E'

$$= E \sum_{j=1}^{n} \frac{(1 + f)^j}{(1 + r)^j}$$

normally $f < r$

Thus, we can define a new effective discount rate

$$h = \frac{1 + r}{1 + f} - 1$$

Then the total present value of the earnings

$$= \frac{E}{CRF(n,\ h)}$$

[If $r = 5\%$ and $f = 2\%$ $h = 2{\cdot}94\%$ $h \simeq r - f$]

Then the net present value NPV

$$= \frac{E}{CRF(n,\ h)} - \frac{K}{CRF(n,\ r)} - I$$

the effect of discounting on the earnings is reduced and the NPV is increased. If the earnings are reducing at a compound rate of 'f', then the total present value of the earnings

$$= E \sum_{j=1}^{n} \frac{1}{(1 + r)^j (1 + f)^j}$$

A new effective discount rate for the earnings can again be defined

$$K = (1 + r)(1 + f) - 1.$$

and the total present work of the earnings

$$= \frac{E}{CRF(n, k)}$$

[If r = 5%, f = 2%, R = 7·1%, $k \simeq r + f$]
and the net present value NPV

$$= \frac{E}{CRF(n, k)} - \frac{K}{CRF(n, r)} - I$$

This effectively increases the rate at which earnings are being discounted and reduces the net present value.

Developments in fuel prices are of fundamental importance for the future economics of geothermal developments. Rapidly rising prices will produce windfall profits while falling prices will cause bankruptcy in some cases.

References <u>**Chapter 4**</u>

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Chapter 5 Well Costs

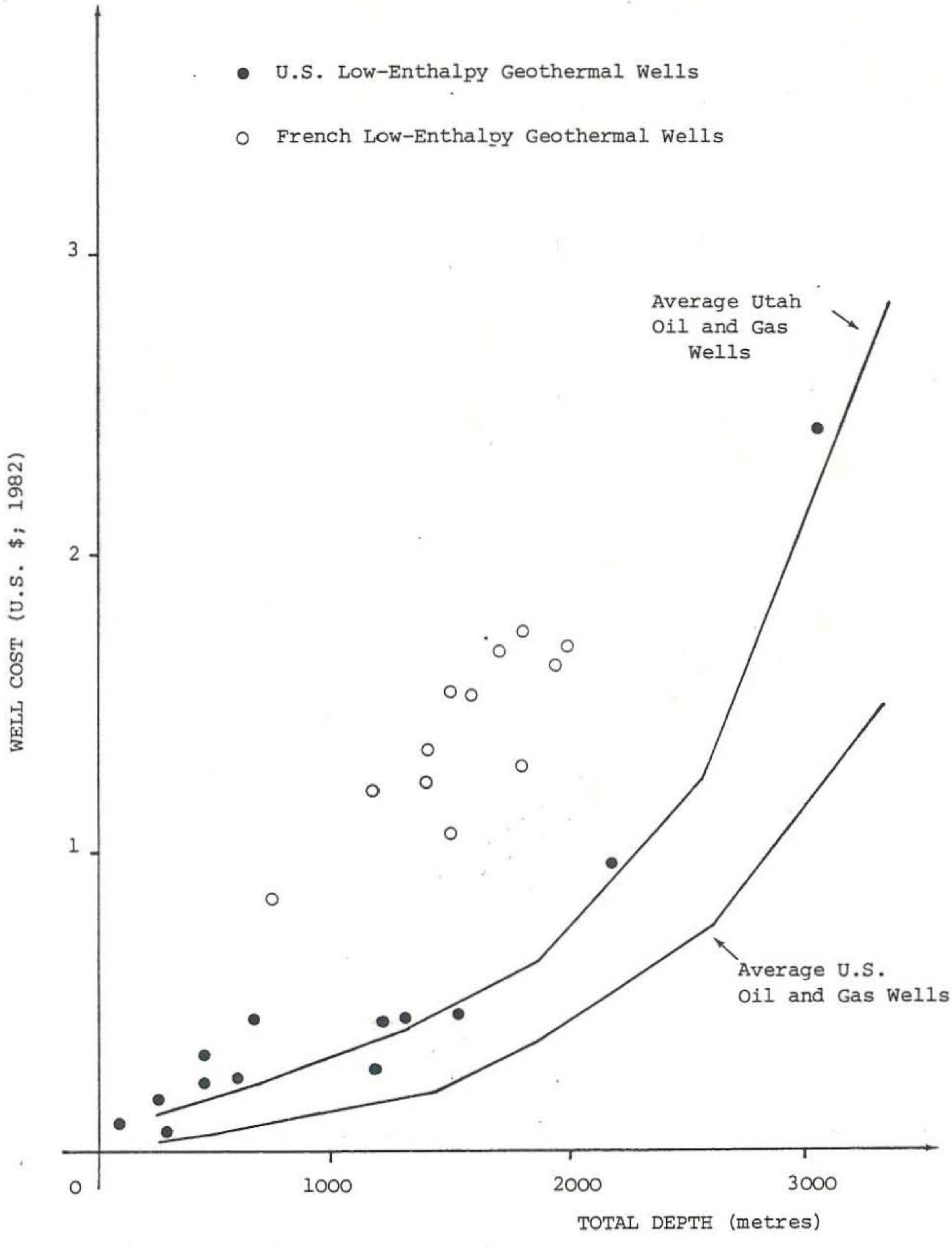
5.1 Introduction

Well drilling is one of the basic operations in any geothermal exploitation and well costs normally account for a major proportion of the total costs. However, forecasts of well costs are difficult if not impossible to make for geothermal engineers who do not have access to the priviledged information possessed by drilling contractors and drilling consultants. For this reason they are often the least well understood element in the costs of a scheme.

The Joint Association Survey which is sponsored by American Petroleum Institute, the Independent Petroleum Association of America and the Mid-Continent Oil and Gas Association is a common reference source for well costs (Ref. 5.1). It is conducted annually and provides a catalogue of information on the costs of different categories of wells in all of the main oil and gas regions in the U.S.A. Average trends are calculated and the variation with depth is often displayed (see Figure 5.1) and used as a costing guide. However, this is, at best, an unreliable guide. Drilling in the U.S.A. is dominated by activity in the southern states of Texas, Lousiana, Kansas and Oklahoma. Low costs are obtained in these states and these dominate the averages. Most other states show higher cost trends. See, for example, the data points for Utah on Figure 5.1. European geothermal wells show higher costs still (after converting currencies). It is often argued that the explanation for these differences lies in the market for drilling services. That high activity in the U.S. produces a highly competitive market for drilling rigs and for drilling supplies and that this gives low costs. On the other hand, the argument goes, the relatively low level of drilling activity in European provinces gives rise to higher costs because of reduced competition.

Drilling contractors and oil and gas companies will often produce estimates of the costs of drilling new wells in areas for which they already possess recent detailed cost breakdowns by adjusting the most relevant breakdowns which they have to match the programme of the new well. However, if this information is not available or if the well is to be drilled into a new area or into a rock type with which there is little experience then estimates are difficult to make.

Figure 5.1 International Comparison of Low-Enthalpy Geothermal Well Costs (Ref. 4.5)



Geothermal developers are often posed with this problem. A recent extreme example is the problem of estimating the costs of deep wells in granite rocks for hot dry rock geothermal developments.

This chapter outlines the methods which can be used by geothermal engineers, who have no specialist knowledge of drilling, to make estimates of drilling costs and to investigate problems relating to well costs. Some results from recent drilling cost studies carried out by the author and his co-workers will also be discussed.

5.2 The Modelling Approach

The well cost breakdowns reflect the way in which the drilling operation is organised and also the nature supplies and services which are used.

Normally the customer employs a drilling contractor who charges for his services on 'dayrate' basis. Service companies are employed for specialist tasks such as logging, well testing, casing running, cementing, etc. Drilling bits casing, fuel, drilling mud additives, etc. are bought in as required. Thus, categories such as payments to drilling contractors (= rig dayrate x drilling time) and casing (= casing quantities x casing price) appear in the breakdowns.

In order to understand drilling costs and to be able to make estimates it is necessary to have a method for calculating the physical quantities which underly the costs in the different categories. A variety of procedures and models which are based upon this type of approach have been developed for estimating the costs of geothermal wells. A cost simulation procedure has been developed by the Sandia National Laboratory (Ref. 5.2) and a study by the Mitre Corporation eventually resulted in an engineering cost model - WELCST (Ref. 5.3). Also, drawing upon this work, Sunderland Polytechnic have developed a model specifically to estimate the costs of low-enthalpy geothermal wells in European settings - WELC (Ref. 5.4).

The Sandia procedure is based upon a detailed simulation of the drilling process. WELC and WELCST are partial simulations. All of these models require substantial data inputs for them to be run successfully. Thus, a variety of approaches are available for geothermal well cost estimating. These range from simple empirical equations of the Joint Association Survey type to simulations of the types referred to above. Any estimating tool which is to be of value to a geothermal engineer must be capable of providing reasonably reliable estimates using the limited amounts of physical and pricing information which are available to them. However, the procedure must also be sufficiently flexible so that it can accommodate those changes in design, setting, etc. which can have large impacts on cost. Simple cost equations, based on actual well costs, can be used to give quick, approximate results. These, however, may be inappropriate in certain cases since single equations cannot reflect significant fluctuations in total costs caused by practical differences between individual wells. Also, there is no reliable and readily accessible method of adjusting simple cost equations, derived from data for a particular country in a particular year, to values of currency for different countries at entirely different times. Unlike manufactured items that can be traded between countries, well cost cannot be converted simply on the basis of official exchange rates. In contrast to the use of derived equations, the detailed costing procedures or models, that are based on the simulation of drilling operations, can often accommodate a range of technical choices and price data, and can provide relatively reliable cost results. However, these procedures are only available in the form of computer programmes and normally require a substantial amount of basic information which may not be available to a geothermal engineer. A compromise is required between these apparently conflicting extremes of simplicity and accuracy, and an approach is outlined here which attempts to strike this balance.

5.3 The Well Cost Drilling Model WDCM

The approach has been developed from the WELC model referred to above. The basis of the approach is a sequence of equations which are used to estimate time and cost components for most common types of low - and high - enthalpy geothermal well. Conventional drilling technology is assumed, based on onshore "pack-up" rotary rigs using mud fluids for drilling to depths in a range between 1000 metres and 4000 metres. As such, the procedure could be applied to onshore oil and gas drilling as well as geothermal drilling. For reasons of simplicity, the method cannot be used to calculate the cost of drilling and completing wells with some of the less conventional methods that have been suggested and applied in high temperature geothermal areas. Consequently, the effects of using air, mist or foam as drilling fluids, in addition to re-drilling operations and "multiple leg" well completion cannot be specifically accommodated. However, the method can be used to estimate the cost of deviated as well as straight wells and any well profile and casing design can be selected.

The 'Well Cost Drilling Model' - WDCM - estimates well costs broken down into a simplified set of ten cost categories, Table 5.1. The details of the model calculations in each of these categories are given in Appendix 3. The main independent calculations of the model are the calculations of drilling time and the calculation of the quantities of casing required in the well. When multiplied by rig rates and casing prices, these give the drilling charges and the casing costs; two costs which together usually make up about 50% of total costs. The majority of the other costs are estimated using simple rules or as factors of the main categories. It is useful to consider the calculation of the costs in these main categories in some more detail.

5.3.1 Drilling charges

This is the most difficult part of the well cost estimating problem. Drilling times depend upon drilling programme, geology and drilling practices in complex ways. Rig rates depend upon the state of the market for drilling services and the differences between rates when demand is high and rates when demand is low can be large. Both of these aspects must be considered.

Drilling times

Drilling times have been studied by a number of workers and statistics of time versus depth have been collected. Figure 5.2 shows drilling times in the Geysers (Ref. 5.5) an important high-enthalpy field and figure 5.3 shows drilling times for

Figure 5.2 Comparison of Actual and Estimated Total Rig Hire Time: The Geysers, U.S.A.

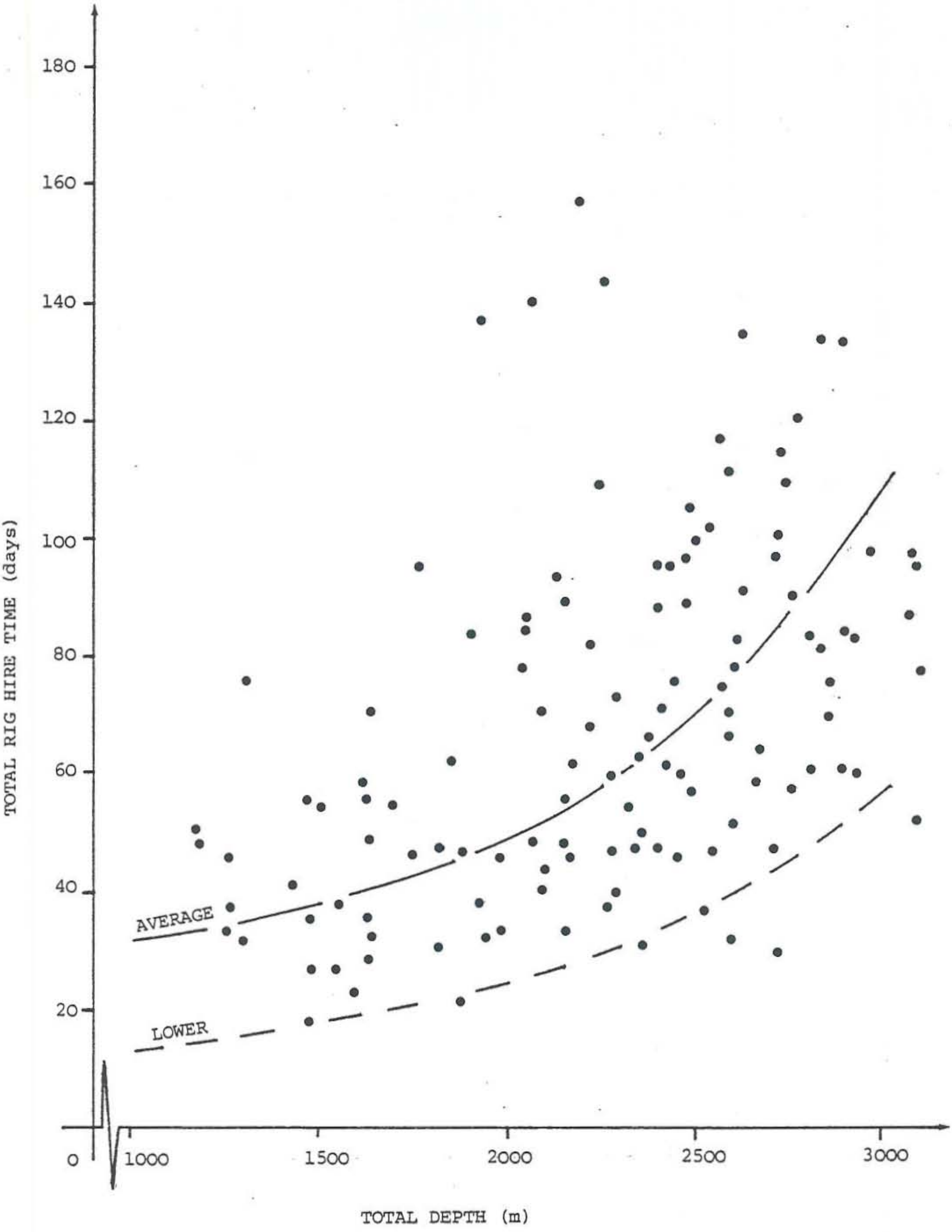


Figure 5.3 Comparison of Estimated and Actual Total Rig Hire Times For Straight Wells in the Paris Basin

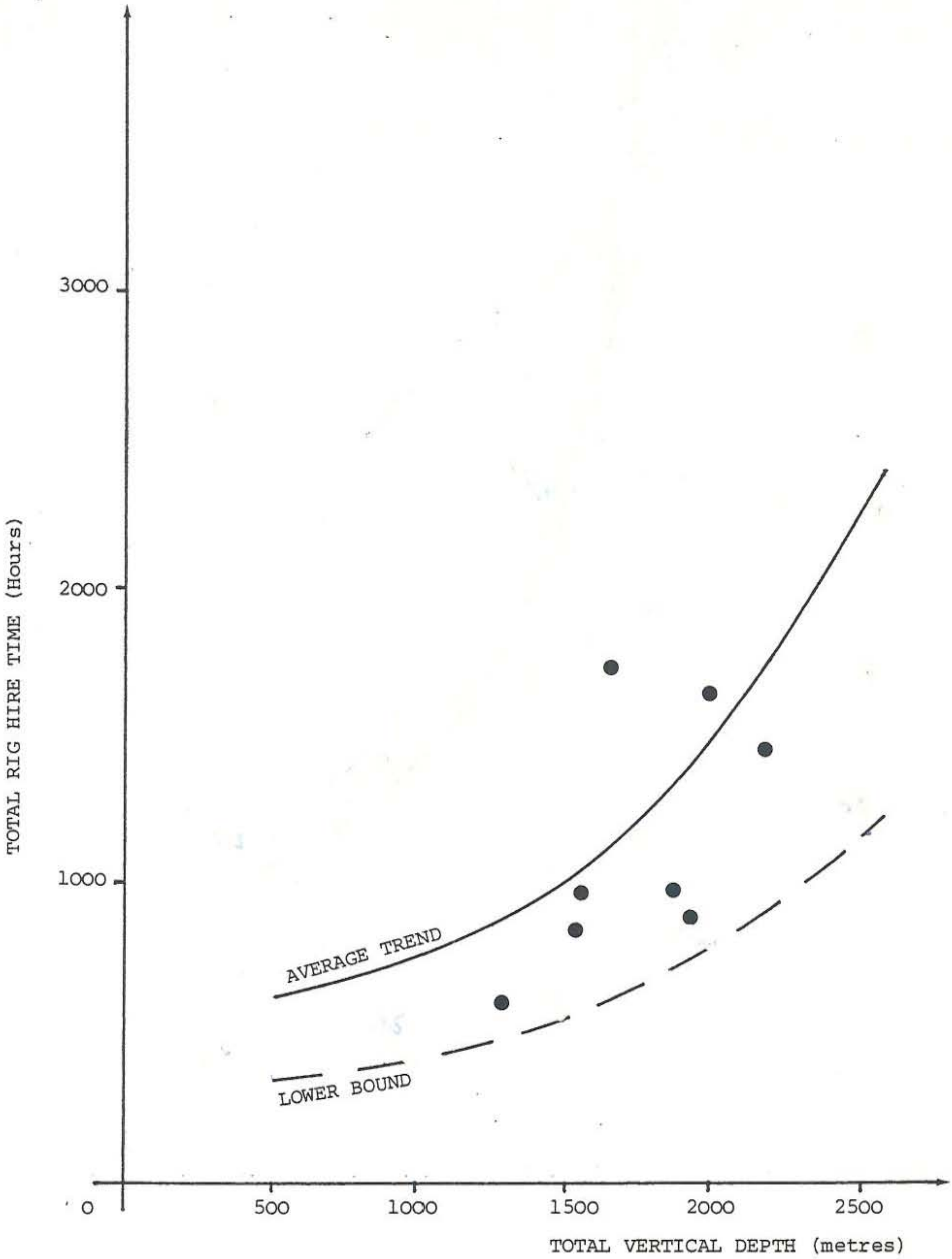


Table 5.1 Summary of Well Cost Components

SYMBOL	COST COMPONENT	COMPOSITION
c_1	DRILLING CHARGES	Total cost of rig hire
c_2	RIG TRANSPORTATION	Cost of rig transport, rig up and rig down operations
c_3	SITE PREPARATION	Cost of preparing site and restoration after drilling
c_4	FUEL, MUD, BITS, ETC.	Cost of rig fuel, drilling mud, water, mud disposal, mud engineering and logging, and drilling bits
c_5	CASING, ETC.	Cost of casing, accessories, screen/liner
c_6	CEMENT, ETC.	Cost of cement and cementing services
c_7	WELLHEAD	Cost of wellhead equipment and installation
c_8	WELL LOGGING	Cost of well measurements, surveys, etc.
c_9	WELL TESTING	Cost of supplies and equipment, other than the drilling rig, for air/gas lift tests, production pump tests, etc.
c_{10}	MISCELLANEOUS	Cost of special equipment, supplies and services, analysis, transport, insurance, supervision, etc.

geothermal wells in the Paris basin an important low enthalpy field. Clearly, there is a high degree of scatter and in this form the data is not very useful as an estimating guide. The scattergrams tend to show lower boundaries below which drilling times do not fall but many of the wells are drilled in times which are substantially higher than these minima. Geology, drilling practice, drilling programme, and mishaps can all play a part in determining drilling times. In order to estimate drilling times reliably it is necessary to calculate the times in sub-categories which individually are sensitive to these factors, see Table 5.2. The 'Sandia' procedure, referred to above, does this in a detailed, operation by operation, simulation of the drilling of the well.

The WDCM approach is to use model equations to calculate the times rather than direct simulations. The three main independent calculations are rotating time, tripping time and casing time. Rotating time is the total time spent actually drilling, i.e. with the bit in contact with the rock and 'making hole'. In order to model rotating times empirical information is required on the variation of rotating time with depth. This can only be obtained from drilling reports on wells drilled in geologically similar areas. There are two possible approaches depending upon the nature of the information. Some drilling engineers will report drilling time breakdowns in the drilling report. If these can be obtained for a number of wells of various depths a relationship between rotating time and depth can be determined, see Figure 5.4. This shows results for geothermal wells drilled in the Paris basin. An exponential function of the form shown in Table 5.3 ususally gives a good fit to this type of data over a limited range. A linear fit can also be used in some cases over the major part of the range, see Table 5.3. A linear equation for the rotating time versus depth implies a constant rate of penetration and the evidence seems to indicate that this does in fact occur in hard rocks and in the deeper sections of the wells. A rotating time which is increasing exponentially with depth implies a rate of penetration which

Table 5.2 <u>Summary of Rig Hire Time Elements</u>

Symbol	Time Element	Description
t_1	Rotating time	Time spent drilling on penetrating rock
t_2	Tripping time	All operations involved in the replacement of drilling bits
t_3	Casing and Cementing time	All operations involved in placing and cementing casing
t_4	Mishap time	Delays due to drilling problems and recovery operations
t_5	Logging and completion time	All measurements in the well and operations such as simulating, fracturing etc.
t_6	Well testing time	All operations concerned with measuring reservoir conditions with the rig on site
t_7	Miscellaneous time	All remaining activity including maintenance, servicing, etc.

