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**ENERGY ANALYSIS OF GEOTHERMAL-
ELECTRIC SYSTEMS**

By
Robert A. Herendeen
Randall Plant

December 1979

Work Performed Under Contract No. ET-78-S-02-5085

Energy Research Group
Office of Vice Chancellor for Research
University of Illinois at Urbana-Champaign
Urbana, Illinois

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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FINAL REPORT TO THE U.S. DEPARTMENT OF ENERGY

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ABSTRACT

We have applied standard energy analysis to 4 types of geothermal-electric technologies: liquid dominated, hot dry rock, geopressure, and vapor dominated. We find that all are net energy producers, i.e., have an energy ratio exceeding unity, where

$$\text{energy ratio} = \frac{\text{net electric energy produced over lifetime}}{\text{primary nonrenewable energy inputs over lifetime (excluding geothermal energy itself)}}$$

Expected uncertainties are not large enough to threaten this conclusion.

Vapor dominated, the only technology in current commercial use to produce electricity in the U.S., has the highest energy ratio (13 ± 4).

These results for energy ratio are equal to or less than some from other workers. In the case of liquid dominated, environmental control technology has a considerable energy requirement.

TABLE OF CONTENTS

	<u>Page</u>
<u>I. INTRODUCTION AND SUMMARY OF RESULTS</u>	1
1. Energy Ratios	2
2. Power Curves	4
3. Ecoenergetics	4
4. Effects of Changing Energy Prices	13
5. Uncertainty in Energy Ratios	15
<u>II. METHODOLOGY</u>	25
A. Liquid-Dominated Hydrothermal	28
B. Hot Dry Rock.	29
C. Geopressure	30
D. Vapor Dominated	31
<u>III. ENERGY INPUTS ACCORDING TO "STANDARD" ENERGY ANALYSIS</u>	33
A. Liquid Dominated.	33
B. Hot Dry Rock.	36
C. Geopressured Geothermal	44
D. Vapor Dominated	46
E. Price Deflators	68
<u>IV. ECOENERGETICS</u>	72
A. Probable Impacts Affecting Air Chemical System.	76
1. Vapor Dominated (The Geysers)	76
2. Liquid Dominated	81
3. Hot Dry Rock	81
4. Geopressure	82

	<u>Page</u>
B. Probable Impacts Affecting the Water Chemical System.	83
1. Vapor Dominated	83
2. Liquid Dominated	85
3. Hot Dry Rock	89
4. Geopressure	90
C. Probable Impacts Affecting Biotic Chemical System	91
1. Vapor Dominated	91
2. Liquid Dominated	93
3. Hot Dry Rock	94
4. Geopressure.	95
D. Energy Evaluation of Probable Impacts Affecting Other Natural Environment Energy Flows.	96
<u>V. EFFECTS OF ENERGY PRICE INCREASES</u>	98
<u>VI. TREATMENT OF UNCERTAINTY</u>	103
<u>VII. COMPARISON WITH OTHER STUDIES</u>	106
References	109

LIST OF TABLES

<u>Table No.</u>		<u>Page</u>
I-1.	Energy Ratios for Geothermal-Electric Technologies	3
I-2.	Energetic Inputs Over Lifetime	14
I-3.	Effects of Energy Price Changes on Energy Ratios	16
1-4a through 1-4h.	Uncertainty in Energy Inputs	17 -24
III-1.	Energy Inputs, Liquid Dominated High Turbine Power Plant and Wellfield.	51
III-2.	Energy Inputs, Liquid Dominated Low Turbine Power Plant and Wellfield.	52
III-3.	Energy Inputs, Liquid Dominated Silica Treatment Facility. .	53
III-4.	Energy Inputs, Hot Dry Rock Gradient = 35°C/km Wellfield Components	54
III-5.	Energy Inputs, Hot Dry Rock Gradient = 45°C/km Wellfield Components	55
III-6.	Energy Inputs, Hot Dry Rock Gradient = 55°C/km Wellfield Components	56
III-7.	Energy Inputs, 50 MWe Binary Plant	57
III-8.	Energy Inputs, Hot Dry Rock Recompletion Costs	58
III-9.	Energy Input, Hot Dry Rock Low Temperature Resource Wellfield Components	59
III-10.	Energy Input, Hot Dry Rock Low Temperature Resource Power Plant	60
III-11.	Energy Inputs, Hot Dry Rock "Best Case" Wellfield Components	61
III-12.	Energy Input, Hot Dry Rock "Best Case" Power Plant	62
III-13.	Energy Inputs, Geopressure Wellfield Costs	63
III-14.	Energy Inputs, Geopressured Power Plant.	64
III-15.	Energy Inputs, Vapor Dominated Power Plant and Wellfield . .	65

<u>Table No.</u>	<u>Page</u>
III-16. Energy Inputs, Vapor Dominated Hydrogen Sulfide Abatement System.	67
III-17. Deflators for Various Sectors	70
IV-1. Concentration of Most Common Gases at The Geysers	78
IV-2. Composition (in ppm by weight) of Steam Condensate From Typical Wells in The Geysers field.	84
IV-3. Ecoenergetic Impacts.	97
V-1. Effects of Changing Energy Prices	102
VII-1. Results of Previous Energy Analyses of Geothermal Electric Systems	108

<u>Figure</u>	<u>LIST OF FIGURES</u>	<u>Page</u>
I-1a through I-1f. Power curve for geothermal-electric system. .		5 - 10

I. INTRODUCTION AND SUMMARY OF RESULTS

Like any energy supply technology, geothermal-electric systems require energy to build and operate. Theoretically, it is always possible that the energy "in" to the system exceeds the energy "out." In practice, most of today's proposed energy technologies seem comfortably far from that "net energy limit" [Pilati, 1977], but a few are getting uncomfortably close (e.g., gasohol and the solar power satellite [Chambers, et al, 1979; Herendeen, et al, 1979]). In this study we have subjected four types of geothermal-electric plants, in the 50 MW range, to a detailed comparison of energy inputs and outputs.

1. Hydrothermal (2 examples).
2. Hot Dry Rock (5 examples).
3. Geopressure (1 example).
4. Vapor dominated (1 example).

In some earlier work [Iceman, 1976; Riemann, et al, 1976], as well as some early rough calculations of our own, it was found that geothermal electric systems are far from the net energy limit, that is, the energy ratio (ER) well exceeds unity, where

$$ER_{\text{without fuel}} = \frac{\text{net electrical energy out over lifetime}}{\text{primary non-renewable energy to build and operate (except geothermal energy input)}}$$

---

*If fuel were included, ER would always be less than unity for a non-solar technology. See [Herendeen, et al, 1979.]

1. Energy Ratios

After continued analysis we confirm that finding: Geothermal-electric is a net energy producer. We do find, however, that the energy ratios are generally somewhat lower than those previously reported. This is in part due to our inclusion of additional inputs such as pollution control. The results are shown in Table I-1. We indicate an estimate of uncertainty, but the uncertainties are sufficiently small that the conclusion of positive net-energy production seems unthreatened.* For hot dry rock technology we list energy ratios for several different thermal gradients (i.e., different drilling depths), an indicator of sensitivity to that input.

The first three technologies - liquid dominated, hot dry rock, and geopressure - have energy ratios of order 3 to 4 (excepting the "best" case for hot dry rock, which is likely too optimistic). Vapor dominated, on the other hand, has a significantly higher energy ratio of 13 or more. Our vapor dominated example is from The Geysers, California, the only geothermal-electric plant now in commercial use in the United States.

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*The value of $ER=1$ would represent the "net energy limit" in an economy with just one energy type. (The technology requires as much energy from the economy as it returns.) With several kinds of energy, ER becomes a bit more ambiguous. The denominator or the expression is primary energy. If that energy had to be supplied by electricity, then $ER = 1$ is the limiting case. In actuality, some of the primary energy in the denominator is used to produce electricity to make (say) steel, and if we had an all-electric economy, the size of the denominator would decrease somewhat since we would supply the electricity directly. The consequence is that an ER of somewhat less than 1 (as we define it) would represent the net energy limit. We therefore adopt $ER = 1$ as a conservative indicator.

Table I-1.

ENERGY RATIOS FOR GEOTHERMAL-ELECTRIC TECHNOLOGIES

TECHNOLOGY	NET OUTPUT POWER(MWe) ^{a)} and CAPACITY FACTOR	LIFETIME (yr)	DATA SOURCE	ER ^{b)}	COMMENTS
<u>Liquid Dominated:</u>					
High Turbine	50 @ 85%	30	Bechtel (1977)	4.3 ± 1	Pollution control costs are a significant factor
Low Turbine	50 @ 85%	30	Bechtel (1977)	4.4 ± 1	
<u>Hot Dry Rock</u>					
35°C/km	50 (avg.) @ 85%	30	EPRI (1978) and Republic Geothermal (1979)	2.7 ± 0.9	Energy ratio strongly dependent on size of the produced fracture.
45°C/km	50 (avg.) @ 85%	30	EPRI (1978) and Republic Geothermal (1979)	3.4 ± 1.0	
55°C/km	50 (avg.) @ 85%	30	EPRI (1978 and Republic Geothermal (1979)	3.9 ± 1.1	
Low Temp. Resource	50 (avg.) @ 85%	30	EG&G (1979) and Republic Geothermal (1979)	1.9 ± 0.6	
"Best" Case	100 (avg.) @ 85%	30	Milora & Tester (1976) and Republic Geothermal (1979)	13 ± 3	
Geopressure	25 @ 85%	30	Rieman, Rios-Castellon, and Underhill (1976)	2.9 ± 0.9	Energy contained in methane not included.
Vapor Dominated	106 @ 85%	25	Pacific Gas and Electric (1973)	13 ± 4	Only form of geothermal currently used for commercial production of electricity in the U.S.

a) Net after use of some electricity on site.

b) ER = Energy Ratio =
$$\frac{\text{Net electrical energy output over time}}{\text{primary non-renewable energy to build and operate over lifetime.}}$$

2. Power Curves.

Energy ratio and energy pay back time (which is defined as the time after startup the facility must operate to pay back the total energy invested) are two shorthand quantities which attempt to summarize the "time stream" of energy inputs and outputs over the facility lifetime. This is called the "power curve" and conveys all net energy balance information. In Figure I-1 we include power curves for the technologies studied. In general, these contain no surprises: there are some increased energy inputs at points in the lifetime when new wells must be drilled, or old ones recompleted; and there is some time variation of power plant capacity as one well is drawn down (i.e., the temperature of the fluid decreases) before another well is tapped.

We assume no decommissioning costs. The operation and maintenance power inputs, including that of drilling new wells, or producing new fractures in the case of hot dry rock, in general are relatively small compared with the output of the plants. One exception to this is for liquid dominated hydrothermal, where the power cost of environmental protection proves quite high. The operation and maintenance power here is approximately one-sixth of the output power, and the energy needed for this over the plant's 30-year lifetime is over 2 times as much as the energy for initial construction.

3. Ecoenergetics.

The energies considered in the above are what one normally calls energy - coal, oil, natural gas, nuclear and hydropower, as

Fig. I-1a. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

Fig. I-1b. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

Fig. I-1c. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

Fig. I-1d. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

Fig. I-1e. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

Fig. I-1f. Power curve for geothermal-electric system.

Output (unshaded) is net electric energy costed at 3413 Btu/kWh (enthalpic energy content). Input (shaded) is primary energy equivalent of construction, operation and maintenance. Geothermal energy input is excluded, consistent with definition of energy ratio in Section I-1.

inputs, electricity as output. These inputs are non-renewable (except for hydroelectricity, which accounts for only 4% of U.S. primary energy and which, by convention, is treated like the equivalent fossil-fuel produced electricity). In addition, we have performed some Ecoenergetics [Odum, 1976; Odum, 1978; EA Handbook, 1979; Gilliland, 1975] calculations which attempt to include solar energy in its various manifestations, in its role of driving the total ecosystem as it nurtures life and processes pollution. This work was originally to be performed on sub-contract, but the sub-contractor was unable to carry out the work and we have done it ourselves. We state at the outset that although we find the goal of ecoenergetics laudable (Brother Sun does give us life), we do not find it particularly useful for policy decisions at this point in its development. Debate about this continues sporadically, and we may change our views in the future. But for now, we see Ecoenergetics as a nascent technique. Our major objections are:

1. In contrast with Ecoenergetics, we do not calculate the energy cost of labor (e.g., counting the energy that supplies a worker's food as an energy input to the car he produces).

Our argument is that this double counts energy; to be consistent the only independently varying output of an economy would then be exports [Costanza, 1978].

2. We do not accept that the various scaling arguments used to determine the energy cost of the ecosystem's assimilation of pollution [see Odum, 1978] are valid. We feel (perhaps ironically, given that we are energy analysts) that energy is not a useful numeraire for all environmental services.

3. We are not satisfied with Ecoenergetics' conversion techniques for comparing "diffuse" sunlight with "concentrated" wood, coal, etc.

4. Most worrisome of all, we cannot find a coherent, self-consistent and non-contradictory statement of the whole of Ecoenergetics and how the various components are used for policy. The latest book by the founder of Ecoenergetics, Howard T. Odum, contains circular reasoning regarding the Maximum Power Principle [Odum, 1976]. A more recent work [Odum, 1978] is more directed towards policy criteria, but maintains the ambiguity.

- a. Is it "yield ratio" [Odum, 1978, p. 76] or "investment ratio" [Odum, 1978; p. 79] that should be used? (As defined they both would apply to an energy technology such as grain-based ethanol.)
- b. How are monetary flows converted to energy equivalents. Originally Odum and workers used a single factor (National energy consumption ÷ GNP); later work used more product specific energy intensities derived by other workers using input-output techniques.
- c. Should future energy costs be discounted? Odum and co-workers generally have not done so, but did in [Bayley, et al, 1977].
- d. Is "waste heat" a pollutant or a beneficiator?
One Odum paper [Odum, 1974] indicates that this can

be a "good" by increasing biological production, yet this seems contradictory to the general notion that any deviation from natural equilibrium is undesirable [EA Manual, 1979].

We have, however, followed the procedures of Ecoenergetics practitioners regarding points 2 and 3, and present some of the results in Table I-2. There we see that most econenergetic energies are considerably less than the conventional energy inputs. However, the ecoenergetic energy cost of air pollution assimilation is larger than conventional energy inputs. Whether this is a deciding factor is the question which we must leave to the reader.

It should be noted that these environmental energies are the result of direct impacts on the geothermal site. We have not calculated the environmental impacts of the production (say) of steel. This indirect effect is what is treated by general energy to dollar conversions by some ecoenergetics practitioners, e.g., [Gilliland, 1978]. Because of the lack of disaggregation of this approach, we do not use it.

4. Effects of Changing Energy Prices

One of many economists' criticisms of net energy analysis is that improved efficiency of energy use, caused by increasing energy price, will tend to decrease energy inputs to a facility and increase the energy ratio -- in other words, that net energy analysis is itself affected by price effects. While this is true, energy analysts point out that if an energy ratio is already significantly greater than 1,

Table I-2.

ENERGETIC INPUTS OVER LIFETIME

TECHNOLOGY ^{a)}	NON-RENEWABLE ENERGY INPUT (10 ¹² BTU)	ECOENERGETIC INPUT (10 ¹² BTU)		
		Air	Water	Biotic
Liquid Dominated	8.8	18	0.6	0.003
Hot Dry Rock ^{b)}	11	--	0.13	0.09
Geopressure	6.6	22	---	0.04
Vapor Dominated	6.2	320	---	0.03

a) Note that these technologies have different capacities; See Table I-1.

b) Generic case, 45°C/km.

this effect can only increase it; hence there is no need to worry for proven net energy producers.

Nonetheless, for several of the technologies studied here, we have investigated the effect of "anticipated" price increases. To do so in a disaggregated fashion we have made use of a projected 1990 input-output table from the Bureau of Labor Statistics [BLS, 1979]. This model incorporates some assumed energy price increases and responses. By scaling our project (1967) energy intensities with the 1990 BLS (purely economic) table we estimate the change in energy intensities. Details are in Section IV. The results are given in Table I-3.

In general the changes are in the expected direction but small of order 5%. These changes are much smaller than the uncertainties mentioned in Section V below. They are also rather small compared with some already-publicized increases in energy productivity attained by industry.

We estimate that efforts to decrease the uncertainty in large ratios for geothermal are better directed towards reducing uncertainty in technological requirements (drilling, etc.) and in determination of energy intensities than in effects of energy prices.

5. Uncertainty in Energy Ratios

We find that a rather approximate approach to this question is justified by the fact that the energy ratios we obtain are significantly greater than unity. Table I-4 gives a breakdown by aggregated input category, and the effect is included in the uncertainties in energy ratio given in Table I-1. The energy output is also uncertain, but we have ignored that effect.

Table I-3.

Effects of Energy Price Changes on Energy Ratios.^{a)}

TECHNOLOGY	ER ^{b)}	% Uncertainty ^{c)}	% Change in ER (1967 → 1990)
<u>LIQUID DOMINATED</u>			
High Turbine	4.3	±24	-4.5
Low Turbine	4.4	±24	-4.1
<u>HOT DRY ROCK</u>			
35°C/km	2.7	±35	+0.7
45°C/km	3.3	±29	+1.1
55°C/km	3.9	±28	+2.0
Low Temperature	1.9	±34	
"Best" Case	13	±22	+5.2
<u>GEOPRESSURE</u>	2.9	±31	+3.4
<u>VAPOR DOMINATED</u>	13	±34	+1.6

a) Based on a scaling of energy intensities from Bureau of Labor Statistics input-output matrices [BLS, 1979]. Assumed range of energy prices, 1967-1990:

	<u>(Price(1990)/Price(1967))</u>	
	Current \$	Constant \$
Coal	5.6	1.7
Crude Oil and Gas	14.7	4.4
Electricity	5.6	1.7

b) From Table I-1.

c) From Table I-4.

Table I-4a
UNCERTAINTY IN ENERGY INPUTS

TECINOLOGY: LIQUID DOMINATED
POWER (Net):   50 MWe
SOURCE OF DATA: Bechtel (1976)
LIFETIME: 30 years
CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.13	0.15	0.0195
Plant Operating Costs	0.11	0.50	0.055
Wellfield Costs	0.16	0.50	0.08
Wellfield Operating Costs	0.22	0.50	0.11
Environmental Costs	0.38	0.50	0.19
 TOTAL	 1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.45$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.24$

Table I-4b.

