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ESTIMATES OF THE COST OF HOT WATER GEOTHERMAL ENERGY

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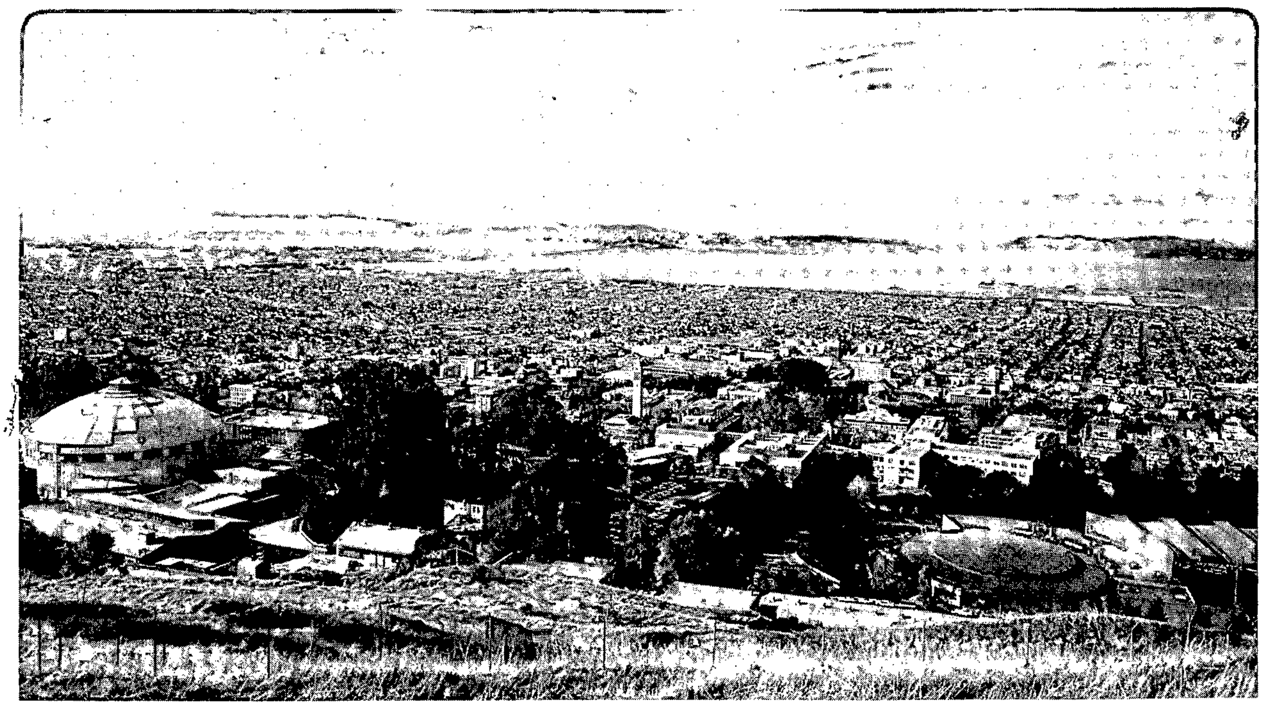

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DISCLAIMER

ESTIMATES OF THE COST OF HOT WATER GEOTHERMAL ENERGY

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ABSTRACT

The cost of developing the capability to produce hot water geothermal energy is dominated by the cost of wells. The cost of wells as a function of depth has been correlated statistically by Chappell et al. (1979) who indicate that:

$$c = e^{0.32175d + 4.86338}$$

where c is well cost in thousands of 1978 dollars and d is depth in thousands of feet.

With information on well costs, it is possible to estimate the cost of recovery of hot water energy on a pound mass basis provided one can also estimate ultimate recovery per well and "additional other costs" per well (such as exploration expenses, site development expenses, etc.) Available data suggest that ultimate recoveries for operating wells of the order of 10×10^9 lbm per well are reasonable to expect and that ultimate recoveries as large as 100×10^9 lbm are possible. "Additional other costs" are not statistically known and are specific to each site. Thus the contribution of these costs has simply been estimated as 50% of drilling costs.

Combination of information on well costs, approximate estimates of "additional other costs" and information on ultimate recovery per well together lead to estimates of the cost of developing the capability to produce hot water geothermal energy. Estimates are displayed in a manner that permits separation and identification of the components that lead to the total estimate, namely wells, ultimate recovery per well, and "other costs". Cost estimates have been developed as a function of depth and ultimate recovery (Figure 5) and are typically expected to lie in the range of 0.04 mils/lbm to 0.4 mils/lbm in terms of 1980 dollars, depending on depth to the resource.

Increases in costs of wells has been about 10-15 per cent per year since 1974. Thus, estimates of the costs for recovery of hydrothermal geothermal energy from wells yet-to-be-drilled are expected to increase on this same order per year. Escalation of cost of recovery of geothermal energy is less however, than the anticipated escalation in prices of alternate fuels on which geothermal energy prices depend. Alternate fuel prices are anticipated to increase 20-25% per year.