Table 5.3 Main Drilling Time Calculations - Undeviated Wells

Rotating Time

(1) Exponential form for wells of depth D_T between D_L and D_H.

$$t_1 = K_{1a} \exp \{ K_{1b} D_T \}$$

(K_{1a} and K_{1b} are constants)

(2) Linear form for wells of depth D_T between D_L' and D_H'

$$t_1 = m D_T + C$$

(m and C are constants)

Tripping Time

(1) Exponential form of the rotating time equation

$$t_2 = K_{2a} \left[\frac{1}{K_{1b}} \log e \left\{ \frac{n_b!}{n_o!} \left(\frac{t_b}{K_{1a}} \right)^{(n_b - n_o)} \right\} + \frac{D_L}{2} (n_o + 1) \right] + n_b K_{2b}$$

$$n_b = \text{integer} \left[\frac{K_{1a}}{t_b} \exp (K_{1b} \cdot D_T) \right] \quad \text{(number of bits)}$$

$$n_o = \text{integer} \left[\frac{K_{1a}}{t_b} \exp(K_{1b} \cdot D_L) \right] \quad \text{(correction factor)}$$

(2) Linear form of rotating time equation

$$t_2 = K_{2a} \, t_b \, \frac{n_b(n_b + 1)}{2m} + n_b K_{2b}$$

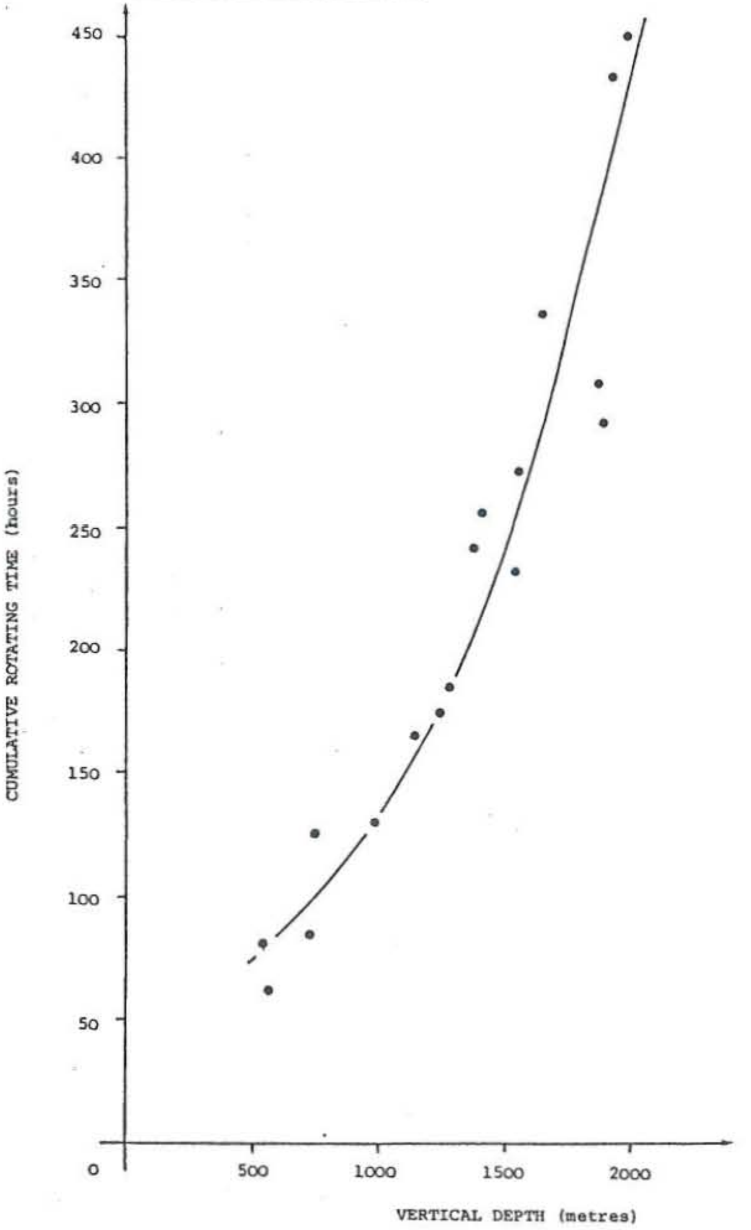
$$n_b = \text{integer} \left[\frac{m D_T + C}{t_b} \right]$$

K_{2a} = round tripping rate hrs m^{-1}

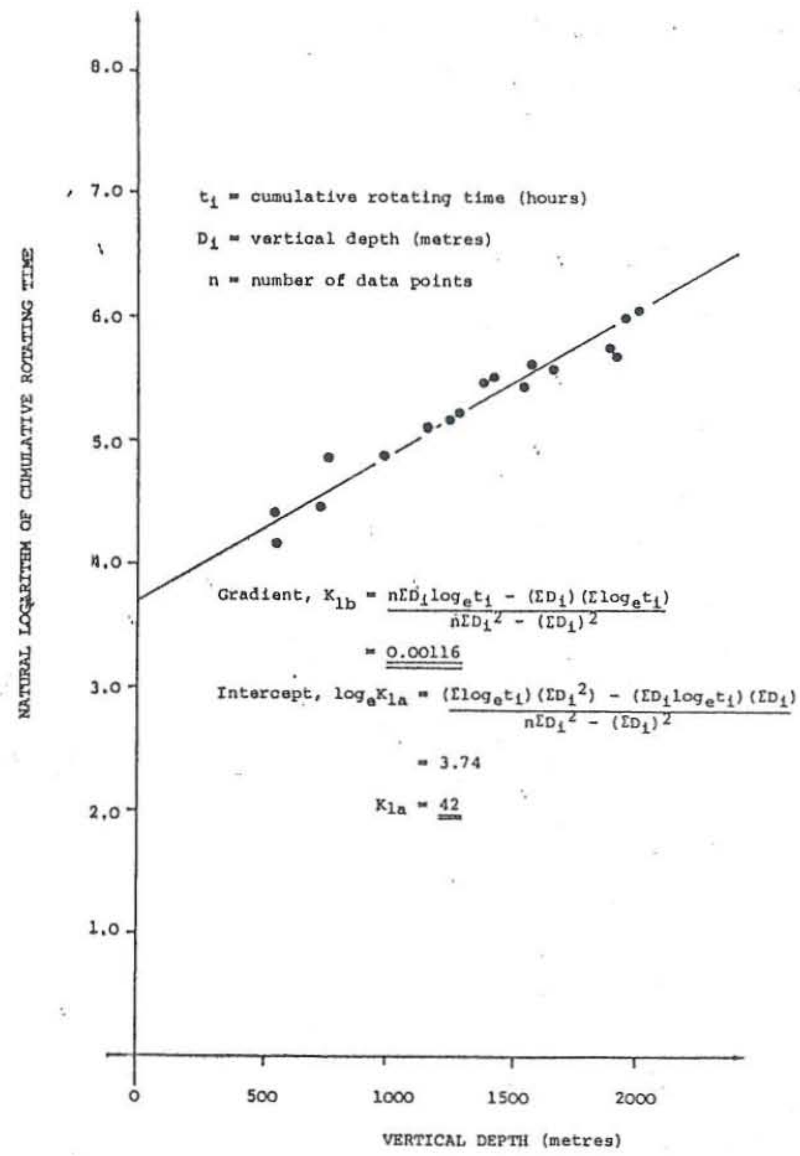
K_{2b} = bit change time hrs/bit

Figure 5.4 Derivation of Rotating Time Relationships

(a) Variation of Cumulative Rotating Time with Vertical Depth for the Paris Basin, France



(b) Derivation of a Representative Equation for the Variation of Cumulative Rotating Time with Vertical Depth



is falling exponentially with depth and this will give unrealistically high rotating times for wells which lie outside of the depth limit of the expression.

An alternative approach, when rotating time data of this kind is not available, is to analyse bit records for wells which have been drilled in similar geology. Figure 5.5 shows some entries from a typical bit record. The plot of cummulative rotating time with depth of the bits used gives a rotating time versus depth curve. This can be fitted with exponential or linear curves as appropriate. Figure 5.6 shows a plot of cummulative rotating time which has been derived in this way for one of the wells which has been drilled in granites in Cornwall. These show rotating times which are linear with depth. This will be returned to later.

Tripping times can also be modelled fairly simply. A trip is the operation of removing the drill string from the well, disconnecting the drill pipe, removing and replacing the bit, reconnecting the drill pipe and replacing the drill string to continue drilling. Trips are made for a variety of reasons but the main reason is to replace worn drilling bits. Tripping times are determined by the number of trips and the depths at which they occur. In WDCM it is assumed that trips are only made to replace bits. The basic empirical data which is required is the bit life and once again this can be obtained from bit records. Short bit lives result in frequent trips and long tripping times and vice versa. Tripping times also assume a greater importance in deeper wells as the average depth and hence the duration of the trips increases. The total tripping time is the sum of all of the trips made. If the rotating time varies linearly with depth and the bit life is constant, then successive trips all occur after equal intervals in time and depth. The times of the individual trips form an arithmetic series in a straight well. If the rotating time increases exponentially with depth and with constant bit life successive trips still occur after equal intervals in time but the intervals in depth progressively fall. More trips are required to reach equivalent depths and the times of the individual trips form a more complex

Figure 5.5 <u>Example of a Bit Record</u> (Melleray Orleans production well, Paris basin, France)

NO.	MAKE	TYPE	DIAMETER (inches)	DEPTH (metres)		DISTANCE DRILLED (metres)	TIME ON BIT (hours)	WEIGHT ON BIT (tonnes)	ROTATION SPEED (r.p.m.)	MUD FLOW RATE (litres/min)	PUMP PRESSURE (bars)	RATE OF PENETRATION (m/hr)
				IN	OUT							
1	S.M.F.	TS3	17½	14.5	95.6	81.1	26.25	1/5	60/70	1400	25/30	3.09
2	S.M.F.	TS3	17½	95.6	183.0	87.4	9.25	4/5	80	1900	50	9.45
3	S.M.F.	TS3	17½	183.0	538.0	355.0	41.00	5/10	80	1500	35	8.66
4	S.M.F.	TS3	17½	538.0	549.0	11.0	4.75	7/10	80	1500	40	2.32
5	SECURITY	S3	12¼	549.0	730.0	181.0	20.25	5/7	60/100	2000	45	8.94
6	SECURITY	S3	12¼	730.0	920.0	190.0	30.25	15	110	2000	85	6.28
7	SECURITY	S3	12¼	920.0	1008.7	88.7	24.00	13	110	2000	95	3.70
8	SECURITY	S3	12¼	1008.7	1103.0	94.3	24.50	15	110	2000	85	3.85
9	SECURITY	S3	12¼	1103.0	1229.0	126.0	34.75	12	110	2000	80	3.63
10	SECURITY	M44N	12¼	1229.0	1322.0	93.0	24.75	15	80	2000	60	3.76
11	SECURITY	M44N	12¼	1322.0	1369.0	47.0	15.50	15	80	2000	65	3.03
12	SECURITY	M4N	8½	1369.0	1439.0	70.0	21.00	8	100/140	2000	65	3.33
13	SECURITY	M4N	8½	1439.0	1470.8	31.8	6.75	12	100/140	2000	65	4.71
14	REED	FP62	8½	1470.8	1667.5	196.7	54.50	15	130/140	2000	60	3.61

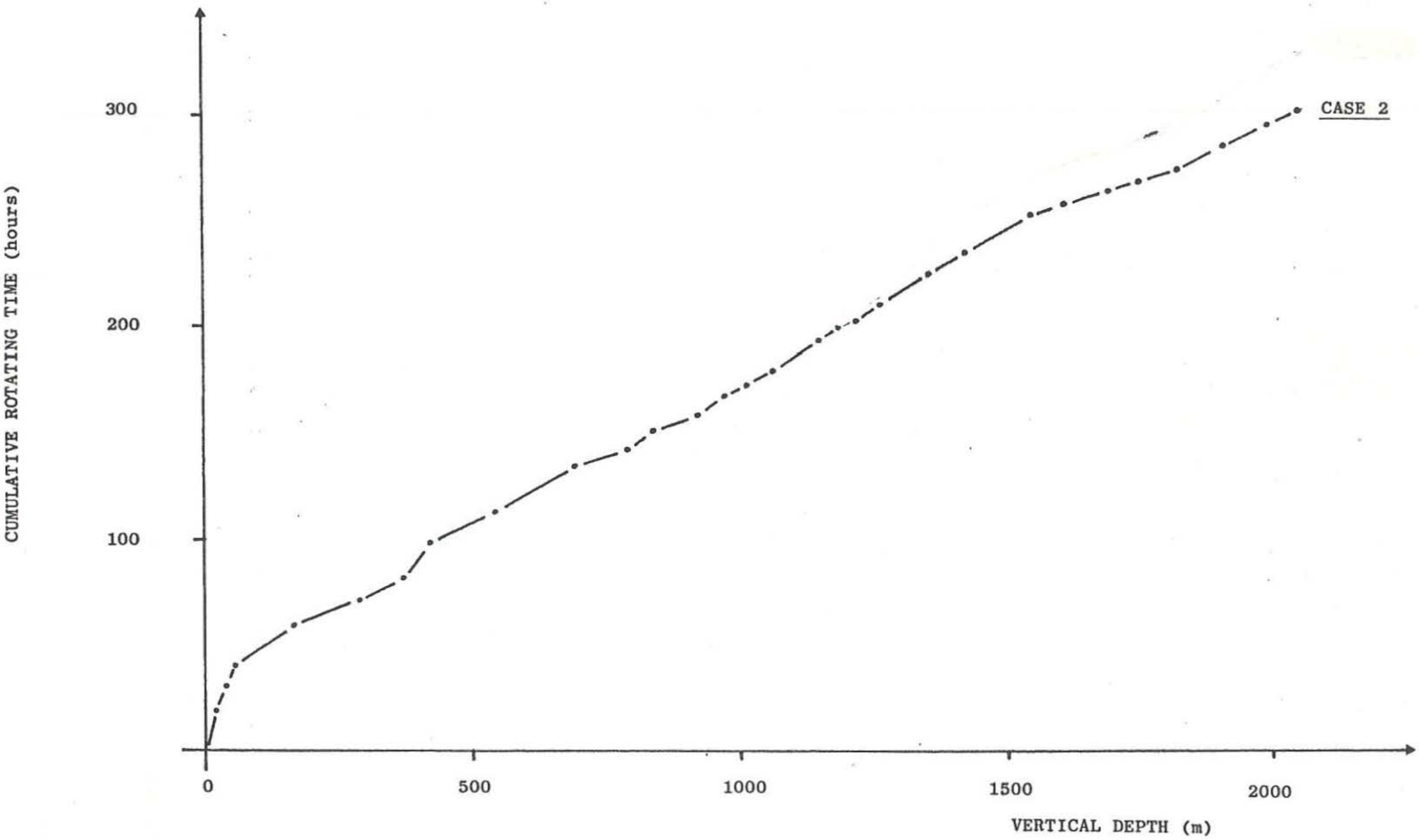
VERTICAL DEPTH (metres)	CUMULATIVE ROTATING TIME (hours)
95.6	26.25
183.0	35.50
538.0	76.50
549.0	81.25
730.0	101.50
920.0	131.75
1008.7	155.75
1103.0	180.25
1229.0	215.00
1322.0	239.75
1369.0	255.25
1439.0	276.25
1470.8	283.00
1667.5	337.50

Cumulative "time on bit" = 337.3 hours
Total number of bits = 14

$$\text{Average bit life} = \frac{337.3}{14} \text{ hours}$$

$$= \underline{\underline{24}} \text{ hours}$$

Figure 5.6 <u>**Variation of Cumulative Rotating Time with Vertical Depth**</u>
<u>Carnmanellis Granites</u>



series. However, it is possible to solve both problems mathematically and the appropriate equations are given in Table 5.3.

The third major time element is that required for the operations of casing and cementing. This is related to the numbers of pieces of casing in the well and the lengths of the sections. The time is made up of time required to clean the hole and run in the lengths of casing together with the time required to prepare the rig for casing, time waiting for cement to set and the time required to restore the rig to begin re-drilling. Data available gives values of between 25 to 85 hours for the combined times in this last category.

These three times categories are strongly related to well depth and the casing and cementing time is also strongly affected by the well profile. However, the variations which are observed in the physical data and in the rate constants in the equations can give rise to substantial differences in the times. The remaining time categories are less easy to model based upon well depth and tend to be determined by other aspects relating to the nature of the well. However, in order to make some estimates simple default rules are given in Appendix 3.

One interesting category is 'mishap' time. This is the time which is lost due to problems which occur during drilling:- 'stuck' pipe, 'lost circulation', 'fishing', well collapse, and so on. It is widely claimed that this is an important time category particularly for high-temperature wells and it is suggested that mishaps may account for a large proportion of the scatter observed in drilling time statistics. Table 5.4 shows some mishap times which can have been collected for some French low-enthalpy wells and some Italian high-enthalpy wells. Also given are average mishap times for the Geysers and Imperial valley quoted by the Mitre Corp. (Ref. 5.3). Clearly, mishaps are significant and the average time lost in the high-temperature wells at 10·5% of total rig time is higher than that of low-enthalpy wells at 6% total rig time. However, the figures are not unduly high and can in

Table 5.4 Examples of Mishap Times

Well	Vertical Depth	Mishap Time Total (hrs)	Mishap Time Fractional
Low enthalpy (Paris)			
Beauvais 1	1287	0	0
Beauvais 2	1269	0	0
Cergy Pontoise 1	1997	69	4·2
Cergy Pontoise 2	1500	113	11·5
Melleray 1	1667	245	14·1
Malleray 2	1661	81	8·3
Reims Murigny 1	1542	30	3·6
High enthalpy (Italy)			
Cesano 6	3217	132	3.8
Cesano 7	2035	138	4·3
Cesamo 8	960	284	15·7
Latera 1	2796	377	12·6
Latera 3	2485	27	1·0
Latera 3D	1369	184	8·7
Latera 4	1809	255	10·8
Trecase	2100	339	12·4
Mofete 1	1600	217	7·6
Mofete 2	2000	505	16·16
San Vito 1	3050	1215	22·5

Average mishap times in Geysers 340 hrs/well

Average mishap times in Imperial Valley 97 hrs/well.

no way account for the scatter observed in the drilling time statistics.

Rig rates

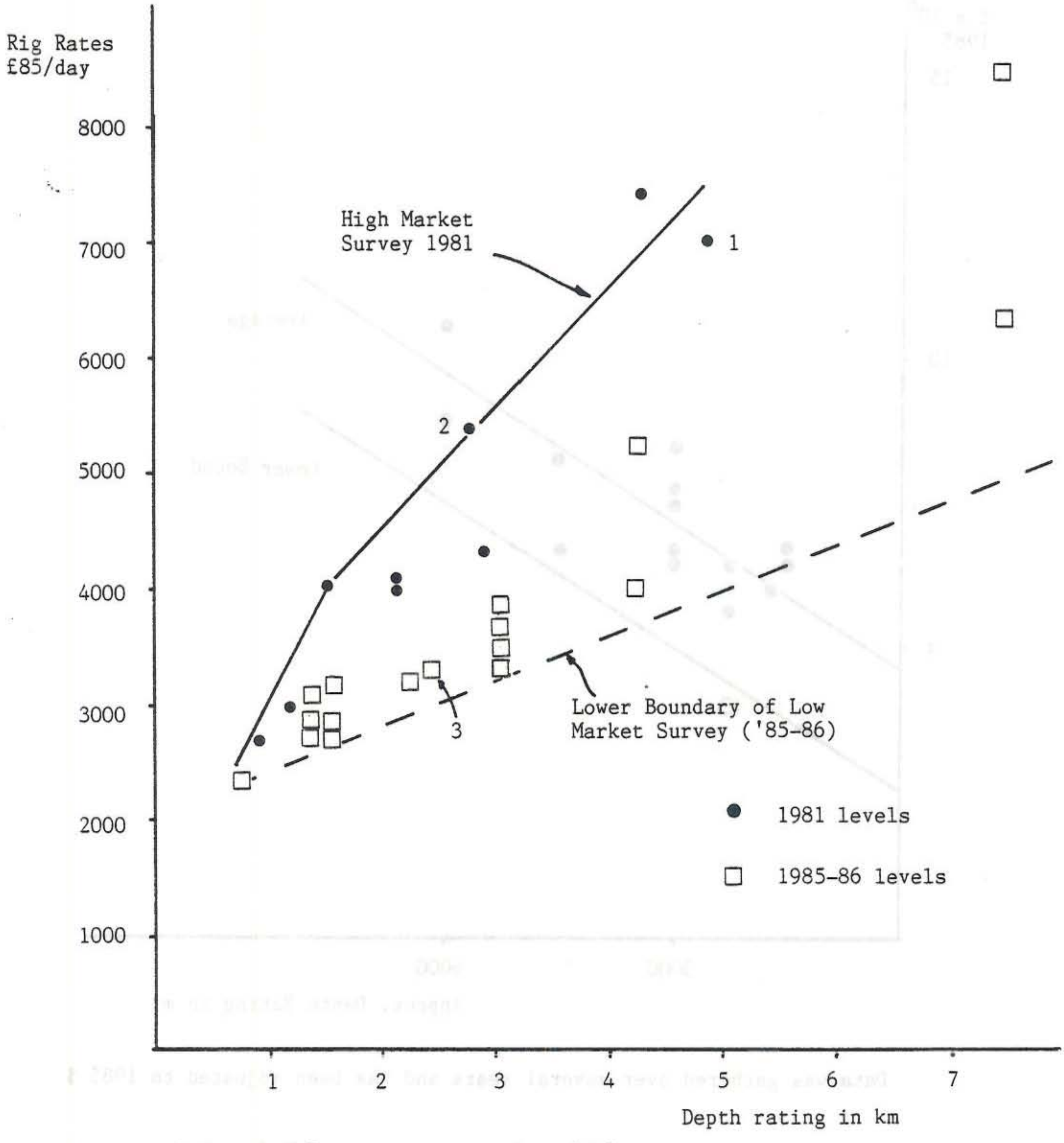
Demand for the services of drilling contractors fluctuates braodly in line with fluctuations in the oil market. Day rates quoted by contractors can be substantially different between periods of high and low demand. This is another important factor which affects well costs. Figure 5.7 shows day rates for U.K. drilling rigs collected during 1985 and 1986. It also shows rates collected during a similar survey in 1981. These latter observations have been adjusted for inflation so that they can be compared with the recent data. Although the data is sparse, it is clear that current rates are in general much lower than the rates which were obtained in 1981. 1981 was a period of high activity in oil exploration and development; demand for drilling rigs was high. Today we are observing a slump in oil-related activities and a very low level of demand in drilling rigs.

There is no definitive way of characterising the rates which will apply under any market conditions. Thus, in high demand situations, some contractors will be able to obtain exceptionally high rates due to special short-term circumstances while others, because of local effects, may only command relatively modest rates. Also, in a low market situation, some contractors will be better placed to resist pressure on rates than will others because of special skills and/or facilities. However, general economic principles will set the trends in both situations. In high demand situations, rig rates will rise to levels which make it attractive for contractors to buy and commission new rigs and the costs of doing this will tend to limit the levels which rig rates will reach in the medium term.

In economic terms, the rates are determined by the average costs including financing of producing and operating drilling rigs. It is interesting that the points 1 and 2 taken from the 1981 survey represent new rigs commissioned at this time.

In low demand situations contractors will not operate rigs

Fig. 5.7 <u>Deep Drilling Rig Market</u>



Points 1 & 2 represent new rigs which were commissioned in 1981

Point 3 represents a rig which was decommisioned in 1986

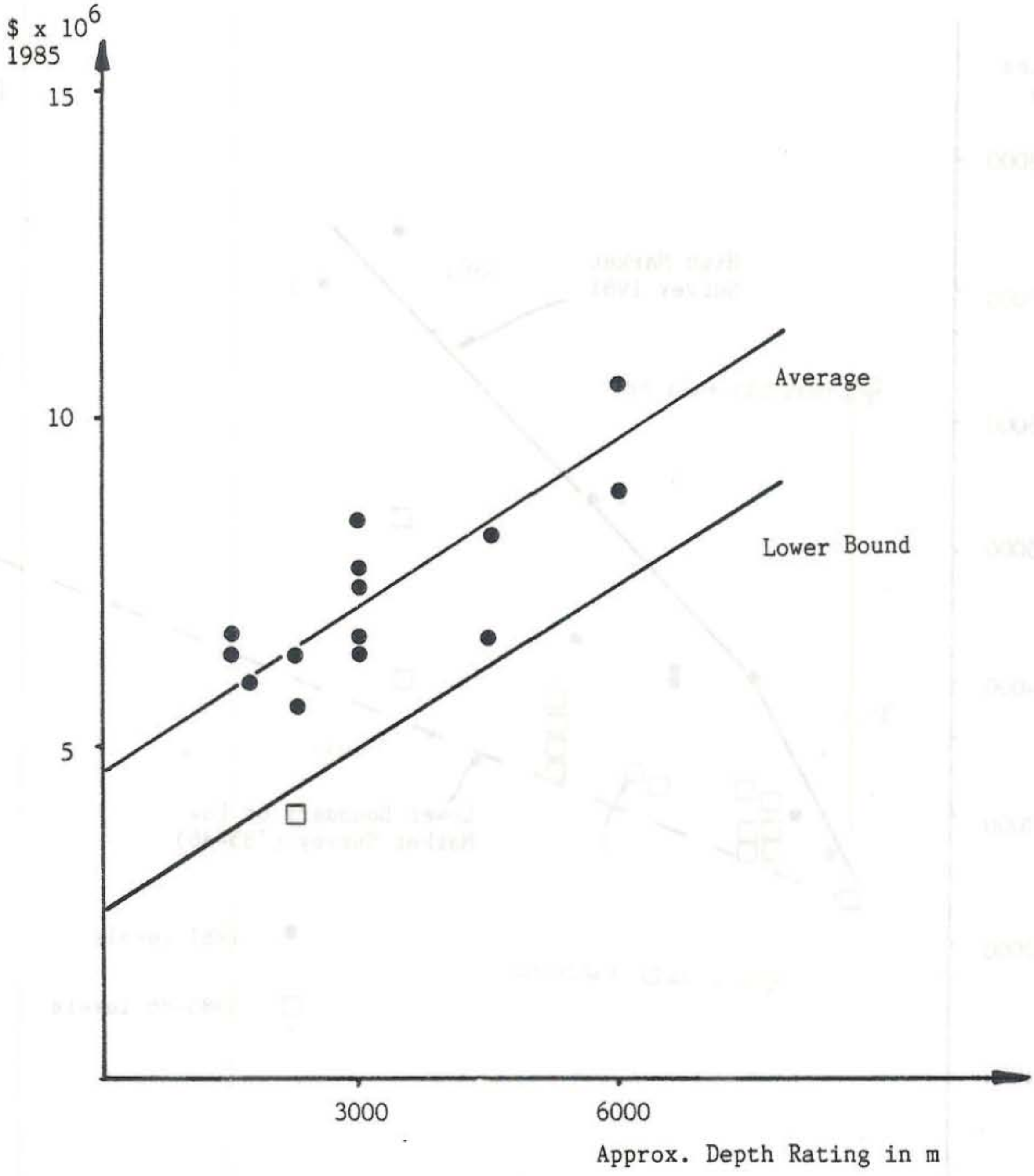
Data from 1981 has been inflated to '85 levels at day rates which are below the day to day running costs of the rig. In economic terms, the lower rates are limited by the average running costs (excluding financing) of drilling rigs. Rigs which cannot command these rates would be decommissioned. It is interesting that the rig represented by point 3 taken from the 1985 survey has now been decommissioned.

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

- The average running costs include the costs of labour, tool pushers, administration, insurance, minor maintenance, fishing reserve, drill pipe and collars, transport, site management and also major renewals on the rig. Major renewals were estimated from an annual charge of 2% of capital apportioned over an assumed 300 days per year of operation. The other categories were estimated from information obtained from a drilling contractor.
- The total costs including financing. In addition to the running costs specified above, these also include the costs of financing the purchase of a new rig. These have been calculated assuming that 30% of the capital cost is financed through secured debt and is repayed over 10 years. The remaining 70% is provided as an unsecured equity contribution by shareholders. This is repayed over 5 years; a 5% discount rate is assumed for both contributions. The shareholders accept a considerable risk in financing the rig; they do this in the expectation of a rapid payback of the investment (at a low interest) and the prospect of large profits from the operation of the rig over the remainder of its lifetime (assumed to be 15 years).