UNCERTAINTY IN ENERGY INPUTS

TECHNOLOGY: HOT DRY ROCK - 35°C/km
 POWER (Net): 50 MWe
 SOURCE OF DATA: Republic Geothermal (1978), EPRI (1978)
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.06	0.15	0.009
Plant Operating Costs	0.03	0.50	0.015
Exploration	0.01	0.50	0.005
Drilling Time & Depths	0.61	0.55	0.336
Drilling Area	0.02	0.25	0.005
Recompletion	0.03	0.50	0.015
Wellfield Operating Costs	0.12	0.50	0.060
Environmental	0.12	0.50	0.060
 TOTAL	 1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.51$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.35$

Table I-4c.

UNCERTAINTY IN ENERGY INPUTS

TECHNOLOGY: HOT DRY ROCK, 45°C/km
 POWER (Net): 50 MWe
 SOURCE OF DATA: Republic Geothermal (1978) EPRI (1978).
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.09	0.15	0.013
Plant Operating Costs	0.05	0.50	0.025
Exploration	0.02	0.50	0.010
Drilling Time & Depth	0.40	0.55	0.264
Drilling Area	0.03	0.25	0.007
Recompletion	0.03	0.50	0.015
Wellfield Operating Costs	0.15	0.50	0.075
Environmental	0.15	0.50	0.075
 TOTAL	 1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.48$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.29$

Table I-4d.

UNCERTAINTY IN ENERGY INPUTS

TECHNOLOGY: HOT DRY ROCK, 55°C/km
 POWER (Net): 50 MWe
 SOURCE OF DATA: Republic Geothermal (1978) EPRI (1978)
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.09	0.15	0.013
Plant Operating Costs	0.05	0.50	0.025
Exploration	0.02	0.50	0.010
Drilling Time & Depth	0.46	0.55	0.253
Drilling Area	0.03	0.25	0.007
Recompletion	0.03	0.50	0.015
Wellfield Operating Costs	0.18	0.50	0.090
Environmental	0.17	0.50	0.085
TOTAL	1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.50$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.28$

Table I-4c.

UNCERTAINTY IN ENERGY INPUTS

TECINOLOGY: HOT DRY ROCK, Low Temperature
 POWER (Net): 50 MWe
 SOURCE OF DATA: Republic Geothermal (1978); EE&G (1978)
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.07	0.15	0.010
Plant Operating Costs	0.01	0.50	0.005
Exploration	0.01	0.50	0.005
Drilling Time & Depth	0.59	0.55	0.324
Drilling Area	0.07	0.25	0.017
Recompletion	0.03	0.50	0.015
Wellfield Operating Costs	0.15	0.05	0.075
Environmental	0.07	0.50	0.035
 TOTAL	 1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.49$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.34$

Table I-4f.
UNCERTAINTY IN ENERGY INPUTS

TECHNOLOGY: HOT DRY ROCK, Best Case
 POWER (Net): 100 MWe
 SOURCE OF DATA: Tester & Milora (1976); Republic Geothermal (1978)
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.23	0.15	0.034
Plant Operating Costs	0.15	0.50	0.075
Exploration	0.04	0.50	0.020
Drilling Time & Depth	0.33	0.55	0.182
Drilling Area	0.04	0.25	0.010
Recompletion	--	0.50	--
Wellfield Operating Costs	0.08	0.50	0.040
Environmental	0.16	0.50	0.050
TOTAL	1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.441$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.22$

Table I-4g.

UNCERTAINTY IN ENERGY INPUTS

TECINOLOGY: GEOPRESSURE
 POWER (Net): 25 MWe
 SOURCE OF DATA: Riemann, Rios-Castellon/Underhill
 LIFETIME: 30 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Power Plant	0.07	0.15	0.008
Plant Operating Costs	0.27	0.50	0.135
Wellfield	0.54	0.50	0.270
Wellfield Operating Costs	0.12	0.50	0.060
TOTAL	1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.47$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.31$

Table I-4h.

UNCERTAINTY IN ENERGY INPUTS

TECHNOLOGY: VAPOR-DOMINATED
 POWER (Net): 106 MWe
 SOURCE OF DATA: Pacific Gas and Electric Co (197)
 LIFETIME: 25 years
 CAPACITY FACTOR: 85%

<u>INPUT CATEGORY</u>	<u>FRACTION OF ENERGY INPUT (f)</u>	<u>FRACTIONAL UNCERTAINTY (α)</u>	<u>$f_i \alpha_i$</u>
Plant Capital Costs	0.12	0.15	0.018
Plant Operating Costs	0.07	0.50	0.035
Wellfield Costs	0.67	0.50	0.335
Wellfield Operating Costs	0.13	0.50	0.065
Environmental Costs	0.01	0.50	0.005
TOTAL	1.00		

MAXIMUM FRACTIONAL UNCERTAINTY: $\sum_i f_i \alpha_i = 0.46$

PROBABLE FRACTIONAL UNCERTAINTY: $\sqrt{\sum_i (f_i \alpha_i)^2} = 0.34$

II. METHODOLOGY

As indicated in the Introduction, we have used "standard" energy analysis [IFIAS, 1974] rather than Ecoenergetics as our preferred method of energy analysis. This involves energy costing the inputs to the systems with the total primary energy (coal + crude oil and gas + fossil equivalent of hydro and nuclear) needed to manufacture and deliver them to the site, as well as support on-site activities, and subsequent operation* and maintenance. (As discussed in Section I this does not include an energy cost of human labor.) The output on the other hand, is electricity. We energy cost this with no conversion. (Multiplying by a factor of 3 to 4 is often justified by pointing out that the electricity will displace present day electricity, which is largely produced by burning fossil fuels, but we multiply by 1.) Non-energy inputs such as materials and services are energy costed by multiplying the dollar cost for them times energy intensities (Btu/\$) derived from input-output energy studies and published elsewhere [Herendeen and Bullard, 1974; Bullard, Penner and Pilati, 1978].

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*Even here there is some ambiguity since some of the electricity needed for operation is supplied by the plant itself (in which case it is subtracted from the numerator in the energy ratio). If instead the electricity were supplied by today's energy supply infrastructure, approximately 3 times that electrical energy would be added to the denominator. The convention of assuming that the geothermal-electric plant uses inputs produced by "today's" energy industry is a marginal approach, which does not treat the case in which geothermal electricity is a non-negligible fraction of the nation's electricity. This is also a traditional problem in energy analysis, which requires an arbitrary decision (such as ours) for resolution. This has been discussed by [Chapman, 1975].

These intensities are based on detailed ones (358 sectors) for the year 1967 which have been updated to match the construction data (90 sectors) and which are expressed in 1976, or more recent, dollars by the use of sector specific deflators and overall energy/GNP ratios [Bullard & Herendeen 1975, pp. 276-77]. These are thus based on old data but are quite disaggregated. (This is a general tradeoff in energy analysis - detail vs. up-to-dateness.) The input-output technique in theory accounts for all conventional energy inputs doing the entire chain of extraction-processing-fabrication-assembly-shipping-marketing of a commodity. Deflators are listed in Table III-17.

The energy intensities developed for an input-output matrix represent the state of a technology at a given time (in this case 1967). In order to approximate the changes, we normalize our energy inputs according to the change in energy/gross national product ratios for the years in question. The ratio of energy to GNP is first calculated for 1967. A similar ratio is calculated for the years in which costs for the various projects were expressed. Both of these ratios represent the average intensity of the economy for that year. In order to account for this, total energy inputs (not the intensities) were multiplied by the ratio of average intensity in a given year divided by the average intensity in 1967. This is referred to as "NRG/GNP" in Table III-1. For example, the ratio of the average intensities for 1978 and 1967 is 0.9586; all inputs developed with 1978 cost data were therefore multiplied by 0.9586 (see Table III-7). Likewise, the ratio between 1976 and 1967 is 0.9879; inputs developed with 1976 cost data were

multiplied by 0.9879 (see Table III-12). This is an approximation. See [Bullard and Herendeen, 1975].

The sources of geothermal-electric technology materials and services are generally design studies. Only the vapor dominated refers to an actual, operating installation; the others are at various stages of planning or construction. It is ironic that we had the most difficulty (of any technology) obtaining drilling data for vapor dominated, since this comes from a private company which has some interest in keeping its working affairs private.

The basic intent is to obtain all requirements for energy, materials (including capital equipment), and purchased services to build, operate, and maintain the plant. The sources, with a brief comment on each, follow.

A. Liquid-Dominated Hydrothermal

The largest percentage of geothermal energy is in the form of heated liquids, located from five to ten thousand feet beneath the earth's surface. Among the liquid-dominated areas closest to commercialization for electrical generation are the Known Geothermal Resource Areas (KGRA) in the Imperial Valley of Southern California. Bechtel Corporation has performed economic and design studies for 50 MWe geothermal power plants at the Heber and Niland KGRA [Bechtel, 1977]. This study includes provisions for declining resource temperature, as well as variations in plant capacity. We chose to analyze the design for the Heber plant, utilizing a two-stage flashed-steam energy conversion process. Cost estimates developed by Bechtel included capital cost of both the plant and the wellfield, and an estimate of the annual operation and maintenance costs. It should be noted that Bechtel used a relatively low estimate for the cost per well for drilling compared with, for example, estimates by Union Oil Co. for the Geysers [Pacific Gas & Electric, 1979]. For the sake of consistency, however, we retained these figures for our calculations.

The Heber KGRA, along with all others in the Imperial Valley, is characterized by a high concentration of total dissolved solids (TDS). In order to dispose of this brine, as well as to minimize the danger of subsidence, it was originally assumed that all of the fluid could be reinjected. However, tests at the Geothermal Loop Experimental Facility (GLEF) at Niland indicate that portions of the dissolved silica must be removed prior to reinjection to prevent scaling [GLEF Annual Report, 1978]. Inputs for these brine treatment costs

were developed by Lawrence Livermore Laboratory for San Diego Gas and Electric Company [GLEF, Appendix A, 1978] and from pollution control studies by the Environmental Protection Agency [Hartley, 1978].

B. Hot Dry Rock

This technique depends on the capability of producing and maintaining fractions in deep hot dry rock bodies. There are several data sources, although there are no working plants at this time. We have relied strongly on the work, and workers, at the Los Alamos hot dry rock facility. Most of the hot dry rock sources available are from LASL personnel now involved in the LASL project, or from private companies under contract to LASL. For example:

1. Testor and Milora (1976) - We view the figures presented in this early book as somewhat optimistic considering the large fracture radii assumed in some of the calculations.
2. The LASL HDR group - Many of the concepts contained herein are based on work by the LASL hot dry rock group. References to some of the group's articles are given in the following sections.
3. Republic Geothermal (1979) - Drilling costs for hot-dry rock are derived using a study prepared by Republic Geothermal, Santa Fe Springs, California. This study developed a model to calculate the cost of each component of drilling, logging, recompletion, etc., based on depth and on drilling parameters.
4. EG&G of Idaho (1978) - Costs for a low temperature hot dry rock power plant were developed using cost assumptions by EG&G for a

binary plant at their Raft River Complex.

5. Holt/PROCON (1978) - Costs for a binary power plant was also estimated from designs produced by Holt/PROCON, for the Electric Power Research Institute. Fluid temperatures required for this and the above plant set the drilling depths required (assuming a given thermal gradient).

C. Geopressure

In the Northern Gulf of Mexico basin are large resources of hydrothermal fluids under higher than normal hydrostatic pressure. These geopressurized resources are also characterized as containing a large amount of dissolved methane (up to 50 cubic feet per barrel of fluid, depending on its temperature and salinity), [Muffler, 1978]. A net energy analysis of geothermal-geopressure power plants has previously been performed [Carlson and Underhill, 1976]. This study utilized 1963 energy intensities [Herendeen, 1975] and cost figures for Gulf Coast geopressured geothermal power plants, developed in 1975 by Brown & Root.

The analysis presented here relies on cost figures for a geopressured geothermal production plant in the U.S. Gulf Coast, developed by the Dow Chemical Company [Dow, 1976] and on a report on the economic analysis of this plant by Carl Friedrich Riemann, Lorenzo Rios-Castellon, and Gary K. Underhill [Riemann, et al, 1976]. The costs for the power plant are disaggregated into a somewhat detailed bill of goods. With the exception of the actual drilling cost, the same holds true

for the wellfield costs. Geopressure technology is the least well-known of the four technologies in our opinion, and therefore the technical and economic specifications are the most uncertain.

D. Vapor Dominated.

Perhaps the most valuable forms of geothermal energy are those resources known as vapor-dominated, or dry steam. Vapor dominated systems are unique in that the resource contains large amounts of saturated steam, in addition to the hot water. Utilization of this heat energy is much easier than hydrothermal, or hot water resources, as there is seldom a need for flashers to separate steam from water. Moreover, the steam is relatively clean and there is little need for pre-treatment before it enters the turbines. There are, however, significant problems with the release of hydrogen sulfide. In many cases, "scrubbers" must be installed to remove this obnoxious chemical from the released steam.

Vapor-dominated systems are extremely rare. One of these, the Geysers in Northern California, are currently the only site in the United States where electricity is being generated with geothermal energy. In fact, over 500 MWe of capacity is installed at the Geysers. We relied on specific cost data from one of these sites for our analysis. Capital and operating costs were provided by Pacific Gas and Electric Company for several of their units. We chose to analyze units 9 and 10, as they seemed representative of the type of plants at the Geysers. These units were completed in 1973, so the

cost data is over 6 years old. This will, however, have little effect on any net energy calculation. Both of these units have a net output of 53 MW, for a total net output of 106 MW.

Pacific Gas and Electric recently installed hydrogen sulfide abatement equipment on a pair of their units of similar size. Cost data of these systems was obtained from the utility and was included in our capital cost estimate.

A disaggregated bill of goods for drilling costs was difficult to obtain. Union Oil Company, the company from whom Pacific Gas and Electric purchases the steam, has an interest in maintaining the proprietary nature of these costs. We were, however, given an aggregated total cost per well for drilling. As explained in Section III, a "hybrid" energy intensity was used to determine energy inputs.

III. ENERGY INPUTS ACCORDING TO "STANDARD" ENERGY ANALYSIS

A. Liquid Dominated

Costs were developed in the Bechtel report [Bechtel, 1977] for 50, 100, and 200 MWe plants, operating in either a constant power or constant flow rate mode. The constant power mode, chosen for this study requires an increase in flow-rate over the thirty-year lifetime of the plant to offset the declining resource temperature. The plant operates with a two-stage flash steam conversion process using steam at a temperature of 330°F. Downhole temperature of the steam is assumed to be 360°F. Initially 13 production wells and 6 reinjection wells are drilled. Four additional production wells are drilled later to maintain a constant power output.

Power plant equipment costs were developed by Bechtel for two different possibilities: "high" turbine-generator and "low" turbine-generator. "High" and "low" simply refer to a possible range in turbine costs, based on a survey of manufacturers by Bechtel. Both cases were studied in our report.

Labor costs were subtracted from the capital cost estimates using Bechtel's estimation that indirect field costs were 65% of the direct construction labor costs. Although cost for installation (and, therefore, labor) are only given for the base (i.e., constant flow) case, it was assumed that labor costs would be roughly the same for the constant power output case. (This is reasonable in light of the fact that equipment cost only varies by 3% between the base and constant output case).

According to the Bechtel study, yearly operation and maintenance costs are 2% of the installed capital cost of the plant. Plant

administration costs are 25% of the operations and maintenance costs. The annual cost for plant insurance is estimated to be 0.1% of the plant capital cost.

Wellfield operations cost include a portion for site manager salaries, as well as costs primarily composed of materials and chemicals. Only the latter cost was included, totalling \$250,000(1978\$) per year. The cost of maintaining the wells is estimated at \$50,000/well/year for the production wells and \$80,000/well/year for the reinjection wells (both 1978\$). Note that these maintenance costs increase over time as more wells are drilled. Finally, Bechtel has estimated that wellfield administration will annually cost an amount equal to 10% of the operations and maintenance costs, and annual wellfield surface equipment maintenance costs will be 0.5% of the capital cost of the surface facilities.

The only environmental factor that the Bechtel report specifically deals with is scrubbing the vented gases to remove hydrogen sulfide. With regard to silica scale, the original report states only that "it is unlikely that silica scaling will present a serious problem in the plant," and they feel that addition of caustic soda will minimize any problem that may occur. However, recent fieldwork at San Diego Gas and Electric's test loop facility has shown that the formation of silica scale may indeed present a problem (Conversation with Bill Jacobsen, 17 September 1979). Scale precipitates inside the pipes and prevents effective reinjection of the fluid. Experimentation has been underway testing the use of various water treatment methods to remove the silica prior to reinjection. The operation that currently appears most successful is the use of self-seeding reactive clarifiers. Cost estimates for a reactor type upflow contact

clarification with granular media filtration have been developed by Lawrence Livermore Laboratory for San Diego Gas and Electric Co. This system is designed for a plant of similar size (50 MWe), but of higher resource temperature. The required flow rate is much lower than that assumed for the Heber plant, in fact only about 28% as great a flow. Costs for a facility would, therefore, be greater at Heber, but there would be reductions on a per unit basis due to economies of scale. A good estimate of the magnitude of these scale economies can be derived from the E.P.A. publication on "Pollution Control Guidance for Geothermal Energy Development" [Hartley, 1978]. This report lists costs for waste water treatment as a function of flow rate. Although the specific process of reactive clarification with granular filtration is not given, two of its major components are shown (chemical precipitation and filtration). From these functions, a scaling factor for capital and operation costs in the range between 3 and 12 million pounds per hour can be found. From these graphs, the scaling factor for both components of the reactive clarification, as well as for the operation and maintenance, was found to be approximately 0.4 (i.e., the cost per unit is inversely proportional to the ratio of the flow rates raised to the 0.4 power). With this scaling factor, costs for the treatment of water at the proposed Heber facility were calculated.

Disposal of the removed effluent is complicated by its composition. Although the major component is simply silica, the effluent also contains hazardous materials such as barium and lead

sulfides. As such, the material must be hauled to a special Class I landfill. For the purposes of this study, we assumed conventional hauling of the brine effluent.