INTRODUCTION

This paper discusses estimates for the cost of developing the capability to produce hot water geothermal energy. Included here are the costs of finding as well as producing the energy. Costs for its direct use or for conversion of the energy to electricity are not part of the analysis. Estimates are given in terms of cost per pound mass of geothermal fluid as a function of representative depth of occurrence of the geothermal resource. Comparison of these costs with expected sales price provides information related to estimates of the value of the geothermal property, in particular in deciding that all or part of a resource is a reserve (Muffler and Guffanti, 1979, p. 4).

The estimates provided in this paper for cost of developing hydrothermal geothermal energy take into account well costs, ultimate production per well, and "additional other costs." The estimates are approximate and do not address special problems and therefore costs that might have to be borne at a specific site (e.g. scaling and very frequent well clean-outs). The estimates are not intended to replace estimates of specific sites under circumstances in which actual data on costs and expenses is available. Rather, these estimates, when combined with sales price (see Howard, 1980a) provide perspective on the economics of development of a geothermal resource.

The sales price estimates reported earlier (Howard, 1980a) and the cost estimates reported in this paper should be a useful reference in preliminary valuation of a geothermal property. Information derived from these estimates should be useful as a guide in setting bonuses at lease sales, in the outright sale of a property, and in national resource assessments wherein it is desired to determine that fraction of the resource that is a "reserve." These estimates also would provide a basis for ranking different prospects in order to select a small number for more thorough financial analysis.

METHOD OF ANALYSIS

Review of Cost Components

The total cost of developing the capability to produce--for sale--hot water energy includes those items listed in Table 1. The list follows a review of similar costs prepared for oil and gas economic valuation by Hughes (1967, Chap. 7). The fraction of total costs that each component represents is not known statistically and obviously will vary with each resource. However, there appears to be agreement that the largest fractional component is cost of wells (Polito and Smith, 1979). Planning studies by two major oil companies (Greider, 1975, Table 3, and Jul-Dam and Dunlop, 1975, Table 1) show drilling costs greater than 50% of total costs for obtaining geothermal energy; and fractional costs for wells as high as 75% or more are conceivable under some circumstances (e.g. deep wells, thoroughly drilled prospect; cf. Jul-Dam and Dunlop, 1975, Table 1).

In this paper, we begin by assuming that the cost of wells is 100% of the total cost of obtaining geothermal energy. This assumption -- which we later modify -- is practically useful to begin with for the following reasons. First, it sets a lower bound for the cost of geothermal energy. Consequently if a favorable economic appraisal cannot be reached under this assumption, it would be expected that the resource is unlikely to be economically exploitable. Second drilling costs appear to be quite well known from experience and, thus, keeping well costs separate from other costs (which are not so well known) allows one to separate the "hard" and "soft" components of the total cost estimate. Finally, the simplicity of the assumption permits a relatively easy-to-follow, clear argument that can be modified later in order to bring into the analysis other cost estimates that are not so well known but are, nevertheless, a concern.

In the sections which follow, we estimate the cost of a pound of geothermal fluid by considering, first, the cost of wells, and then, the ultimate production per well. The ratio of well cost to ultimate production per well is proposed as the minimum cost of geothermal fluid. This ratio times a factor to account for "additional other costs" is discussed still later in this paper and is presented as a more realistic guide to the cost for developing the capability to produce hot water geothermal energy.

Estimates of Well Costs

Chappell, Prestwich, Miller and Ross (1979) provide valuable data on the costs of geothermal wells. Their proposed correlation of well costs (in 1978 dollars) vs well depth is

(1) $$\text{well cost (1978 \$k)} = e^{a \times \text{depth} + b}$$

Depth is given in units of thousands of feet.

From their data set of 19 points, we have determined that

$$a = 0.32175$$

$$b = 4.86338$$

so that

$$\text{well cost} = e^{0.32175\ \text{depth} + 4.86338} \tag{2}$$

This equation corresponds to their graph of well cost vs. well depth, reproduced here as Figure 1.

Several other items from the Chappell et al. (1979) report should be noted. First, well diameters are not given for all wells, but casing diameters of the deepest string are typically reported in the 7" to 9 5/8" range. We presume that variation in hole diameter does not affect the well-cost/depth function.

Second, the data set involves holes in the depth interval 1,500-11,000 feet. Chappell et al. (1979, p. 102) propose that the well cost equation leads to excessively high costs if extrapolated to shallow depths (say 200 to 1500 feet).

Third, costs of wells have doubled since 1974 (namely about 10% per year on average 1974-1978). Thus, were one to estimate costs of a pound of geothermal fluid for a project that was to drill its first well at some future time, one should escalate well costs. Chappell et al. (1979, Figure 3) provide a basis for such escalation and our Figure 2 is based on their data and figure.

Chappell et al. (1979, p. 102) also point out that "mean cost is considerably higher than would be predicted by the aggregation method of estimation". They also report a standard deviation from the mean line such that

$$\text{well cost} = e^{(0.32175\ \text{depth} + 4.86338) \pm 0.22} \tag{3}$$

(the value $\pm$ 0.22 has been read graphically from Chappell et al., 1979, Figure 1). The consequence of adding this deviation to the mean equation (2) can be illustrated by the fact that a 6400 foot deep, $1 M average hole would cost $1.250 M. The point is that experience suggests that wells can cost significantly more than planned and that the high costs reflected in equation (2) have a basis in actual experience.

We propose to use equation (2), mindful of the escalation factors shown in Figure 2 to estimate well costs and to form the foundation for estimating the costs for recovery of hot water geothermal energy.