The capital costs of drilling rigs are also affected by the level of demand for drilling services. Figure 5.8 shows some costs which were collected during 1979-81 when demand was high. The lower bound line is based upon some more recent data from a drilling contractor and may represent current trends.

Fig. 5.8 **Drilling Rig Capital Costs**



Data was gathered over several years and has been adjusted to 1985 $

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

The results of the calculations are shown in Figure 5.9. A comparison of the total costs including financing with the high market line in Figure 5.7 and the average running costs with the low market line in Figure 5.7 show a reasonable degree of consistency. This supports the market interpretation advanced above.

Low market rates are unstable. At these rates some drilling contractors will not be able to meet debt repayments and will go bankrupt. In general, old rigs will be decommissioned, they will not be replaced and thus rig fleets must decline. Ultimately, reduction in supply will cause rates to rise again and these will stabilise at the level at which it becomes economic to buy and commission new rigs. The industry is stable in this condition with fleets being maintained by new rigs replacing old ones. Thus, the higher rates shown in Figure 5.7 are more stable than the lower rates, in the long run. It is these high market rig rates which should be assumed when forecasting drilling costs over the medium to long-term.

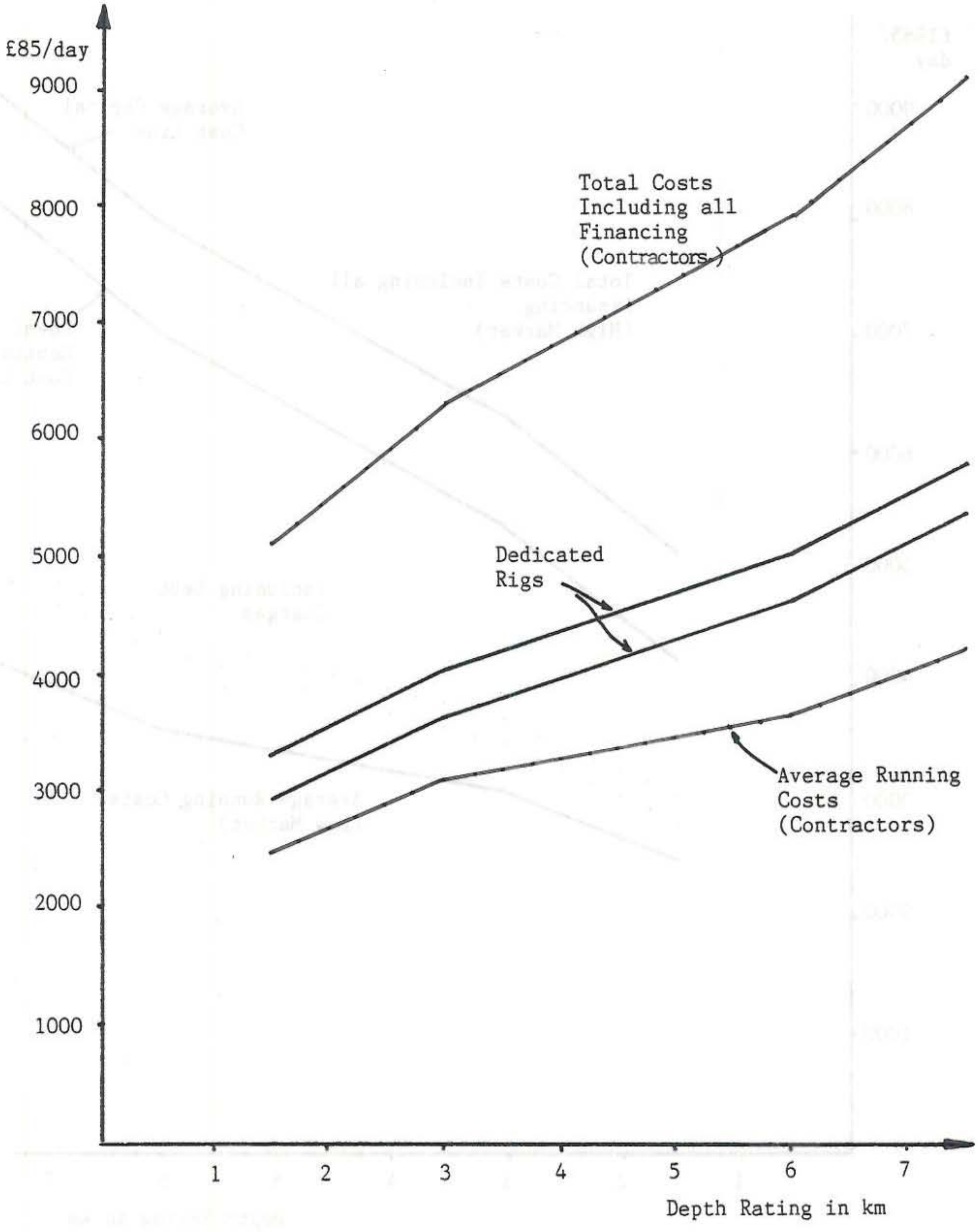
Dedicated rigs

The use of rigs solely dedicated to the drilling of geothermal wells over their lifetime offers the prospect of reducing rig day rates. This is because 'dedication' could lead to improved utilisation of the rig and of the trained labour.

- Rigs can be financed over the whole of their operating lives.
- Crews may work a more normal 'factory' shift routine and this will reduce dislocation and standby premiums.

Revised calculations of running costs and financing charges have been carried out to estimate rig rates for dedicated rigs which can be compared with the 'contractor' rates given

Fig. 5.9 **Simulation of Day Rates**



above. The basic assumptions are given in Table 5.5 and a comparison between the 'dedicated' rates and the total rates including financing for contractor operation is shown in Figure 5.9. Clearly, substantial reductions may be possible. These arise mainly from reductions in financing charges.

Dedicated rig fleets do exist in the geothermal field operated by Orkustofnun in Iceland and ENEL in Italy.

Casing costs

After drilling charges well casing is usually the second most important item in well costs. Casing quantities can easily be calculated from the casing programme of the well. However, casing prices may show considerable variation over time and with location. Some operators will have a policy of buying long-term supplies of casing to take advantage of periods of low demand when suppliers will offer discounts which make nonsense of published prices. The details of the operation of this market are difficult to describe because of its secretive nature. Casing prices are often reduced to a price/unit volume of metal for comparative purposes and some such prices are given in Appendix 3.

5.4 Examples of Drilling Cost Studies Using WDCM

5.4.1 Estimates of drilling times

The drilling time estimates are the core of the model and hence the validation of them is important. A summary of the equations is given in Appendix 3. To perform the calculations requires empirical data relating to rates of penetration bit lives etc. which may be affected by the geology. Also required are technological parameters - tripping rate - casing and cementing time, mishap times which may be a function of the drilling practice. In any particular case this data covers considerable ranges. The fastest drilling times will be obtained by assuming fastest rates of penetration, longest bit lives fastest tripping times etc. The longest drilling times will be obtained by assuming lowest rates of penetration, shortest bit lives and so on. There are no good reasons for choosing one as opposed to another, both have a real likelihood

Table 5.5

Different Assumptions of the 'Dedicated' and 'Contractor' Rig Rate Calculations

		Contractor	Dedicated
<u>Crews</u>			
Depth < 1.5 km		14	25
1.5 < Depth < 7.5		17	29
7.5 < Depth		20	34
<u>Utilisation</u>		300 days	340 days
<u>Financing</u>			
a)	Debt	30%	100%
	rate	5%	5%
	period	10 years	15 years
b)	Equity	70%	-
	rate	5%	-
	period	5 years	-

In the dedicated rig operation it is assumed that toolpushers are paid £15,000 per year and that other labour is paid £10,000. Allowance is made for national insurance and superannuation. Crews include two additional men as a training reserve to cover the loss of trained personnel.

All other contributions to the running costs are assumed to be the same in each context.

of occurring. However, the obvious default data to use are the averages. Figures 5.2 and 5.3 show calculations of drilling times for the Geysers and for the Paris basin against a background of actual drilling times. The average trend lines calculated using average default data (and an appropriate standard drilling programme) pass reasonably through the centre of the scattergrams. The lower bound trend lives calculated assuming the most optimistic combination of the data are consistent with the fastest drilling times. Because of the difficulties in assigning upper limits to mishap times calculations of the upper bound trend times have not been shown. The range of the observed points in the scattergram can be accommodated by the known variations in the model parameters and this indicates that the model is working reasonably well in describing the drilling process.

Another interesting, recent, use of the model to forecast drilling times is a study which has been carried out, for the U.K. Department of Energy to estimate drilling costs in granite rock. Three wells have been drilled to between 2 and 3 km in granites at Rosemanowes quarry in Cornwall and the bit records of these wells have been analysed to model rotating times and to give bit lives. Some data is shown in Figure 5.6 above. The rates of penetration are essentially constant with depth and if it can be assumed that these can be maintained at greater depths then the rig times as shown in Figure 5.10 would be obtained. These rig times are consistent with the drilling times for the Rosemanowes wells. They are also consistent with Siljan well at 4 km. If this performance can be maintained to 7 km then this would constitute very rapid, efficient drilling at these depths.

As a final example of the use of the modelling approach to study overall costs it is interesting to return to the comparison of European and U.S. well costs mentioned initially. During the course of the U.K. geothermal aquifer R & D programme, four deep exploratory wells were drilled. Figure 5.11 shows the costs of these wells converted to U.S. $ and inflated to 1984 levels using appropriate indices. The costs can be compared with the U.S. national average well cost.

Figure 5.10 <u>Comparison of Simulated and Actual Total Rig Hire Times for Single Wells</u>

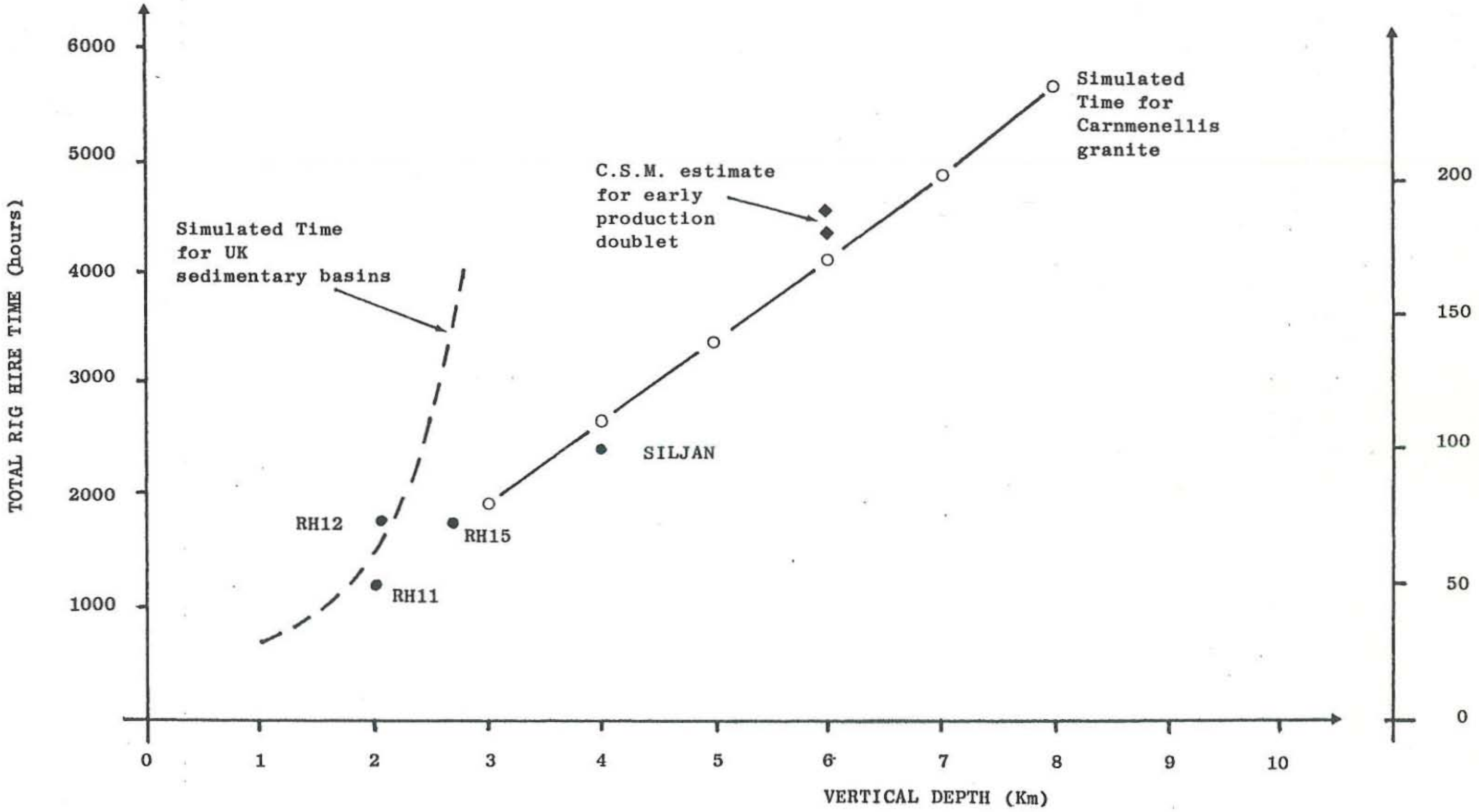
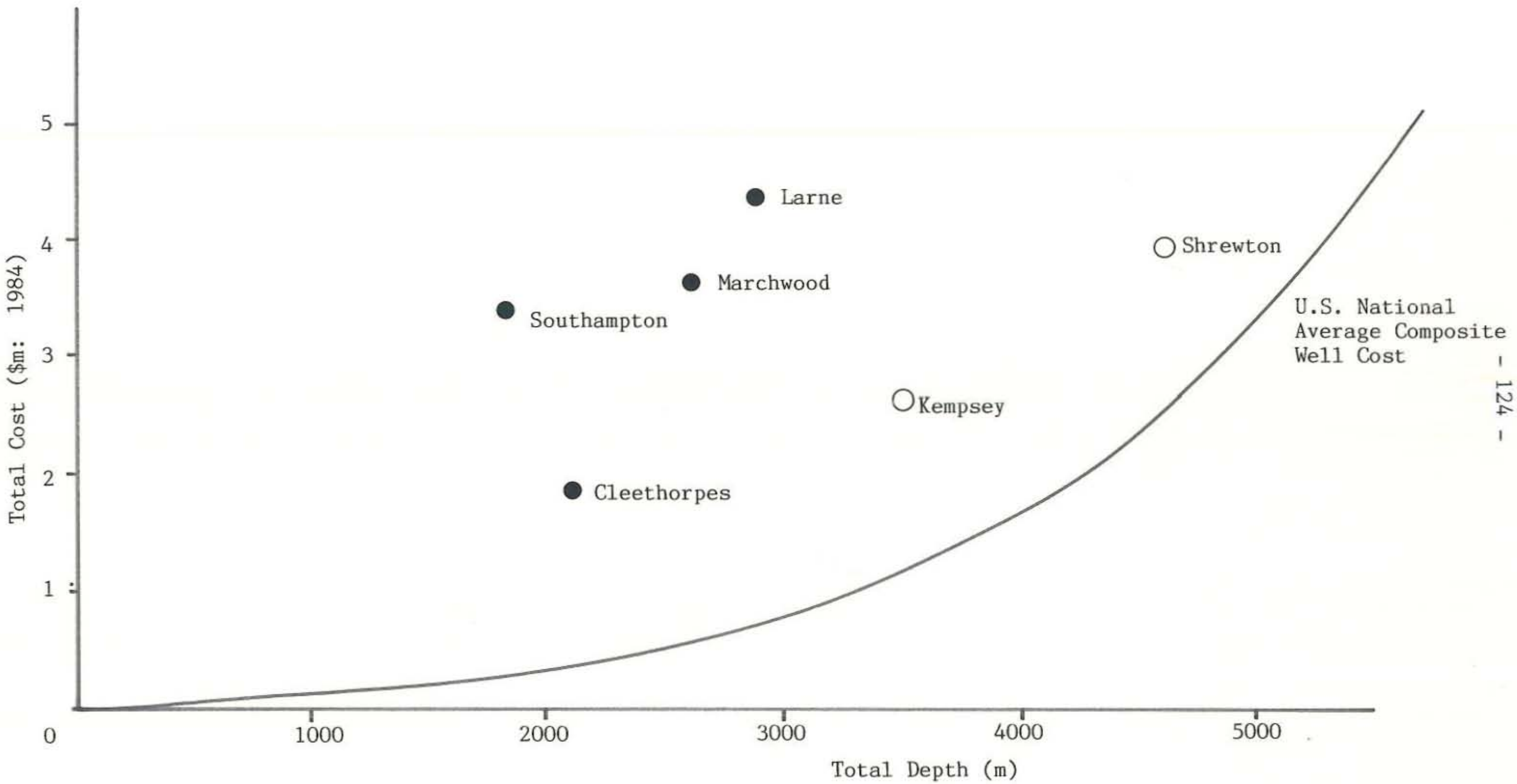


Figure 5.11 Comparison of U.K. Well Costs with U.S. Average Trends (1984)



Of the four U.K. wells, the Cleethorpes well approached closest to a production well. The research element was limited and also no significant drilling problems were encountered. Nevertheless, the costs of this well are of the order of five times the cost of the equivalent depth 'average' to U.S. well. In order to investigate this difference, the drilling model has been used to simulate drilling times and estimate different cost categories for a representative U.S. well of the same depth (2100 m) which can be compared with the Cleethorpes well (Ref. 5.6). In order to do this drilling data was taken from a pulished account of drilling in the East Niles field in Oklahoma (Ref. 5.7) and 1984 U.S. prices for selected drilling supplies and services were taken from previous studies. The cost of the representative Oklahoma well was calculated to be $374,000 and this can be compared with a cost of $367,000 indicated by the average well cost statistics. The profiles of the two wells are shown in Figure 5.12 and the rig hire time breakdowns are shown in Table 5.6. There are a number of obvious differences. The Oklahoma well has a narrower profile. It requires less casing (70 tonnes) than the Cleethorpes well (190 tonnes) and was drilled and tested in a substantially shorter time; 17 days as opposed to 45 days. Rotating times were lower indicating softer geology or more closely optimised drilling, bit lives were longer, 75 hours as opposed to 20 hours, and this has the effect of reducing the tripping time. The pricing differences, on the other hand, are less marked. Rig rates were broadly equal in both countries and the casing prices in the U.K. were actually lower than the casing prices in the U.S. To summarise, the comparison gives no support to the argument that increased drilling activity in the U.S. reduces the prices of drilling supplies and services and that this accounts for the observed cost differences. In fact, the comparison strongly indicates that the significant physical differences between the drilling profiles, the geology, etc. are sufficient to account for the differences in cost.

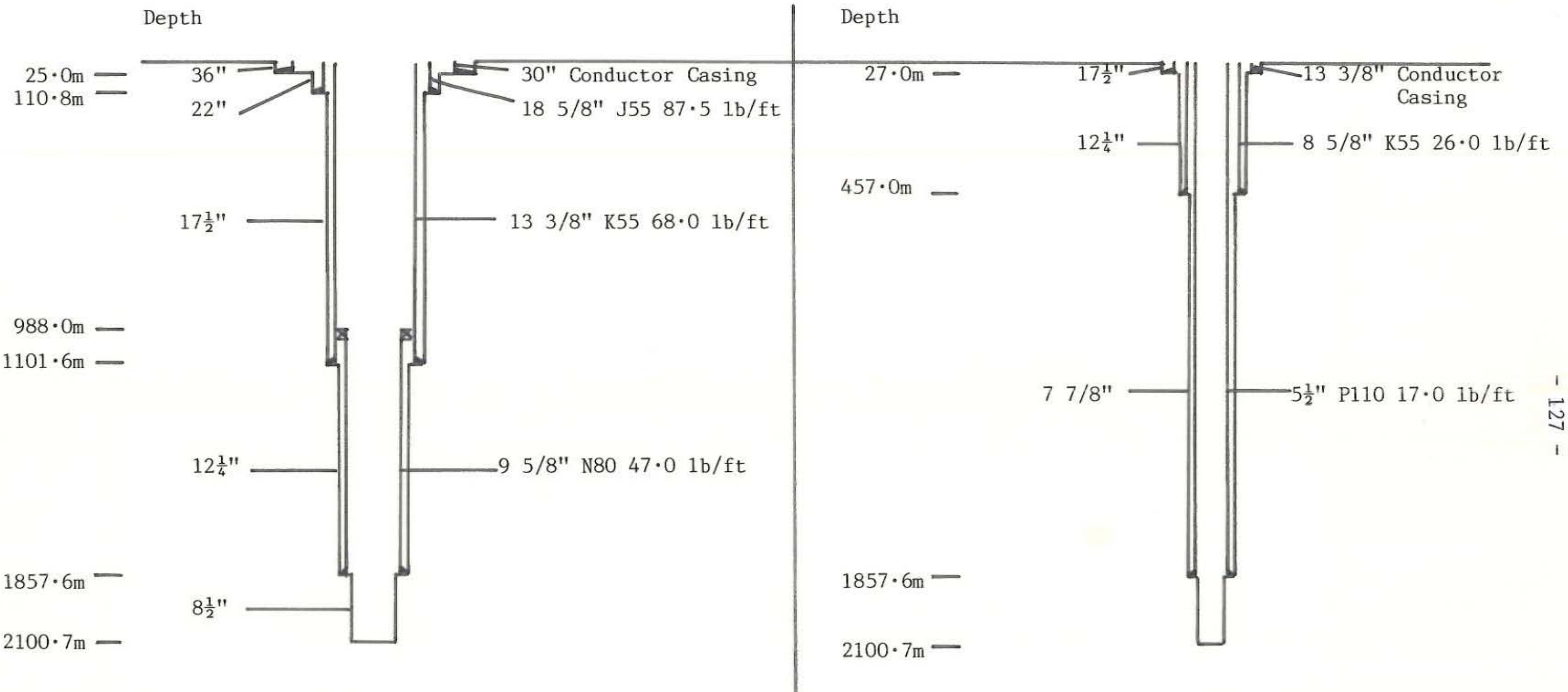
Table 5.6 <u>**Comparison of Rig Hire Time**</u>

Time Elements	Cleethorpes Geothermal Well - Actual Time (hrs)	Oklahoma Oil Well - Simulated Time (hrs)
Rotating	364	218
Tripping	206	14
Casing and Cementing	134	114
Mishaps	3	0
Logging and Completion	78	33
Well Testing	190[a]	0
Miscellaneous	102	30
Total	1077	409

Note:

(a) Including making up and breaking out bottom hole assemblies such as gas lift testing equipment, number of bits.

Figure 5.12 U.K. Geothermal Well and U.S. Oil Well - Comparison of Well Profiles and Casing Programmes



Cleethorpes Geothermal Well, U.K.

Simulated Oklahoma Oil Well, U.S.A.

References **Chapter 5**

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Chapter 6 Review of the Economics of Geothermal Heating

6.1) Introduction

The details of the economics of geothermal heating schemes are determined in a complex way by a series of physical factors and engineering choices. The range of choices open to the engineers designing geothermal heating schemes is usually limited in any particular situation. However, in the great majority of geothermal schemes the economics are marginal and it is important that the choices which are made are made correctly. In some cases there may be choice of which reservoir to exploit. Employing a deeper, higher temperature, reservoir will increase the thermal power of the wells. However, deeper drilling incurs the penalty of higher well costs and will only be justified if the heat loads can absorb the extra power and hence increase earnings. Well power can also be increased by increasing the flow which is drawn from the reservoir. But costs rise through increased pumping and this is only justified if the extra flow results in an adequate increase in the heat supply. Reducing fluid return temperatures by using low temperature heaters and/or heat pumps will improve the performance of a scheme but again this will only be justified if the extra earnings outweigh the increases in costs. These are complex issues and the precise conditions defining the economics of schemes will only become established through extensive systematic study over the wide range of resource and market situations which are possible. There are two methods of approach to this:

- comparative studies of real and proposed schemes
- modelling of scheme costs and earnings.

This chapter will describe some results which have been obtained through both types of studies.

6.2) Case Studies of Geothermal Heating in France and the U.S.A.

Information on 25 U.S. and 15 French geothermal schemes was collected and analysed. Some of these schemes have been developed, for instance, most of the French schemes. Some of the schemes have been abandoned and others are in abeyance. The current status of all of the schemes is not known to the author. Most of the information on the schemes was drawn from preliminary, pre-feasibility assessments, and some of these were thorough studies which included detailed costings and assessments of scheme performance. Some of the information was taken from accounts or summaries issued after the start-up of the schemes. In this work, the sources are treated as a representative set of preliminary assessments of equal weight. They establish some general economic picture which includes good, bad and indifferent schemes.