B. Hot Dry Rock

Tapping of hydrothermal energy is limited to those few regions where hot bodies of water are located near the surface. A far greater resource of energy is the enormous amount of heat contained in the hot rock within a few miles of the earth's surface. (It has been estimated that 74000 quads of energy as heat over 150°C exist beneath the land area of the U.S. to depths of 10 km [Tester, et al, 1979]). Recent research in several parts of the country has been aimed at extracting heat from these resources. The method under development, known as Hot Dry Rock (HDR) Geothermal Energy, consists of drilling two wells into the hot region. Fractures are hydraulically created between the two wells, creating in effect an enormous heat transfer region. Cold water is pumped under pressure into one well and warmed as it passes through the fracture. The water is returned to the surface through the other well and pumped into the power plant. Flashers can then be used to produce steam, or, in the case of a binary plant, a secondary working fluid can be heated. After condensation, the water is recirculated through the injection well to complete the loop.

Small field tests of HDR are currently being conducted by Los Alamos Scientific Laboratory (LASL) at their Fenton Hill test site. Two wells have been drilled to a depth of about three kilometers, and a fracture has been created connecting the two [Pettitt, 1978]. Observations over time have indicated that this fracture system

accurately fits a model describing a circular fracture 0.2 mm thick, with a radius of 60 meters and a heat transfer region of about 8000 m². During a 75 day test in early 1978, flow rates of 15 kilograms per second were realized, with power output peaking at 5 Mwt [LASL, 1978a]. Both of these wells will be deepened to obtain downhole temperatures of 275°C, with the hope of creating a much larger power output [LASL, 1978b]

Advantages of the HDR power plant are twofold. First, the location of a HDR plant can theoretically be built wherever the thermal gradient is sufficiently large. Moreover, there is a certain amount of flexibility in the design of the well fields and plants. Since the resource is not localized at a particular depth or temperature, cost optimization can be used to determine the proper parameters for the wells. Second, since the flow of heated fluids is a closed cycle, environmental problems are, in theory, greatly diminished. The recirculation of this water not only minimizes the problem of surface disposal of fluids, but is also lessens the likelihood of subsidence. Induced seismicity, a potentially serious environmental factor, has not been observed at Fenton Hill [LASL, 1978a].

Still, Hot Dry Rock power plants can not be universally sited, as there are many physical constraints on the system. Perhaps the most important is the depth required to reach a resource that is economically recoverable. This is, in turn, related to the temperature gradient of the earth's crust at a particular region. On the average, the temperature increases about 22°C with each kilometer increase

in depth [Tester, et al., 1979]. Though this may result in a tremendous amount of heat even at shallow depths, it is of such low temperature as to virtually eliminate the possibility of electrical generation. A higher Carnot efficiency can be obtained by deeper drilling, but economic and technical factors currently constrain maximum well depth to about six, and at most ten kilometers. (In 1977, only 8 oil wells, or 0.04% of the total were drilled to depths greater than 5.3 kilometers. The deepest was 6.78 km [API, 1977] Hot dry rock therefore appears most feasible at those areas with high temperature gradients. Estimates have made that over 33% of the U.S. land area may have gradients of 30 to 36°C/km, and that 5% has a gradient of greater than 40°C/km [Tester, et al., 1979]. Gradients as high as 60 and 70°C/km exist in some areas, often, but not always near hydrothermal resources. (At Fenton Hill, temperatures of 200°C have been reached at depths of 3 km. [Pettitt, 1978]).

High temperatures alone are not sufficient to define a recoverable HDR resource. It is also important that the surrounding rock have very low permeability. Highly permeable rock would allow a significant amount of the water, and therefore the heat, to be lost to the surrounding region. Finally, the fractured rock itself must have very high permeability through the induced cracks. Pumping demands can become significant if the permeability of the fractured rock is low. Both of these conditions are necessary in order to extract as much of the injected water as possible.

Cost and energy of geothermal power plants are, in general, subject to large uncertainties due to the many variables in the drilling process. These uncertainties are further magnified for a hot dry rock wellfield, as the technology may require numerous deep wells in hard rock. In the past, drilling costs have been estimated using an extrapolation of oil and gas well cost experience [Milora and Tester, 1976]. For this study, drilling costs were estimated using guidelines developed in the study "Industrial Assessment of Drilling Completion and Workover Costs of the Well and Fracture Subsystems of Hot Dry Rock Geothermal Systems," by Republic Geothermal, Inc. [Republic Geothermal, 1979]. The Republic Geothermal report used a fairly general (in terms of site location) methodology to determine individual cost components of the drilling and fracturing operations for an injector/producer well pair. This model is a detailed analysis of each component in a hot dry rock well program. The most important input into this model is the desired drilling depth, or, given a certain geothermal temperature gradient, the desired rock temperature. Once this is known, the model branches out and calculates the time, material and cost for the different aspects of drilling. For example, one can calculate the drilling and non-drilling rig time and casing required to reach a certain depth. This will, in turn, lead to approximate cost for fuel, drilling bits, drilling mud, casing, etc.

Since Hot Dry Rock is still in its early stage of development, several of the assumptions in this energy analysis (and the Republic cost estimates) are based on techniques both inherently difficult and not fully tested. Perhaps the most significant of these is the creation

of extremely large and well-defined fractures deep in the earth. Although this fracturing technique has previously been used in oil and gas wells, its application there was not as critical as that required to unite two separate well holes.

Hot Dry Rock, as usually described, is also dependent on the technique of directional drilling. The economics of HDR are substantially improved if it is assumed that multiple fractures can be created between a single well-pair. This allows a well to be used despite the depletion, or cooling, of the original fractures, which takes on the order of 5 years. Multiple fracturing is most effectively accomplished between parallel well holes that are also at an angle with respect to the vertical. There are methods, most notably whipstock and downhole motor, for angling the well shaft. However, these techniques have been developed for oil drilling and therefore are used most often in softer sedimentary basins. Hot Dry Rock well-field will most likely be located in much harder rock, resulting in more difficult drilling operations.

A continual flow of cool water through a fractured region will lead to a cooling of the rock. Calculations have shown the dependence of the rate of cooling on the flow rate of water as well as the radius of the fractures [Tester and Smith, 1977; and McFarland and Murphy, 1976]. It is hoped, however, that as the rock cools, thermal contraction will cause it to fracture and provide new flow regions for the circulating fluid [Tester, et al, 1979]. Thermal stress fracturing therefore, has the potential for expanding the

size of the heat exchange area. To date, field tests at the Fenton Hill test site have not yet shown whether thermal fracturing is occurring [LASL, 1978a]. Although the observed thermal draw-down curve was at times slower than predicted analytically, there were many other factors besides increased heat exchange area which could have affected these temperature changes [LASL HDR Staff, 1978].

Other areas of concern for all high temperature drilling include accurate logging techniques, development of high temperature drilling mud and cement, improved drilling bits and elastomeric seals for bits and packers, etc. Since the problems of high temperature drilling occur in virtually all geothermal resources, there should be some carry-over of technological improvements between the various forms of geothermal energy.

As of yet, no power plant has been built at a Hot Dry Rock site. Specific plans for a plant would depend heavily on the physical parameters at the well site. As mentioned earlier, there may be some flexibility in choosing the power cycle for the generating components. We have assumed here that a binary plant will be used to generate electricity. Binary plants (also a new and not fully developed technology) have often been proposed for use at high-salinity resources, as the process isolates turbines and other components from the corrosive brine. Designs also call for the use of binary plants at low temperature resources. Working fluids with low boiling points and high vapor phase energy density are used in the hope that turbine size and cost can be reduced.

Three different "cases" of hot dry rock were analyzed each reflecting different assumptions regarding resource parameters. The most optimistic was labeled the "Best Case," as it assumed the creation of four extremely large (1000m radius) fractures between each well-pair. Large multiple fractures such as this allow for a slower flow rate, which, in turn, greatly reduces the thermal drawdown of the rock. This "best" case assumed four well-pairs were created, each containing four of these large fractures. The wells were drilled deep enough to create a resource temperature of 250°C. The region beneath the well-field was assumed to have a fairly high geothermal gradient (50°C/km). Because of the large fractures and slow flow rate (40 kg/second/fracture), no refracturing would be needed as the power drop would be no more than 20% over the 30-year life of the plants. Cost figures for the binary plant were developed from [Milora and Tester, 1976].

The second case studied actually consisted of three separate assumptions. A net energy analysis was done for three different geothermal gradients: 35, 45, and 55°C/km. The desired temperature of the resource was 215°C, to allow for a 5% loss in the heat exchange process. It was assumed that a single well-pair could produce six usable fractures, separated by a distance of 50m. Recompletion would be required every five years to create new fractures between the well-pairs. Relatively low values for flow rates and fracture radii were used: 50 kg/sec/well-pair and radius of 300m. The

wellfield was assumed to consist of 20 well-pairs, creating a total possible flow of 1000 kb/sec. These parameters are such as to minimize the "ripple" that will occur as thermal drawdown cools the rock. It is estimated that power output will vary from approximately 60 MWe to 40 MWe at five-year intervals in a sawtooth fashion. As such, energy calculations assumed a constant power output of 50 MWe.

Cost figures for the geothermal plant for this option were developed from a study prepared by Holt/PROCON for the Electric Power Research Institute, entitled "Preliminary Design Manual for a Geothermal Demonstration Plant at Heber, California." [EPRI, 1978].

Heber is a hydrothermal resource in the Imperial Valley of California, containing brine with a total dissolved solids concentration of about 13000 ppm. It is quite likely that, for fluids of the same temperature, the engineering problems associated with solutions at a Hot Dry Rock plant would be less and could result in lower plant capital costs. Nevertheless, for this study it was decided that this binary process could be applied without significant error to a hot dry rock resource, provided that the fluid inlet temperatures were the same (Conversation with Dr. Fred Abel, U.S. Department of Energy, June, 1979).

The final Hot Dry Rock case considered was a binary plant using relatively low temperature fluid from shallow wells. For these calculations we assumed that the gradient was 40°C/km. Costs for the power plant were based on preliminary figures from EG&G Idaho, Inc. for a binary plant at the Raft River complex in Idaho.

As with the EPRI design, this plant is also designed for operation at a hydrothermal resource. It is also, however, indicative of the type of plants being considered at Hot Dry Rock resources. Working fluid temperature is only 143°C so a flow rate of 7.1×10^6 kg/hr is required (Conversation with Tom Lawford, EG&G, 12 June 1979). Flows such as these will probably be more economically achieved from naturally occurring hydrothermal systems than from artificially created heat transfer regions. It should be emphasized that these calculations pertain to a hot dry rock facility which would power plants similar to the design proposed at the Raft River hydrothermal facility. They bear no relationship to the Raft River site itself. Drilling parameters were quite similar to the "generic" hot dry rock case: flow rate of 50 kg/sec. through the fractured region, recompletion is performed five times at 5-year intervals, and a slightly larger fracture radius (500 meters). Because of the large number of wells, as well as the larger fracture radius and the lower temperature, it was assumed that a near constant power output of 50 MWe could be maintained in this case.

In all cases, a 20% contingency was added to drilling cost. This amount, in agreement with general industry estimates, accounts for any unexpected expenditure or increase in costs [Republic Geothermal, 1979].

C. Geopressured Geothermal

The production plant described here is a 25 MWe two-stage flash plant [Dow, 1976]. Power for the plant came from 10 wells producing 40,000 barrels of water per well per day. It was assumed

by Dow that these wells would be drilled to a depth of 4.2 km feet at a cost (completed) of \$1,925,000 (1976\$). One well in three is assumed to be dry, which is then converted into a reinjection-well at a cost of \$500,000 (1976\$). A total of 19 reinjection wells is required so other wells are drilled specifically for reinjection to a depth of 6,000 feet, at a cost of \$600,000 (1976\$).

Capital cost estimates for both the wellfield and the power plant were given as equipment cost and installed cost. In order to exclude labor costs from our energy input calculations, only the equipment cost was included.

As mentioned earlier, energy output calculations were made only on the basis of electrical output. This method will, for two reasons, produce a lower energy ratio: (1) There is, to be sure a significant amount of energy in the methane, and (2) capital cost estimates assume equipment is built to separate and collect the methane. The collection equipment would probably not be necessary if the only desired output was electricity. An exact separation of the facilities appropriate to electricity and methane production is probably impossible. This is another example of the joint products or partitioning problem [IFIAS, 1974].

No major environmental equipment was deemed necessary for the geopressured-geothermal plant. It is felt by Dow that there is no dissolved hydrogen sulfide in the fluid, and that the brine can be reinjected without prior treatment. To a certain extent, this may be an echo of the optimism voiced with the Imperial Valley resources

several years ago. Future field tests will determine whether clarifiers or similar treatment facilities will be necessary to remove the silica from the brine.

A plant lifetime of thirty years, and a capacity factor of 85% was assumed for the plant. The Dow report contains no specific mention of thermal drawdown or depletion of the resource. Aside from the initial drilling of a spare well, there is no provision for increased fluid flow or additional redrilling. Power output is apparently considered to be constant both from the wellfield and the power plant. Our output calculations assume a flat 25 MWe capacity which may, therefore, be optimistic. Again, it is extremely difficult to accurately judge these factors until more experience is gained and a specific geothermal resource is chosen.

D. Vapor Dominated.

A detailed breakdown of capital costs for the number 9 and 10 units, entitled "Segregation of Completed Construction Work" was supplied to us by Pacific Gas and Electric Company. We also received an even more disaggregated breakdown in a second listing entitled "Detail of Direct Costs and Overhead and Indirect Expenses." The former breakdown was used, not only because it was more comparable to the level of our energy intensities, but also because it explicitly separated labor from the cost figures. Virtually all of the costs were expressed in 1973 dollars.

Pacific Gas and Electric also supplied us with a specific breakdown of power plant operations and maintenance costs for 1977. It was noted that there was a wide variation in these costs, even among units of identical size. An average was taken of these amounts in order to determine a typical yearly price.

One of the more interesting aspects of the cost calculations was the determination of the wellfield costs. As mentioned earlier, we were able to obtain only the total cost for the drilling of a well. This cost was, in addition, given for the years 1975 to 1979. It would be possible to convert this figure (once expressed in the proper year) to energy through the use of the energy intensity for the sector 1105, "New Construction, Other." However, New Construction for oil/gas wells comprise only 28% of this sector, and as such it probably is not an accurate reflection of drilling intensities [Bullard, Penner and Pilati, 1976]. In order to more accurately determine the energy inputs of drilling, a "hybrid" intensity was developed with specific drilling cost data. In particular, costs from the hot dry rock case, calculated with the Republic Geothermal Study, were used. Total energy inputs to drilling were divided by the estimated cost, in 1978 dollars. The result was a figure that fairly accurately represents the energy intensity of drilling. There are, to be sure, at least two possible problems with this method: (1) it assumes that energy intensity is the same at different depths, and (2) it assumes that the energy intensity is the same for hot dry rock drilling as at the Geysers. Inspection of the hybrid intensities at 35°C/km, 45°C/km,

and 55°C/km indicated little obvious relationship with depth (68745 Btu/\$, 61297 Btu/\$, and 61969 Btu/\$, respectively, all 1978\$). The figure obtained at 55°C/km was used, as it represented the most shallow well. Although this method has its faults, it was felt to be more accurate than the use of an energy intensity sector which included farm construction, farm service construction, and military construction.

Based on conversation with persons at Union Oil and Pacific Gas and Electric, it was estimated that 18 wells would be necessary to supply a 106 MWe power plant (the range given was 16-20 wells) (Conversation with Harry Bain, 22 October, 1979). It was also assumed that a typical well could remain productive for 12-1/2 years. Based on past drilling experience at the Geysers, it was indicated that there has been a 90% success rate in drilling productive wells (Conversation with Glenn Horton, 4 December, 1979. This figure contrasts sharply with a success rate of 25% assumed in a previous net energy analysis [Icerman, 1976]. In order to temper possible over-optimism, a success rate of 80% was assumed here.

Finally, it was indicated that the Geysers currently has 6 reinjection wells for about 125 production wells. This is a reinjection-production well ratio of about 0.05, well below previous assumptions (Icerman assumed 0.25). To a certain extent it is inaccurate to include costs for reinjection wells, as they are usually simply abandoned production wells. However, in order to obtain costs for a new plant, we assumed an initial drilling of two reinjection wells, at a cost identical to production well costs.

Wellfield operation and maintenance costs were based on estimates by Bechtel for liquid-dominated wells (\$50,000 per year for a production well, \$80,000 per year for a reinjection well; both 1978\$) [Bechtel, 1976]. Lifetime for the wellfield, as well as the plant, was estimated at 25 years.

The hydrogen sulfide emission abatement system under installation at the Geysers is a new cost that must be added to capital and operating costs. We received a detailed breakdown of costs for the system just completed at Units 5 and 6. Because it is so new, data are not available on the operation and maintenance costs of this pollution control facility. These costs were, therefore, estimated as a yearly cost of 2% of the total capital cost. It should be noted that these costs could rise significantly in the future, resulting in a lower energy ratio.

The tables on the following pages show the bill of goods for each of the nine geothermal technologies. These tables include total operation and maintenance costs for the lifetime of the plant, as well as initial capital costs.

Tables III-1 and III-2 show the power plant and wellfield costs for the liquid-dominated high and low turbine, respectively. To these figures must be added the costs for construction and operation of the silica treatment facility, shown in Table III-3.

The energy inputs for the hot dry rock technologies are shown on Tables III-4 through III-12. There are three major components to the energy cost of a hot dry rock facility: the power plant, the initial drilling at the wellfield, and the refracturing that must

occur over time as the fractured region cools. Each of these components is listed in a separate table. (Note that there are no recompletion costs in the "Best Case" technology. This follows from our earlier assumption that refracturing would not be necessary.) Tables III-4, III-5, and III-6 show the wellfield costs for the facilities at thermal gradients of 35°C/km, 45°C/km, and 55°C/km, respectively. The power plant costs for these facilities are shown in Table III-7 (all three "generic" plants are assumed to use this power plant). Finally, the costs for recompletion are shown in Table III-8. Low temperature hot dry rock costs are shown in Tables III-9 and III-10. As above, each of these tables shows the costs for recompletion, wellfield, and power plant, respectively. Lastly, the "Best Case" hot dry rock costs for the wellfield and power plant are shown in Tables III-11 and III-12.

Energy inputs for the geopressured wellfield and power plant are shown in Tables III-13 and III-14. Finally, the power plant and wellfield costs for the vapor-dominated system are shown in Table III-15, and costs for the hydrogen sulfide abatement system in Table III-16.