Estimates of Well Productivity

We would like to be able to compare the ultimate recovery from a well with the total cost of the well, because, as explained above, this ratio provides the basis for estimating costs on a per pound basis. Unfortunately, we are aware of no statistics on ultimate recoveries of expired geothermal wells. Instead we will have to deal with two groups of substitute information in order to get an understanding of reasonable values to expect for ultimate recoveries. These groups are: 1) information on cumulative recoveries to date on wells from Wairakei and Cerro Prieto and 2) information on flow rates for geothermal wells.

Information on cumulative recoveries during well lifetime of operating wells (i.e."cumulatives to date") are given by Pritchett, Rice and Garg (1978) for Wairakei and by Dominguez (1978) for Cerro Prieto. This information is summarized in Figure 3, and several important generalizations can be drawn from this figure. First, it would seem reasonable to expect about half of the wells drilled to yield ultimate productions of the order of 10 x 10^9 lbm. This assertion is based on the observation that the median (50th cumulative percentile) cumulative production is approximately 5 x 10^9 lbm at Cerro Prieto, where the field has been under commercial production since 1973 and almost 9 x 10^9 lbm at Wairakei where the field has been on production since the '50's. Greater cumulative production is obviously to be expected with increasing age, and extrapolation of present cumulatives to values of 10^{10} lbm may even be conservative.

Second, ultimate recoveries of the order of 100 x 10^9 lbm are possible but appear likely to occur only rarely, say perhaps 10% of the time. Again this assertion is based on observation and extrapolation of cumulatives to date.

Third, there are a significant fraction of wells having no reported cumulative production. The data set for Wairakei and Cerro Prieto indicate non-productive holes 27 and 34 percent of the time, respectively. However, these values should not be taken as estimates of dry hole risk because some of the holes having zero cumulatives are capable of production but, for various reasons, have not been brought into service (see, for example, Pritchett et al. 1978, p. 107). Obviously some dry holes are going to be drilled in a prospect. However, if drilling is confined to holes for production only (i.e. no outstepping wells are drilled) the fraction of non-producing holes should be less than 25%.

Information on flow rates of individual wells is of interest because this information along with reasonable estimates for lifetimes of wells provides another insight into the ultimate recoveries to be anticipated from geothermal wells. Lawford (1979, Figure 5) has summarized some information on well productivities and the essence of his summary is shown on Figure 4. Also shown on Figure 4 is information we have derived from Dominguez (1978). This figure shows that median production rates of approximately 240,000 lbm/hr are reasonable. The figure also indicates that production rates greater than 500,000 lbm/hr are rare. It is of interest to multiply these production rates (i.e. 240,000 lbm/hr and 500,000 lbm/hr) by 5, 10, 15, and 20 year time periods in order to calculate ultimate recoveries of wells with such production rates. The calculated values are shown in Table 2 and these values range from 10 to almost 100×10^9 lbm. Comparison of Table 2 with Figure 3 shows that generalizations that were presented earlier regarding ultimate recoveries are consistent with conclusions reached by considering production rates and reasonable possible lifetimes.

The overall conclusions are: 1) that ultimate recoveries of 10×10^9 lbm are typically to be expected, 2) that ultimate recoveries of 100×10^9 lbm are not unreasonable but less common, and 3) that a portion of wells drilled will be essentially nonproductive; this fraction seems to be on the order of 25%.

We will use these estimates of ultimate production per well to estimate costs on a pound-mass basis for recovery of hot water geothermal energy.

Estimated Costs of Hydrothermal Geothermal Energy

Earlier, we proposed that the cost of a geothermal well can be estimated by

(2) $$\text{well cost (1978 \$k)} = e^{0.32175 \text{ depth (1000's feet)} + 4.86338}$$

In the last section, we argued that the median ultimate recovery from a geothermal well is about 10×10^9 lbm and that ultimate recoveries of the order of 100×10^9 lbm are possible although less likely to occur. These two lines of reasoning, namely well cost and ultimate recovery per well, are combined in Figure 5. The scale of costs at the left of Figure 5 shows estimated cost for recovery of hot water geothermal energy when only well costs are taken into account. As explained earlier, however, costs other than well costs must be taken into account. These additional costs are not statistically known and are specific to each site. We approximate these additional costs at 50% of well costs. The scale on the right of Figure 5 shows estimated costs for recovery of hot water energy according to this approximation.

Figure 5 shows cost estimates in terms of mills/lbm as a function of depth to the resource and of anticipated ultimate recovery per well. The left hand scale of Figure 5 shows cost estimates if only 1978 well costs are taken into account. The right hand scale shows cost estimates in terms of 1980 dollars taking into account "additional other costs."