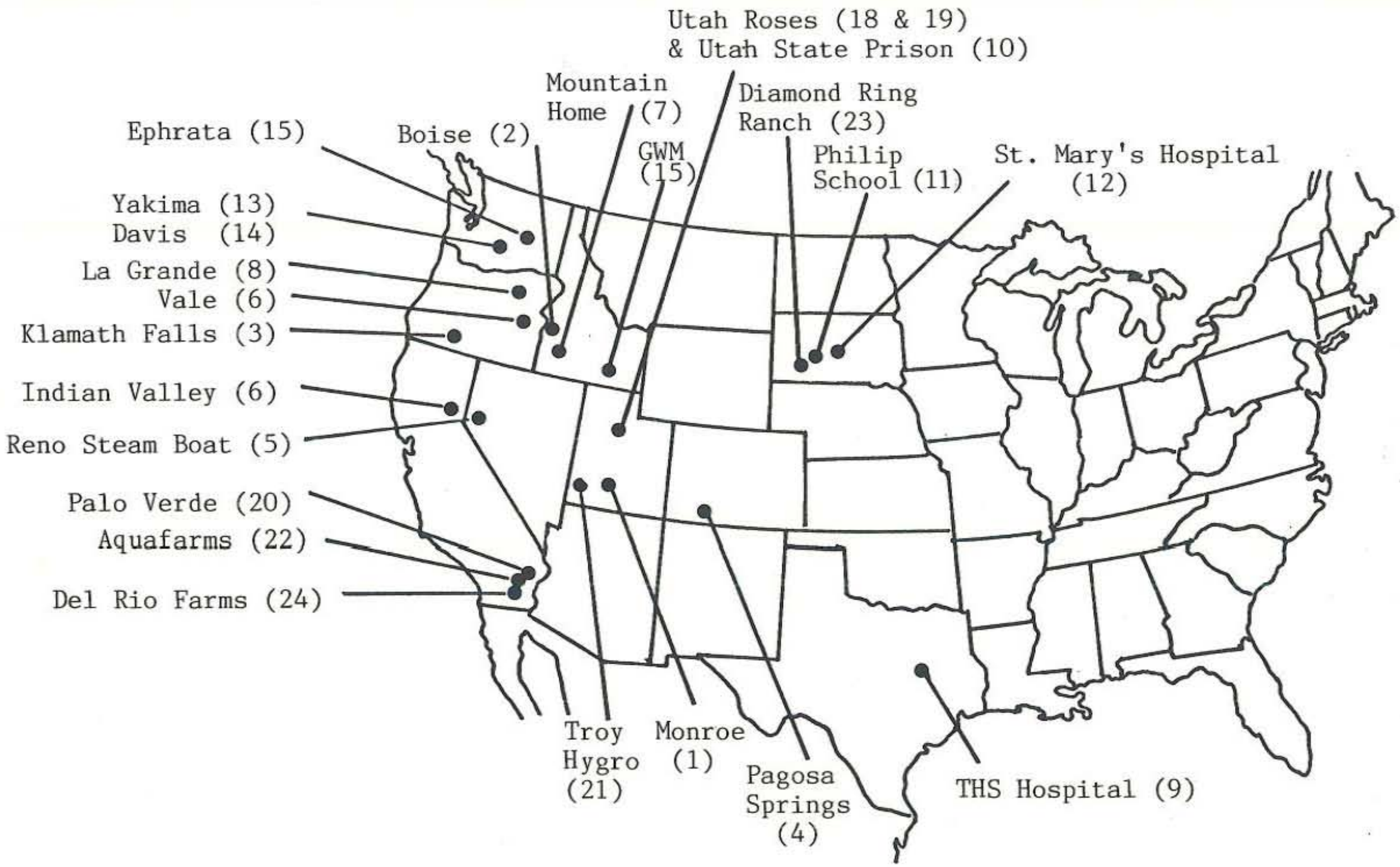
As described above in Chapter 2 with reference to Figures 2.1 and 2.2, the schemes fall into two basic categories with different characteristics. Thus, the U.S. schemes tend to employ high temperature fluids from shallow wells and these are being used to cover all the heating demands of, typically, rather small schemes. This indicates that the developments are taking place in locations with low heat load densities where connection costs are high. The French schemes are in settings with lower thermal gradients, only moderate temperature fluids are available from deep expensive wells. Also, the heat load densities are high and connection costs are moderate. Taken together these are conditions which favour the base load coverage of the demands of large schemes.

These are the most useful points which can be made by considering all of the schemes together. For a more detailed discussion it is appropriate to divide the collection down in different groups and categories.

6.2.1 U.S. schemes

Figure 6.1 shows the locations of the schemes. One of the schemes (9) is situated in the Ouachita structural belt in Texas. Three (11, 12, and 23) use fluids from the Madison Aquifer group in South Dakota and the remainder are in the more favourable resource settings of the Western States. Some of these (2, 3, and 4) are in locations where geothermal heating is well established. All but five schemes employ wells of less than 800 m in depth and sub-surface costs are small elements in the capital costs. For 13 of the schemes the proportion is less than 20%. In these cases, the load factor of the heat load is probably an important economic

Figure 6.1 Locations of U.S. Geothermal Schemes



indication. Two of the process heat applications have high load factors 57% and 90%. Three of the greenhouses have load factors of between 40 and 50% but the schools and the district heating systems have low load factors. Remoteness of the geothermal resource from the heat load and also value of heat load density are two important parameters which affect surface system costs. At the level of $1000 to $1600 (80) per metre transmission costs may be higher than well costs ($100 to $1000 per metre). Only two of the district heating schemes have heat load densities comparable with the levels found in the Paris basin schemes ($\sim$15 MWh m^{-1}) the remainder have values of 6 MWh m^{-1}.

The schemes can be divided into five sub-categories.

The district heating schemes

Eight schemes have been examined and they range, in size of heat load, from 310,000 MWh for the Reno 'Steamboat' scheme down to 3,900 MWh for the Vale scheme. If it were to be developed, the Reno 'Steamboat' scheme would be one of the largest geothermal district heating schemes in the world.

In an attempt to identify any relationships which exist between the main physical parameters of the schemes and the economic indices, the important parameters have been collected together in Table 6.1. Thermal gradient relates to well cost, transmission distance to transmission pipeline costs, heat load density to distribution pipeline costs and load factor to the efficiency with which the facilities are being used. Clearly, the most cost effective scheme configurations will be where a prolific shallow resource is situated close to a large, high density, heat load which has a high load factor. The Boise scheme (No. 2) is the closest to this ideal and it is the most attractive scheme economically. The La Grande scheme (No. 8) would be ranked next in physical terms, it has a lower heat load density than Boise and requires a large number of wells drilled to a greater depth. However, its economic ranking would put it below the Pagosa Springs scheme (No. 4) which is a smaller scheme with a lower

Table 6.1 __U.S. District Heating Schemes__

	Scheme	Capital		Grad	Heat load	L	Heat load Density	Trans$^{\underline{n}}$ Distance	Competing Fuel	Discounted Unit Cost \$/MWh	
		W %	S %	°C km^{-1}	MWh	%	MWh m^{-1}	m		Geotherm	Ref.
1	Monroe (1982)	17	83	144	7,350	30	4	600	Coal	25·5	9·5
2	Boise (1982)	52·5	47·5	110	64,700	?	21	0	Gas	6·7	21
3	Klamath Falls (1982)	3	97	104	13,300	25	5·8	1,240	Gas	14·84	23
4	Pagosa Springs Full Size (1981)	?	?	500	16,920	12	5·3(?)	0	Gas	9·6	23
4	Pagosa Springs Initial Scheme (1981)	?	?	500	8,400	12	5·3(?)	0	Gas	16·4	23
5	Reno Steamboat (1981)	16	84	835	310,000	26	6·5	11,600	Gas	19	25
6	Vale (6) (1982)	6	94	200	3,900	?	3·1	0	Fuel Oil & Electricity	16·6	32·5
7	Mountain Home Base (1982)	27	73	55	35,000	18	2·19	7,300	Fuel Oil	30	41·7
8	La Grande (8) (1982)	16	84	86	58,750	18	13	0	Gas	18·6	29·9

W = wells; S = surface; L = load factor

Discounted unit costs are calculated in the currency of the year of the study heat load density. The capital cost estimates of the Pagosa Springs scheme do not include any provision for building retrofit and the inclusion of these costs could have a significant and detrimental effect on the schemes economics and may alter its ranking in relation to the La Grande scheme. The Klamath Falls scheme is similar to Pagosa Springs in terms of size and heat load density, however, the wells are remote from the heat load in this case and an expensive transmission pipeline is required which accounts for 54% of the capital costs. The resources are even more remote in the Mountain Home (No. 7) and Reno Steamboat (No. 5) schemes. Transmission accounts for 30% of the capital costs in the Reno case. The Mountain Home scheme also has a very low heat load density. This scheme has the highest discounted unit cost of heat delivered; it is only economic because of the comparison with the costs of fuel oil-fired heating which is the current major form of heating on the air base.

The smallest schemes are Monroe (No. 1) and Vale (No. 6). Both have low heat densities and the Monroe scheme has, in addition, high costs associated with a transmission pipeline and an injection well. However, despite the adverse physical characteristics, the major reason for the poor economics of the Monroe scheme lies in the comparison with the costs of cheap coal-fired heating. The Monroe scheme would be economic, even if only marginally so, if it were compared with the reference discounted unit costs of any of the other schemes. The attractive economics of the Vale scheme, on the other hand, are largely due to the comparison with a high cost heating system.

With such a small collection of schemes it is not possible to go further than these qualitative comments in identifying the relationship between the physical parameters of the scheme and the scheme economics. As a group, the schemes exhibit a high degree of diversity with the important five or so physical parameters varying substantially from scheme to scheme. The precise definition of the dependence of scheme economics on physical parameters would require a substantial study and could be a difficult task.

Finally, it is not clear whether investment in these schemes would give adequate internal rates of return. In some of the schemes the investors do not have guaranteed heat sales and there must be considerable uncertainty about the extent to which the geothermal heat will penetrate the potential market.

Heating of public buildings

Public buildings are examined separately because, in general terms, they are attractive prospects for geothermal heating as they usually represent large high-density heat loads (the reverse of single family dwellings). Hospitals have, in addition, high occupancy levels and reasonably high load factors, e.g. Case 16 has a load factor of 20%. In addition, forced air heating systems are often used in hospitals and these are particularly suitable for geothermal applications because of the low return temperatures which are possible. On the other hand, some public buildings such as schools and colleges may have low utilisation factors which would give low system load factors. The district heating schemes in the last section nearly all involve some public buildings and the La Grande scheme is almost entirely comprised of public buildings. To this extent the distinction between these two categories is artificial.

Four of the schemes employ direct heat exchange and five employ heat pumps. The physical and economic characteristics are given in Tables 6.2 and 6.3. The four schemes employing direct heat exchange are similar in size and all have poor fluid conditions. In the two hospital schemes (Nos. 9 and 12), low flows and temperatures have limited the usefulness of the geothermal fluid with the result that only 60% of the heat load is derived from the fluid and significant fossil fuel fired heating loads remain. In the case of St. Mary's Hospital (No. 12), high-cost fuel oil is displaced and the geothermal scheme is economic. However, at the T.H.S. Hospital, natural gas is being displaced and the scheme is uneconomic. In this latter case, even with improved fluid conditions which would allow 100% geothermal coverage of

Figure 6.2 **Public Buildings Summary**

	Scheme	Capital		Grad °C km^{-1}	Heat load MWh	L %	Competing Fuel	GC %	Discounted Unit Cost $/MWh	
		W %	S %						Geotherm	Ref.
9	THS Hospital (1982)	36·6	63·4	46	2600	15	Gas	61	41·5	25·4
10	Utah State Prison (1981)	?	?	230	4853	?	Gas	66	18·4	17·1
11	Philip School (1982)	20	80	45	2500	18	Electricity & Fuel Oil	100	36·4	37·8
12	St. Mary's Hospital (1981)	?	?	46	5830	?	Fuel Oil	58	30·8	38·16

GC = percentage coverage of heat load by geothermal heat

W = wells

S = surface

L = load factor

the heat load, the scheme would still be uneconomic. The Utah State Prison Scheme (No. 10) is another case of limited geothermal flow. Here, despite a restricted heat load, only 66% geothermal coverage is obtained, however, in this case increased flow could transform the economics of the scheme. The discounted unit costs of the geothermal heat supplied to Philip School (No. 11) are very high, however, high cost fuel oil and electricity are being displaced in this case and the scheme is marginally economic. The temperature of the fluid employed at St. Mary's Hospital is 42°C and this is the lowest temperature fluid employed in any of the direct heat exchange schemes in this study. Of the five heat pump schemes, three (Nos. 13, 14 and 15) have low heat loads (∿4,500 MWh). The other two (Nos. 16 and 17) have extremely low heat loads. These last two have the highest discounted unit costs of all of the schemes examined. The economics of these schemes, taken as a group, are marginal, only in the case of Ephrata Schools (No. 15) does the internal rate of return approach 10% and this is a case where there are no well costs, no fluid distribution costs and where the comparison is with high-cost fuel oil. In the cases of the schools (Nos. 13, 14 and 15) the heat pumps represent 40 to 50% of the capital costs and the utilisation factor achieved by this element of these investments must be important for scheme economics. In all cases, the heat pump is designed to meet the demands of the peak heat load and this gives the lowest possible utilisation factors. It may be that the economics of these schemes would be improved if the size of the heat pump was reduced to a base load or to an intermediate load level. There would be a need for some fossil fuel fired backup heating if this were done, however, the costs of this could be more than offset by reductions in the heat pump costs. In order to test whether reducing the rating of the heat pump would improve the economics, the case of Ephrata schools was re-examined. It was assumed that halving the heat pump rating would reduce the heat pump assisted geothermal coverage to 80% of the total heat load. This is typical of French heat pump exploit-

Table 6.3 **U.S. Heat Pump Schemes**

	Scheme	Capital		Grad	Heat Load	L	Competing Fuel	Discounted Unit Cost $/MWh	
		W %	S %	°C km^{-1}	MWh	%		Geotherm	Fossil Fuel
13	Yakima College (1982)	30	70	54	4544	17	Gas	29·55	27·86
14	Davis High School (1981)	18	82	55	4400	19	Gas	30·6	27·37
15	Ephrata School (1980)	0	100	36·5	4588	17	Fuel Oil	26·9	34·65
16	Indian Valley Hosp. (1980)	30	70	230	405	28	Electricity	54·1	56·95
17	Merrill Church (1981)	16	84	74	94	?	Fuel Oil	77·87	38·84

W = wells

S = surface

L = load factor

Unit costs calculated in the currency of the year of the study ations. In a simple calculation, it was assumed that the heat pump capital and associated costs (including maintenance) would be reduced by half while the present worth of the geothermal fuel costs would be increased because of the need for fuel oil to provide backup heat. The result was to increase the NPV of the project from $\$460 \times 10^3$ to $\$611 \times 10^3$. If the backup heating was to be provided by electricity (which is particularly cheap in this case) rather than fuel oil then the NPV would be increased to $\$802 \times 10^3$ and the discounted unit cost of the heat pump assisted scheme with electric backup heating would be \$21 per useful MWh compared with \$34·4 per useful MWh for the fuel oil-fired reference scheme. It would appear that further analysis of these three schemes: Ephrata, Davis and Yakima may reveal optimum configurations which are significantly better than those represented in Table 6·3.

The relative levels of electricity and heating fuel prices are important for the economics of these schemes. Heat pumps have large parasitic loads associated with the engine which drives the compressor. In all of these schemes the compressors are electrically driven. If the coefficient of performance of the heat pump is about 3 then 1 MWh of electricity will displace about 3 MWh of useful heat which would be generated from fossil fuel. Thus, from the point of view of fuel costs alone this can be economic only if:-

Electricity costs per MWh $<$ 3 x fossil fuel costs per useful MWh.

For the three schools, the electricity costs are very much less than 3 x the fossil fuel useful heat costs. These relative costs are highly favourable for the viability of these schemes. In fact, the electricity costs are so low in these locations that direct electrical heating may in fact be the most economic heating option. Even given these favourable conditions the economic performance of these schemes is poor; this must be a pessimistic indication of the economic prospects for geothermal exploitations using electrically driven heat pumps in the U.S.A.

Greenhouse heating

The data on these schemes is summarised in Table 6.4. Four schemes have been studied, three of these are in Utah (Nos.

Table 6.4 **U.S. Schemes – Greenhouse Heating**

	Scheme	Capital		Grad	Heat Load MWh	L %	Product	Competing Fuel	Discounted Unit Cost $/MWh	
		W %	S %	°C km^{-1}					Geotherm	Fossil Fuel
18	Utah Roses Sandy (1981)	72	28	26·5	13,000	44	Roses	Gas	17·6	20·6
19	Utah Roses Bluffdale (1981)	?	?	629	6,600	44	Roses	Gas	1·7	19·7
20	Palo Verde (1982)	7·3	92·7	86	2,860	14	Cucumbers	Gas	15·7	26·37
21	Troy Hygro (1982)	6·9	93·1	644	17,600	49	?	–	2·82	17·13

GC = percentage of the total load met by geothermal heat

W = wells

S = surface system

L = load factor

Unit costs calculated in the currency of the year of study

18, 19 and 21) and the other (No. 20) is in Southern California. The greenhouses in Utah have a specific heat load 0·54 MWh per m^2 and load factors of 44% while the one in California has a specific heat load of 0·15 MWh per m^2 and a load factor of 14%. The differences are presumably due to differences in climate between the two locations and also to the different requirements of crops. Three of the greenhouses (Nos. 18, 20 and 21) employ low temperature forced air heating systems; these systems are particularly well suited to geothermal applications as they enable low return temperatures to be obtained. The relationship between the solar heating action of the transparent greenhouse covering and the geothermal heat is interesting. The solar heating tends to reduce supplementary heat demands and there will be situations when the solar heating will tend to displace geothermal heat. It could be that the use of geothermal heat in these applications opens up interesting opportunities in the area of greenhouse fabrication.

The economics of greenhouse heating depends primarily upon the market for the produce. The costs of a reference heating system are irrelevant if the greenhouse produce is not sufficiently valuable to be able to recoup these costs through earnings. In two of these schemes the discounted unit costs of the geothermal system are relatively high. The Sandy greenhouse (No. 18) has only 47% coverage of the heat load, and the unit costs include the costs of backup gas heating. The Palo Verde greenhouse (No. 20) has a low load factor of 14% when compared with the other greenhouses and this will have increased the unit costs in this case. These two schemes require high value products to justify their operation. The other two schemes have low discounted unit costs and would be economically viable with lower value products.

Process heating applications

These are four very different schemes, see Table 6.5. Neither the Aquafarms scheme nor the Del Rio Ethanol scheme has a fossil fuel fired equivalent, hence the discounted unit costs

Table 6.5 **U.S. Schemes – Process Heating**

	Scheme	Capital		Grad	Heat load	Load	Product	Competing	Discounted Unit Cost $/MWh	
		W %	S %	°C km^{-1}	MWh	Factor		Fuel	Geoth	Ref
22	Aquafarms (1982)	8·7	91·3	250	50,000	57	Prawns	–	–	–
23	Diamond Ring Ranch (1981)	?	?	45	2,300	27	Grain & Space Heat	Electricity & Propane	18·58	29·15
24	Del Rio Ethanol (1980)	9	91		106,000	90	Ethanol & Animal Feed	–	–	–
25	Great Western Maltings (1981)	37	63	90	126,000	–	Malt	Gas	13·7	25·8

GC = percentage of the total load met by geothermal heat

W = wells

S = surface system

Unit costs calculated in the currency of the year of study are irrelevant indices in these cases. In a sense, the economics of these schemes are similar to those of the greenhouse schemes, being ultimately dependent upon the market for products other than fuels. The Aquafarms project is dependent upon the local market for prawns and the economics of the Del Rio scheme are dependent upon the relative markets for ethanol, feedstock and by-product. Small shifts could undermine the economics of the scheme. The Diamond Ring Ranch Scheme is of a different type the heat load is a mixture of space heating and grain drying. The maltings is a different type of application again. From an energy point of view the malt production process is mainly one of grain drying in a low temperature forced draught kiln. This application is well suited to geothermal energy. The heat load is very large and scheme economics are insensitive to fluid parameters. This is likely to be the most economically viable of the schemes which are represented in this collection, never-the-less, this development is in abeyance because of uncertainties regarding the future of gas prices in the area.

Effects of the markets and the appraisal assumptions

The costs of heating fuels in the U.S.A. have been discussed in Chapter 4. Price and availability can change substantially from one location to another.

The relative competitiveness of the geothermal costs in relation to fossil fuel price levels is complex because of the range of fossil fuel prices. Figure 6.2 shows the situation. Two of the schemes are more expensive than fuel oil, two are only economic with respect to high price fuel oil. The bulk of the schemes are consistently cheaper than fuel oil but in competition with gas their economics will depend upon local prices. Schemes which would be economic in high price areas may not be economic in low gas price areas. Only five of the schemes have geothermal unit costs which are lower than gas prices in the cheapest locations. The discounted unit costs of geothermal heat for all of the schemes are shown in Table 6.6 adjusted to the same year

Figure 6.2 <u>Unit Costs of Heat Delivered from the Geothermal Schemes Compared with the Range of U.S. Natural Gas and Fuel Oil Prices</u>

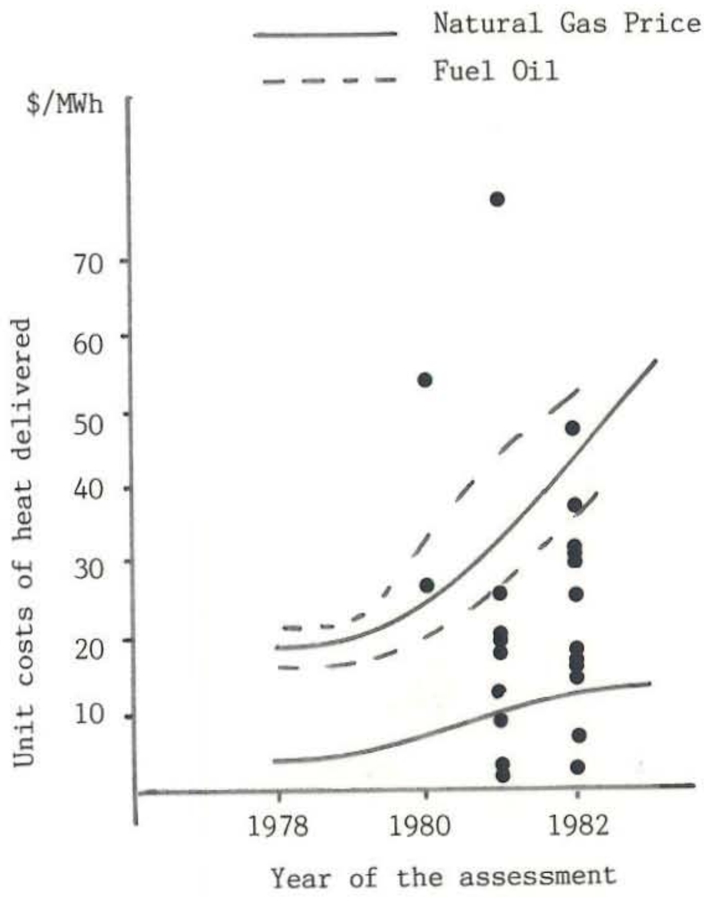


Table 6.6 U.S Schemes - Summary of Unit Costs and Internal Rates of Return

Scheme No.		Discounted Unit Cost $(82) per MWh	Internal Rate of Return Pessimistic	Optimistic
District Heating				
Monroe	1	25·5	<- 9	- 8·23
Boise	2	6·7	24·2	27·4
Klamath Falls	3	14·8	6·13	10·4
Pagosa Springs	4	10·6	17·4	21
Reno	5	20·9	4·1	8·76
Vale	6	16·6	10·8	14·6
Mountain Home	7	30·0	4·5	8·8
La Grande	8	18·6	7·1	11·3
Average		18·0		
Public Building (Direct)				
THS	9	47	<- 9	- 3·6
Utah Prison	10	21·6	- 2·3	3·1
Philip School	11	32·7	0·2	5·0
St. Mary's	12	28·2	6·9	11·6
Average		32·4		
Heat Pump				
Yakima	13	29·6	- 1·9	3·5
Davis	14	30·6	- 4·7	2·1
Ephrata	15	35·5	5·0	9·9
Indian Valley	16	65	0·3	6·0
Merill	17	78	<- 9	- 7·7
Average		47·8		
Greenhouses				
Utah Roses (S)	18	14·3	7·0	11·0
Utah Roses (B)	19	2·1	150	154·6
Palo Verde	20	15·7	10·4	14·4
Troy Hygro	21	2·8	55·3	58·3
Average		8·7		
Process Heating				
Aqua Farms	22	-	40·2	40·4
Diamond Ring	23	20·6	6·4	10·6
Del Rio Ethanol	24	-	- 0·14	11·6
GWM	25	2·6	105	109

Pessimistic assumptions scheme life 15 yrs. fossil price rise 0

Optimistc assumptions scheme life 20 yrs. fossil price rise 1·8%

(1982). As a group the geothermal unit costs of the greenhouse schemes are the lowest averaging \$8·7 (82) per MWh the district heating schemes are next \$18 (82) per MWh with the public buildings at \$32·4 (82) per MWh (direct exchange) and \$47·8 (82) per MWh (heat pump). If the two very small heat pump schemes are excluded (Nos. 16 and 17), this average falls to \$31·9 (82) per MWh. Because of the details of schemes 9, 12, and 16, it is likely that these results give an unduly pessimistic indication of the economics of the geothermal heating of hospitals.

Table 6.6 shows the effect of changing the assumptions of the appaisal on the internal rates of return. Using assumptions, which would have been acceptable in 1982, the IRR's of all the schemes apart from four (2, 19, 22 and 25) are poor. Six of the schemes have IRR's less than 5%. These preferred assumptions include a 2% real rate of increase in fossil fuel prices. If it is assumed that fossil fuel prices do not increase at all and that scheme lifetimes are shorter than expected, then the number of schemes with IRR's less than 5% increases to 12.

6.2.2 French schemes

The use of medium and low temperature brines from deep aquifers for district heating is well established technology in France. Agence Francaise Pour La Maitrisse de L'Energy (AMFE) (Ref. 6.1) report that since 1978 twenty geothermal schemes have been put into operation every year and it is foreseen that France will have an installed geothermal heating capacity equivalent to an annual saving of 10 tonnes of oil equivalent* by the late 1980's. These forecasts were made before the fall in oil prices which has occurred in recent years and recent developments have not matched expectations. Never-the-less a major programme is under way.