The capital cost given below each tabulation represents only the initial capital costs required. In other words, the cost of a well required in the future is not listed. They are listed only for the purpose of rough comparisons. All amounts are in 1967 dollars.

Table III-1.

ENERGY INPUTS, LIQUID DOMINATED HIGH TURBINE POWER PLANT AND WELLFIELD

Source: Bechtel, 1977.

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Turbine Generator	6,536,000	43.01	74,189	48.49
2 Flash Tanks	237,000	40.06	100,712	2.39
3 Condensor	336,000	40.06	100,712	3.39
4 Cooling Tower	772,000	40.06	100,712	7.78
5 Pumps and Drives	1,349,000	49.01	59,006	7.96
6 Auxilliary Services	368,000	49.01	59,006	2.17
7 Piping Valves & Insulation	1,974,000	(a)	90,173	17.80
8 Instruments and Controls	720,000	(b)	39,334	2.83
9 Distribution Equipment	1,080,000	53.03	49,027	5.30
10 Cable and Raceways	461,000	53.08	63,182	2.91
11 Lighting and Misc.	205,000	55.03	64,679	1.32
12 Turbine Building	912,000	11.03	85,922	7.83
13 Site Improvements	195,000	11.02	72,491	1.41
14 Concrete Earthwork	471,000	11.03	85,922	4.05
15 Plant Engineering Service	2,015,000	73.03	28,103	5.66
16 Well Surface Equipment	3,704,000	(c)	220,764	81.77
17 Wells	5,913,000	11.05	93,248	55.13
18 Well Engineering Service	816,000	73.03	28,103	2.29
19 Plant Oper. and Maint.	13,395,000	12.02	61,453	82.31
20 Plant Insurance	756,000	70.04	23,513	1.79
21 Plant Administration	3,840,000	73.01	30,807	11.83
22 Wellfield Operations	4,811,000	12.02	61,453	29.57
23 Wellfield Maintenance	25,375,000	12.02	61,453	155.94
24 Wellfield Administration	3,461,000	73.01	30,807	10.66

Capital cost, plant and wellfield^(d) (1967\$) = \$548/kW   TOTAL = 5.526 x 10¹² BTU
 Corrected for NRG/GNP = 5.456 x 10¹² BTU

(a) Weighted average: 80% of 40.02 and 20% of 36.20.

(b) Weighted average: 50% of 53.01 and 50% of 53.05.

(c) Weighted average: 80% of 37.01 and 20% of 45.03.

(d) Scrubber capital cost not included. Wellfield cost includes only the initial drilling costs.

Table III-2.

ENERGY INPUTS, LIQUID DOMINATED LOW TURBINE POWER PLANT AND WELLFIELD

Source: Bechtel, 1977.

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10^{10} BTU)
1 Turbine Generator	3,675,000	43.01	74,189	27.26
2 Flash Tanks	237,000	40.06	100,712	2.39
3 Condensor	336,000	40.06	100,712	3.39
4 Cooling Tower	772,000	40.06	100,712	7.78
5 Pumps and Drives	1,349,000	49.01	59,006	7.96
6 Auxilliary Services	368,000	49.01	59,006	2.17
7 Piping Valves & Insulation	1,974,000	(a)	90,173	17.80
8 Instruments and Controls	720,000	(b)	39,334	2.83
9 Distribution Equipment	1,080,000	53.03	49,027	5.30
10 Cable and Raceways	461,000	53.08	63,182	2.91
11 Lighting and Misc.	205,000	55.03	64,679	1.32
12 Turbine Building	912,000	11.03	85,922	7.83
13 Site Improvements	195,000	11.02	72,491	1.41
14 Concrete Earthwork	471,000	11.03	85,922	4.05
15 Plant Engineering Service	1,706,000	73.03	28,103	4.79
16 Well Surface Equipment	3,704,000	(c)	220,764	81.77
17 Wells	5,913,000	11.05	93,248	55.13
18 Well Engineering Service	816,000	73.03	28,103	2.29
19 Plant Oper. and Maint.	11,683,000	12.02	61,453	71.80
20 Plant Insurance	660,000	70.04	23,513	1.55
21 Plant Administration	3,349,000	73.01	30,807	10.32
22 Wellfield Operations	4,811,000	12.02	61,453	29.57
23 Wellfield Maintenance	25,375,000	12.02	61,453	155.94
24 Wellfield Administration	3,461,000	73.01	30,807	10.66

Capital cost, plant and wellfield^(d) (1967\$) = \$483/kW   TOTAL = 5.182×10^{12} BTU
 Corrected for NRG/GNP = 5.120×10^{12} BTU

(a) Weighted average: 80% of 40.02 and 20% of 36.20.

(b) Weighted average: 50% of 53.01 and 50% of 53.05.

(c) Weighted average: 80% of 37.01 and 20% of 45.03.

(d) Scrubber capital cost not included. Wellfield cost includes only the initial drilling costs.

Table III-3.

ENERGY INPUTS, LIQUID DOMINATED SILICA TREATMENT FACILITY

Source: GLEF Annual Report, 1978

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10^{10} BTU)
1 Clarifier	519,000	40.06	100,712	5.23
2 Field Material	221,000	48.06	63,177	1.40
3 Filter Pump Tankage	21,000	40.06	100,712	0.21
4 Filter Influent Pump	175,000	49.01	59,006	1.03
5 Filter Tankage	761,000	40.06	100,712	7.66
6 Surface Wash Pump	44,000	49.01	59,006	0.26
7 Piping & Valves	240,000	40.02	69,322	1.66
8 Field Instrumentation	41,000	53.05	41,307	0.17
9 Concrete	40,000	36.12	185,757	0.73
10 Liquid Storage Tanks	24,000	40.06	100,712	0.24
11 Injection Pumps	20,000	49.01	59,006	0.11
12 Filter Press	197,000	48.06	63,177	1.25
13 Solids Conveyor	52,000	46.02	67,252	0.35
14 Solids Transfer	15,000	40.06	100,712	0.15
15 Equip. Maintenance	81,000	12.02	61,453	4.96
16 Polymers	12,416,000	27.04	169,354	210.27
17 Sludge Disposal	9,595,000	68.03	114,263	109.64

Capital cost (1967\$) = \$47/kW

TOTAL = 3.453×10^{12} BTUCorrected for NRG/GNP = 3.311×10^{10} BTU

Table III-4.

ENERGY INPUTS, HOT DRY ROCK GRADIENT = 35°C/km WELLFIELD COMPONENTS

Source: Republic Geothermal, 1979

	1967\$	I-O SECTOR	ENERGY INTENSITY ^(c) (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Casing	11,220,000	37.02	98,054	110.01
2 Wellhead Liner	772,000	45.03	76,704	5.92
3 Cementing	1,931,000	(a)	256,262	49.49
4 Moving	492,000	11.05	93,248	4.59
5 Roads	49,000	11.04	125,758	0.62
6 Drilling Pad	491,000	45.03	76,704	3.77
7 Pit	55,000	11.03	85,922	0.47
8 Cement Pipe	104,000	36.11	101,021	1.05
9 Concrete Cellar	61,000	36.11	101,021	0.62
10 Miscellaneous Equipment	75,000	45.03	76,704	0.57
11 Bit Cost	5,224,000	45.03	76,704	40.07
12 Miscellaneous Equipment	1,646,000	45.03	76,704	12.63
13 Drilling Mud	257,000	27.04	169,354	4.36
14 Evaluation	688,000	73.01	30,807	2.12
15 Fracturing Equipment	142,000	45.03	76,704	1.09
16 Fracturing	203,000	11.05	93,248	1.89
17 Transport	1,412,000	65.01	92,917	13.12
18 Stabilizer	324,000	45.03	76,704	2.49
19 Rig Time	29,442,000	11.05	93,248	274.54
20 Water Costs	181,000	45.03	76,704	1.39
21 Surface Piping	3,304,000	(b)	107,314	35.46
22 Well Operation and Maintenance	29,079,000	12.02	61,453	178.70
23 Silica Disposal	86,000	68.03	114,263	0.99
24 Fuel	(d)	31.01	1.2157(d)	398.85

Capital Cost for Wellfield (1967\$) = \$1161/kW

TOTAL = 1.145 x 10¹³ BTUCorrected for NRG/GNP = 1.097 x 10¹³ BTU

(a) Weighted average: 40% of 36.01 and 60% of 27.04

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Corrected for margins

(d) Energy content of diesel fuel assumed to be 1.382 x 10⁵ BTU/gallon,
with a total demand of 2.37 x 10⁷ gallons.

Table III-5.

ENERGY INPUTS, HOT DRY ROCK GRADIENT = 45°C/km WELLFIELD COMPONENTS
Source: Republic Geothermal, 1979

	1967\$	I-O SECTOR	ENERGY INTENSITY ^(c) (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Casing	7,479,000	37.02	98,054	73.33
2 Wellhead Liner	772,000	45.03	76,704	5.92
3 Cementing	1,380,000	(a)	256,262	35.37
4 Moving	197,000	11.05	93,248	1.84
5 Roads	49,000	11.04	125,758	0.62
6 Drilling Pad	491,000	45.03	76,704	3.77
7 Pit	55,000	11.03	85,922	0.47
8 Cement Pipe	104,000	36.11	101,021	1.05
9 Concrete Cellar	61,000	36.11	101,021	0.62
10 Miscellaneous Equipment	75,000	45.03	76,704	0.57
11 Bit Cost	4,268,000	45.03	76,704	32.74
12 Miscellaneous Equipment	1,374,000	45.03	76,704	10.54
13 Drilling Mud	233,000	27.04	169,354	3.94
14 Evaluation	502,000	73.01	30,807	1.55
15 Fracturing Equipment	119,000	45.03	76,704	0.92
16 Fracturing	159,000	11.05	93,248	1.49
17 Transport	1,024,000	65.01	92,917	9.51
18 Stabilizer	246,000	45.03	76,704	1.88
19 Rig Time	20,192,000	11.05	93,248	188.29
20 Water Costs	181,000	45.03	76,704	1.39
21 Surface Piping	3,304,000	(b)	107,314	35.46
22 Well Operation and Maintenance	29,079,000	12.02	61,453	178.70
23 Silica Disposal	86,000	68.05	114,263	0.99
24 Fuel	(d)	31.01	1.2157(d)	202.13

Capital Cost for Wellfield (1967\$) = \$845/kW

TOTAL = 7.931 x 10¹² BTU

Corrected for NRG/GNP = 7.603 x 10¹² BTU.

(a) Weighted average: 40% of 36.01 and 60% of 27.04

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Corrected for margins

(d) Energy content of diesel fuel assumed to be 1.382 x 10⁵ BTU/gallon,

Table III-6

ENERGY INPUTS, HOT DRY ROCK GRADIENT = 55°C/km WELLFIELD COMPONENTS

Source: Republic Geothermal, 1979

	1967\$	I-O SECTOR	ENERGY INTENSITY ^(c) (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Casing	4,652,000	37.02	98,054	45.61
2 Wellhead Liner	1,053,000	45.03	76,704	8.08
3 Cementing	1,022,000	(a)	256,262	26.20
4 Moving	197,000	11.05	93,248	1.84
5 Roads	49,000	11.04	125,758	0.62
6 Drilling Pad	491,000	45.03	76,704	3.77
7 Pit	55,000	11.03	85,922	0.47
8 Cement Pipe	104,000	36.11	101,021	1.05
9 Concrete Cellar	61,000	36.11	101,021	0.62
10 Miscellaneous Equipment	75,000	45.03	76,704	0.57
11 Bit Cost	3,694,000	45.03	76,704	28.33
12 Miscellaneous Equipment	1,295,000	45.03	76,704	9.93
13 Drilling Mud	239,000	27.04	169,354	4.04
14 Evaluation	381,000	73.01	30,807	1.17
15 Fracturing Equipment	94,000	45.03	76,704	0.72
16 Fracturing	299,000	11.05	93,248	2.79
17 Transport	741,000	65.01	92,917	6.88
18 Stabilizer	187,000	45.03	76,704	1.43
19 Rig Time	17,350,000	11.05	93,248	161.79
20 Water Costs	181,000	45.03	76,704	1.39
21 Surface Piping	3,304,000	(b)	107,314	35.46
22 Well Operation and Maintenance	29,079,000	12.02	61,453	178.70
23 Silica Disposal	86,000	68.03	114,263	0.99
24 Fuel	(d)	31.01	1.2157(d)	173.70

Capital Cost for Wellfield (1967\$) = \$710/kw

TOTAL = 6.962×10^{12} BTUCorrected for NRG/GNP = 6.674×10^{12} BTU.

(a) Weighted average: 40% of 36.01 and 60% of 27.04

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Corrected for margins

(d) Energy content of diesel fuel assumed to be 1.382×10^5 BTU/gallon,
with a total demand of 1.03×10^7 gallons.

Table III-7

ENERGY INPUTS, 50 MWe BINARY PLANT

Source: Electric Power Research Institute, 1978

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10^{10} BTU)
1 Pressure Vessels	139,000	40.06	100,712	1.39
2 Heat Exchanger	1,959,000	40.06	100,712	19.73
3 Pumps	781,000	49.01	59,006	4.61
4 Cooling Towers	693,000	40.06	100,712	6.98
5 Turbine Generator	2,363,000	43.01	74,189	17.53
6 Water Treatment	102,000	27.04	169,354	1.72
7 Freight	248,903	65.01	92,917	2.31
8 Concrete	390,000	36.12	185,757	7.24
9 Pipes, Valves, Fittings	1,283,000	40.02	69,322	8.89
10 Structural Steel	308,000	40.04	125,536	3.87
11 Instruments	396,000	53.05	41,307	1.63
12 Painting	52,000	30.00	84,576	0.44
13 Electrical	1,471,000	(a)	63,842	9.39
14 Insulation	276,000	36.20	144,354	3.99
15 Paving, Roads	81,000	11.04	125,758	1.02
16 Buildings	80,000	11.02	72,491	0.58
17 Miscellaneous	88,000	40.06	100,712	0.89
18 Indirect Field Costs	179,000	73.03	30,807	0.55
19 Home Office Services	1,696,000	73.03	30,807	5.23
20 Operation and Maintenance	756,000	12.02	61,453	46.44
21 Administration Costs	2,344,000	73.01	30,807	7.22
22 Insurance	442,000	70.04	23,513	1.04
23 Silica Removal ^(b)	9,846,000	68.03	114,263	112.50
24 Exploration ^(c)	1,419,000	11.05	93,248	13.23
			TOTAL 2,784	$\times 10^{12}$ BTU
			Corrected for NRG/GNP = 2.669×10^{12} BTU	

(a) Weighted average: 50% of 53.02 and 50% of 53.03

(b) Based on a cost of 1.8¢/1000 liters [GLEF, 1978].

(c) Source: [Tester, et al, 1979].

TABLE III-8.
ENERGY INPUTS, HOT DRY ROCK RECOMPLETION COSTS
Source: Republic Geothermal, 1979

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
<u>35°C/km</u>				
1 Evaluation	1,163,000	73.01	30,807	3.58
2 Fracturing	1,126,000	11.05	93,248	10.50
3 Fracturing Equipment	710,000	45.03	76,704	5.44
4 Transport	122,000	65.01	92,917	1.13
5 Rig Time	2,755,000	11.05	93,248	25.69
				TOTAL = 4.635×10^{11} BTU
				Corrected for NRG/GNP = 4.443×10^{11} BTU
<u>45°C/km</u>				
1 Evaluation	937,000	73.01	30,807	2.89
2 Fracturing	914,000	11.05	93,248	8.52
3 Fracturing Equipment	597,000	45.03	76,704	4.58
4 Transport	92,000	65.01	92,917	0.85
5 Rig Time	2,244,000	11.05	93,248	20.92
				TOTAL = 3.776×10^{11} BTU
				Corrected for NRG/GNP = 3.620×10^{11} BTU
<u>55°C/km</u>				
1 Evaluation	796,000	73.01	30,807	2.45
2 Fracturing	800,000	11.05	93,248	7.46
3 Fracturing Equipment	471,000	45.03	76,704	3.61
4 Transport	74,000	65.01	92,917	0.68
5 Rig Time	1,870,000	11.05	93,248	17.43
				TOTAL = 3.164×10^{11} BTU
				Corrected for NRG/GNP = 3.033×10^{11} BTU
<u>Low Temperature Resource</u>				
1 Evaluation	1,794,000	73.01	30,807	5.53
2 Fracturing	1,060,000	11.05	93,248	9.88
3 Fracturing Equipment	1,008,000	45.03	76,704	7.73
4 Transport	177,000	65.01	92,917	1.65
5 Rig Time	4,605,000	11.05	93,248	42.94
				TOTAL = 6.773×10^{11} BTU
				Corrected for NRG/GNP = 6.493×10^{11} BTU

Table III-9.

ENERGY INPUT, HOT DRY ROCK LOW TEMPERATURE RESOURCE WELLFIELD COMPONENTS

Source: Republic Geothermal, 1979.

	1967\$	I-O SECTOR	ENERGY INTENSITY ^(c) (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Casing	15,329,000	37.02	98,054	150.31
2 Wellhead Liner	1,506,000	45.03	76,704	11.55
3 Cementing	3,239,000	(a)	256,262	83.00
4 Moving	959,000	11.05	93,248	8.95
5 Roads	96,000	11.04	125,758	1.21
6 Drilling Pad	958,000	45.03	76,704	7.35
7 Pit	107,000	11.03	85,922	0.92
8 Cement Pipe	203,000	36.11	101,021	2.05
9 Concrete Cellar	120,000	36.11	101,021	1.21
10 Miscellaneous Equipment	144,000	45.03	76,704	1.10
11 Bit Cost	4,854,000	45.03	76,704	37.23
12 Miscellaneous Equipment	2,089,000	45.03	76,704	16.02
13 Drilling Mud	502,000	27.04	169,354	8.50
14 Evaluation	1,804,000	73.01	30,807	5.56
15 Fracturing Equipment	202,000	45.03	76,704	1.55
16 Fracturing	212,000	11.05	93,248	1.98
17 Transport	1,918,000	65.01	92,917	17.82
18 Stabilizer	91,000	45.03	76,704	0.70
19 Rig Time	39,605,000	11.05	93,248	369.30
20 Water Costs	354,000	45.03	76,704	2.71
21 Surface Piping	8,997,000	(b)	107,314	96.55
22 Well Operation and Maintenance	50,403,000	12.02	61,453	309.75
23 Silica Disposal	86,000	68.03	114,263	0.99
24 Fuel	(d)	31.01	1.2157(d)	532.71
Capital Cost for Wellfield (1967\$) = \$845/kw ^(e)			TOTAL = 1.669 x 10 ¹³ BTU	
			Corrected for NRG/GNP = 1.600 x 10 ¹³ BTU	

(a) Weighted average: 40% of 36.01 and 60% of 27.04

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Corrected for margins

(d) Energy content of diesel fuel assumed to be 1.382×10^5 BTU/gallon, with a total demand of 3.17×10^7 gallons.