DISCUSSION

Introduction

In this section we comment on the usefulness and limitations of the analysis of costs summarized in Figure 5. In particular, comments are given on

1. presentation of costs in terms of mills/lbm rather than mills/unit-energy.
2. reasonable costs to expect and variation about these values; the importance of depth of occurrence of the resource, of large ultimate recoveries, and of magnitude of costs other than wells in estimating costs of hydrothermal geothermal energy.
3. cost of injection wells.
4. need for a continuing effort to gather statistics on well costs, on ultimate recoveries per well, and on costs in addition to well costs.
5. escalation of costs in the future

Cost Units

Presentation of cost estimates for recovery in terms of mills/lbm rather than mills/unit-energy may seem improper. However, the physical quantity produced by a well is mass that, for geothermal, contains thermal energy. Obviously if one had information on the temperature and pressure of the mass produced from a well, one could calculate the cost per unit energy. Still, we felt that the analysis would be clearer if attention were focused on the costs of producing mass rather than energy. Costs are known to be highly sensitive to well depth and ultimate recovery and, except in the case of wells that might have to be pumped, almost insensitive to energy content. Price, on the other hand, (see Howard, 1980a) is highly dependent on energy content. And, it is in comparison of price with cost that we are concerned with the issue of value, in terms of dollars, of energy.

of energy.

Range of Cost Estimates

Cost estimates depend, as shown in Figure 5, on depth of wells required to recover the resource and on ultimate recovery per well. We believe that median ultimate recoveries per well are about 10×10^9 lbm. Thus, according to Figure 5 (right-side scale) costs for recovery should range from about 0.04 mills/lbm to 0.4 mills/lbm depending on depth for wells in the 1500 foot to 9000 foot depth range. With larger ultimate recoveries per well, costs are less. For instance, for an ultimate recovery of 100×10^9 lbm costs could be as low as 0.004 mills/lbm (i.e. a well 3500 feet deep).

Figure 5 also permits one to determine quickly the consequences of different choices for ultimate recovery and for costs in addition to well costs. It is a straight forward procedure to read the values for cost as a function of ultimate recovery. Determining the consequence of costs additional to well costs is done simply by preparing a new scale for the right side of the figure to replace the one given (i.e. total costs equal 1.5 times well costs). If there were, for example, a reason to believe that well costs would represent only one-half the total because of unusually high costs for access to the property, the proper scale could be substituted.

Costs of Injection Wells

No special costs have been allocated for reinjection wells, despite the fact that well costs are proposed as the most expensive component of total costs. The reasoning behind ignoring the cost of injection wells is two-fold. First, we assume that non-productive holes can be called upon to handle some of the costs of reinjection wells. Their costs are reflected in the conclusion that median ultimates are on the order of 10 x 10^9 lbm and not a higher value (say the median of only productive wells). Second, we anticipate that the factor by which producing well costs are multiplied to give total costs will also help to account for the costs of injection wells. If a special program of drilling to establish a system of injection wells is called for, the cost estimates presented herein will have to be revised upward.

Need for More Statistics

Readers will undoubtedly appreciate the desirability for gathering still more data on the key empirical information described in this paper. An effort is underway to define ultimate recoveries of geothermal wells (Zais, 1980). However, except for government related projects in which costs are revealed, data on costs of drilling and additional other costs, especially, will be difficult to obtain. Thus it may be some time before a wholly satisfactory, publically known statistical basis for costs is established.

We believe that cost estimates in this paper are good enough for the purposes for which we intend to use them: to provide economic perspective on a geothermal resource and to select resources for more detailed study. They are not intended however, to take the place of rigorous cost analysis for planned development of a specific geothermal property.

Escalation of Costs in the Future

As noted earlier, drilling costs, as reported by Chappell et al. (1979) have increased about 10-15% per year since 1974. Consequently, estimates of costs of recovery of geothermal energy from wells to be drilled in the future should take this escalation into account. Assuming a 10% per year cost increase, the cost per pound mass of fluid produced from a scheduled-1983 4000 foot well with an anticipated ultimate recovery of 10×10^9 lbm (five years from the reference year) will be 0.051 mills/lbm and not 0.034 mills/lbm -- an increase of 50%!

On the other hand, the price for alternate fuels is also escalating, and thus one might expect that the price of geothermal energy would likewise increase. Review of the trend of national average fossil fuel costs delivered to steam-electric utility plants (Howard, 1980a) indicates that energy prices are now (1980) increasing on the order of 20-25% per year - 10 to 15% more per year than the anticipated increase in costs.

ACKNOWLEDGEMENT

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TABLE 1

COSTS OF RECOVERING HYDROTHERMAL GEOTHERMAL ENERGY

LEASEHOLD COSTS

- Options and bonuses (or purchase price if a fee property)
- Leasing expense (or title and other legal fees if purchased)
- Surveys
- Rental (if leased)
- Geological, geophysical and shallow drilling exploration costs

DEVELOPMENT COSTS

- Production wells
- Injection wells
- Gathering lines
- Production and injection pumps
- Separators
- Miscellaneous surface installations (road building, drill pads, short gathering lines, etc.)