Figure 6.3 shows the general location of the schemes which have been studied and the main technical and economic characteristics are given in Tables 6.7 and 6.8. All of the schemes are either operating or under active development.

The schemes employ deep, expensive wells in the main. Depths

Figure 6.3 Location of French Geothermal Schemes

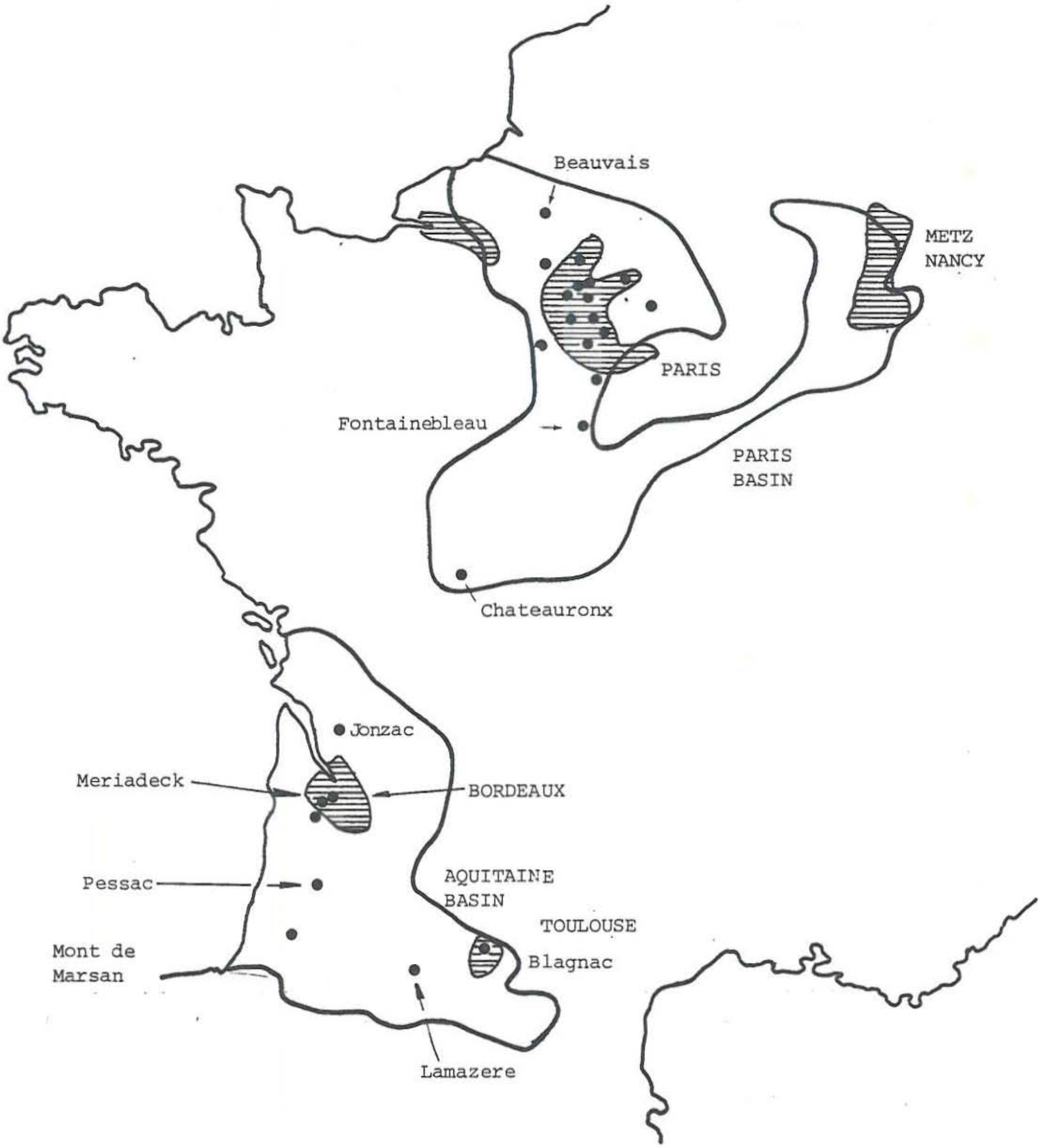


Table 6.7 **French Geothermal Direct Heat Exchange Schemes**

	Scheme	Capital		Grad °C km^{-1}	Heat load MWh	Heat Load Density MWh m^{-1}	Competing Fuel	Coverage %	IRR %	Discounted Unit Cost		
		Well %	Surf %							Geothermal FF/MWh	Reference FF/MWh	GDC 82+ FF/MWh
1	Garges Nord (80)	58	42	28·8	35,000	–	Fuel Oil	73·3	8·5	170	190	206
2	Garges Est (80)	55	45	34·5	40,000	–	Mixture	73·7	10	188	234	227
3	Fontainbleau (79)	45	55	36	45,746	13	Mixture	61·6	7	130	142	173
4	Orly (80)	64	36	33	42,850	–	Heavy Fuel Oil	55	8·1	144	156	174
5	Meaux zup Beauval (82)	35	65	35	191,900	–	–	80	20·5	118	196	118
6	Ris Orangis (81)	57	43	38	37,434	–	–	92	20·5	119	241	131

W = Well cost

S = Surface system

* Costs in the currency of the year of the estimate

\+ Corrected to 1982 using 10% inflation index lie between 800 and 2000 m sub-surface costs account for between 30 and 50% of total capital costs for 9 schemes and over 50% of capital for five schemes. The heat loads are large ranging from 8000 to 190,000 MWh (400 - 9500 dwellings) with an average of 57,000 MWh (2850 dwellings). The wells are situated close to the heat loads and in most cases the reservoir is exploited using a deviated doublet consisting of production and reinjection wells. Transmission costs, therefore, are low. Heat load densities are high ranging from 13 to 28 MWh per m^{-1} of distribution piping. Some area densities between 21 and 37 MW km^{-2} were measured. Also, it is common practice for existing group and district heating facilities to be adopted and modified in geothermal schemes. This seems to have been done to varying degrees in all of the schemes apart from two (3 and 15). As has been discussed in Chapter 2, heating system return temperatures limit the amounts of heat which can be extracted from the geothermal brine. There are a substantial number of dwellings in France which are heated by floor heaters. These have low operating temperatures, typically 52°C supply and 42°C return at peak loads. The inclusion of dwellings of this type in a geothermal scheme gives low return temperatures and hence is advantageous. Normally, the heat loads consist of a mixture of dwelling types, some using floor heaters and others using conventional, higher temperature, radiators. When this occurs, the French practice is to engineer the network, as far as possible, with 'cascade' connections so that the returns from the high-temperature users are used to supply the low-temperature users. This is shown in Figure 2·6 above. In eight of the schemes totally 19,600 dwellings 55% of the dwellings were heated by floor heaters.

Although the schemes are all economically viable in some degree the internal rates of return vary from normally unacceptable levels of 2% to attractive levels of 20%. Many of the schemes would not be economically viable without the support which the French government gave to geothermal development at this time.

It is difficult to draw clear conclusions by comparing the

Table 6.8 French Geothermal/Heat Pump Schemes

Scheme (Date)	Capital		Fluid		Heat Load MWh	Heat Load Density MWh m^{-1}	Competing Fuel	Coverage %		IRR %	Discounted Unit Cost		
	W %	S %	T	°C/km^{-1}				DE	HP		GDC* FF/MWh	RDC* FF/MWh	GDC 82+ FF/MWh
Beauva is (79)	45	55	47	33	25,037	18	Fuel Oil	0	73	3·2	136	130	181
Pessac (82)	45	55	47	41	17,813	–	Heavy Fuel Oil	56	34	2·1	176	305	176
Chateauroux (79)	30	70	35	34·5	22,856	21·8	Gas	6	57	2·3	100	92	133
Bruyeres (82)	29	71	34	32	15,800	–	Heavy Fuel Oil	?	?	10·4	267	334	267
Creil (79)	64	36	59	28	85,850	28	Mixture of Low Grade Oil	42	35	8·2	110	126	142
Meriadeck (79)	42	58	53	37·4	8,331	9·25	Electricity	?	?	20·4	145	311	193
Acheres (83)	46	54	55	28	45,540	–	–	51	31	7·4	331	361	301
Aulnay (83)	30	70	71	34	116,290	–	Heavy Fuel Oil	31·6	20	20·2	171	241	171
Pt. St. Cloude (83)	13	87	61	32	130,000	–	–	47		4·4	318	317	290

W = well cost
S = surface system
T = fluid temp.

DE = direct heat exchange
HP = heat pump

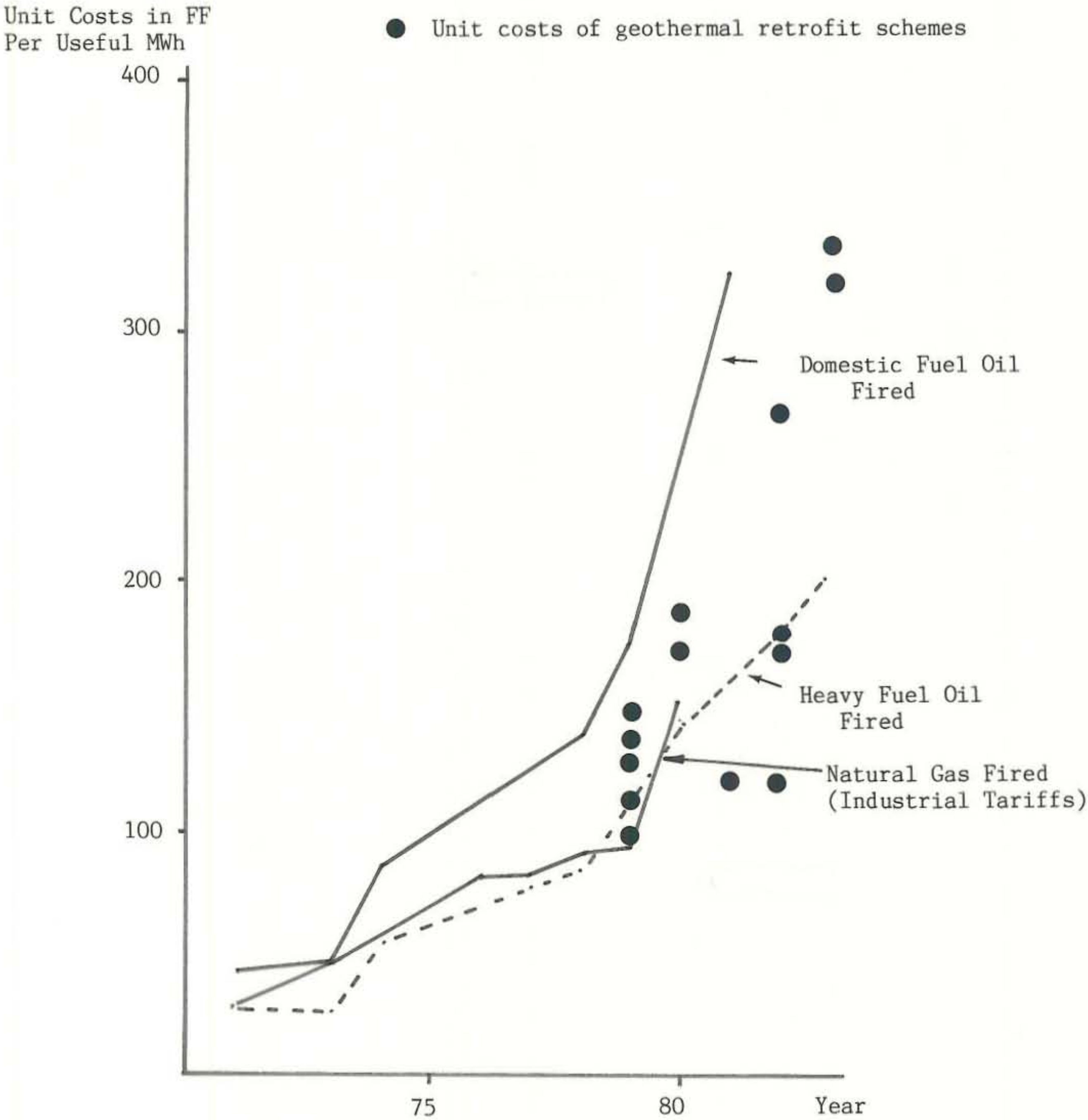
* Costs in the currency of the year of the estimate

\+ Corrected to 1982 using 10% inflation index economics of the schemes. This is for two main reasons. Firstly, none of the schemes are newly built, they all involve the modification of existing heating systems but to varying degrees. Thus, in the Fontainbleau scheme existing boiler houses have been connected together by a new distribution network. In the Orly scheme, on the other hand, only minor modifications to existing networks have been required. Thus, two schemes which are similar in terms of resourses and heat load could have very different capital costs. Also, secondly, as for the U.S. schemes, the heating markets constitute a potentially confusing factor. Thus, the Bruyeres-le-Chatel scheme has one of the highest geothermal discounted unit costs but the reference scheme costs are also high and this gives the scheme an acceptable internal rate of return. However, notwithstanding these difficulties, some points can be made. The economics of the direct heat exchange schemes are marginally better than those of the heat pump schemes. Four of the heat pump schemes employ fluids with temperatures below 50°C and in two of these at least (7 and 9) it is clear that the majority of the geothermal heat is delivered via the heat pump. In the other heat pump schemes fluid temperatures are higher, between 53 and 71°C, and the heat pump is only a more minor element in the scheme delivering about half the amount of heat delivered by the heat exchanger. Four of the heat pump schemes employ single wells.

The French heating fuel market has been discussed in Chapter 4 where data on costs are given. Figure 6.4 shows the unit costs of heat delivered from fifteen French schemes compared with the costs of heat delivered from fossil fuel fired heating schemes. This comparison indicates the economic advantages of retrofitting conventional heating schemes to include a geothermal component.

It can be seen that, the geothermal costs are consistently cheaper than the costs of domestic fuel oil. Also, for some systems the geothermal costs are cheaper than heavy fuel oil and coal. On the other hand, it is clear that if gas supplies could be obtained at prices which are close to industrial gas prices - which may be possible with these large heat loads - then the most economic prospect in many cases would be to convert from domestic fuel oil fired heating to gas fired heating.

Figure 6.4 <u>**Unit Costs of Heat Supplied by Fossil Fuel Fired District Heating Schemes (Current FF)**</u>



6.3) Results of Modelling Studies

Cost models which consistently take account of the way in which changes in resource conditions and scheme parameters affect cost and earnings are powerful tools in the field of geothermal engineering economics. They can be used to carry out sensitivity studies and a number of such studies have been carried out by researchers in Europe and in the U.S.A. (see Refs. 6·2 and 6.3). The results which are described in this section have been produced by using the LEGS computer program (Ref. 6.4) to model the performance of the schemes and to carry out the economic appraisals. The WELC program has been used to estimate well costs. The study was carried out to obtain some indications of the prospects for low enthalpy geothermal developments in sedimentary basins in the United Kingdom and the details are appropriate to the resource and heat load conditions in the U.K. However, some basic trends which will be more generally valid can be seen.
Two broad areas are considered.

6.3.1 Resource/reservoir conditions

There are many parameters which define the conditions of the reservoir and a variety of different studies can be carried out to resolve different issues. The following are some important examples.

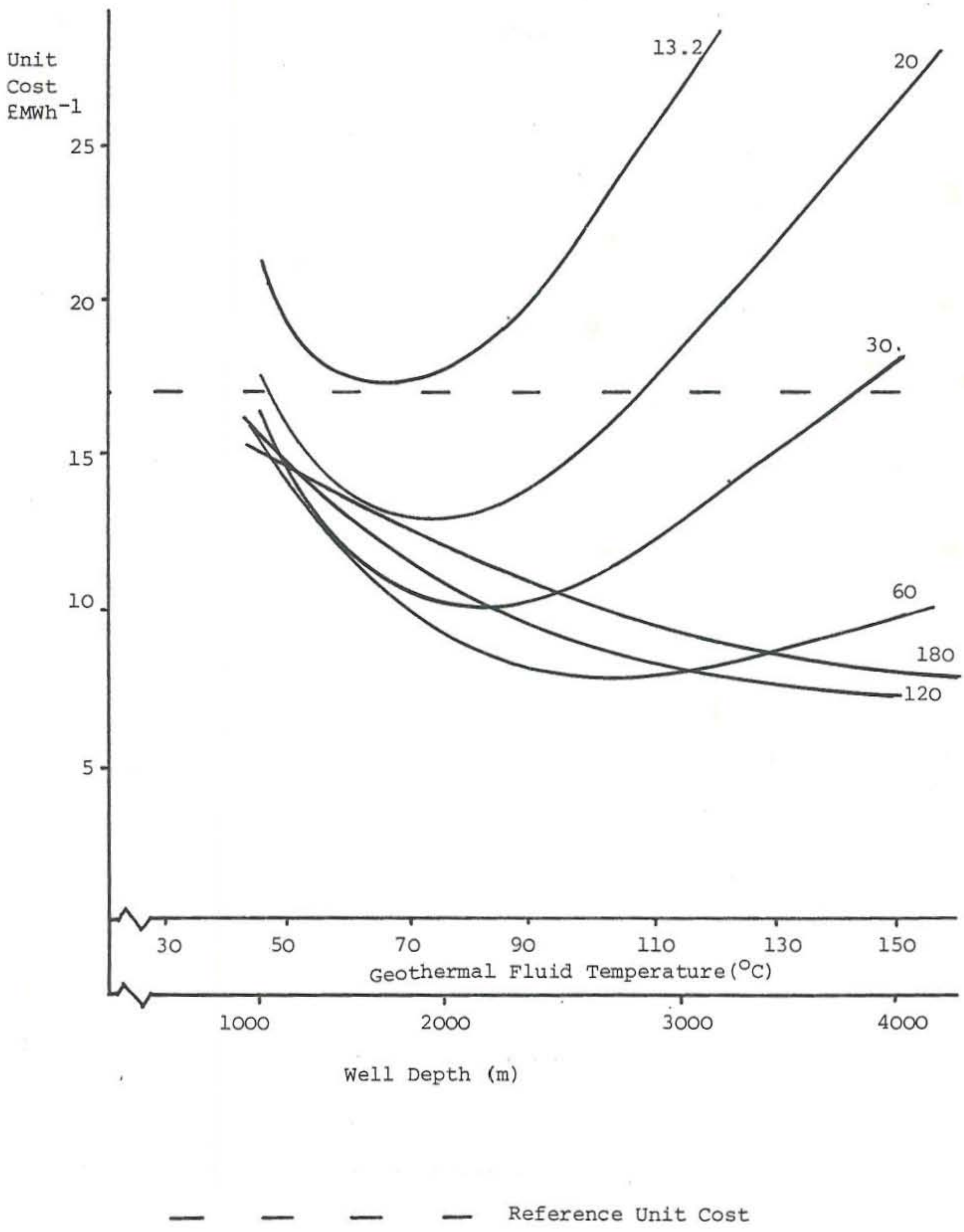
Aquifer depth and scheme costs

The issue being investigated in this example is the advantage of deeper drilling in the context of a fixed thermal gradient. Figure 6.5 shows how unit costs vary with aquifer depth for a variety of scheme sizes. The form of the curves is not difficult to understand. Thus, initially, as the resource conditions improve and higher temperatures are obtained increasing fuel savings are made and the earnings increase at a faster rate than do costs. Hence, the unit costs fall. However, eventually the heat loads become saturated; no advantage can be obtained from increased temperatures and hence a region of diminishing returns occurs. In this region earnings are rising slowly while costs are rising quickly and thus unit costs rise.

Figure 6.5 Unit Costs Versus Well Depths at Various Scheme Size

Scheme Size as marked ($GWhyr^{-1}$)

Temperature Gradient - $35^{o}C\ km^{-1}$



In general terms, the high costs associated with deep drilling can only be recouped by connection to large schemes with large earning capacities. Thus, with schemes in the region of 30,000 MWh it is economic to drill to 2,000 m to develop an aquifer. However, drilling deeper to 3,000 or 4,000 m is only justified if heat loads in the region 60,000 to 120,000 MWhs are available. This has important consequences for the assessment of geothermal reserves.

Production flow and scheme costs

Unit costs are a function of the production flow which is chosen and of the details of the reservoir properties. By using well pumps, the scheme designer has some control over the level of production flow. Figure 6.6 shows how unit costs change as production flow from a given reservoir is increased. Again, the behaviour is shown for a collection of heat loads of different size.

The form of the curves is similar to that of the curves in Figure 6.5. The same arguments explain the behaviour. Thus, initially, as the production flow is increased, the scheme earnings increase more quickly than costs and unit costs fall. Ultimately, the ability of the heat load to absorb the heat from the increasing amounts of fluid declines and slowly increasing earnings do not compensate for the increasing pumping costs. Therefore, unit costs rise. There is an optimum match between scheme size and fluid production in any particular situation. However, the curves are slowly varying and while it must be important to identify the optimum region, obtaining an exact match is not critical.

Reservoir conditions such as transmissivity and 'skin' factors can have significant affects on pumping costs and when the conditions are poor these can dominate scheme costs. In Figure 6.7 one of the scheme sizes from Figure 6.6 has been taken as the base case and the effects of reservoir transmissivity is shown. With good transmissivities, e.g. 20 Dm and above, the sensitivity of the unit costs is not strong. However, with poor transmissivities e.g. below 12 Dm, the sensitivity is much greater and pumping costs alone can

Figure 6.6 The Dependance of Unit Costs upon Well Flows

Scheme sizes are marked ($GWhy^{-1}$)

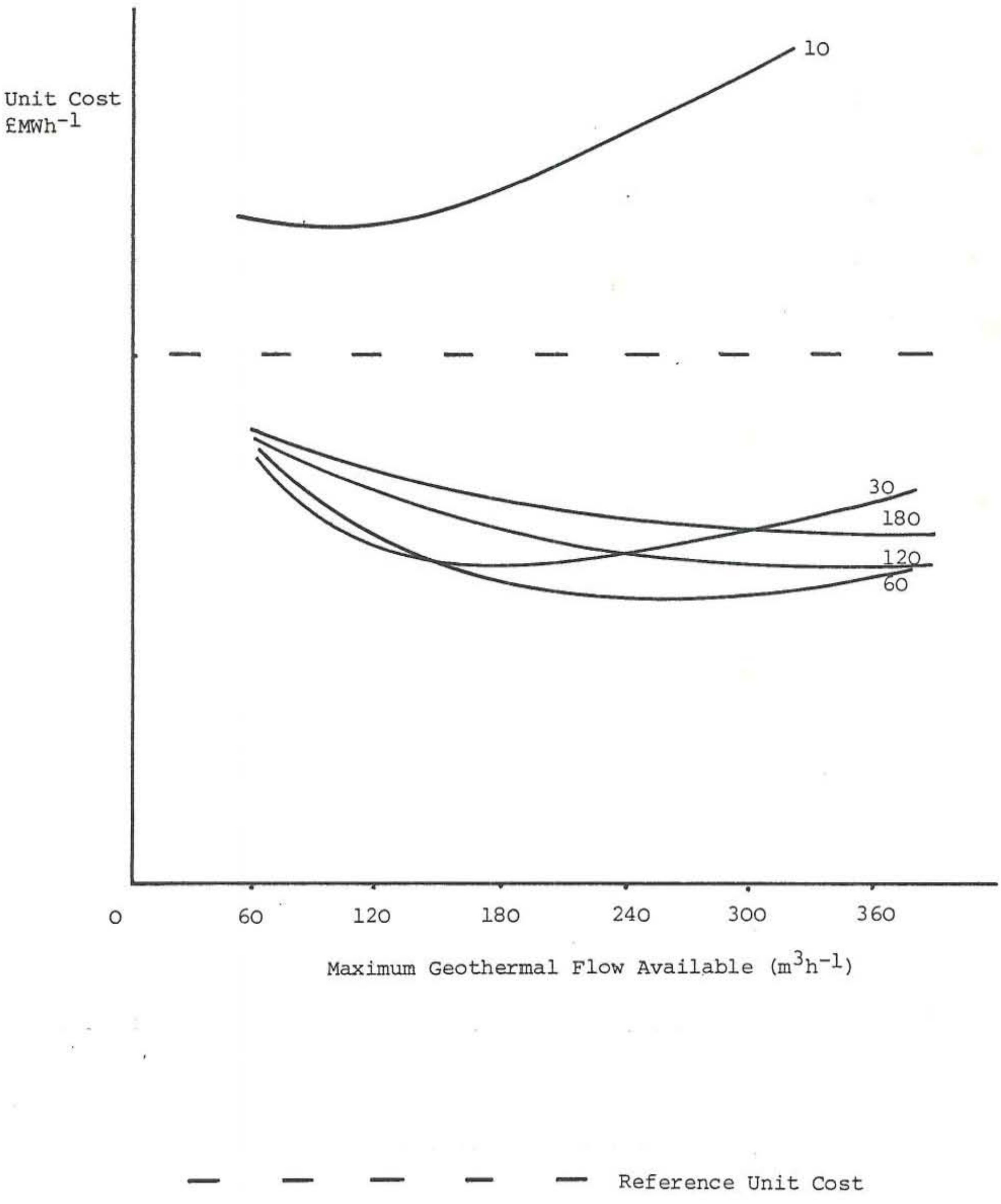
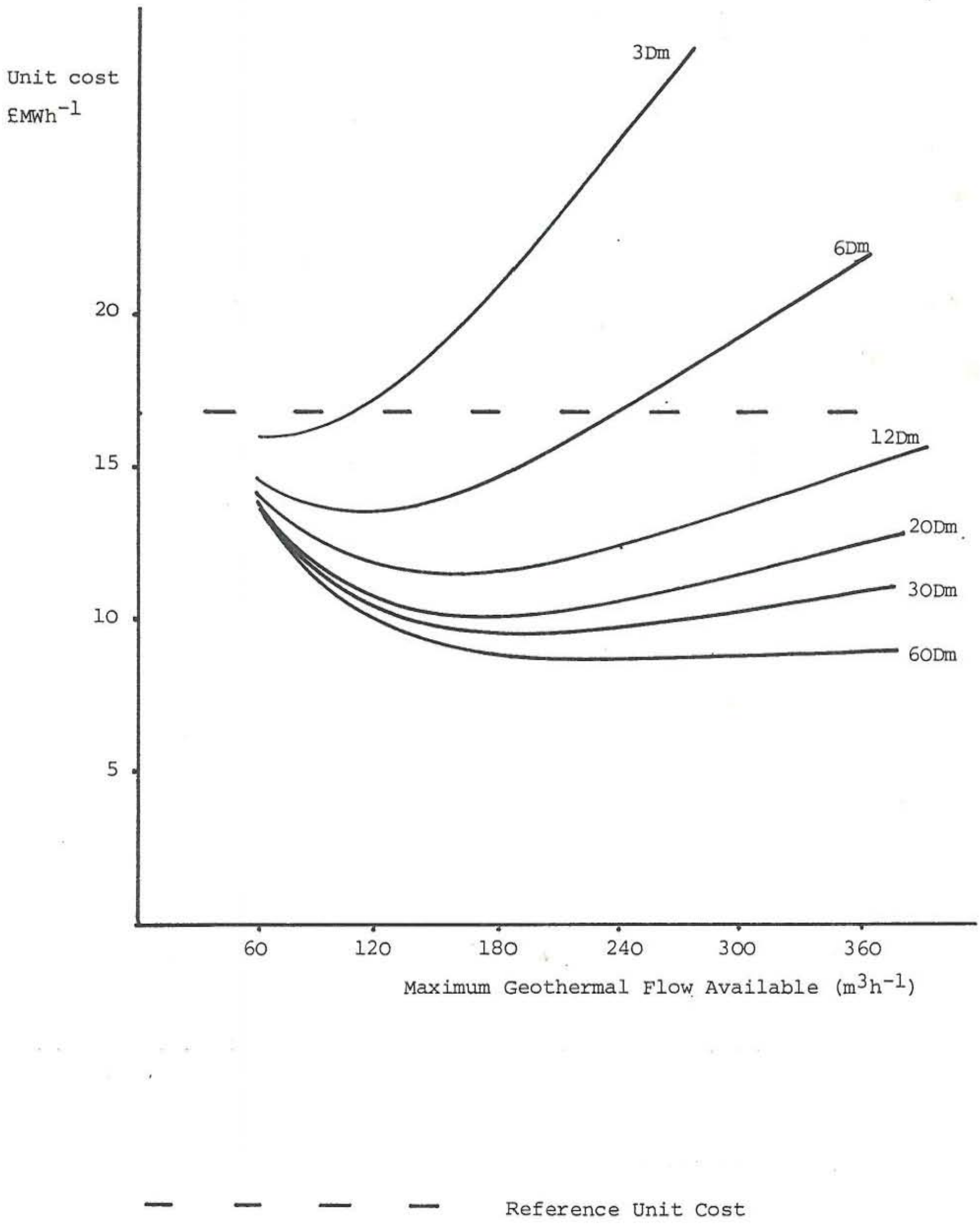