(e) This capital cost includes only the initial drilling and fracturing.

Table III-10.

ENERGY INPUT, HOT DRY ROCK LOW TEMPERATURE RESOURCE POWER PLANT

Source: EG&G of Idaho, 1978

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10^{10} BTU)
1 Heat Exchanger	5,210,000	40.06	100,712	52.47
2 Condensate Tanks	164,000	40.06	100,712	1.65
3 Cooling Tower	2,089,000	40.06	100,712	21.04
4 Turbine-Generator	3,143,000	43.01	74,819	23.51
5 Cooling Water Pumps	484,000	49.01	59,006	2.86
6 Isobutane Pumps	275,000	49.01	59,006	1.62
7 Isobutane Piping & Valves	1,231,000	40.02	100,712	12.40
8 Brine Piping & Valves	333,000	40.02	100,712	3.35
9 Electrical Equipment	1,660,000	(a)	63,842	10.60
10 Instruments & Controls	672,000	53.05	41,307	2.78
11 Cooling Water Piping	568,000	42.08	70,369	4.00
12 Spare Parts & Tools	57,000	(b)	85,812	0.49
13 Structure and Foundation	547,000	11.03	72,491	3.96
14 Crane	118,000	46.03	69,336	0.82
15 Site Improvements	60,000	11.03	72,491	0.43
16 Misc. Equipment	57,000	42.11	84,785	0.49
17 Engineering Service	836,000	73.03	30,807	2.58
18 Design	981,000	73.03	30,807	3.02
19 Cooling Water Oper. and Maintenance	1,842,000	12.02	61,453	11.32
20 Plant Maintenance	2,091,000	12.02	61,453	12.85

Capital cost, power plant (1967\$) = \$370/kW

TOTAL = 1.722×10^{12} BTUCorrected for NRG/GNP = 1.651×10^{12} BTU.

(a) Weighted average: 50% of 53.02 and 50% of 53.03

(b) Weighted average: 50% of 42.02 and 50% of 40.06

Table III-11.

ENERGY INPUTS, HOT DRY ROCK "BEST CASE" WELLFIELD COMPONENTS

Source: Republic Geothermal, 1979

	1967\$	I-O SECTOR	ENERGY INTENSITY ^(c) (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Casing	1,899,000	37.02	98,054	18.62
2 Wellhead Liner	154,000	45.03	76,704	1.18
3 Cementing	321,000	(a)	256,262	8.21
4 Moving	98,000	11.05	93,248	0.92
5 Roads	10,000	11.04	125,758	0.12
6 Drilling Pad	98,000	45.03	76,704	0.75
7 Pit	11,000	11.03	85,922	0.09
8 Cement Pipe	21,000	36.11	101,021	0.21
9 Concrete Cellar	12,000	36.11	101,021	0.12
10 Miscellaneous Equipment	15,000	45.03	76,704	0.11
11 Bit Cost	997,000	45.03	76,704	7.65
12 Miscellaneous Equipment	316,000	45.03	76,704	2.43
13 Drilling Mud	54,000	27.04	169,354	0.91
14 Evaluation	135,000	73.01	30,807	0.42
15 Fracturing Equipment	36,000	45.03	76,704	0.27
16 Fracturing	63,000	11.05	93,248	0.59
17 Transport	259,000	65.01	92,917	2.41
18 Stabilizer	61,000	45.03	76,704	0.47
19 Rig Time	5,542,000	11.05	93,248	51.68
20 Water Costs	36,000	45.03	76,704	0.28
21 Surface Piping	1,780,000	(b)	107,314	19.10
22 Well Operation and Maintenance	6,462,000	12.02	61,453	39.71
23 Silica Disposal	172,000	68.03	114,263	1.97
24 Fuel	(d)	31.01	1.2157(d)	74.74

Capital Cost for Wellfield (1967\$) = \$119/kW

TOTAL = 2.330×10^{12} BTUCorrected for NRG/GNP = 2.233×10^{12} BTU.

(a) Weighted average: 40% of 36.01 and 60% of 27.04

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Corrected for margins

(d) Energy content of diesel fuel assumed to be 1.382×10^5 BTU/gallon,
with a total demand of 4.4×10^6 gallons.

Table III-12.

ENERGY INPUT, HOT DRY ROCK "BEST CASE" POWER PLANT*

Source: Milora and Testor, 1976

	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10^{10} BTU)
1 Turbine	140,000	43.01	74,189	1.04
2 Generator	771,000	43.01	74,189	5.72
3 Pumps	166,000	49.01	59,006	0.98
4 Turbine Drive	7,000	43.01	74,189	0.05
5 Heat Exchanger	2,391,000	40.06	100,712	23.95
6 Condensor	5,455,000	40.06	100,712	54.94
7 Instrumentation	1,251,000	53.05	41,307	5.17
8 Piping in Plant	510,000	37.02	98,054	5.00
9 Insulation	144,000	36.20	144,354	2.08
10 Foundation	303,000	11.03	85,922	2.61
11 Building and Structures	618,000	11.03	85,922	5.31
12 Fireproofing Equipment	318,000	40.02	69,322	2.20
13 Electrical Switchyard	602,000	53.03	49,027	2.95
14 Environment Controls	384,000	48.06	63,177	2.42
15 Engineering and Legal Fees	1,517,000	73.03	28,103	4.26
16 Plant Operation	5,132,000	12.02	61,453	31.54
17 Plant Maintenance	7,698,000	12.02	61,453	47.31

Capital cost for power plant (1967\$) = \$146/kW.

TOTAL = 1.975×10^{12} BTUCorrected for NRG/GNP = 1.951×10^{12} BTU.

* Excluding wellfield.

Table III-13.

ENERGY INPUTS, GEOPRESSURE WELLFIELD COSTS

Source: Riemann, Rios-Castellon and Underhill, 1976

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Fuel Plant Site Develop.	270,000	11.03	85,922	2.32
2 Drilling	22,398,000	11.05	93,248	208.86
3 Methane Separator	732,000	40.06	100,712	7.37
4 Wellfield Redevelopment	13,912,000	11.05	93,248	129.73
5 Pipes	1,117,000	37.02	100,156	11.19
6 Pumps	73,000	49.01	59,006	0.43
7 Coolers	14,000	52.03	68,729	0.10
8 Compressors	210,000	49.01	59,006	1.24
9 Water Separators	9,000	40.06	100,712	0.09
10 Filters	3,000	49.07	68,763	0.02
11 Glycol Separators	68,000	40.06	100,712	0.68
12 Fuel Plant Structures	1,469,000	11.03	85,922	12.63
13 Wellfield Insurance	3,151,000	70.04	23,513	7.41
14 Wellfield Operation and Maintenance	11,547,000	12.02	61,453	70.96
Capital cost, wellfield (1967\$) = \$1055/kW			TOTAL = 4.5302 x 10 ¹² BTU	
			Corrected for NRG/GNP = 4.343 x 10 ¹² BTU	

Table III-14.

ENERGY INPUTS, GEOPRESSURED POWER PLANT

Source: Riemann, Rios-Castellon and Underhill, 1976

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Site Development	237,000	11.02	72,491	1.72
2 Foundation and Structures	1,046,000	11.03	85,922	8.98
3 Cooling Tower	690,000	40.06	100,712	6.95
4 Chilled Water System	21,000	52.03	68,729	0.14
5 Dryer	5,000	52.03	68,729	0.04
6 Vacuum Pump	82,000	49.01	59,006	0.48
7 Condensate Feed Pump	7,000	49.01	59,006	0.04
8 Cooling Tower Pump	127,000	49.01	59,006	0.75
9 Surface Condenser	257,000	40.06	100,712	2.58
10 Steam Separators	66,000	40.06	100,712	0.66
11 Flash Chambers	88,000	40.06	100,712	0.89
12 Hydraulic Turbine	172,000	43.01	74,189	1.28
13 Generator	70,000	43.01	74,189	0.52
14 Turbine-Generator Set	2,284,000	43.01	74,189	16.95
15 Step-up Transformer	141,000	53.02	78,657	1.11
16 Control System	238,000	(a)	39,334	0.94
17 Fire Protection System	150,000	40.02	69,322	1.04
18 Engineering Services	2,248,000	73.03	28,103	6.32
19 Insurance	1,374,000	70.04	23,513	3.23
20 Plant Operation and Maintenance	29,491,000	12.02	61,453	181.23
Capital cost, power plant (1967\$) = \$317/kW			TOTAL = 2.3584 x 10 ¹² BTU	
			Corrected for NRG/GNP = 2.261 x 10 ¹² BTU	

(a) Weighted average: 50% of 53.01 and 50% of 53.05.

Table III-15

ENERGY INPUTS, VAPOR DOMINATED POWER PLANT AND WELLFIELD

Source: Pacific Gas and Electric, 1979

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Grading and Paving	118,000	11.04	125,758	1.48
2 Fences and Gates	19,000	42.05	134,955	0.26
3 Sewer System	3,000	37.02	100,157	0.03
4 Domestic Water System	174,000	40.02	69,322	1.21
5 Lighting Power System	61,000	55.02	67,190	0.41
6 Soil Analysis	14,000	73.01	30,807	0.04
7 Foundations	418,000	11.03	85,922	3.59
8 Superstructure	308,000	11.03	85,922	2.64
9 Plumbing and Water System	26,000	40.02	69,322	0.18
10 Distrib. Constr. Expense	19,000	11.03	85,922	0.16
11 Constr. Overhead	464,000	11.03	85,922	3.99
12 Prelim. Engineering	245,000	73.03	28,103	0.69
13 Outside Engineering	800	73.03	28,103	-
14 Constr. Indirect Expense	47,000	11.03	85,922	40.40
15 General Engineering	289,000	73.03	28,103	0.81
16 Admin. Expense	457,000	73.01	30,807	1.41
17 General Office Overhead	46,000	73.01	30,807	0.14
18 Steam Piping	336,000	37.02	100,157	3.36
19 Drips and Drains	48,000	40.02	69,322	0.33
20 Noise Control Equipment	4,000	49.07	68,763	0.03
21 Instrumentation	317,000	53.01	37,361	1.18
22 Turbine Generators	2,302,000	43.01	74,189	17.08
23 Fire Protection System	120,000	40.02	69,322	0.83
24 Condensers	892,000	40.06	100,712	8.98
25 Pumps	356,000	49.01	59,006	2.10
26 Structures	557,000	11.03	85,922	4.79
27 Circ. Water System	354,000	40.02	69,322	2.45
28 Generator Elec. Equipment	180,000	53.08	63,182	1.14
29 Cable Trays	109,000	40.06	100,712	1.10
30 Wire and Cable	108,000	55.03	71,975	0.78

Table III-15 (continued)
ENERGY INPUTS, VAPOR DOMINATED POWER PLANT AND WELLFIELD

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
31 Grounding System	53,000	55.03	71,975	0.38
32 Power System Equipment	161,000	53.08	63,182	1.02
33 Control Equipment	151,000	53.08	63,182	0.96
34 Compressor	25,000	49.01	59,006	0.15
35 Air Piping	20,000	42.08	70,369	0.14
36 Permanent Tools	44,000	42.02	68,341	0.30
37 Furniture & Fixtures	3,000	23.03	68,396	0.02
38 HVAC Equipment	57,000	40.03	68,336	0.39
39 Cranes	45,000	46.03	69,366	0.31
40 H.V. Transformer Equipment	34,000	53.02	78,657	0.26
41 H.V. Wiring	9,000	55.03	72,340	0.06
42 Retaining Walls	4,000	11.03	85,922	0.04
43 Telephone Cable	7,000	56.03	39,633	0.03
44 Telephone Equipment	7,000	56.03	39,633	0.03
45 Tools and Work Equipment	14,000	42.02	68,341	0.09
46 Power Equipment	18,000	49.07	68,763	0.13
47 Distrib. Poles and Towers	5,000	40.04	125,536	0.06
48 Overhead Conductors	8,000	55.03	71,975	0.06
49 Lube Oil Piping & Equip.	90,000	49.07	68,763	0.62
50 Miscellaneous Environmental Protection Facilities	8,000	49.07	68,763	0.06
51. Power Supply	3,000	53.08	63,182	0.02
52. Transformers	250,000	53.02	78,657	1.97
53. Plant Operation & Maintenance	6,142,000	12.02	61,453	37.74
54. Wellfield Operation & Maint.	11,283,000	12.02	61,453	69.34
55. Well Cost	(a)	(a)	68,745(a)	332.04
56 Surface Piping Cost	3,080,000	(b)	107,314	33.06

Capital Cost (1967\$) = 469\$/kw^(c)

TOTAL = 5.409 x 10¹² BTU

Corrected for NRG/GNP = 5.305 x 10¹² BTU

(a) Hybrid BTU/1978\$ energy intensity used (see text)

(b) Weighted average: 80% of 37.02 and 20% of 36.20

(c) Using 1977-74 cost deflator of 0.794 [Bechtel, 1978] and a 1977-67 deflator of 0.516. [BLS, 1978].

Table III-16.

ENERGY INPUTS, VAPOR DOMINATED HYDROGEN SULFIDE ABATEMENT SYSTEM

Source: Pacific Gas and Electric, 1978

ITEM	1967\$	I-O SECTOR	ENERGY INTENSITY (BTU/1967\$)	TOTAL ENERGY INPUT (10 ¹⁰ BTU)
1 Concrete	2,200	36.12	185,757	0.041
2 Wood	500	20.09	69,249	0.003
3 Reinforcing Bar	990	40.04	125,536	0.012
4 Gravel and Sand	1,400	36.15	55,215	0.008
5 Iron and Steel	850	37.02	100,157	0.009
6 Fabricated Steel	2,000	40.04	125,536	0.026
7 Construction Tools	2,200	45.01	67,987	0.015
8 Admin. Expenses	21,800	73.01	30,087	0.066
9 General Eng. Expenses	13,000	73.03	28,103	0.037
10 Construction Costs	65,200	11.03	85,922	0.561
11 Instruments	400	53.08	63,182	0.002
12 Pipe	570	42.08	97,229	0.006
13 Materials	99,200	49.07	68,763	0.682
14 Construction Equipment	23,300	45.03	76,704	0.179
15 Operation and Maintenance	104,500	12.02	61,453	0.642
TOTAL = 2.2891 x 10 ¹⁰ BTU				
Corrected for NRG/GNP = 2.34 x 10 ¹⁰ BTU.				

E. PRICE DEFLATORS

Energy intensity for goods and services have been developed in units of energy per dollar, in 1967 dollars [Bullard, Penner, and Pilati, 1978]. Dollar deflators must be used to express a cost in a given year in terms of 1967 dollars. For this study, we relied predominantly on two sets of deflators. The first was a set of price indices for the years 1958-1976, developed by the Office of Economic Growth, Bureau of Labor Statistics. These data were disaggregated by BLS into 161 sectors (hereafter called BLS sector) [BLS, 1978]. The second set developed by Bechtel in conjunction with their Energy System Supply Model, consisted of a set of deflators from 1978 dollars to 1974 dollars [Bechtel, 1978]. These deflators have been disaggregated into 50 sectors, though only about six were required for this study. Bechtel has assigned a unique vector of deflators to each of 98 energy transportation and production-conversion facilities; we used the deflators for the facility "Geothermal Power Complex."

Costs in 1978 dollars were first deflated to 1974 dollars with the Bechtel data, then converted to 1967 dollars using the BLS deflators. All costs in years 1976 or less (for example, costs for the vapor-dominated system) were deflated directly to 1967 dollars with the appropriate year dollar. Since the Bechtel deflators were quite aggregated (at least in comparison to the other deflators or energy intensities) the conversion from 1978 to 1974 dollars is not as precise as the conversion from 1974 to 1967 dollars with BLS data.

Table III-17 shows the correspondence between the different sectors used for our analysis, and the deflator for each sector. Certain entries are blank, indicating that not all the sectors were used for all the calculations.

Table III-17.

DEFLATORS FOR VARIOUS SECTORS

I-O SECTOR	BECHTEL SECTOR	BLS SECTOR	DEFLATORS			
			78-74 ^(a)	74-67 ^(b)	76-67 ^(c)	73-67 ^(d)
11.02	23	16	0.794	0.556	0.507	--
11.03	23 & 25	17	0.782	0.587	0.523	0.691
11.04	23	18	0.794	0.516	0.483	0.688
11.05	23	20	0.794	0.516	--	--
12.02	25	21	0.770	0.583	0.535	--
23.03	-	46	--	--	--	0.772
27.04	25	54	0.770	0.538	--	--
30.00	8	59	0.830	0.691	--	--
36.01	10	67	0.664	0.653	--	--
36.11	10	67	0.664	0.653	--	--
36.12	10	67	0.664	0.653	--	--
36.20	10	70	0.664	0.696	0.551	--
37.01	-	71	--	--	0.623	--
37.02	14	72	0.785	0.620	0.488	0.755
40.02	14	77	0.785	0.705	0.620	0.826
40.03	-	77	--	--	--	0.826
40.04	13	78	0.794	0.622	--	--
40.06	13	78	0.794	0.622	0.518	0.784
42.02	-	81	--	--	--	0.808
42.05	-	82	--	--	--	0.784
42.08	13	82	0.794	0.658	--	0.784

Table III-17 (continued)

DEFLATORS FOR VARIOUS SECTORS

I-O SECTOR	BECHTEL SECTOR	BLS SECTOR	DEFLATORS			
			78-74 ^(a)	74-67 ^(b)	76-67 ^(c)	73-67 ^(d)
42.11	13	82	0.794	0.658	--	0.826
43.01	20	83	0.769	0.701	0.570	0.786
45.03	23	85	0.794	0.644	0.520	--
46.03	-	86	--	--	--	0.789
48.06	13	88	0.794	0.665	0.524	--
49.01	13	89	0.794	0.705	0.541	0.794
49.07	-	89	--	--	0.541	0.794
52.03	-	93	--	--	0.696	--
53.01	-	94	--	--	0.641	0.814
53.02	27	94	0.801	0.792	0.641	0.933
53.03	27	94	0.80.	0.792	0.641	--
53.05	26	95	0.781	0.702	0.570	--
53.08	-	95	--	--	--	0.814
55.02	-	97	--	--	0.820	--
55.03	-	97	--	0.586	--	0.820
56.03	-	99	--	--	--	0.792
65.01	25	117	0.770	0.690	--	--
68.03	23	128	0.770	0.646	--	--
70.04	25	133	0.770	0.687	0.604	--
73.01	25	139	0.770	0.728	0.613	0.747
73.03	25	141	0.770	0.579	0.523	0.634

(a) Source: Bechtel

(b) Source: BLS

(c) Source: BLS

(d) Source: BLS

IV. ECOENERGETICS

All energy analysis is dependent upon the system boundary one draws around a specific process. Traditionally, analysts have drawn their boundaries around those primary fuels used in the direct or indirect production of goods. A relatively new school of thought known as Ecoenergetics, holds that this boundary should be extended to include natural subsidies provided by the environment. Traditional economic and energy analysis has simply ignored these values as insignificant or incalculable.