PRODUCTION COSTS

- Wages, salaries and benefits for field personnel
- Fuel and power costs for field equipment
- Well cleanout
- Treatment of brine for reinjection purposes

GENERAL AND ADMINISTRATIVE

- Insurance
- Pro-rata share of non-productive operations

INTEREST AND TAXES

- Interest on borrowed money
- Income tax (federal and state)
- Ad valorem tax (if applicable)
- Production taxes (if applicable)

TABLE 2

ESTIMATED ULTIMATE RECOVERIES BASED ON
MEDIAN AND REASONABLE MAXIMUM PRODUCTION
RATES AND VARIOUS ASSUMED LIFETIMES

PRODUCTION RATE (lbm/hr)	ASSUMED LIFETIME			
	5 Years	10 Years	15 Years	20 Years
240,000 lbm/hr	10.5*	21.0	31.5	42.0
500,000 lbm/hr	21.9	43.8	65.7	87.6

* x 10^9 lbm

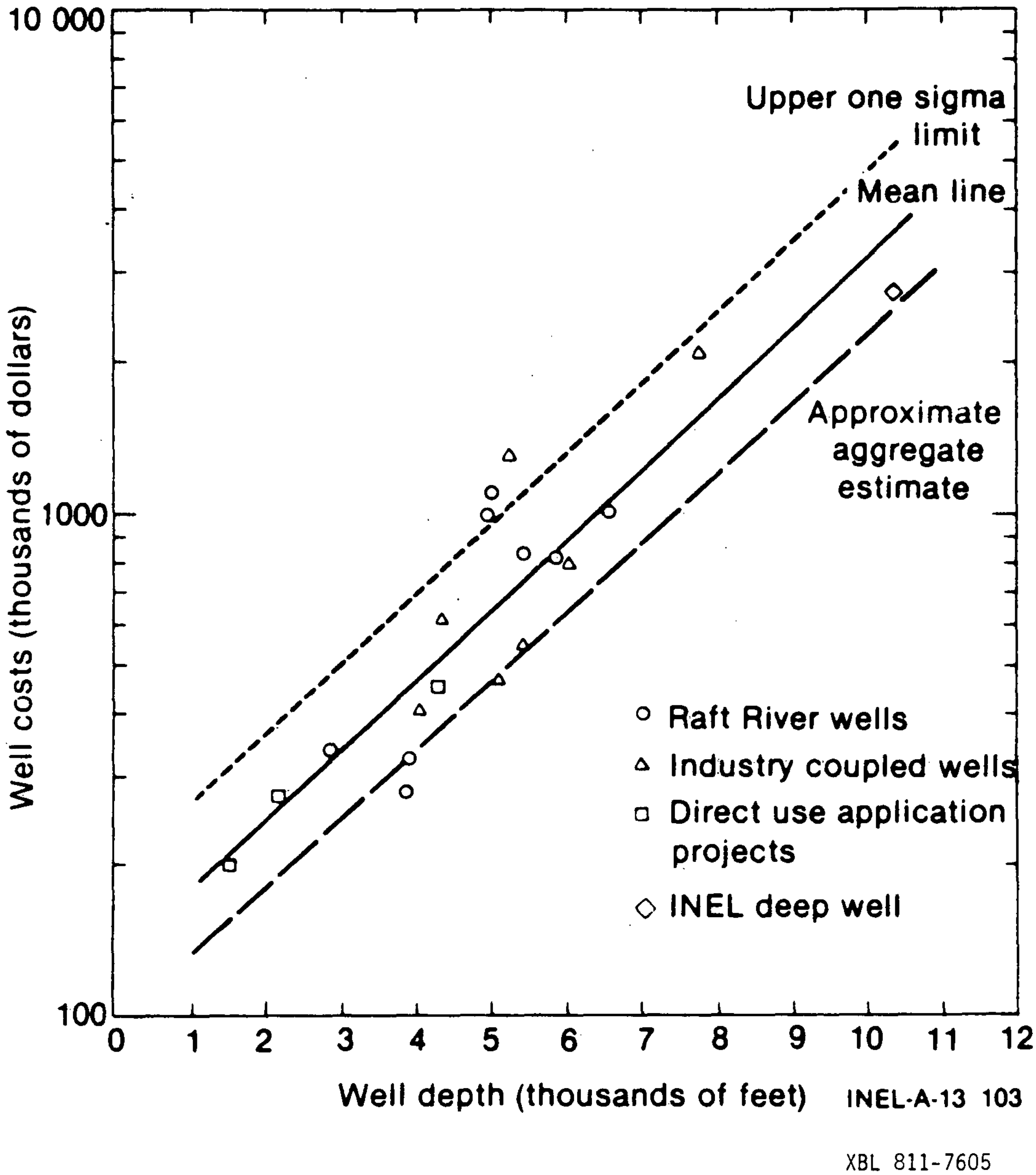

Figure 1. Geothermal well costs vs. depth (after Chappell et al. 1979). Cost is a logarithmic function of depth as shown in the "mean" line and the upper one standard deviation line. The "approximate aggregate estimates" refer to planned-for costs and are actually lower than experience revealed.