Figure 6.7 Unit Cost Versus Production Geothermal Flow at Various Transmissivities

Scheme size - 30 $GWhyr^{-1}$

Transmissivities as marked



result in non-viable schemes. This effect is particularly important with doublet schemes. With single well schemes slightly lower transmissivities can be tolerated, but the lower limit is still in the region of 6 to 10 Dm.

'Skin' factors relate to the condition of the reservoir in the immediate vicinity of the well bore. Positive 'skins' occur when the formation is damaged in some way such that flow is impeded; clogging with drilling and is a common cause. Negative 'skins' occur when the formation is opened up in some way so that flow is increased; stimulation using acids can achieve this. Figure 6.8 shows how 'skin' can have significant effects on unit costs. In some cases reservoir damage due to inappropriate drilling muds can severely impair the economics of fluid extraction.

6.3.2 Technical approach

Again, a number of issues could be considered, two examples are given.

Heater characteristics

Figure 6.9 shows how unit cost of heat depends upon the 'design' return temperature T_{uo} of the heaters for a variety of geothermal fluid temperatures. If high temperature fluids are available then heater temperatures are important. With low temperature fluids low return temperatures are necessary for viable schemes.

Heat pumps

Heat pump capital costs are high and, in addition, they incur high running costs associated with the compressor fuel. In order to be economically viable the heat pump must operate for long periods and give significant fuel savings. The heat pump size should be the subject of an optimisation study in each scheme. It has not been possible to fully optimise heat pump sizes in all of the cases considered in this study and lower costs may be obtained by further careful study of individual schemes.

The general effect of including heat pumps is shown in Figure 6.10.

Figure 6.8 Unit Cost Versus Production Geothermal Flows at Various Skin Factors

Scheme size - 30 $GWhyr^{-1}$

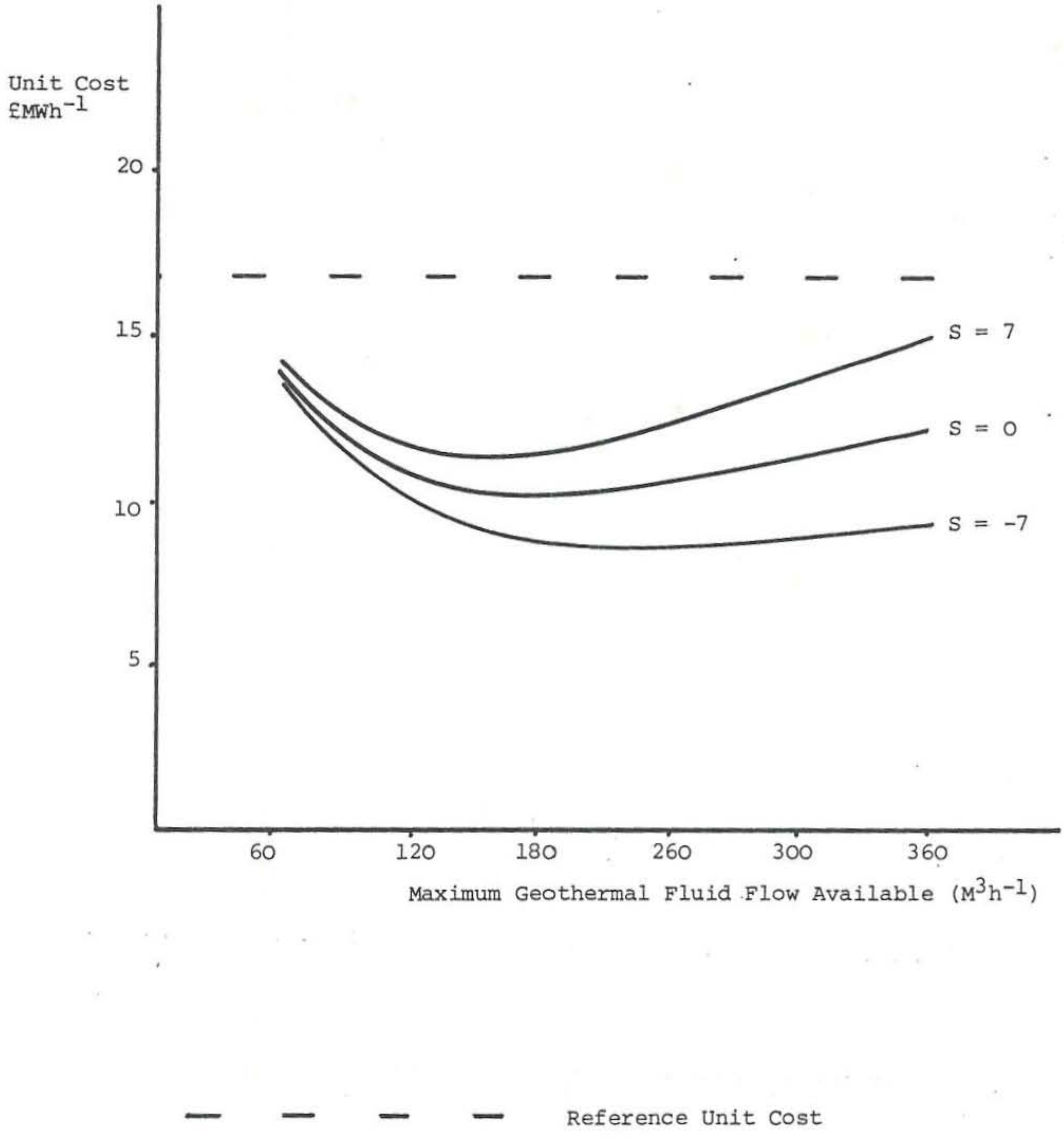


Figure 6.9 Unit Cost for Different Radiator Characteristics and Well Depths

Scheme Size - 30 $GWhyr^{-1}$

Well Cost - WELC Doublet

Geothermal Fluid Supply Temperatures as marked (°C)

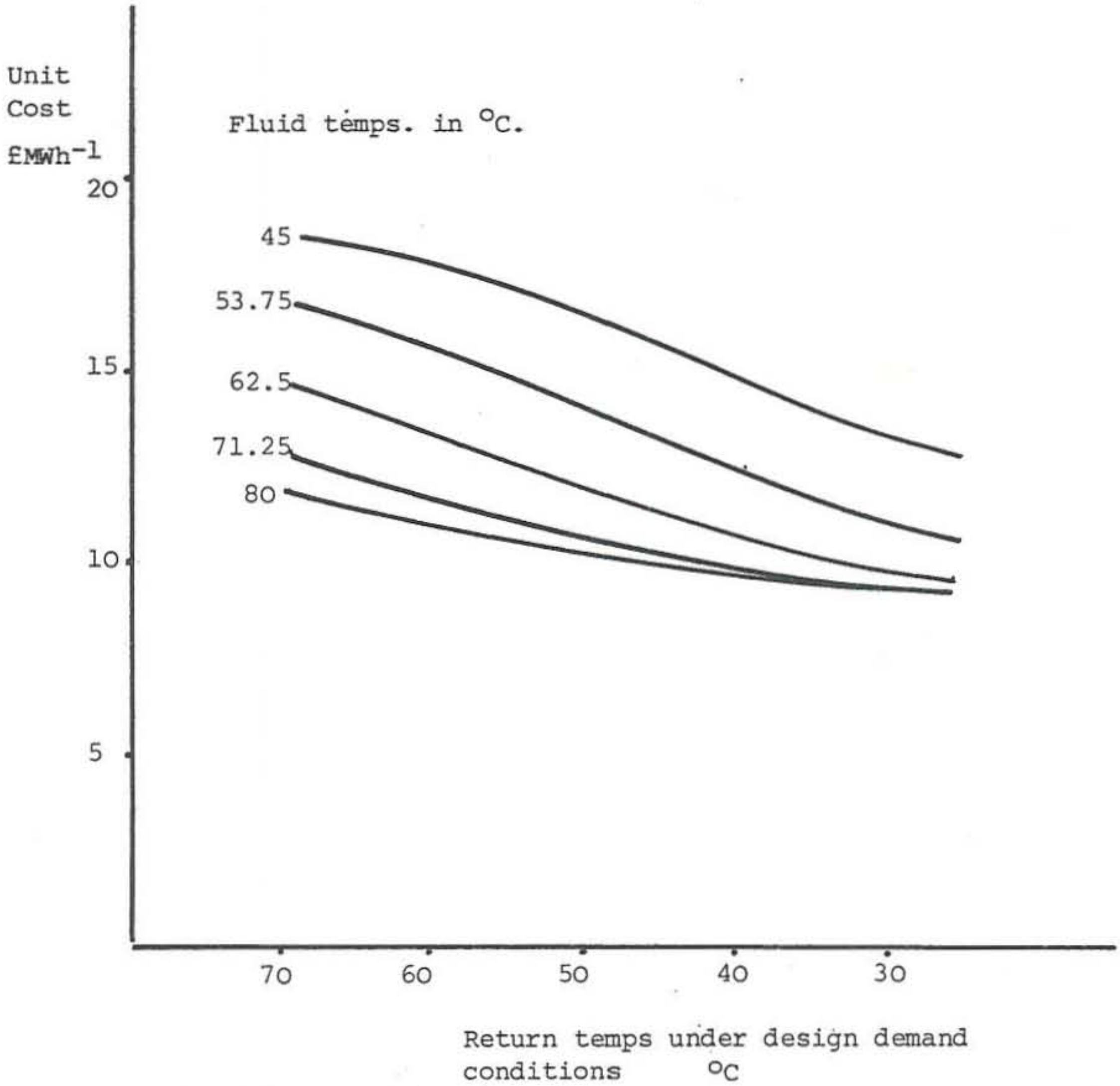
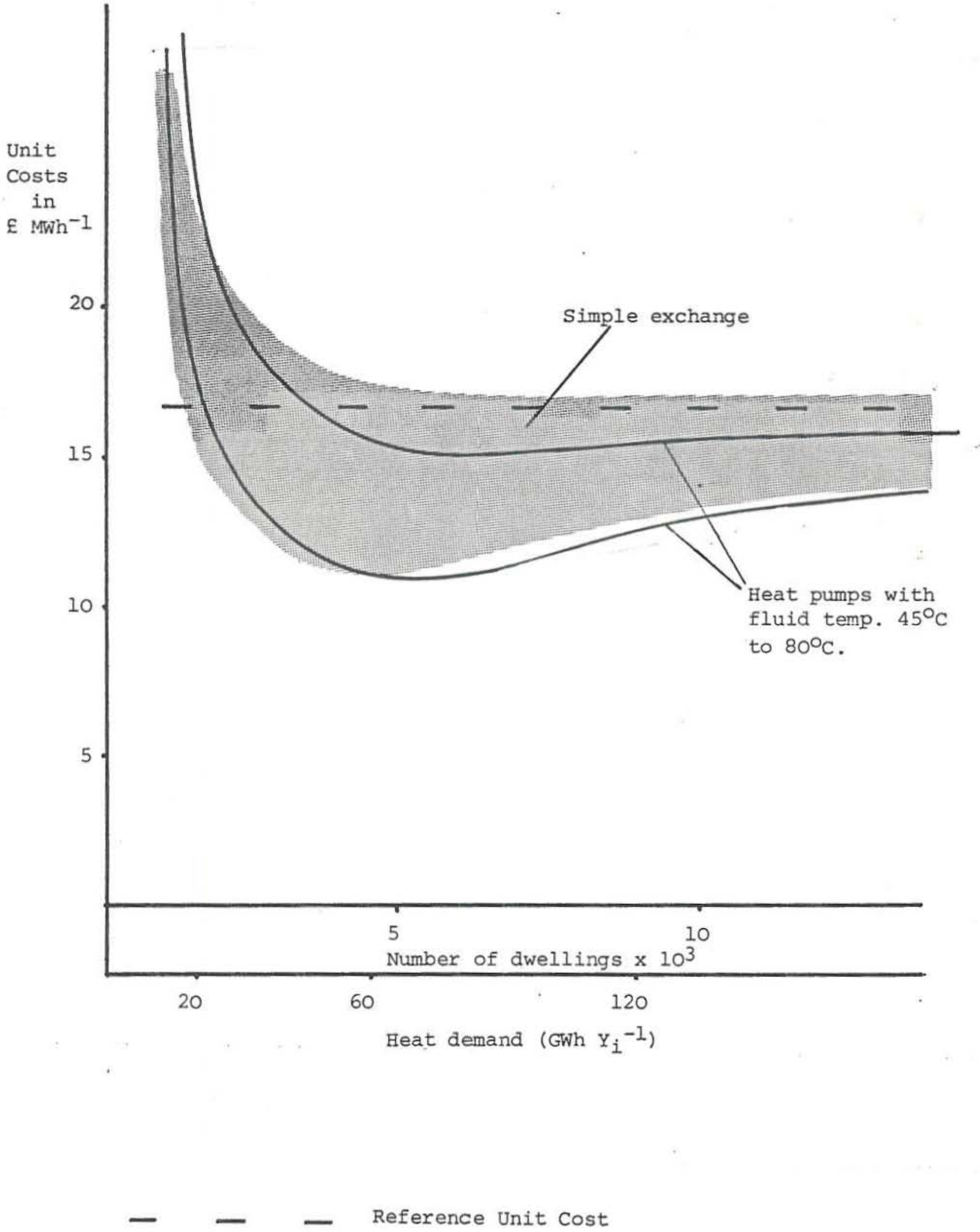


Figure 6.10 The Advantage of Using Heat Pumps in Geothermal Doublet Schemes



- Heat pumps improve the economics of schemes employing low-temperature fluids.
- Using the prices assumed here, heat pumps driven by gas engines are more favourable than electrically driven heat pumps.

The economic advantages of heat pumps are modest and schemes require careful study and optimisation in order to obtain viable results. Much work remains to be done to explore fully the economics of heat pumps in different congifurations and with different resources so that definitive conclusions can be drawn.

Chapter 6 References

6.1 AFME (1983) 'La Geothermie' 27 Rue Louis - Vicat 75015 Paris.

6.2 Lamethe-Parnaix, D., Raymond, M. and Pourbaix, M. (1980), 'Le Chauffage Geothermique' EDF Direction. Des Etude et Recherches Chatou Paris.

6.3 Lease, R., (1983) 'Integration of Hydrothermal Energy Economics Quantitative Studies, NTIS DE 83-001407.

6.4 Harrison, R., Lockwood, M.J. & Bryant, C.B. (1984) 'LEGS Low Enthalpy Geothermal Simulation Computer Program Vols. 1 and 2' Sunderland Polytechnic, Energy Workshop.

Glossary of Symbols

Symbol	Description	Units
A	Surface area of geothermal heat exchanger	m^2
C	Coefficient of performance	-
C_c	Coefficient of cooling	
C_h	Coefficient of heating	
c	Specific heat	$JK_g^{-1}{}^\circ C^{-1}$
c_g	Geothermal brine	"
c_n	Network fresh water	"
D	Characteristic total heat loss coefficient	$W^\circ C^{-1}$
E	Heat exchanger effectiveness	-
F or f	Volume flows	$m^3\ hr^{-1}$
	F - indicates major branches	
	f - indicates minor branches	
F_g	Geothermal flows	"
F_n	Network flows	"
F_u	Heater flows	"
G	Dwelling heat loss coefficient	$Wm^{-3}\ {}^\circ C^{-1}$
K	Number of equivalent dwellings	
M	Heat capacity of mass flow	$W\ {}^\circ C^{-1}$
M_g	Geothermal flow	"
M_n	Total network flow	"
M_u	Heater flow	"
M_x	Secondary heat exchanger flow	"
M_b	Bypass flow	"
N	Number of heat exchanger transfer units	-
P	Thermal power level	W(MW)
P_b	Back-up power	"
P_d	Power demand	"
P_g	Geothermal heat supply by simple exchange	"
P_{gh}	Combined geothermal heat with heat pumps	"
P_g	Additional heat extracted by heat pumps	"
P_c	Cooling power of evaporator	"
P_h	Heating power of condenser	"

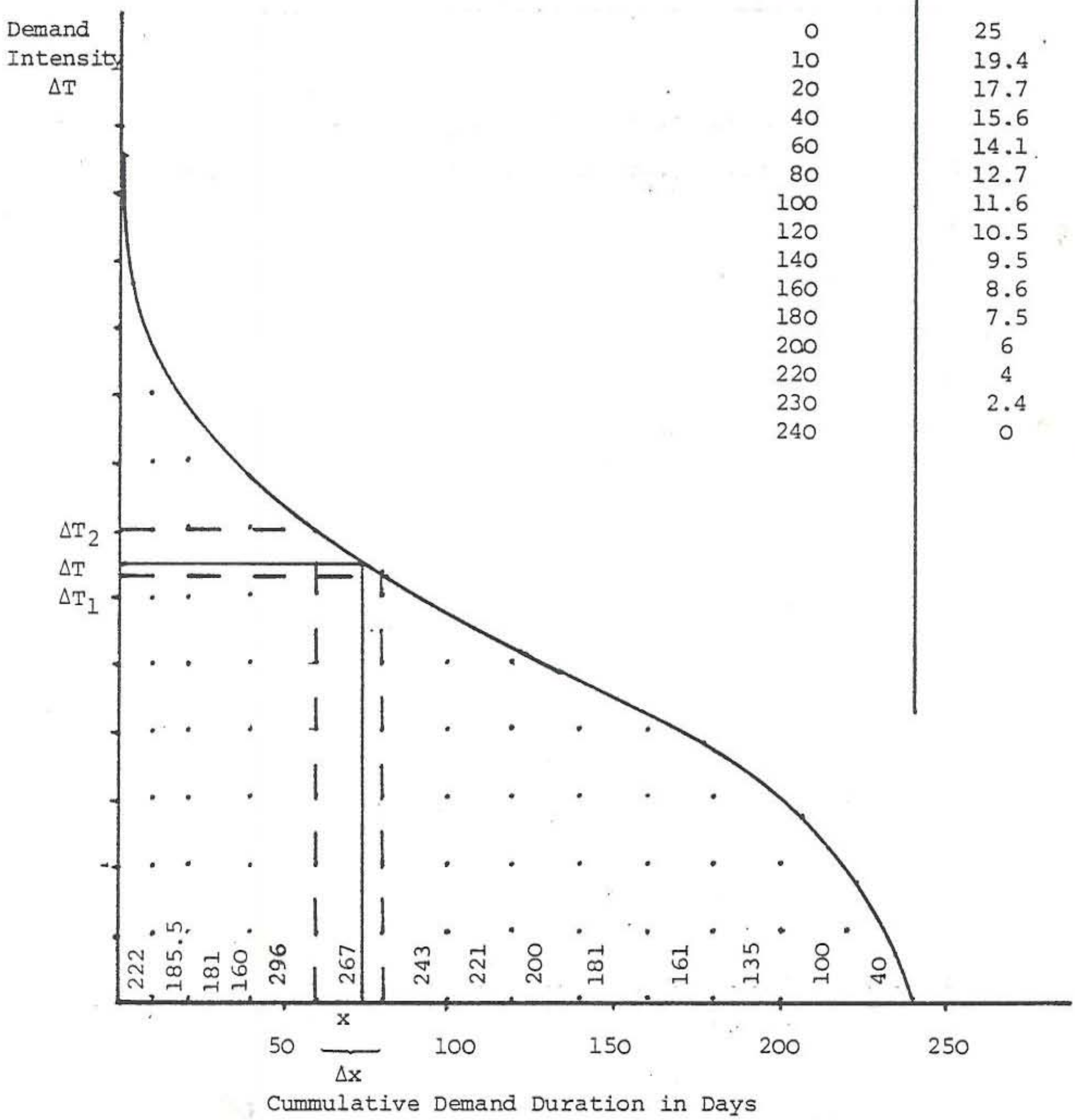
Symbol	Description	Units
Q	Total heat	J(MWh)
Q_d	Heat demand	"
Q_g	Geothermal heat supplied by simple exchange	"
Q_{gh}	Total heat supply in heat pump scheme	"
R	Flow ratio smaller to large flow through heat exchanger	-
S	Regulation characteristic	-
S_{ui}	Heater inlet	
S_{uo}	Heater return	
S_{ni}	Network inlet	
S_{no}	Network return	
T	Temperature	°C
T	Outside air	"
T_d	Demand temperature	"
T_i	Internal temperature	"
dT	Effect of incidental gains	"
T_{ui}	Heater inlet	"
T_{uo}	Heater outlet (return)	"
T_{ni}	Network inlet	"
T_{no}	Network return	"
T_{gi}	Geothermal supply	"
T_{go}	Geothermal return	"
T_{ci}	Evaporator inlet	"
T_{co}	Evaporator outlet	"
T_{hi}	Condenser inlet	"
T_{ho}	Condenser outlet	"
T_{xi}	Heat exchanger inlet	"
T_{xo}	Heat exchanger outlet	"
ΔT	Heat demand intensity	"
t	Time	hours
U	Overall heat transfer coefficient	W °C^{-1} m^{-2}
V	Volume of heated space	m^3
w	Heat pump compressor power	W(MW)

Symbol	Description	Units
θ	Heat pump temperature stretch	°C
	Density	$k_g m^{-3}$
ρ_g	Geothermal brine	"
ρ_n	Fresh water	"
$\hat{}$ $\hat{}$	Signifies maximum values	
$\smile$	Signifies minimum values	
$-$	Signifies mean values	
$\sim$		

Appendix 1 Geothermal Heating Calculations - Direct Heat Exchange

Figure 1 Temperature Duration Curve Characteristic of the Paris Basin

Cummulative Durations Days	Demand Intensity ΔT °C
0	25
10	19.4
20	17.7
40	15.6
60	14.1
80	12.7
100	11.6
120	10.5
140	9.5
160	8.6
180	7.5
200	6
220	4
230	2.4
240	0



Integration gives 2592.5 degree days

Min. external Temp. $\check{T} = -7^{\circ}C$ Demand Temp. $T_d = 18^{\circ}C$
$\widehat{\Delta T} = 25^{\circ}C$