In recent years we have become increasingly aware of the services provided by nature. Some of these include nitrogen fixation by micro-organisms, cleansing of the air and water, maintenance of the atmospheric CO₂ level, absorption of waste heat, etc. Attempts have been made to perform cost-benefit analysis of these natural processes [Westman, 1977]. Dollar values have usually been assigned to these services, reflecting the cost required to artificially perform the same service performed for free by nature. Apart from the fact that these figures are usually given little weight in policy decisions, there are two important limitations with this methodology: (1) it is extremely difficult to account for all the environmental impacts, and 2) the use of dollar units may be inappropriate or misleading [Wharton, 1970; Gosselink, 1973; Westman, 1977].

Ecoenergetics attempts to overcome these limitations through its use of an energy theory of environmental value. Natural subsidies are calculated as the replacement energy required to return the ecosystem

to its original level. Since these energies are dependent only on the laws of thermodynamics, they should be more far-reaching than dollar values (probably inadequately costed in present economic calculations) of human system processes.

The forms in which energy is contributed to the environment are many and diverse. It would be improper to assume that all these energies should be counted identically. Certain forms of energy are of higher "quality" in that they have embodied in them a greater ability to do work in the physicist's sense. For example, a substantial number of Btu's of solar radiation are required to product one Btu of energy embodied in wood. For this reason, the theory of ecoenergetics maintains that, in adding up the energy inputs, greater weight should be applied to a Btu of wood energy than a Btu of solar energy. The weighting element used for this calculation is known as the "quality factor."

Quality factors are obtained empirically by comparing the natural rate at which various processes occur with the total solar power incident over a given region [Odum, 1978]. This method is based on the assumption that the web of natural processes has evolved to use all of the incoming solar radiation in the most "efficient" manner. Since solar energy is considered to be the driving force of this web of interaction, calculations are made on the basis of solar equivalent calories. These units can then be converted to more conventional values, such as calorie coal equivalents.

Past studies in ecoenergetics have used, as a quality factor

for solar radiation, the figure of 0.0005 solar calories per calorie coal equivalent [Odum, 1978]. In other words, 2000 calories of solar radiation are embodied in one calorie of wood, which can be burned like coal. This ratio is usually justified by reference to the net primary productivity of selected biomes. [Odum and Klystra, 1976].

The method utilized in this paper for calculation of environmental subsidies is based on a report by M. J. Lavine, T. J. Butler, and A. H. Meyberg entitled "Energy Analysis Manual for Environmental Benefit/Cost Analysis of Transportation Actions," [E.A. Manual, 1979]. The procedure outlined in the E.A. Manual applies specifically to transportation system components, such as roads or bridges. As such, the environmental impacts air in the form of air pollutants, salt, paving of the land, etc. One can, however, adapt this methodology to power producing systems.

Three broad environmental impacts are considered in the E.A. Manual: air-system chemical impacts, water-system chemical impacts, and biotic system impacts. An explanation of these terms, and a description of the process utilized can be found below.

There is a certain amount of confusion in the definition of ecoenergetics as to the procedure for calculating the net contribution from natural subsidies. The E.A. Manual assumes that only the energy required to replace the largest environmental loss should be counted. Since most environmental factors are interwoven, it is reasoned, replacement energy for an individual impact will eventually work through the system and affect all impacts. Other studies by

[Bayley, et al, 1977], however, consider not the largest, but the total of replacement energies for each of the impacts. To be sure the former method offers clear advantage in simplifying the analysis. Once one factor has been identified as predominant, all others can be effectively ignored. For this study, we will follow the procedure in the E.A. Manual and sum components within the individual impact categories (e.g. air system chemical impact) and then separately compare these impacts.

Two of the very controversial and potentially damaging environmental impacts of geothermal energy are subsidence and fault activation. For this analysis we have not considered these two factors. This decision is based on the following two assumptions: (1) Most current geothermal schemes involve reinjection, which will hopefully minimize the possibility of subsidence or fault activation; (2) It would be extremely difficult to quantify the energy contribution provided by nature in the categories. One study [Kreitler and Gustavson, 1976] has attempted to estimate the effect subsidence has had on the area that could be flooded in the event of a hurricane. However, these are all very tentative estimates at best, and are strongly dependent on the irregularities of nature. Also, the system boundary question is always present: should the once in a decade (or century) event be considered?

A. PROBABLE IMPACTS AFFECTING AIR-CHEMICAL SYSTEM

1. Vapor Dominated (The Geysers)

Chemicals which are emitted from natural processes are eventually included in a large environmental cycle. By assumption, this cycle operates most "efficiently" when substances are emitted at the natural rates. Any perturbation caused by man-made emissions will lower the "efficiency" of this process. An added amount of energy will, therefore, be required from nature to process the naturally and artificially produced chemicals which have been dissipated throughout the atmosphere. The energy required for this, it is argued, could otherwise be available for the "ongoing natural human and system processes" [EA Manual, 1979].

The first step in this process is to determine the rate of emissions of a particular substance produced naturally. It is assumed that the environment most effectively uses, or processes, these substances when they are emitted at these rates. The natural release of these chemicals is usually just one portion of a closed cycle consisting of release and subsequent absorption. This entire cycle is driven by energy supplied from the sun. Comparison of the total solar input to the environment with the amount of emissions can then be used to develop a quality factor in calories coal equivalent per gram. It is then assumed that the energy required (from the environment) to process an additional amount is proportional to the quality factor. This is a linear approximation.

In their work on transportation systems, Lavine, Butler and Meyburg refer to emissions of six chemicals: carbon monoxide, (CO), oxides of nitrogen (NO_x and N_2O), hydrocarbons (H_xC_x) sulfur dioxide (SO_2) and carbon dioxide (CO_2). A geothermal power plant at the Geysers would release, among others, the following chemicals: CO_2 , hydrogen (H_2), methane (CH_4), nitrogen (N_2), hydrogen sulfide (H_2S), ammonia (NH_3) and P_3PO_4) [FES, 1973]. Quality factors for most of these emissions can be calculated according to the guidelines developed in the CER paper.

The quality factor, in units of Cal CE/gram, is defined as follows [E.A. Manual, 1979]:

$$\text{Quality Factor} = \frac{\text{Annual Solar Radiation}}{\text{Annual Natural Emission of Pollutant}} \times 0.0005 \frac{\text{Cal}}{\text{Cal}} \frac{\text{Coal}}{\text{Equivalent}}$$

$$\begin{aligned} \text{Quality Factor for } \text{CH}_4 &= \frac{84.4 \times 10^{19} \text{ Cal}}{12 \times 10^{14} \text{ g/yr}} \times 0.0005 \frac{\text{Cal CE}}{\text{Cal}} \\ &= 3.52 \times 10^2 \text{ cal CE/gram} \end{aligned}$$

CH_4 and N_2 Natural emissions from [Holland, 1978].

$$\begin{aligned} \text{Quality Factor for } \text{H}_2\text{S} &= \frac{84.4 \times 10^{19} \text{ Cal}}{9.1 \times 10^{13} \text{ /yr}} \times 0.0005 \frac{\text{Cal CE}}{\text{Cal}} \\ &= 4.4 \times 10^3 \text{ Cal CE/gram} \end{aligned}$$

$$\begin{aligned} \text{Quality Factor for } \text{NH}_3 &= \frac{84.4 \times 10^{19} \text{ Cal}}{1.0 \times 10^{15} \text{ g/yr}} \times 0.0005 \frac{\text{Cal CE}}{\text{Cal}} \\ &= 4.2 \times 10^1 \text{ Cal CE/gram} \end{aligned}$$

H_2S and NH_3 natural emissions from [Rassool, 1973].

Finally, the quality factor for CO_2 has been calculated in the E.A. Manual:

$$\text{Quality Factor for } \text{CO}_2 = 1.45 \text{ Cal CE/gram}$$

Air emissions from the Geysers will occur as the result of the release of non-condensable gases contained within the steam.

Table IV-1 shows the eight most common gases associated with the Geysers, and the percent of emissions by weight and volume:

Table IV-1

Concentration of Most Common Gases at The Geysers

GAS	PERCENT VOLUME	PERCENT WEIGHT
H_2O	98.045	96.5
CO_2	1.242	2.99
H_2	0.287	0.0031
CH_4	0.299	0.262
N_2	0.069	0.106
H_2S	0.033	0.0614
NH_3	0.025	0.0232
P_3PO_4	0.0018	0.0181

SOURCE: [FES, 1973]

For reasons of safety and odor, abatement measures are required for some of these chemicals. In particular the amount of hydrogen sulfide released must be reduced. (The Environmental Protection Agency has suggested a limit of 200 grams H_2S released per megawatt.

hour) [Hartley, 1978]. A promising technology in this area is the EIC process, which uses a copper sulfate solution to remove the hydrogen sulfide from the steam. The EIC process has been field tested and has produced a 97% abatement in hydrogen sulfide and an 80% removal of ammonia and boric acid. Moreover, the EIC process is an "upstream" system, in that the H_2S is removed prior to the turbines and therefore operates 100% of the time, (Many methods simply vent the gases when the plant is not operating).

A 50 MWe vapor-dominated power plant at the Geysers requires a steam flow of at least 1.3×10^2 Eg/sec (4.5×10^5 kg/hr). [FES, 1973]. It is assumed that the EIC process is successful in limiting the H_2S emissions to 200 grams per megawatt-hour, and also in removing 80% of the of the ammonia. The remaining gases are vented to the atmosphere. The net releases and the corresponding impact on the air chemical system are:

$\Delta N_{\text{air chemical system}}$

For hydrogen sulfide:

$$\Delta N_{H_2S} = (g/yr H_2S) (4.64 \times 10^3 \frac{\text{CalCE}}{g})$$

$$g/year H_2S = (200 \frac{g}{MW-hr}) (8760 \frac{hr}{year}) (50 MWe) = 8.76 \times 10^7 g/yr$$

$$\Delta N_{H_2S} = (8.76 \times 10^7 g/yr) (4.64 \times 10^3 \frac{\text{CalCE}}{g}) = 4.1 \times 10^{11} \frac{\text{CalCE}}{yr}$$

For methane:

$$\text{g/yr CH}_4 = (4.53 \times 10^8 \text{ g/hr}) (8760 \text{ hr/yr}) (0.0026) = 1.03 \times 10^{10} \text{ g/yr}$$

$$\Delta N_{\text{CH}_4} = (1.03 \times 10^{10} \text{ g/yr}) (3.52 \times 10^2 \frac{\text{CalCE}}{\text{g}}) = 3.6 \times 10^{12} \frac{\text{CalCE}}{\text{yr}}$$

For ammonia:

$$\text{g/yr NH}_3 = (4.53 \times 10^8 \text{ g/hr}) (8760 \text{ hr/yr}) (0.2) (0.00023) = 1.8 \times 10^8 \text{ g/yr}$$

$$\Delta N_{\text{NH}_3} = (1.8 \times 10^8 \text{ g/yr}) (4.21 \times 10^1 \frac{\text{CalCE}}{\text{g}}) = 7.6 \times 10^9 \frac{\text{CalCE}}{\text{yr}}$$

For carbon dioxide:

$$\text{g/yr CO}_2 = (4.53 \times 10^8 \text{ g/hr}) (8760 \text{ hr/yr}) (0.0299) = 1.19 \times 10^{11} \text{ g/yr}$$

$$\Delta N_{\text{CO}_2} = (1.19 \times 10^{11} \text{ g/yr}) (1.45 \frac{\text{CalCE}}{\text{g}}) = 1.7 \times 10^{11} \frac{\text{CalCE}}{\text{yr}}$$

For nitrogen:

$$\text{g/yr N}_2 = (4.53 \times 10^8 \text{ g/hr}) (8760 \text{ hr/yr}) (.00106) = 4.21 \times 10^9 \text{ g/yr}$$

$$\Delta N_{\text{N}_2} = (4.21 \times 10^9 \text{ g/yr}) (2.11 \times 10^3 \frac{\text{CalCE}}{\text{yr}}) = 8.9 \times 10^{12} \frac{\text{CalCE}}{\text{yr}}$$

$$\text{TOTAL} = 1.3 \times 10^3 \frac{\text{CalCE}}{\text{yr}}$$

2. Liquid Dominated

Composition of the non-condensable gas at the Salton Sea is approximately 90% CO₂ and 10% H₂S, by weight [Wahl, 1977]. These non-condensable gases comprise about 0.3% of the weight of the steam vented [Bechtel, 1976]. If we assume a flow rate of 12×10^6 lb/hr: $(1.51 \times 10^3 \text{ kg/sec}) (0.3\%) = 4.5 \text{ kg/sec}$ $1.51 \times 10^3 \text{ kg/sec}$ [Bechtel, 1977].

0.45 kg/sec H₂S.

4.05 kg/sec CO₂.

This rate of H₂S emission is comparable to 32 kg/hr/MWe, and is therefore in excess of E.P.A. guidelines. It is assumed that scrubbers will reduce these emissions to an allowable 200 grams/MWe hr.

We have then:

$$\text{g/hr H}_2\text{S} = (200 \text{ g/MWhr}) (50\text{MW}_e) (8760 \text{ hr/yr}) = 8.76 \times 10^7 \text{ g/yr}$$

$$\Delta N_{\text{H}_2\text{S}} = (8.76 \text{ g/hr}) (4.64 \times 10^3 \frac{\text{CalCE}}{\text{g}}) = 4.1 \times 10^{11} \frac{\text{CalCE}}{\text{YR}}$$

And for CO₂

$$\Delta N_{\text{CO}_2} = (1.27 \times 10^{11} \text{ g/yr}) (1.45 \frac{\text{CalCE}}{\text{g}}) = 1.8 \times 10^{11} \frac{\text{CalCE}}{\text{yr}}$$

$$\text{TOTAL} = 5.9 \times 10^{11} \frac{\text{CalCE}}{\text{yr}}$$

3. Hot Dry Rock

Preliminary tests at LASL's Fenton Hill test sight indicate that air emissions from Hot Dry Rock plants are likely to be extremely small [Gutschick and Rea, 1978]. Initial concentrations of hydrogen-sulfide were on the order of 30 parts per billion, which was at the

lower edge of observable limits. Most of the gases were CO_2 , N_2 , O_2 , and these were found at levels approximating the natural concentration of air. Impacts of air emissions will therefore not be considered for the Hot Dry Rock case.

4. Geopressure

Much of the interest in geopressure is due to the dissolved methane in the fluids. For our analysis we assume that the methane is collected, but it is not considered part of the electrical output. One could visualize the methane transported in a pipeline outside our system boundary. The impact of this methane release will, therefore, not be considered in our ecoenergetics calculations.

On-site chemical analysis of dissolved geopressured gases has been made by Karkolits and Hankins for two wells in Louisiana [Karkalits and Hankins, 1978]. Their data indicate that about 1 to 2%, by molar concentration, of the dissolved gases are CO_2 , and 0.1 to 0.3% are N_2 ; the remainder being methane or a similar hydrocarbon. Dow has assumed that about 40 scf of gases are dissolved in each barrel of fluid [Dow, 1976]. If we take the averages of the above concentrations, this works out to be approximately 36 grams CO_2 and 2.8 grams N_2 per barrel. If we assume all of these gases are released to the atmosphere, the yearly release of CO_2 and N_2 are:

CO_2 :

$$(40,000 \text{ bbl/day/well})(10 \text{ wells})(365 \text{ days})(36 \text{ g/bbl } \text{CO}_2)$$

$$= 5.3 \times 10^9 \text{ g/yr } \text{CO}_2$$

N₂:

$$(40,000 \text{ bbl/day/well})(10 \text{ wells})(365 \text{ days})(28 \text{ g/bbl CO}_2) \\ = 4.1 \times 10^8 \text{ g/yr N}_2.$$

Using previously derived quality factors, the air chemical impact of these systems is:

$$\Delta N_{\text{CO}_2} = (5.3 \times 10^9 \text{ g/yr CO}_2)(1.45 \text{ CalCE/yr}) = 7.7 \times 10^9 \frac{\text{CalCE}}{\text{yr}}$$

$$\Delta N_{\text{N}_2} = (4.1 \times 10^8 \text{ g/yr N}_2)(2.11 \times 10^3 \text{ CalCE/yr}) = 8.7 \times 10^{11} \frac{\text{CalCE}}{\text{yr}}$$

For a total of 8.7×10^{11} CalCE/yr.

B. PROBABLE IMPACTS AFFECTING THE WATER CHEMICAL SYSTEM

1. Vapor Dominated

The impact on the water chemical system will be felt at both the short term and the long term level. During drilling of the wells, a large amount of drilling mud will be produced. Drilling muds usually contain chemicals which could be harmful to the environment. According to the Final Environmental Statement, "It is not known what may happen to these chemicals during the following winter season." [FES, 1973] Since these are chemicals which do not occur naturally, it would be impossible to analyze their impact using the methods outlined in the previous section. Though they won't be considered here, a complete study would require measurements of environmental degradation at the specific site.

The water condensed from the steam at the Geysers has a fairly large amount of minerals dissolved in it. Table A-2 below shows the composition of the steam condensate at a particular well site [FES, 1973].