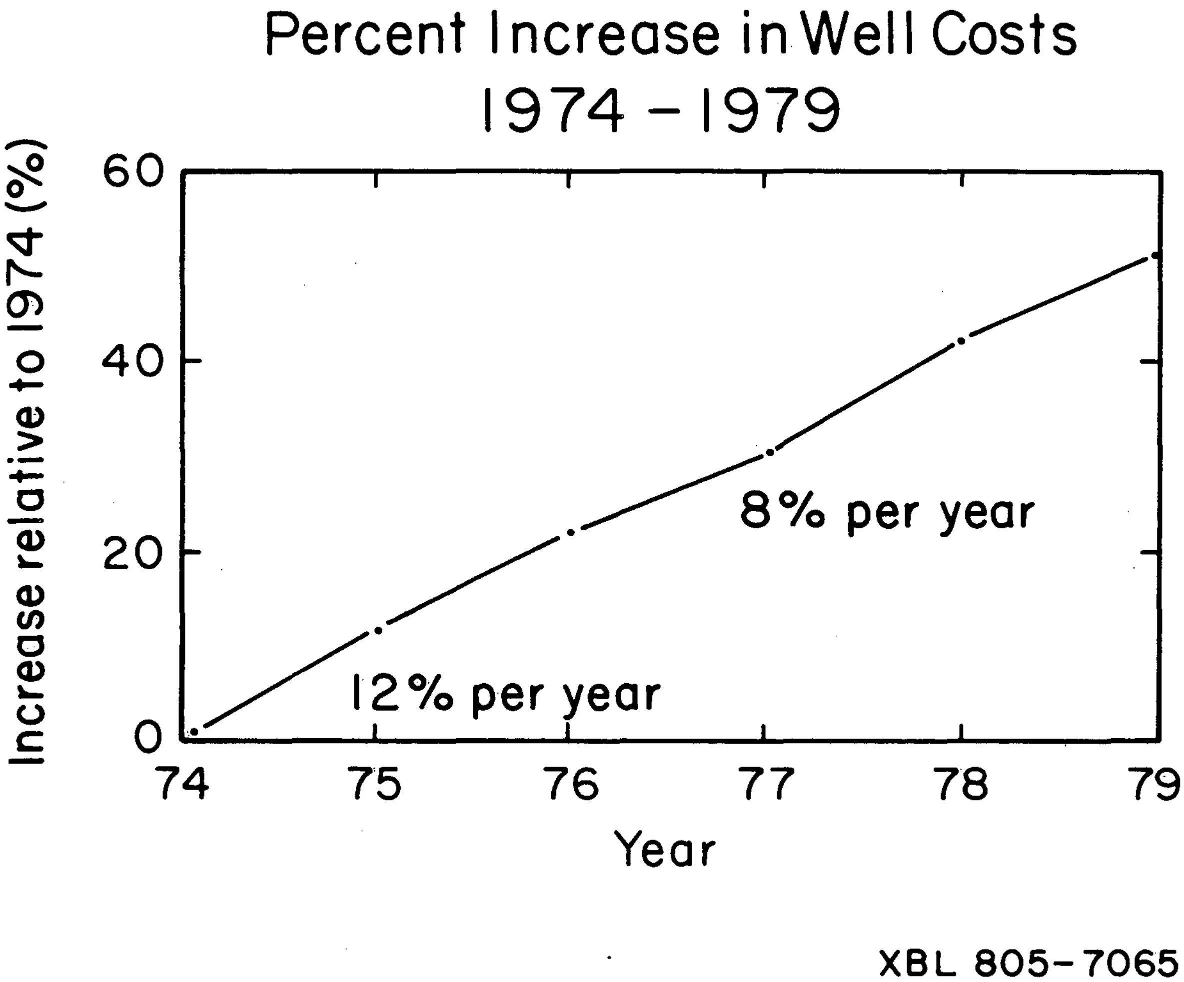

Figure 2. Escalation factors for cost of wells (derived from Chappell et al. 1979). Costs here increased over 50% between 1974 and 1979, with the average increase per year slightly over 10%.