Figure 2 Heat Exchanger Effectiveness

NTU = 5

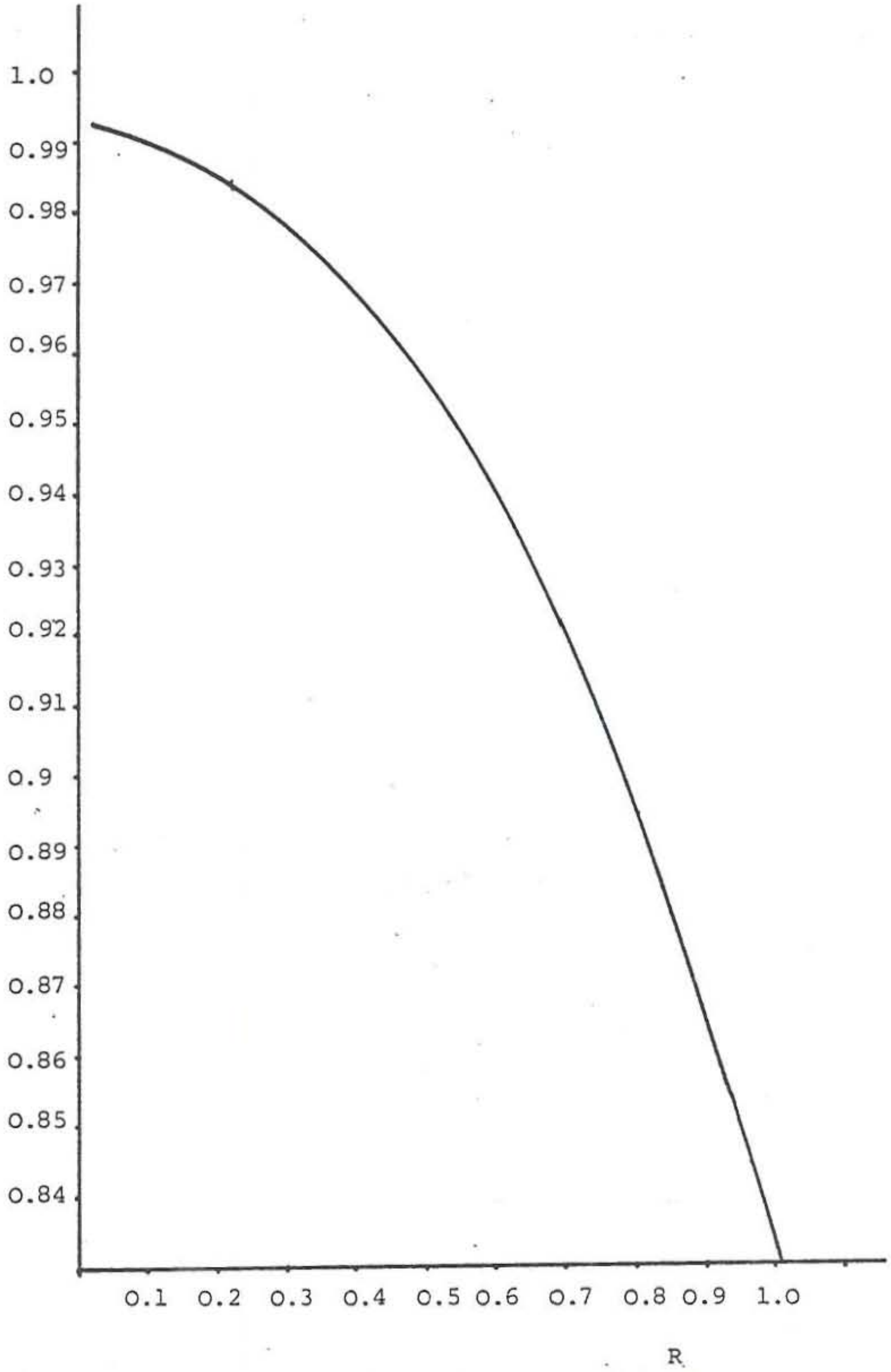


Table 1 Scheme - Simple Case 2000 Dwellings

Heat Demands, Flow Requirement of Users and Characteristic Temperatures

Room Temperature T_d = 18°C, Extreme External Temperature $\check{T}$ = -7°C, Max. $\widehat{\Delta T} = T_d - \check{T}$ = 25°C
Number of Degree Day Θ = 2590
Total Heat Demand Coefficient D = 0.4 MW $°C^{-1}$ Peak Demand $\hat{P}_d$ = D x 25 = 10 MW
Total Energy Demand = 24900 MWh

Heat Demand	
Number of dwellings N	2000
Specific heat loss per dwelling (VG)	200 x 10^{-6} MW $°C^{-1}$
Heat demand coefficient D = NVG (MW $°C^{-1}$)	0.4 MW $°C^{-1}$
Q = 24θD MW	24900 MWh
Heater Characteristics	
$\hat{T}_{ui}$	70 °C
$\hat{T}_{uo}$	50 °C
$\check{T}_u$	20 °C
Required Flow	
$f_u = \frac{Q}{T_{ui} - T_{uo}}$ 0.345 m^3h^{-1}	432 m^3h^{-1}
Characteristics of equivalent mixing stations	
network flow f_u' (m^3h^{-1})	
$\hat{T}_{ui}'$	
$\hat{T}_{uo}'$	

Table 2

Geothermal Power Calculations SIMPLE CASE

90/70 Radiators 2000 dwellings
Direct Heat Exchange
Fluid Condition

	Geothermal Supply	Network Return Main
Temperature	$T_{gi} = 60\,^{o}C$	$T_{no} = 2\,\Delta T + 20\,^{o}C$
Flow	$F_g = 180\, m^3 h^{-1}$	$F_n = 432\, m^3 h^{-1}$
Density	$\rho_g = 1050\, kgm^{-3}$	$\rho_n = 1000\, kgm^{-3}$
Specific Heat	$C_g = 3900 Jkg^{-1}\,^{o}C^{-1}$	$C_n = 4180\, Jkg^{-1}\,^{o}C^{-1}$
Heat Capacity	$M_g = 0.205 Mw\,^{o}C^{-1}$	$M_n = 0.502\, Mw\,^{o}C^{-1}$

$S_{no} = 2$

$\check{T}_n = 20^{o}C$

$T_{no} = S_{no} \Delta T + \check{T}_n$

$M_n = \dfrac{F_n \rho_n C_n}{3600}$

$M_g = \dfrac{F_g \rho_g C_g}{3600}$

Heat Exchange $\quad R_X = \dfrac{M_g}{M_n} = 0.408 \qquad E_X = 0.97$

Power Levels

Geothermal
(Direct Exchange)

$P_g = M_g E\,(T_{gi} - \check{T}_n) - M_g E S_{no} \Delta T;$

$P_g = 7.95 - 0.4\,\Delta T$ MW;

Demand

$P_d = D\,\Delta T$

$P_d = 0.4 \Delta T$ MW

Transistor Temperature

$$\Delta T_e = \frac{T_{gi} - \check{T}_n}{(D/M_g E_x) + S_{no}}$$

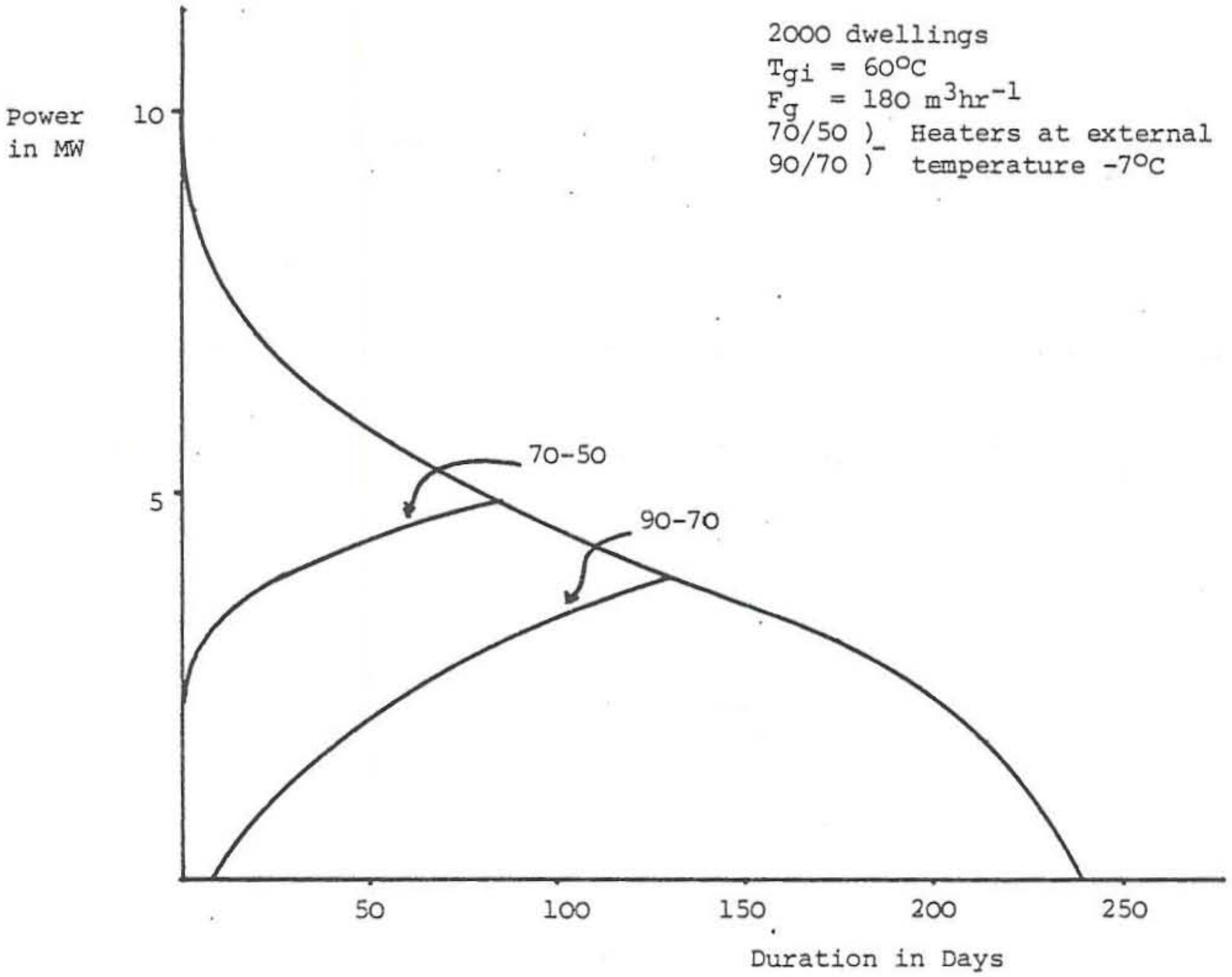
$$= 10^{o}C$$

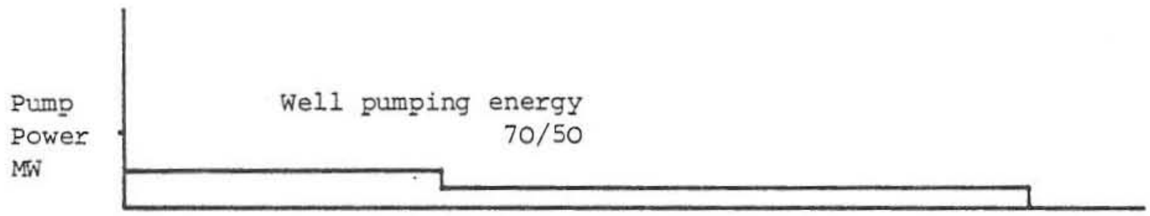
$$T_e = T_d - \Delta T_e = 8^{o}C$$

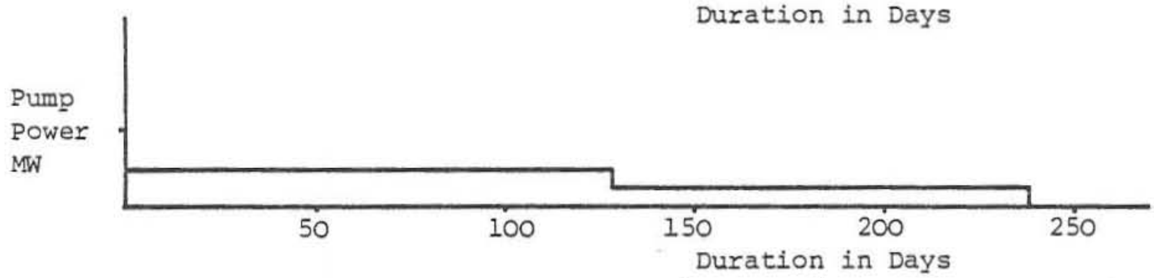
Power Level Durations

Duration K_u Days	ΔT ^{o}C	P_d MW	P_g MW	Heat Pump Power Levels			
				P_{Mgh}	W	r	P_{gh} + W + r
0	25	10					
10	19.4	7.76	0.19				
20	17.7	7.1	0.87				
40	15.6	6.24	1.71				
60	14.1	5.64	2.31				
80	12.7	5.1	2.87				
100	11.6	4.64	3.31				
120	10.5	4.2	3.75				
140	9.5	3.8	4.15				
160	8.6	3.44					
180	7.5	3					
200	6	2.4					
220	4	1.6					
230	2.4	0.96					
240	0	0					

Figure 3 Simple Example Simple Heat Exchange







Energy Demand Q_d = 24900 MWh

70/50	90/70
Geothermal Energy Q_g = 19,950 MWh	Geothermal Energy Q_g = 14,200 MWh
Coverage Ratio C = 80%	Coverage Ratio C = 57%

Appendix 2 <u>Geothermal Heating Calculations - Heat Pumps</u>

Table 1 **Definition of Simple Case**

The heat load is identical with that in Appendix 1.

Fluid conditions

Flow	180 m^3 m^{-1}
Temp T_{gi}	50°C

Heat pump compressor power = 0·6 MW

Configurations

(i) Heat pump assisted HPA as in figure

(ii) Heat pump only HPO as in figure

Table 2 Heat Pump Power Calculations: Heat Pump Assisted (HPA) Configuration Scheme

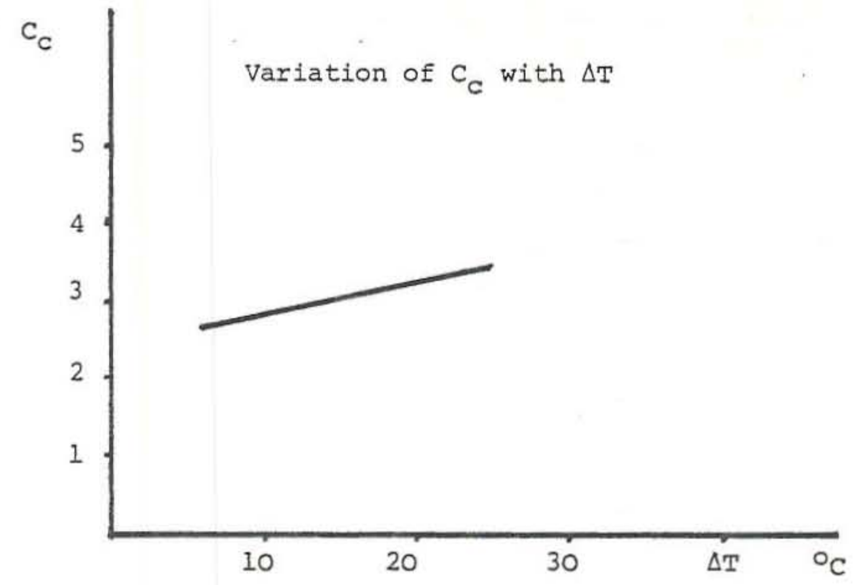
T_{gi} = 50 ^oC; $M_g = 0.200 MW^oC^{-1}$; M_n = 0.5 MW^oC^{-1}; M_x = 0.25 MW^oC^{-1}, $R_x = \frac{M_x}{M_g} = 0.8$; E_x= 0.9 ; W = 0.6 MW;

T_{no} = 1.2ΔT + 20; $C_c = 9.37 - 0.24\theta + 0.00187\theta^2$; $\theta = T_{ho} - T_{co}$, M_b = 0.25 MW^oC^{-1};

Simultaneous Equations	ΔT / T_{no}	25 / 50			7.5 / 29					
	C_c	5	5.4		5	4.7				
	n	1	2		1	2				
Evaporator										
$P_c = C_c W$	(MW)	3	3.24		3	2.87				
$T_{co} = T_{no} - P_c/M_x$	(^oC)	38	37		17	17.7				
Heat Exchanger										
$P_{gh} = M_g E(T_{gi} - T_{co})$	(MW)	2.16	2.3		5.94	5.8				
$T_{xo} = T_{co} + P_{gh}/M_x$	(^oC)	46.64	46.37		40.74	41				
Mixing										
$T_{hi} = \frac{M_x T_{xo} + M_b T_{no}}{M_n}$	(^oC)	48.32	48.1		34.87	35				
Condenser										
$P_h = P_c + W$	(MW)	3.6	3.84		3.6	3.42				
$T_{ho} = T_{hi} + P_h/M_n$	(^oC)	55.5	55.78		42.07	41.8				
$\theta = T_{ho} - T_{co}$	(^oC)	17.5	18.74		25.07	24.14				
C_c		5.7	5.4		4.5	4.65				

n = number of the iteration

Figure 1 Heat Pump Assisted Layout
0.6MW HP with bypass



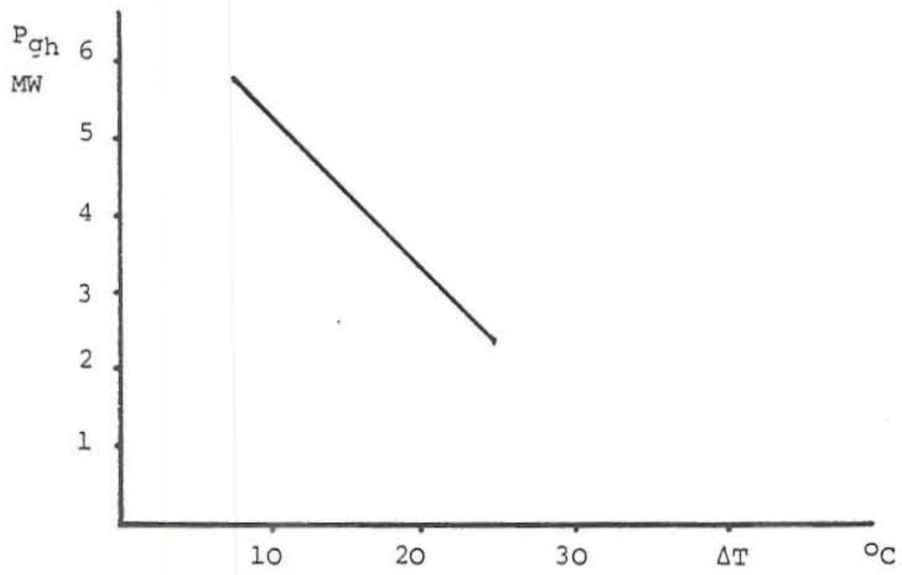


Table 3

Geothermal Power Level Calculations SIMPLE CASE

Heat Pump Assisted Using 0.6MW heat pump

Fluid Condition

	Geothermal Supply	Network Return Main
Temperature	$T_{gi} = 50\ ^oC$	$T_{no} = 1.2\Delta T + 20\ ^oC$
Flow	$F_g = 176\ m^3h^{-1}$	$F_n = 430\ m^3h^{-1}$
Density	$\rho_g = 1050\ kgm^{-3}$	$\rho_n = 1000\ kgm^{-3}$
Specific Heat	$C_g = 3900\ Jkg^{-1}{}^oC^{-1}$	$C_n = 4180\ Jkg^{-1}\ {}^oC^{-1}$
Heat Capacity	$M_g = 0.2\ Mw\ {}^oC^{-1}$	$M_n = 0.5\ Mw\ {}^oC^{-1}$

$S_{no} = 1.2$

$\check{T}_n = 20$

$T_{no} = S_{no}\Delta T + \check{T}_n$

$M_n = \frac{F_n \rho_n C_n}{3600}$

$M_g = \frac{F_g \rho_g C_g}{3600}$

Heat Exchange $R_x = \frac{M_g}{M_n} = 0.8$ $E_x = 0.9$ $M_x = 0.25$

Power Levels

Geothermal
(Direct Exchange)

$P_g = M_g E (T_{gi} - \check{T}_n) - M_g E S_{no} \Delta T;$

$P_g = 5.4 - 0.22\Delta T$ MW;

Demand

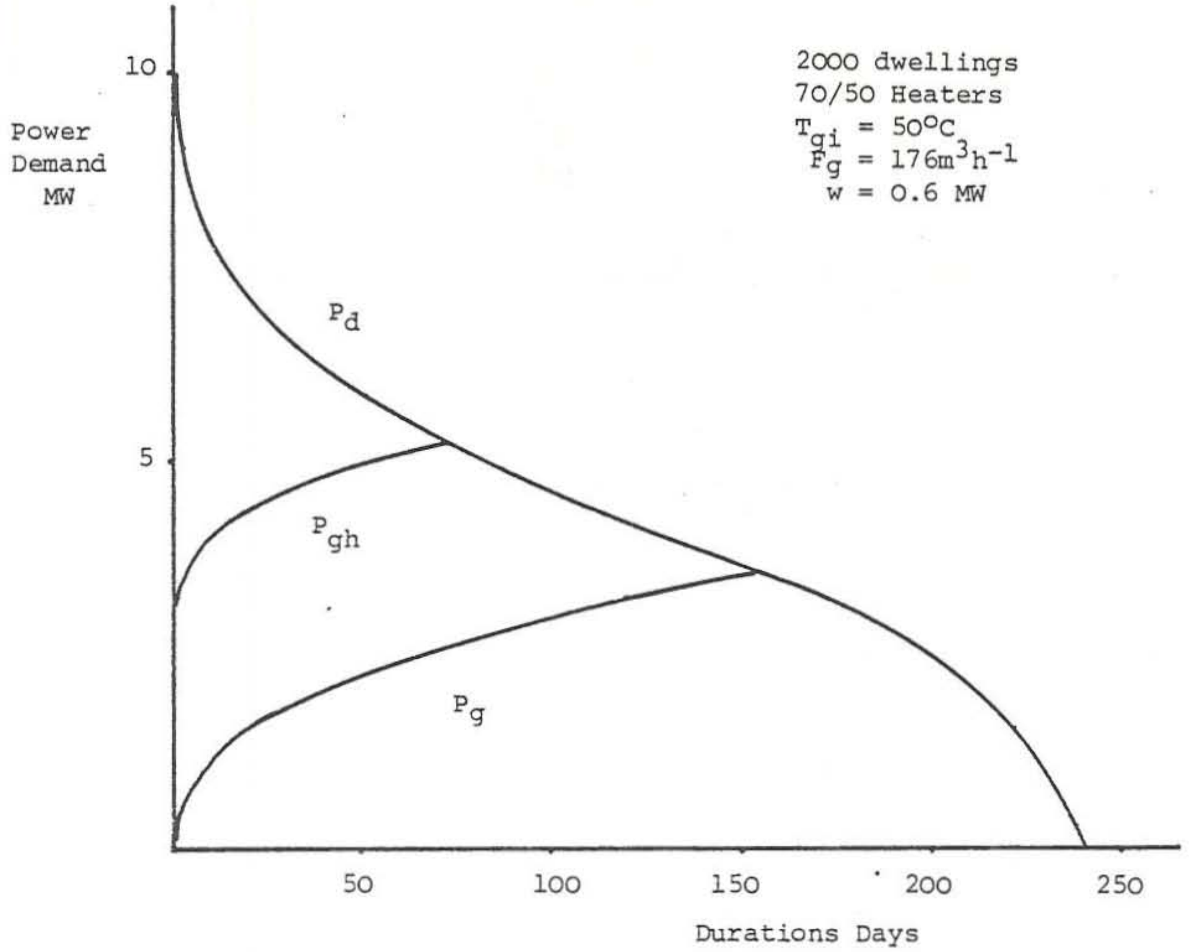
$P_d = D\Delta T$

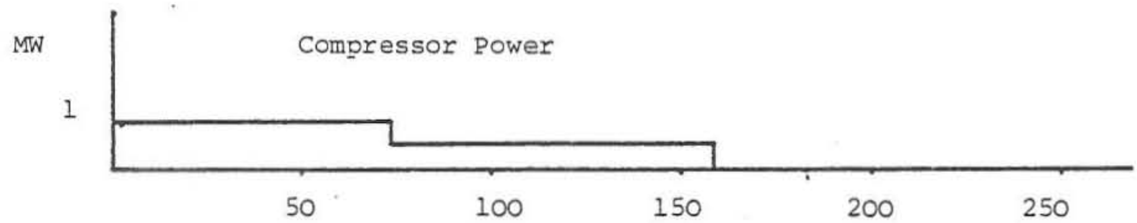
$P_d = 0.4\Delta T$ MW

Power Level Durations

Duration K_u Day	ΔT ^oC	P_d MW	P_g MW	Heat Pump Power Levels MW			
				P_{gh}	W	r	P_{gh} + W + r
0	25	10	0.1	2.3	0.6	0	2.9
10	19.5	7.76	1.1	3.4	0.6	0	4.0
20	17.7	7.1	1.5				
40	15.6	6.24	2.0	4.2	0.6	0	4.8
60	14.1	5.64	2.3				
80	12.7	5.1	2.6	4.75	0.6	0	5.35
100	11.6	4.64	2.8				
120	10.5	4.2	3.1	5.15	0.6	0	5.75
140	9.5	3.8	3.3				
160	8.6	3.44	3.5	5.55	0.6	0	6.15
180	7.5	3					
200	6	2.4					
220	4	1.6					
230	2.4	0.96					
240	0	0					