In the past, the water containing these contaminants has been successfully reinjected. This reinjection disposes of the minerals and also reduces the likelihood of subsidence problems. Consequently, no environmental impact from these materials will be considered here.

Table IV-2

Composition (in ppm by weight) of Steam Condensate
From Typical Wells in The Geysers field

<u>CONSTITUENT</u>	
Silica	0.50
Calcium	0.20
Magnesium	0.06
Strontium	0.10
Sodium	0.12
Potassium	0.10
Lithium	0.002
Ammonium	236.00
Bicarbonate	775.00
Carbonate	0.06
Sulfate	7.10
Chloride	20±3
Fluoride	0.10
Boron	0.01

SOURCE: [FES, 1973]

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2. Liquid Dominated

The brine at the Imperial Valley region is also reinjected after passing through the power plant. This is done primarily to prevent subsidence, but also to dispose of the solution. In order to prevent clogging of the reinjection pipes, a certain amount of the total dissolved solids, and particularly the silica, must be removed. Currently, experiments are being conducted with a reactive clarifier to remove these solids. According to estimates supplied to San Diego Gas and Electric by Lawrence Livermore Laboratory [GLEF, 1978], a plant operating at 6900 gallons/minute (46 kg/sec) would produce about 33,000 lbs. (dry)/day of solids. This corresponds to a removal of approximately 400 ppm to a reinjected concentration of as low as 5 ppm. Conversation with personnel at San Diego Gas and Electric confirmed this figure, actually indicating it may at times be as low as 300 ppm [Conversation with Bill Jacobsen, 17 Sept. 1979].

According to the Bechtel study, the flow rate through the proposed Heber plant is $(1.51 \times 10^3 \text{ kg/sec})$. Assuming a removal rate of 400 ppm, this corresponds to a production of solids of:

$$(12 \times 10^6 \text{ lb/hr}) (400/(1 \times 10^6)) (24 \text{ hr/day}) = 115,000 \text{ lb/day.}$$

Sample runs with the reactive clarifier at Niland indicate that the percent solids removed by weight are:

Silica - 91.75%, Calcium - 7.92%, Sulfur - 1.06%, Iron - 0.85%,
Strontium - 0.63%, Manganese - 0.31%, Lead - 0.18%.

A similar composition of sludge will be assumed for the Heber plant. The daily and yearly production of solids is shown below.

<u>Solid</u>	<u>%</u>	<u>lb/day</u>	<u>lb/yr at 85% capacity</u>
Silica	92	106,000	3.3×10^7
Calcium	8	9,200	2.8×10^6
Sulfur	1	1,200	3.6×10^5
Iron	0.8	980	3.0×10^5
Strontium	0.6	700	2.1×10^5
Manganese	0.3	300	1.1×10^5
Lead	0.2	200	6.4×10^4

The utility currently plans to dump these sludge products at a land fill site. In terms of ecoenergetics analysis, however, this can only be viewed as a temporary disposal. The true cost incurred by the environment is best determined by estimating the perturbation these chemicals would have if released to the environment. The impact will, therefore, be measured by calculating the Gibbs free energy (ΔF) associated with mixing these solids (approximated to be in pure form) with seawater. This is the energy required to reversibly create a concentration gradient between two mixed ideal fluids, the entropy of mixing. The equation used in these calculations is [E.A. Manual, 1979]:

$$\Delta F = MNRT \ln C_1/C_2, \text{ where}$$

M = Annual mass of emission produced artificially

N = Number moles/gram

R = Universal gas constant

T = Average temperature

C_1 = Concentration of pure emission (1×10^6 ppm)

C_2 = Concentration of same material in sea water

Once this ΔF is calculated, it is multiplied by the quality factor for this form of energy. The E.A. Handbook has calculated a quality factor of salt release of 6.3 Cal CE/Cal Salt. Since data on the other chemicals are sketchy, this quality factor will be assumed for all the emissions.

The concentration of these materials in sea water is as follows [Smith, 1974].

<u>MATERIAL</u>	<u>PPM</u>
Silica	5
Calcium	410
Sulfur	2700
Iron	6.6×10^{-3}
Strontium	8.1
Manganese	1.5×10^{-3}
Lead	5×10^{-5}

The energies associated with these mixings are:

ΔN_{silica}

$$M = (3.3 \times 10^7 \text{ lb/yr}) (453 \text{ g/lb}) = 1.5 \times 10^{10} \text{ g/yr.}$$

$$n = 0.0167 \text{ moles/g}$$

$$\Delta N = (1.5 \times 10^{10} \text{ g/yr}) (0.0167 \text{ moles/g}) (1.986 \times 10^{-3} \text{ Cal/mole}^\circ\text{K}) \\ (288^\circ\text{K}) (\ln(1 \times 10^6/\text{g})) (6.3 \text{ Cal CE/Cal})$$

$$\Delta N_{\text{silica}} = 1.1 \times 10^{10} \text{ CalCE/yr.}$$

$\Delta N_{\text{calcium}}$:

$$M = 1.27 \times 10^{10} \text{ g/yr}$$

$$n = 0.025$$

$$\Delta N = (1.27 \times 10^{10})(2.5 \times 10^{-2})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6/410))(6.3)$$

$$\Delta N_{\text{calcium}} = 8.9 \times 10^9 \text{ CalCE/yr}$$

ΔN_{iron} :

$$M = 1.36 \times 10^8 \text{ g/yr}$$

$$n = 1.79 \times 10^{-2} \text{ moles/g}$$

$$\Delta N = (1.36 \times 10^8)(1.79 \times 10^{-2})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6/6.6 \times 10^{-3}))(6.3)$$

$$\Delta N_{\text{iron}} = 1.6 \times 10^8 \text{ CalCE/yr}$$

$\Delta N_{\text{strontium}}$:

$$M = 10.0 \times 10^7 \text{ g/yr}$$

$$n = 1.14 \times 10^{-2} \text{ moles/g}$$

$$\Delta N = (10.0 \times 10^7)(1.14 \times 10^{-2})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6/3.1))(6.3)$$

$$\Delta N_{\text{strontium}} = 4.8 \times 10^7 \text{ CalCE/yr}$$

$\Delta N_{\text{manganese}}$:

$$M = 5.0 \times 10^7 \text{ g/yr}$$

$$n = 1.82 \times 10^{-2} \text{ moles/g}$$

$$\Delta N = (5.0 \times 10^7)(1.82 \times 10^{-2})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6/1.15 \times 10^{-3}))(6.3)$$

$$\Delta N_{\text{manganese}} = 6.7 \times 10^7 \text{ CalCE/yr}$$

ΔN_{lead} :

$$M = 2.9 \times 10^7 \text{ g/yr}$$

$$n = 4.83 \times 10^{-3} \text{ moles/g}$$

$$\Delta N = (2.9 \times 10^7)(4.83 \times 10^{-3})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6 / 5 \times 10^{-5}))(6.3)$$

$$\Delta N_{\text{lead}} = 1.2 \times 10^7 \text{ CalCE/yr}$$

So we have:

<u>Material</u>	<u>Energy Subsidy (CalCE/yr)</u>
Silica	110×10^8
Calcium	89×10^8
Sulfur	1.1×10^8
Iron	1.6×10^8
Strontium	0.48×10^8
Manganese	0.67×10^8
Lead	0.12×10^8
TOTAL	$2.0 \times 10^{10} \text{ CalCE/yr}$

3. Hot Dry Rock

The table below indicates the composition of fluid recovered from the fracture after a flow of 5.6×10^6 liters [LASL Annual Report, 1977]. Only the eight most concentrated chemicals are shown.

<u>Material</u>	<u>Concentration (ppm)</u>
SiO ₂	220 - 260
Na	240 - 300
Cl	310 - 400
HCO ₃	180
SO ₄	80
K	25 - 40
CA	14 - 16
F	12 - 14
	89

It will be assumed that only the silica needs to be removed.
For a flow rate of 3.4×10^6 g/hr. or 2.98×10^{13} g/yr, we have:

$$(2.98 \times 10^{13} \text{ g/yr.}) \left(\frac{200}{1 \times 10^6} \right) = 5.96 \times 10^9 \text{ g/yr silica.}$$

This figure is in approximate agreement with another estimate that a 100 MW plant will produce 1000 - 10,000 kg/day of silica [LASL Annual Report, 1978]. Extrapolating down to a 50 MWe plant would decrease this figure to the order of 10^9 gram/year.

Use the method described for a liquid dominated resource:

ΔN_{silica} :

$$M = 5.96 \times 10^9 \text{ g/yr}$$

$$n = 0.0167$$

$$\Delta N = (5.96 \times 10^9)(1.67 \times 10^{-2})(1.986 \times 10^{-3})(288)(\ln(1 \times 10^6/5))(6.3)$$

$$\Delta N = 4.4 \times 10^9 \text{ CalCE/yr}$$

4. Geopressure

The chemical composition of the fluids in the geopressurized regions of the Southeast vary widely from well to well. For example, analysis of fluids from three different wells in one county in Texas shows a 20-fold variation in total dissolved solids (a low of 3100 ppm, and a high of 68,500 ppm) [White, et al, 1977]. The largest proportion of this variation is in the concentrations of

sodium and chlorine. The silica concentration, while varying by a factor of five with different wells, never gets higher than 2 ppm. Since current plans call for reinjection of the fluids into salt-water bearing formations, a large absolute variation in silica concentration could require different disposal techniques for each well. However, the low concentration of silica in all the wells indicates that there probably will not be a need for demineralization prior to reinjection. Impacts on the water system will therefore not be included.

C. PROBABLE IMPACTS AFFECTING BIOTIC CHEMICAL SYSTEM

1. Vapor Dominated

Due to the construction and operation of the power plant, there will be a decrease in the production of plant sugars ($C_xH_{2x}O_x$) and oxygen. A certain amount of vegetation will be eliminated entirely, and other vegetation may have its output decreased due to the generating and transmission process. One can use the gross primary productivity (GPP) as a measure of the gross amount of vegetation produced per area per year at a particular location. The values of GPP are dependent, of course, on the type of vegetation, the climate of the area, the soil and several other factors. For example, the GPP of a riverine hardwood swamp is $5.21 \times 10^4 \text{ Cal/m}^2/\text{yr}$, whereas that of a dry desert is $30 \text{ Cal/m}^2/\text{yr}$. These and other values of GPP for different biomes have been tabulated in the E.A. Manual.

The Geysers KGRA lies on the Northwestern edge of a broad sclerophyll (oak-chaparral) biome, also referred to as the woodland-brushland biome. The predominant cover is chaparral [FES, 1973]. The E.A. Manual lists three different values of GPP for chaparral, depending on the soil capability class. Since the National Cooperative Soil Survey lists eight different soil types at this KGRA, the mid-value of the GPP's will be chosen as representative.

A 50 MWe plant will require 8 to 12 production wells during its lifetime, and about 8 wells for reinjection. In order to avoid overlap, one well is drilled for each 40 acre area [FES, 1973]. Choosing the larger figure for the number of wells, the total area required is, therefore, about 800 acres. According to the Final Environmental Statement, from 7 to 10% of the gross area involved will be disturbed [FES, 1973]. The breakdown for the specific uses are: well site pads and work area, 45%; power house and cooling unit, 10%; mainline road, 20%; and access roads, 25%. It is assumed here that 10% of the gross area involved is removed from production during the 30 years lifetime of the plant. Furthermore, it is assumed that this area is only 50% productive for the following 30 years. We have then:

For the first 30 years:

$$\Delta N_{C_x H_{2x} O_x} = (\text{area affected}) (\text{GPP/area}) (30\text{years}) (\text{quality factor})$$

In the E.A. Manual, the quality factor for the biological production of sugars is calculated to be $0.26 \frac{\text{CalCE}}{\text{CalGPP}}$. The total area affected is 80 acres or $3.24 \times 10^5 \text{ m}^2$. The GPP is given as 788 Cal/yr/m^2 .

$$\Delta N_{H_x C_x O_x} = (3.24 \times 10^5 m^2) (7800 \text{ Cal/yr/m}^2) (30 \text{ yr}) (.26 \frac{\text{CalCE}}{\text{CalGPP}})$$

$$\Delta N_{H_x C_x O_x} = 1.97 \times 10^{10} \text{ CalCE}$$

For the next thirty years, the productivity lost is one-half of this,
or

$$\Delta N_{H_x C_x O_x} = 9.85 \times 10^9 \text{ CalCE}$$

For the well and plant site, the thirty year total is
 3.0×10^{10} CalCE. Averaged over 25 years, this is 1.2×10^9 CalCE/yr.
The biotic effects then are several orders of magnitude less than the
air-chemical impact.

2. Liquid Dominated

Description of the Heber region was based on material in the
Final Environmental Statement for the Geothermal Leasing Program.
The East Mesa KGRA, assumed to be similar to the Heber region, is
described as 50% creosote community (of which creosote is 90%),
40% sand dune, and 10% agriculture [FES, 1973]. Based on the E.A. Manual,
this will be considered a desert scrub region with a gross primary
productivity of $730 \text{ Cal/m}^2/\text{yr}$. Twenty-four wells are required, each
occupying approximately 40 acres [FES, 1973]. Of these 960 acres, it
is again assumed that 10%, or 100 acres ($4.05 \times 10^5 m^2$) are removed
entirely from productivity for 30 years, and removed 50% for the
next 30 years.

We have then:

First 30 years:

$$\Delta N_{\text{H}_x\text{C}_x\text{O}_x} = (4.05 \times 10^5 \text{ m}^2)(730 \text{ Cal/m}^2/\text{yr})(30 \text{ yr})(.26 \text{ CalCE/Cal})$$

$$= 2.3 \times 10^9 \text{ CalCE.}$$

For the next years, the total would be 1.1×10^9 CalCE, for a total of 3.4×10^9 CalCE. Averaged over 30 years, this is 1.1×10^8 CalCE/yr.

3. Hot Dry Rock

It is assumed that approximately four well pairs can be located on one square kilometer. For a 20 well-pair system the area occupied will be 5 km^2 , or $5 \times 10^6 \text{ m}^2$. If 10% of this is assumed removed from productivity, the affected area is $5 \times 10^5 \text{ m}^2$.

Since this hot dry rock power plant is generic in nature, it is difficult to assign it to a specific biota. Using as an example, LASL's Fenton Hill site, the area will assume to consist of mixed coniferous forest [LASL Annual Report, 1977]. The GPP for this ecosystem is, under best conditions, $16,000 \text{ Cal/m}^2/\text{yr}$.

Fir the first thirty years the amount of lost productivity is:

$$\Delta N_{\text{H}_x\text{C}_x\text{O}_x} = (5 \times 10^5) (1.6 \times 10^4) (30) (.26 \text{ CalCE/cal})$$

$$\Delta N_{\text{H}_x\text{C}_x\text{O}_x} = 6.2 \times 10^{10} \text{ CalCE.}$$

For the next thirty years half of this or 3.1×10^{10} CalCE, are lost. The total, then, is 9.3×10^{10} CalCE. This is a yearly average of 3.1×10^9 CalCE/yr.

4. Geopressure

The two stage 25 megawatt geopressure plant designed by Dow will require a minimum of about 1000 acres. It is assumed that 10% of this, 100 acres ($4.05 \times 10^5 \text{ m}^2$) is removed entirely from production for the first 30 years, and that it is only 50% productive for the next thirty years. The type of ecosystem removed from production will vary from site to site, but is assumed here to be Southeastern mixed hardwoods ($7625 \text{ Cal/m}^2/\text{yr}$).

The loss for the first thirty years is then:

$$\begin{aligned}\Delta N_{\text{H}_x\text{C}_x\text{O}_x} &= (4.05 \times 10^5 \text{ m}^2)(7625 \text{ Cal/m}^2/\text{yr})(30 \text{ yr})(.26 \text{ CalCE/cal}) \\ &= 2.4 \times 10^{10} \text{ CalCE}\end{aligned}$$

For the next thirty years it is one half of this, or $1.2 \times 10^{10} \text{ CalCE}$.

The average over thirty years of production is

$$\Delta N_{\text{H}_x\text{C}_x\text{O}_x} = 1.2 \times 10^9 \text{ CalCE/yr.}$$

The total impact is, therefore, $3.6 \times 10^{10} \text{ CalCE}$. Averaged over thirty years of operation, this is $1.2 \times 10^9 \text{ CalCE/yr}$.

D. ENERGY EVALUATION OF PROBABLE IMPACTS AFFECTING
OTHER NATURAL ENVIRONMENT ENERGY FLOWS

An important environmental impact of virtually all power plants is the cooling system. If a body of water, such as a river, is used as a sink for the waste heat, the environmental effects could be substantial. It is a relatively simple matter to calculate the amount of heat discharged into a body of water. Far more difficult, however, is a determination of the effect this heat has on an ecosystem. It is impossible to calculate the impact of waste heat for an unspecified power plant. The heat could have a destructive effect on plant and animal life in a pond, or it could be used to promote life in heated greenhouses. Odum has done a study of a specific Florida estuary and its response to increased temperature from an 800 MWe reactor. He states, "The thermal energy of the plume is large enough to make a large contribution to the estuary, but, since observed metabolism and diversity are similar to that in other areas, this energy is apparently being harnessed as much for biologically favorable effects as it is for negative ones [Odum, 1974]."

Since the power plant under consideration here is assumed to have other cooling towers, aquatic impacts from plume discharges should not occur. However, cooling towers undoubtedly produce some environmental side effects stemming from the release of heat into the low atmosphere. Data are unfortunately unavailable in this area, so this environmental impact will not be considered in this study.

Table IV-3.