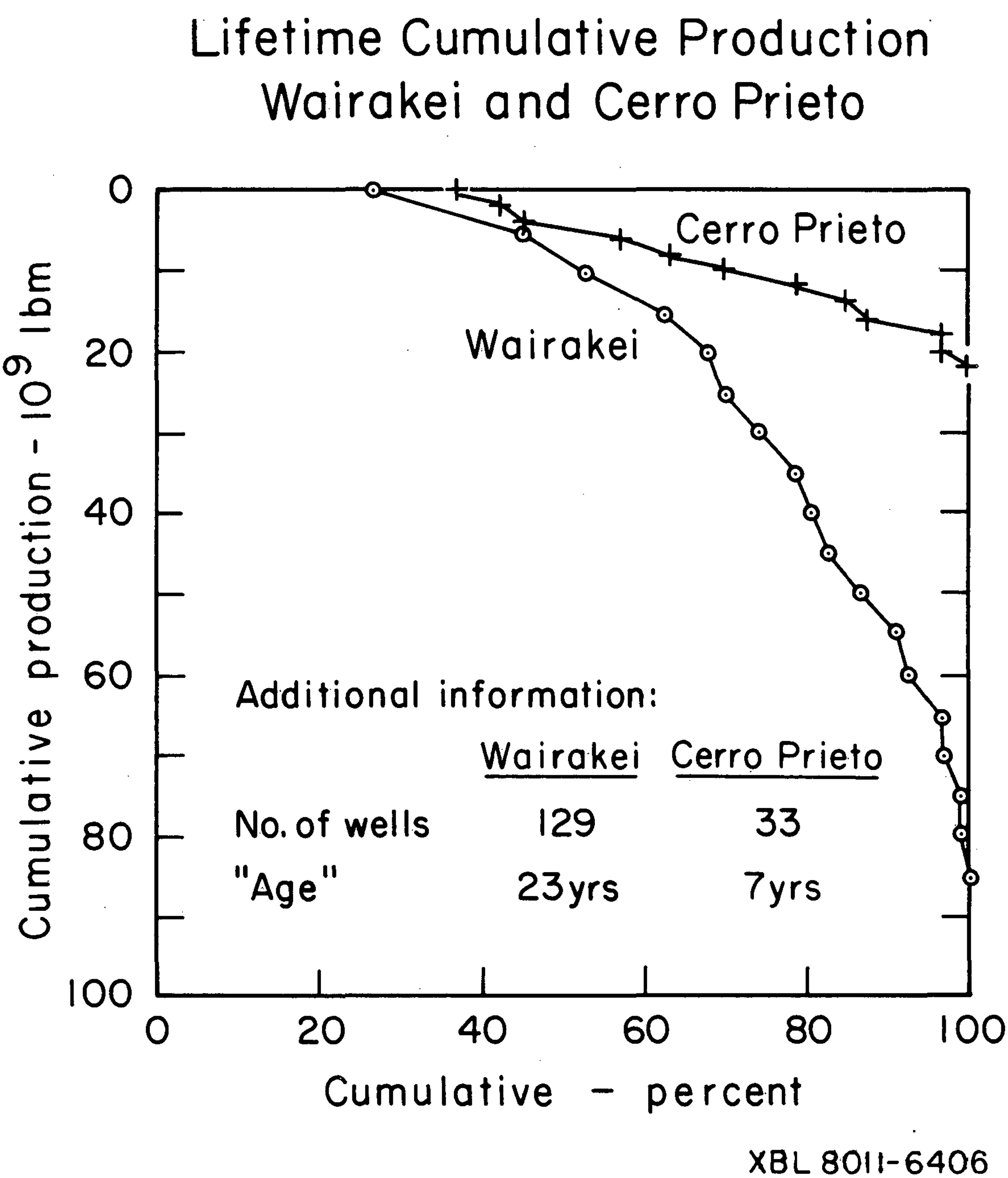

Figure 3. Cumulative production for the Wairakei and Cerro Prieto fields. Data derived from Pritchett et al. (1978) and Dominguez (1979). The data indicate that in a certain fraction of nonproductive holes, ultimate recoveries of 10×10^9 lbm are reasonable and that ultimate recoveries of as much as 100×10^9 lbm are attainable.