Figure 2 Simple Example Heat Pump Assisted Heat Exchange





Total Demand	Q_d = 24900 MWh	
Geothermal by Direct Exchange (with all network flow passing through heat exchanger)	Q_g = 14550 MWh	58%
Heat Pump Assisted Heat Transfer	Q_{gh} = 21000 MWh	84.3%
Compressor work	Q_c = 1570 MWh	

$$PER = \frac{(21000 - 14550)}{1570}\,0.25 = 1.03$$

Table 4 Heat Pump Power Calculations: Heat Pump Only Configuration (HPO)

$T_{gi} = 50\ ^{o}C$; $M_g = 0.2\ MW^{o}C^{-1}$; $E = 0.9$; $M_x = 0.25\ MW^{o}C^{-1}$; $M_n = 0.5\ MW^{o}C^{-1}$; $W = 0.6\ MW$; $S_{uo} = 1.2$; $T_{no} = 1.2\ \Delta T + 20$

$C_c = 9.37 - 0.24\theta + 0.00187\theta^2$

Simultaneous Equations	ΔT / T_{no}	25 / 50			19.5 / 43					
	C_c	5	4.8		5.5					
	n	1	2		1					
$P_g = P_c = C_c W$	(MW)	3	2.88		3.3		It is assumed that all of the network flow passes through the condenser until ΔT falls to 19.4°C when θ falls to the minimum accepteable level (18°C) with C_c at its maximum. When ΔT is below 19.4°C it is assumed that a proportion of the user flow bypasses the condenser to maintain θ at 18°C and C_c at 5.5; hence in this region P_{gh} is constant at ≃4MW			
Evaporator $T_{co} = T_{gi} - \frac{P_g}{M_g E}$	(°C)	33.3	34		31.6					
Condenser $P_h = P_c + W$	(MW)	3.6	3.48		3.9					
$T_{ho} = T_{no} + \frac{P_h}{M_n}$	(°C)	57.2	56.96		50.8					
$\theta = T_{ho} - T_{co}$	(°C)	23.9	22.96		19.2					
C_c		4.7	4.8		5.5					

n = number of iteration

Figure 3 Heat Pump Performance in the Heat Pump Only Layout

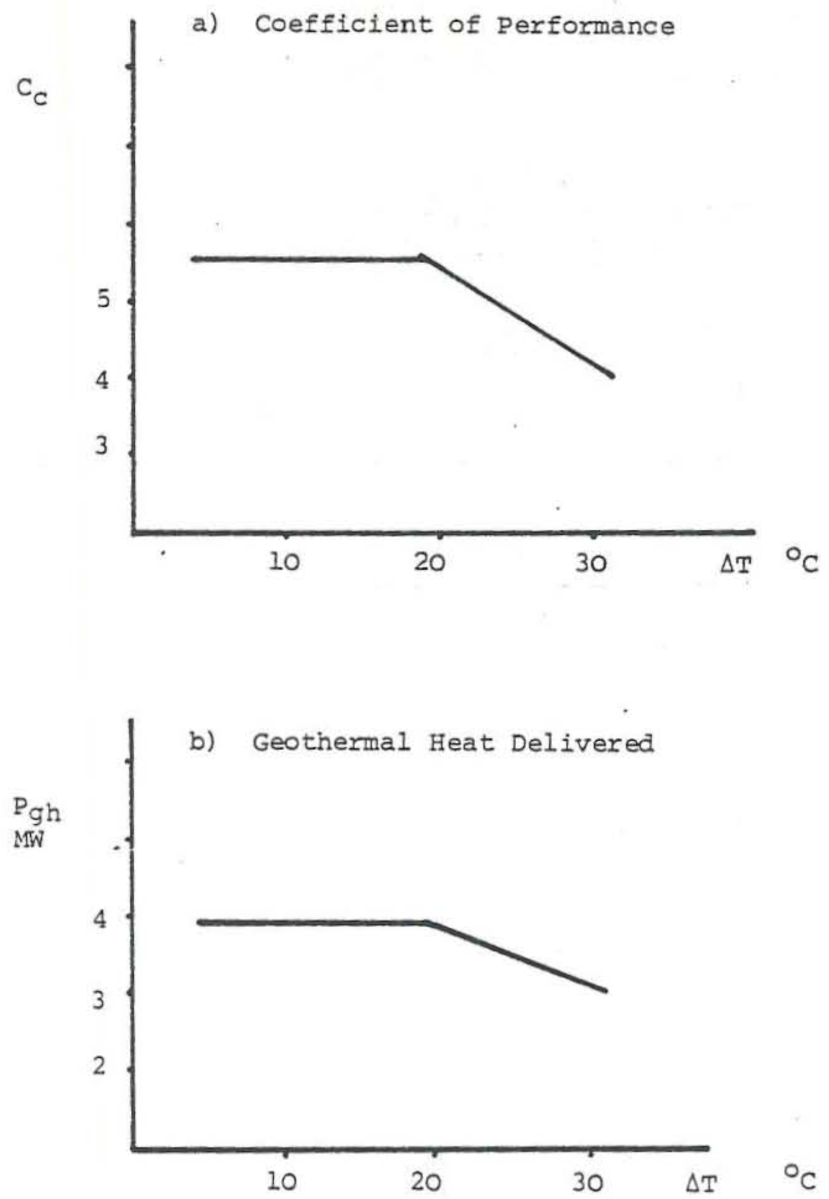


Table 4

Geothermal Power Levels SIMPLE CASE

0.6 MW Heat Pump in Heat Pump Only Layout and Condenser Bypass

Fluid Condition

	Geothermal Supply	Network Return Main
Temperature	$T_{gi} = 50\ ^oC$	$T_{no} = 1.2\ \Delta T + 20\ ^oC$
Flow	$F_g = 176\ m^3h^{-1}$	$F_n = 430\ m^3h^{-1}$
Density	$\rho_g = 1050\ kgm^{-3}$	$\rho_n = 1000\ kgm^{-3}$
Specific Heat	$C_g = 3900\ Jkg^{-1}\,^oC^{-1}$	$C_n = 4180\ Jkg^{-1}\,^oC^{-1}$
Heat Capacity	$M_g = 0.2\ Mw\ ^oC^{-1}$	$M_n = 0.5\ Mw\ ^oC^{-1}$

$S_{no} = 1.2$

$\check{T}_n = 20$

$T_{no} = S_{no}\Delta T + \check{T}_n$

$M_n = \dfrac{F_n\,\rho_n\,C_n}{3600}$

$M_g = \dfrac{F_g\,\rho_g\,C_g}{3600}$

Evaporator Circuit flow capacity
$M_e = 0.25\ MW^oC^{-1}$

Heat Exchange $R_x = \dfrac{M_g}{M_n} = 0.8$ $E_x = 0.9$

Power Levels This is a hyperthetical calculation in this case

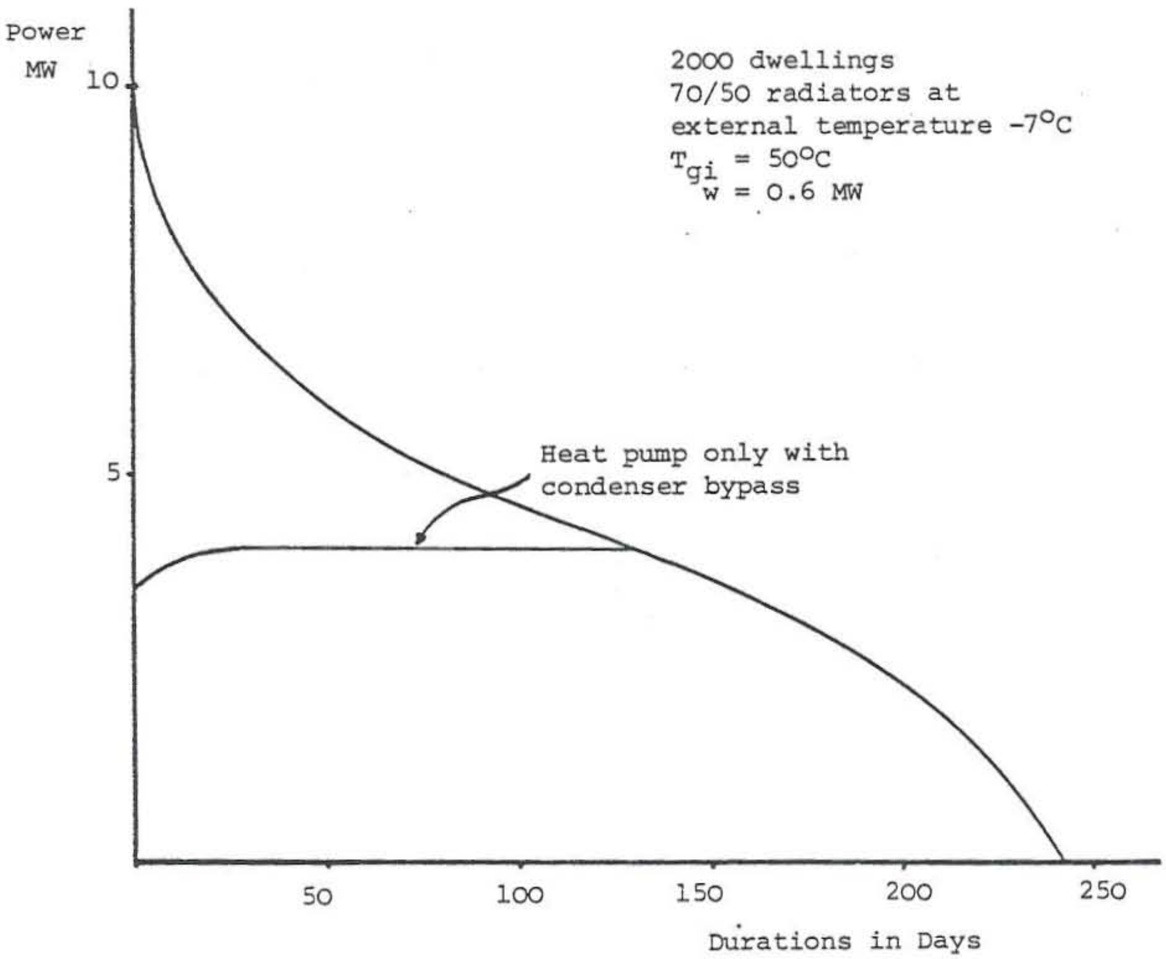
Geothermal (Direct Exchange)	Demand
$P_g = M_gE\,(T_{gi} - \check{T}_n) - M_gES_{no}\Delta T;$	$P_d = D\,\Delta T$
$P_g = 5.4 - 0.22\,\Delta T$ MW;	$P_d = 0.4\Delta T$ MW

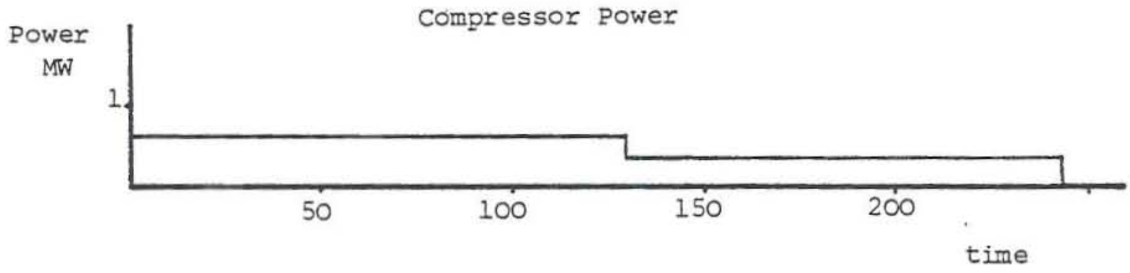
Power Level Durations

Climatic Data Northern France $T_d = 18^oC$

Duration K_u	ΔT	P_d	P_g	Heat Pump Power Levels			
				P_{gh}	W	r	P_{gh} + W + r
0	25	10					3.48
10	19.5	7.76					3.9
20	17.7	7.1					
40	15.6	6.24					4
60	14.1	5.64					4
80	12.7	5.1					4
100	11.6	4.64					4
120	10.5	4.2					4
140	9.5	3.8					4
160	8.6	3.44					
180	7.5	3					
200	6	2.4					
220	4	1.6					
230	2.4	0.96					
240	0	0					

Figure 4 Simple Example Heat Pump Only Layout





Q_d = 24900 MWh

Q_{gh} = 19176 MWh

Q_c = 2664 MWh

Appendix 3 Well Cost Estimating Procedure

Table 1 Summary of Rig Hire Time Equations

ROTATING TIME, t_1 (hours)	$= \left\{1 + \left[\frac{D_D}{D_T}\right]^2\right\} K_{1a} \exp\left(K_{1b}\ D_T\right)$
TRIPPING TIME, t_2 (hours)	$= \sqrt{1 + \left[\frac{D_D}{D_T}\right]^2}\ K_{2a} \left(\frac{\log_e}{K_{1b}} \left\{ \frac{n_b!}{n_o!} \left[\frac{t_b}{K_{1a}}\right]^{(n_b - n_o)} \right\} + \frac{D_L}{2}\left(n_o + 1\right) \right) + n_b K_{2b}$
	$n_b = \text{integer} \left| \left\{1 + \left[\frac{D_D}{D_T}\right]^2\right\} \frac{K_{1a}}{t_b} \exp\left(K_{1b}\ D_T\right) \right|$
	$n_o = \text{integer} \left| \left\{1 + \left[\frac{D_D}{D_T}\right]^2\right\} \frac{K_{1a}}{t_b} \exp\left(K_{1b}\ D_L\right) \right|$
CASING AND CEMENTING TIME, t_3 (hours)	$= \sqrt{1 + \left[\frac{D_D}{D_T}\right]^2}\ K_{3a} \left\{ \sum_{i=1}^{i=n_k} D_i \right\} + K_{3b}\ n_k$
MISHAP TIME, t_4 (hours)	= empirical data
LOGGING & COMPLETION TIME, t_5 (hours)	= modelling data
WELL TESTING TIME, t_6 (hours)	= modelling data
MISCELLANEOUS TIME, t_7 (hours)	$= K_m \sum_{j=1}^{j=6} t_j$
TOTAL RIG HIRE TIME, t_t (days)	$= \frac{1}{24} \sum_{j=1}^{j=7} t_j$

Design Data

D_T = total vertical depth (metres)

D_D = displacement of well from the vertical at total depth (metres)

n_k = number of sections of casing

D_i = vertical setting depth of the ith section of casing (metres)

Empirical Data: time statistics

K_{1a} and K_{1b}; rotating time equation constants (see equation 4.1)

D_L = lower depth limit to the rotating time equation (metres)

t_b = bit life (hours)

t_4 = mishap time (hours)

Modelling Data: technological factors

K_{2a} = round tripping rate (hours/metre)

K_{2b} = bit change time (hours/bit)

K_{3a} = wiper and casing running rate (hours/metre)

K_{3b} = associated casing and cementing time (hours/casing)

t_5 = logging and completion time (hours)

t_6 = well testing time (hours)

K_m = miscellaneous time fraction

Table 2 Summary of Well Cost Equations

DRILLING CHARGES, c_1	$= \left(a_1 \left\{1 + 0.01 \tan^{-1}\left[\frac{D_D}{D_T}\right]\right\} D_T + b_1\right) t_t$
RIG TRANSPORATION COSTS, c_2	$= \frac{c_1}{t_t} \frac{\left(a_2 D_T + b_2\right)}{n_s}$
SITE PREPARATION COSTS, c_3	$= \frac{\left(a_3 D_T + b_3\right)}{n_s}$
FUEL, MUD AND BIT COSTS, c_4	$= a_4 \sum_{j=1}^{j=3} c_j$
CASING COSTS, c_5	$= \left(1 + a_5\right) \sum_{i=1}^{i=n_k} c(i)\, I_i$
	$I_i = \left(D_i - D_i'\right) \sqrt{1 + \left[\frac{D_D}{D_T}\right]^2}$
	$c(i) = c'(i)\, d_{ci}\, u_{ci}$
CEMENT COST, c_6	$= a_6\, c_5$
WELLHEAD COST, c_7	= modelling data
WELL LOGGING COST, c_8	= modelling data
WELL TESTING COSTS, c_9	= modelling data
MISCELLANEOUS COST, c_{10}	$= a_{10} \sum_{j=1}^{j=9} c_j$
TOTAL WELL COST	$= \sum_{j=1}^{j=10} c_j$

Design Data

D_T = total vertical depth (metres)

D_D = displacement of well from the vertical at total depth (metres)

n_s = number of wells per well site

n_k = number of sections of casing

D_i = vertical setting depth of the ith section of casing (metres)

D'_i = vertical starting depth of the ith section of casing (metres)

d_{ci} = outside diameter of the ith section of casing (metres)

u_{ci} = thickness of the ith section of casing

Empirical Data: price information

a_1 and b_1; rig day rate equation constants (see equation 4.2)

$c(i)$ = unit linear price of the ith section of casing (currency/metre)

$c'(i)$ = unit volume price of the ith section of casing (currency/m^3)

Modelling Data: costing assumptions

a_2 and b_2; rig transportation time equation constants

a_3 and b_3; site preparation cost equation constants

a_4 = fuel, mud and bit cost fraction

a_5 = casing accessory cost fraction

a_6 = cement cost fraction

c_7 = well head cost

c_8 = well logging cost

c_9 = well testing cost

c_{10} = miscellaneous cost fraction

Table 3 Suggested Values for Modelling Data

(a) Technological Factors

Round Tripping Rate, K_{2a}	0.0097 ± 0.0026 hours/metre
Bit Change Time, K_{2b}	1.5 ± 0.5 hours/bit
Wiper and Casing Running Rate, K_{3a}	0.021 ± 0.007 hours/metre
Associated Casing and Cementing Time, K_{3b}	37 ± 15 hours/casing
Logging and Completion Time, t_5	33 ± 6 hours
Well Testing Time (gas lift test only), t_6	146 ± 51 hours
Miscellaneous Time Fraction, K_m	0.20 ± 0.08

(b) Costing Assumptions

Rig Transportation Time Equation Constants, a_2	0.0061 ± 0.0023 days/metre
b_2	5.1 ± 5.1 days
Site Preparation Cost Equation Constants	
European, a_3	41.6 ± 6.7 U.S. $ (1979)/metre
b_3	-4,116 ± 14,447 U.S. $ (1979)
U.S.A., a_3	8.3 ± 5.3 U.S. $ (1979)/metre
b_3	+25,077 ± 14,484 U.S. $ (1979)
Fuel, Mud and Bit Cost Fraction, a_4	0.26 ± 0.04
Casing Accessory Cost Fraction, a_5	0.10 - 0.05/+0.15
Current Cost Fraction, a_6	0.29 ± 0.12
Well head Cost, c_7	22,689 ± 7,211 U.S. $ (1979)
Well Logging Cost, c_8	41,127 ± 18,468 U.S. $ (1979)
Well Testing Cost	
Gas Lift Test, c_9	16,025 ± 5,895 U.S. $ (1979)
Production Pump Test, c_9	112,518 ± 24,249 U.S. $ (1979)
Miscellaneous Cost Fraction, a_{10}	0.19 ± 0.07

Table 4 Some Casing Costs and Rig Rates

a) Selection of Unit Volume Casing Prices

Country	Year	Currency	Grade	Unit Volume Price Currency m^{-3}
France	1983	Franc	K55	200,000 ± 30,000
Italy	1983	Lira	J55	$28 \times 10^6 + 5 \times 10^6$
	1983	"	L80/N80	$34 \times 10^6 \pm 2 \times 10^6$
	1983	"	P110	$39 \times 10^6 \pm 0{\cdot}4 \times 10^6$
U.K.	1983	£s	K55	13,000 ± 1,000
	1983	"	L80/N80	22,600 ± 5,000
	1983	"	P110	23,500 ± 500
U.S.A.	1983	$	K55	31,000 ± 4,000
	"	"	L80/N80	48,000 ± 10,300
	"	"	P110	45,000

b) Rig Day Rate Equation Parameters

Day Rate = a (depth rating) + b Units day^{-1}

Country	Year	Currency	a Currency m^{-1}	b Currency
France	1981	Franc	17 ± 3	11,400 ± 6,000
Italy	1983	Lira	1200	6×10^6
U.K. *	1985 (High Market)	£s	1	2,400
U.K. *	1985 (Low Market)		0·4	2,000
U.S.	1981	$	0·66 ± 0·09	5,300 ± 450

* Taken from Figure 5.7

Reliable estimates can only be obtained if casing prices and rig rates are surveyed directly from suppliers and contractors. This data is supplied as default information which can be used to make outline estimates only.

Table 5 Example of Design Data for a Deviated Well

WELL PROFILE DATA

TOTAL VERTICAL DEPTH = 1830 m
DISPLACEMENT = 850 m

CASING PROGRAMME DATA

SECTION NO.	VERTICAL STARTING DEPTH	VERTICAL SETTING DEPTH	GRADE	OUTSIDE DIAMETER	THICKNESS
1	0	40m	K55	25" (0.635m)	0.011m
2	0	120m	K55	18⅝" (0.473m)	0.011m
3	0	380m	K55	13⅜" (0.340m)	0.008m
4	320m	1630m	K55	7" (0.178m)	0.008m

OPEN HOLE COMPLETION TO 1830m

Table 6 Example of Rig Hire Time Estimation

ROTATING TIME, t_1

Depth and displacement from Table 4.3
Rotating time equation parameters from Table 4.7 (Paris basin data)

$$t_1 = \{1 + (\frac{850}{1830})^2\} \times 42 \times \exp(0.00116 \times 1830) \quad \ldots\ldots = 426.6 \text{ hours}$$

TRIPPING TIME, t_2

Depth and displacement from Table 4.3
Rotating time equation parameters from Table 4.7 (Paris basin data)
Average bit life from Table 4.9

$$n_o = \text{integer}\left[\{1 + (\frac{850}{1830})^2\} \times \frac{42}{20} \times \exp(0.00116 \times 500)\right] = 5$$

$$n_b = \text{integer}\left[\{1 + (\frac{850}{1830})^2\} \times \frac{42}{20} \times \exp(0.00116 \times 1830)\right] = 22$$

$$t_2 = \{1 + (\frac{850}{1830})^2\}^{\frac{1}{2}} \times 0.0097 \times \left[\{\frac{1}{0.00116}\} \times \log_e\{\frac{22!}{5!}(\frac{20}{42})^{17}\} + \frac{500}{2} \times (5 + 1)\right] + (22 \times 1.5) \quad \ldots\ldots = 335.5 \text{ hours}$$

CASING AND CEMENTING TIME, t_3

Depth, displacement and casing programme data from Table 4.3

$$t_3 = \{1 + (\frac{850}{1830})^2\}^{\frac{1}{2}} \times 0.021 \times (40 + 120 + 380 + 1630) + (37 \times 4) \quad \ldots\ldots = 198.2 \text{ hours}$$

MISHAP TIME, t_4

From Table 4.10 (Paris basin data), t_4 .... = 77.0 hours

LOGGING AND COMPLETION TIME, t_5

Modelling data from Table 4.15a, t_5 .... = 33.0 hours

WELL TESTING TIME, t_6

Modelling data from Table 4.15a, t_6 .... = 146.0 hours

MISCELLANEOUS TIME, t_7

$t_7 = 0.20 \times (426.6 + 335.5 + 198.2 + 77.0 + 33.0 + 146.0)$ .... = 243.3 hours

TOTAL RIG HIRE TIME, t_t .... =1459.6 hours

~ 61 days

Table 7 Example of Well Cost Estimating (in 1980 French Francs)

DRILLING CHARGE, c_1

Rig day rate given as 46,088 French Francs per day
Total rig hire time = 61 days (Table 4.17)
$c_1 = 46{,}088 \times 61$ .... = 2,811,368 FF

RIG TRANSPORTATION COST, c_2

Depth from Table 4.3
Number of wells per site given as 4
Rig transportation equation constants from Table 4.15b

$c_2 = \frac{2{,}811{,}368}{61} \times \{\frac{(0.006 \times 1830) + 5.1}{4}\}$ .... = 187,382 FF

SITE PREPARATION COST, c_3

Depth from Table 4.3
Number of wells per site given as 4
Site preparation cost equation parameters for Europe from Table 4.15b.
1979 exchange rate = 4.02 FF/$ (Appendix D)
Adjustment for increase in general prices for France between 1979 to 1980 given as 1.16

$c_3 = \{\frac{(41.6 \times 1830) - 4116}{4}\} \times 4.02 \times 1.16$ .... = 83,952 FF

FUEL, MUD AND BIT COSTS, c_4

Modelling data from Table 4.15b
$c_4 = 0.26 \times (2{,}811{,}368 + 187{,}382 + 83{,}952)$ .... = 801,503 FF

CASING COSTS, c_5

Casing programme data from Table 4.3
Unit volume casing prices for France in 1980 from Table 4.12
Modelling data from Table 4.15b.

$$I_1 = (40-0) \times \{1 + (\frac{850}{1830})^2\}^{\frac{1}{2}} = 44 \text{ m}$$

$$I_2 = (120-0) \times \{1 + (\frac{850}{1830})^2\}^{\frac{1}{2}} = 132 \text{ m}$$

$$I_3 = (380-0) \times \{1 + (\frac{850}{1830})^2\}^{\frac{1}{2}} = 419 \text{ m}$$