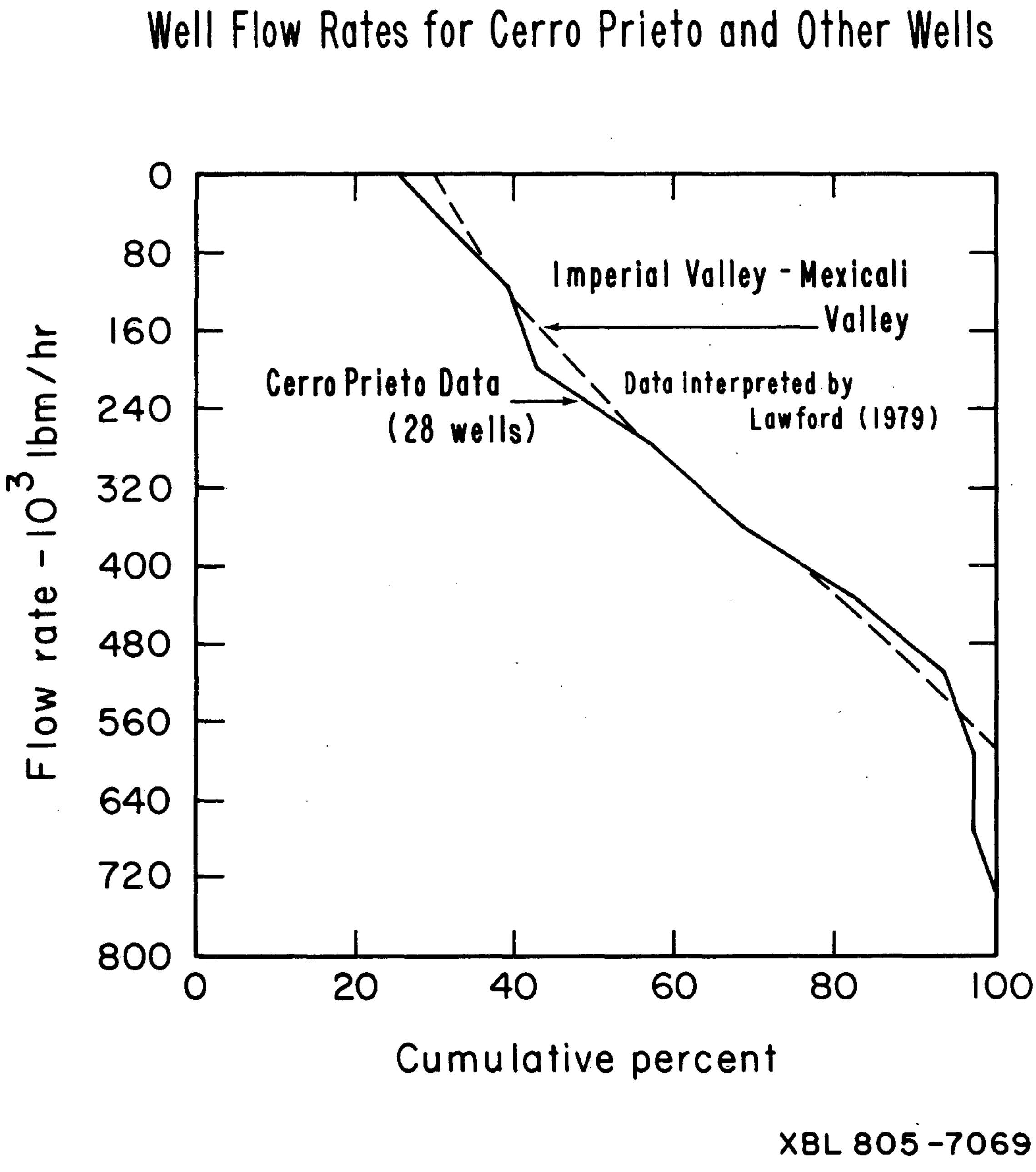

Figure 4. Well flow rates for Cerro Prieto and for wells (Lawford, 1979) in the Imperial-Mexicali Valley. Median productivity appears to be approximately 240,000 lbm/hr. Flow rates as high as 720,000 lbm/hr are also known.

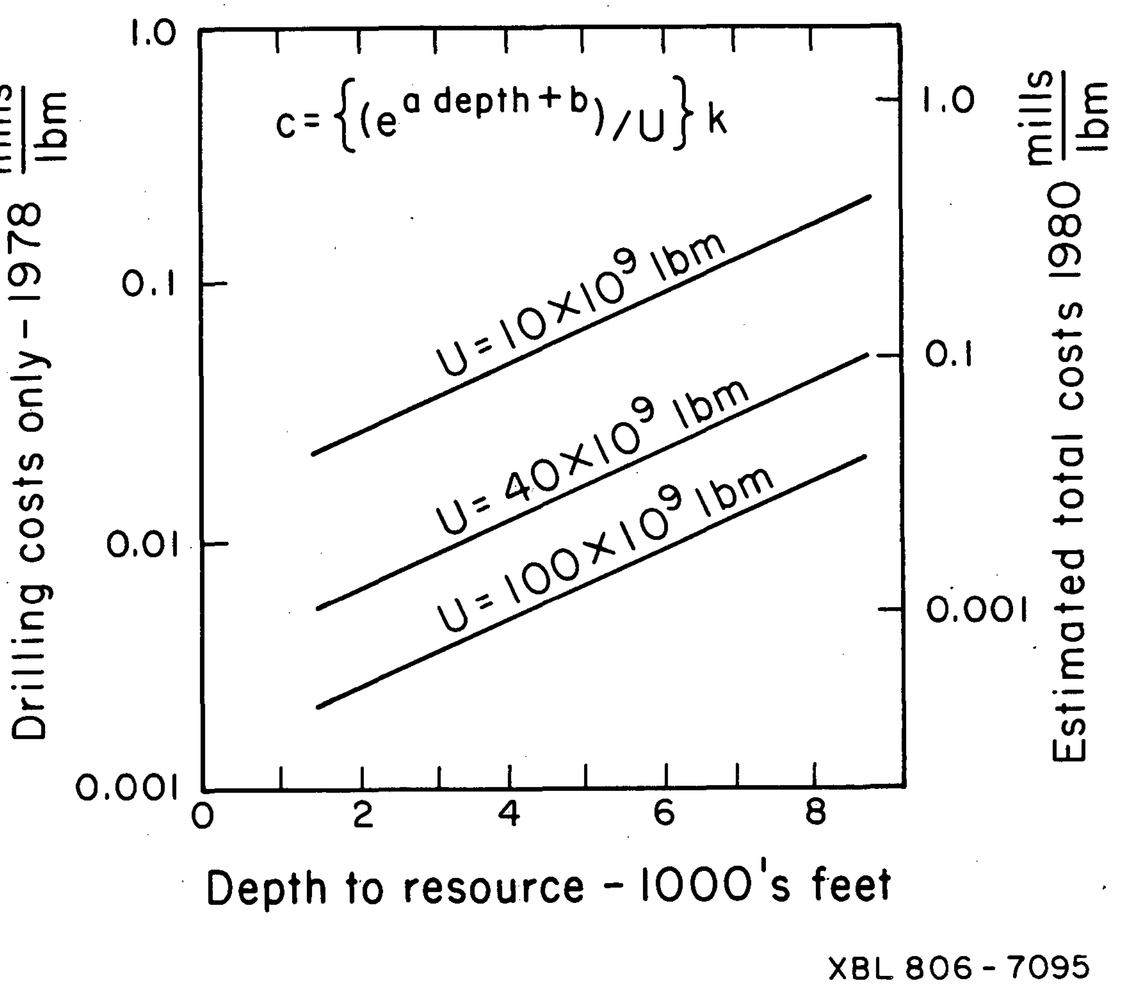

Figure 5. Costs for recovery of hot water geothermal energy. Costs are given on a mils per pound-mass basis where the key parameters are representative depth to the resource, ultimate recovery per well and a factor summarizing the cost of other additional expenses (see text). Costs in 1980 dollars are given on the right hand scale. The left hand scale shows costs when only the cost of wells in terms of 1978 dollars is accounted for.

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