GEOENERGETIC IMPACTS

	VAPOR- DOMINATED	LIQUID DOMINATED	HOT DRY ROCK	GEOPRESSURE
<u>1. Air Chemical System Impacts (CalCE/yr)</u>				
<u>Chemical</u>				
H ₂ S	4.1×10^{11}	4.1×10^{11}	-	-
CH ₄	3.6×10^{12}	-	-	-
NH ₃	7.6×10^9	-	-	-
CO ₂	1.7×10^{11}	1.8×10^{11}	-	7.7×10^9
N ₂	8.9×10^{12}	-	-	8.7×10^{11}
TOTAL	1.3×10^{13}	5.9×10^{11}	-	8.7×10^{11}
<u>2. Water Chemical System Impacts (CalCE/yr)</u>				
<u>Chemical</u>				
Silica	-	1.1×10^{10}	4.4×10^9	-
Calcium	-	8.9×10^9	-	-
Iron	-	1.6×10^8	-	-
Strontium	-	4.8×10^7	-	-
Manganese	-	6.7×10^7	-	-
Lead	-	1.2×10^7	-	-
TOTAL	-	2.0×10^{10}	4.4×10^9	-
<u>3. Biotic Chemical System Impacts</u>				
Total Impact (CalCE)	3.0×10^{10}	3.4×10^9	9.3×10^{10}	3.6×10^{10}
Impact normalized over Operating time (CalCE/yr)	1.2×10^9	1.1×10^8	3.1×10^9	1.2×10^9
Total Annual Impact (CalCE/yr)	1.3×10^{13}	6.1×10^{11}	7.5×10^9	8.7×10^{11}

* 1 Cal = 3.968 Btu.

V. EFFECTS OF ENERGY PRICE INCREASES

As mentioned in Section I, an economist would expect the energy ratio to increase in response to increased energy prices. To estimate how much, one could use aggregated elasticities of demand and some "realistic" estimates of energy prices. (For the next decade energy prices will certainly be determined by factors exogenous to the U.S. economy). A presumably more accurate method would be to estimate future energy intensities for the specific materials used in the geothermal electric technologies we study, while assuming that the bill of goods remain unchanged. Finally, the best approach would involve a disaggregated dynamic model coupling input-output and macro approaches.

These three possibilities can be evaluated on the basis of these criteria:

1. Adequate disaggregation
2. Dynamic responses

The econometric approach fails to satisfy both criteria.

The disaggregated input-output approach satisfies criterion 1, but not criterion 2.

The full equilibrium input-output macro approach fails criterion 1 but satisfies criterion 2. The outstanding example of this approach is the DRI model, which currently contains only four non-energy sectors [Hudson and Jorgenson, 1978].

We therefore have used a disaggregated (160 sector) projected 1990 input-output table from the Bureau of Labor Statistics [BLS, 1979] to scale up the 1967 energy intensities. The BLS matrix is a projection

and incorporates a considerable amount of "expert opinion" on future technological coefficients, to be consistent with the following energy price changes from 1967 → 1990.

	(Price (1990)/ Price 1967)	
	Current \$	Constant \$
Coal	5.6	1.7
Crude oil and Gas	14.7	4.4
Electricity	5.6	1.7

The approach that we use scales our energy intensities by a ratio of economic input-output coefficients. The energy intensities are computed by a method that accounts fully for price discrimination in the sale of energy [Bullard and Herendeen, 1975]. On the other hand, the BLS input-output table is an economic one which does not account for energy price discrimination. We use ratios of BLS results for different years which minimizes, but does not remove, the error resulting from the use of economic-based cost factors. The question we can ask is this: given that

- 1) in 1973 the production of \$1 worth of steam turbine required a total of X Btu of coal, based on an energy-price corrected input-output approach
- 2) in 1973 the production of \$1 worth of steam turbine required a total of \$Y worth of coal
- 3) it is predicted, for specified energy price increases, that in 1990 the production of \$1 worth of steam turbine will require a total of \$Z worth of coal (all dollars are constant dollars),

what can we say about the number of Btu required in 1990 to produce the steam turbine?

An approximate answer is given by $(\frac{Z}{Y}) X$.

Z and Y are the inverse coefficients, $(I - A)^{-1}$, from the BLS

input-output tables [BLS, 1979]. We are forced to compare to the year 1973 because that is the earliest BLS input-output table which is compatible with the 1990 projected table.*

To convert from intensities in 1973 to 1967 we use an (energy/GNP) factor [Bullard and Kerendeen, 1975]. The specific equation follows:**

$$\begin{aligned} \epsilon_{\text{primary},j}^{(67,67)} &= \epsilon_{\text{coal},j}^{(67,67)} + \epsilon_{\text{crude},j}^{(67,67)} \\ &+ \alpha \epsilon_{\text{elect},j}^{(67,67)} \end{aligned}$$

(as defined in [Bullard and Herendeen, 1975])

Our method assumes (for all but the energy sectors)

$$\begin{aligned} \epsilon_{\text{primary}}^{(90,67)} &= \\ &(1.02694) (\epsilon_{\text{coal},j}^{(67,67)} g_{\text{coal},j} + \epsilon_{\text{crude},j}^{(67,67)} g_{\text{crude},j} \\ &+ \alpha \epsilon_{\text{elect},j}^{(67,67)} g_{\text{elect},j}) \\ \text{where } g_{\text{coal},j} &= \frac{(I-A)_{\text{coal},j}^{-1} (90,72)}{(I-A)_{\text{coal},j}^{-1} (73,72)} \end{aligned}$$

---

*We have also done the calculation using instead for Y and the 1967 input-output table from the Bureau of Economic Analysis. [BFA, 1974]. This contains 368 sectors, so that the match to BLS sectors is imperfect. We find that the resulting 1990 using intensities are less satisfactory than those obtained with BLS inputs for Y (More of the 1990 intensities exceed the 1967 intensities than when the BLS input is used.) For the theoretical reason (avoidance of mismatch in sectors and of possible methodology) and the empirical reason (the results which appear better), we use the BLS inputs only.

**Notation: $\epsilon^{(90,67)}$ is ϵ for 1990 technology expressed in 1967 dollars.

With similar terms for crude and electricity, $\alpha = 0.61652$ [Herendeen and Bullard, 1979], and 1.02694 is the energy/GNP factor relating 1967 and 1973. $(I-A)^{-1}$ (90,72) and $(I-A)^{-1}$ (73,72) are the BLS inverse coefficients.

Results of this calculation are listed in Table V-1. The conventional view is, of course, that energy intensity should go down from 1967 to 1990. In fact, all but 14 of 53 intensities go up. Intensities for construction activities go down, as do steel products. But in general these results do not bear out the assumptions of decreased primary energy intensities, and the (in some cases) large increases seem implausible. This leads us to doubt the validity of the BLS projected inverse coefficients.

These projected intensities are used to calculate energy inputs (i.e., they are substituted for those in Tables III-1-16), resulting in Table I-3. For all techniques except liquid dominated, the energy ratio increases (i.e., the energy, inputs decrease as expected). The increases are small - up to 5%. For liquid-dominated, the energy ratio goes down by about 4%, an unexpected result. We find that this is due to a large dependence on chemical inputs of the pollution control technology, and chemicals (see Table V-1) have a predicted large increase in energy intensity. This increase is, of course, subject to the same misgivings about which we commented above.

From Table I-3, however, it is safe to say that the price-induced changes (or price-induced uncertainties in predicting ER) are much smaller than uncertainties in ER from statistical and technological uncertainties. From the standpoint of practicality, the latter uncertainties now dominate energy analysis questions.

Table V-1.
EFFECTS OF CHANGING ENERGY PRICES

	IOCODE	SECTOR	E(67,67)	E(90,67)	E(90,67)/E(67,67)
24	1102	NEW CONST NONRES	72491.	72641.	1.0021
25	1103	NEW CONST PUB UT	85922.	77999.	.9078
26	1104	NEW CONST HIWAYS	125758.	106166.	.8442
27	1105	NEW CONST OTHER	93248.	75820.	.8131
29	1202	MAINT CONST OTHR	61453.	58210.	.9472
100	2009	WOOD PRODUCTS	78108.	136297.	1.7450
108	2303	PUBLIC BLDG FURN	68396.	80805.	1.1814
132	2704	MISC CHEM PROD	189521.	284398.	1.5006
140	3000	PAINT PRODUCTS	129402.	238205.	1.8408
153	3601	CEMENT	501726.	642581.	1.2807
163	3611	CONCRETE PRODUCT	113551.	120518.	1.0614
164	3612	READY-MIX CONCR	188575.	198041.	1.0502
167	3615	STONE PRODUCTS	55215.	72517.	1.3134
172	3620	MINERAL WOOL	162859.	185402.	1.1384
175	3701	STEEL PROD	277392.	209998.	.7570
176	3702	IR, STL FOUNDRIES	102440.	104601.	1.0211
196	4002	PLUMB FITTINGS	79436.	85660.	1.0784
197	4003	HEATING EQUIP	75628.	81982.	1.0840
198	4004	FAB STRUC STEEL	131635.	123657.	.9394
200	4006	FAB PLATE WORK	111172.	106391.	.9570
207	4202	HANDTOOLS	70911.	76782.	1.0828
210	4205	FAB WIRE PRODUCT	162464.	164127.	1.0102
213	4208	PIPE	78483.	82619.	1.0527
216	4211	FAB METAL PROD	109834.	112139.	1.0210
217	4301	STEAM ENGINES	74377.	106580.	1.4330
220	4501	CONST MACHINERY	72010.	74722.	1.0377
222	4503	OIL FIELD MACH	76704.	77907.	1.0157
224	4602	CONVEYORS	68636.	73936.	1.0772
225	4603	HOISTS, CRANES	70766.	76100.	1.0754
236	4806	SPECIAL IND MACH	63177.	66029.	1.0451
237	4901	PUMPS, COMPRESSORS	59006.	63681.	1.0792
243	4907	GENERAL IND MACH	68763.	74017.	1.0764
251	5203	REFRIG MACH	71657.	96313.	1.3441
254	5301	ELEC MEAS INSTR	37361.	54251.	1.4521
255	5302	TRANSFORMERS	78657.	129051.	1.6407
256	5303	SWITCHGEAR	49712.	75203.	1.5128
258	5305	IND CONTROLS	41307.	60303.	1.4599
261	5308	ELEC IND APPARAT	63182.	89027.	1.4091
270	5502	LIGHT FIXTURES	74959.	113042.	1.5080
271	5503	WIRING DEVICES	76971.	123781.	1.6082
274	5603	PHONE, TELEGR EQ	39633.	84765.	2.1387
320	6501	RAILROAD	92917.	90451.	.9735
322	6503	MOTOR FGT TRANSP	54968.	49348.	.8978
323	6504	WATER TRANSPORT	262498.	227905.	.8682
324	6505	AIR TRANSPORT	222024.	220792.	.9945
325	6506	PIPE LINE TRANSP	121420.	132528.	1.0915
326	6507	TRANSP SERVICES	9388.	11217.	1.1948
329	6803	WATER, SANIT SER	114263.	89477.	.7831
330	6901	WHOL SALE TRADE	37501.	37967.	1.0124
331	6902	RETAIL TRADE	37329.	34466.	.9233
335	7004	INSUR CARRIERS	23513.	25642.	1.0906
342	7301	MISC BUS SERVICE	30807.	35312.	1.1462
344	7303	MISC PROF SER	28103.	26942.	.9587

E(67,67) is primary energy intensity for 1967 technology in 1967 dollars.
Units: Btu/\$1967.

E(90,67) is analogously defined.

VI. TREATMENT OF UNCERTAINTY

Uncertainty in data and methodology affects the energy ratios. Early work in error analysis often contained no uncertainty analysis; later work did [Bullard and Sebald, 1977; Herendeen, 1979]. The latter work has even been criticized for excessive detail in this regard:

1. Involved computational techniques were used when quick approximations would suffice.
2. Some major uncertainties do not lend themselves to standard treatments (e.g., in the context of a solar power satellite, can the uncertainty of people's behavior in a space environment really be fitted with a normal distribution?)

In this work on geothermal energy we are most interested in problems of the second type. There are large uncertainties, mostly connected with drilling and extraction (such as the creation and maintenance of large fractures in the hot dry rock technology). The uncertainties are large and themselves uncertain. For example:

1. Maintenance of fractures in Hot Dry Rock (Estimated range of uncertainty $\pm 50\%$).
2. Problems of reinjection, scale buildup, in some Hydrothermal (uncertainty $\pm 50\%$).
3. Directional drilling problems - extension of a soft-rock technology to hard rock (Uncertainty $\pm 50\%$).
4. Environmental protection costs (Uncertainty $\pm 50\%$).

5. Drilling costs (Uncertainty $\pm 50\%$).
6. Operating costs (Uncertainty $\pm 50\%$).

This combination of large but "poorly known" uncertainty leads us to perform relatively simple calculations. But we note that the energy ratios we obtain are significantly greater than unity (typically of order 3 and larger). We can conclude, on the basis of a relatively simple calculation, that the uncertainties will not threaten to reduce this below unity.

Table I-4 shows the results. We have broken the total energy cost of the particular facility into 4 - 8 components, and assigned an uncertainty to each. The uncertainties are of 3 general magnitudes:

1. Low (of order 15%). These apply to the plant capital costs. In general these use relatively standard components whose costs are relatively certain.
2. Mid-range (of order 25%). These apply, for example, to drilling area (a surrogate for length of pipe).
3. High (of order 50%). These apply to exploration, drilling costs (a compounding of depth and difficulty of the rock), recompletion of wells, and environmental protection.

The source of these numbers is in final analysis our own judgment, but they have some basis in reality, particularly the low range. We note that these are energy costs and not dollar costs, which are escalating rapidly. We correct for inflation in determining energy cost.

In Table I-4 we have broken total expenditures down so that the

energy costs are additive.* Whether a particular component leads to a significant contribution to total uncertainty depends on the component's uncertainty. In the middle column we combine these two factors, thus estimating the contribution. If the components' uncertainties are totally dependent on one another (i.e., they "conspired" so as to produce the maximum uncertainty) the total uncertainty is the sum of the component uncertainties. If, instead, the errors are totally dependent, the total error is smaller, the square root of the sum of the squares of the component uncertainties. Both values are given in Table I-4.

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*Some components don't separate this way. E.g., drilling depth and energy cost per unit of depth interact multiplicatively. We have subsummed them under the term "drilling," but have taken into account their interaction. We estimate that drill rate (energy/m) and drill depth (m) have fractional uncertainties of 0.5 and 0.2, respectively. The uncertainty of the product, assuming independence, is

$$[(0.5)^2 + (0.2)^2 + (0.5)^2 (0.2)^2]^{\frac{1}{2}} = 0.55.$$
 If depth and drill rate had interacted additively rather than multiplicatively, their combined uncertainty would be between 0.20 and 0.50.

VII. COMPARISON WITH OTHER STUDIES.

Table VII-1 lists results of several other energy analyses of geothermal-electric systems. These should be compared with our results, Table I-1. The study by Bowen is relatively vague and deserves little comment since the others are more carefully done. Regarding the others:

1. Liquid dominated - Our figure of energy ratio (ER) = 4.3 ± 1 is lower than Icerman's (ER = 7-11) or Gilliland's (ER = 7.8 for "wet steam"). Both of the latter made substantial use of average (energy/GNP) figures to energy-cost components. Gilliland included no costs of pollution control; we do, and find it important (see Table I-4a). Neither listed estimates of uncertainty. In general, we expect our value for ER to be lower, reflecting our increased detail on treatment of inputs, and our uses of contingency factors of order 20%.

2. Hot dry rock - We know of no previous energy analysis.

3. Geopressure - Our figure of $ER = 2.9 \pm 0.9$ is relatively close to those of Carlson and Underhill (ER = 3.4 - 5.0). Our use of a 20% contingency factor would seem to explain much of the small difference.

4. Vapor dominated (dry steam) - Our value of 13 ± 4 is apparently significantly lower than Icerman's (ER = 19), though he does not list uncertainty estimates. We made use of more disaggregated data than he did, and the comments already made about his use of

average (energy/GNP) figures and contingency costs also apply here.

We agree with Gilliland's (ER = 12.5 for "dry steam"). Note that if Gilliland had used our value for capacity factor (85%) instead of 73% (as inferred from her Table 2), her resulting energy ratios would be about 20% higher. In this case, this would still agree with our result within our specified uncertainty.

In conclusion, our values for energy ratio are either equal to or less than those obtained by others; in no realistic case do we find a higher energy ratio. For geopressure, we generally agree; for vapor-dominated, we agree or are slightly lower, while for liquid-dominated we are significantly lower, due in substantial part to our inclusion of environmental control (pollution control) costs.

Table VII-1

Results of Previous Energy Analyses of Geothermal Electric Systems.

STUDY	TECHNOLOGY	SIZE (MWe) and CAPACITY FACTOR ^(c)	LIFETIME (years)	ER ^(a)	COMMENTS
<u>ICERMAN (1976)</u>	Liquid Dominated	100 @ 70%	25	8.0 - 11.3 ^(b)	Liquid dominated: Based on net electric power, which is as much as 25% less than 100 MWe. Evaporative cooling. Operational costs included. Icerman included transmission costs; we have excluded them. Environmental control costs are estimated and are much lower than those we use. Based on [Icerman, 1976], Tables 7, 8, 9.
	Vapor Dominated	2 x 50 @ 77.5%	25	22.6	Vapor dominated: Based on net electricity output, 4% less than 100 MWe. Operational costs included. Transmission costs excluded. Environmental control costs estimated. Based on [Icerman, 1977], Table 14. Both: Substantial use of (energy/GNP) ratio for energy intensity. Energy intensities based on 1963 input-output data.
<u>GILLILAND (1975)</u>	Wet Steam	100 @ 73%	30	7.8	No on-site power use subtracted from output. Gilliland energy costs electricity at 3.5 x 3413 Btu/kWh; we use 1 x 3413 Btu/kWh. Gilliland includes large energy inputs for transmission and small ones for environmental subsidies (Ecoenergetic inputs). We neglect both. Based on [Gilliland, 1975], Table 2.
	Dry Steam	100 @ 73%	30	12.5	
<u>BOWEN (1976)</u>	--	--	--	22.5	Data based on generic cost estimates developed by the Oregon Office of Energy Research and Planning in 1974, normalized to 1000 Btu output. Energy intensities based on a single Energy/dollar ratio. Pollution control treatment of fluids not included. Capital costs are included; operating costs are not.
<u>CARLSON AND UNDERHILL (1976)</u>	Geopressure Secondary Fluid Pilot Plant	10 @ 90%		(3.4)	Figures in parentheses exclude methane. Based on net electric power. Operational costs included. Transmission costs excluded from original study. Energy intensities based on 1963 input-output data.
	Geopressure Flashed Steam Plant	25 @ 87%		17.6 (5.0)	
	Geopressure Secondary Fluid Working Plant	33 @ 92%		14.0 (3.7)	

(a) Energy ratios for all technologies are expressed according to the definition in Section I. Electrical output energy costed at 3413 Btu/kWh.

(b) Range includes binary cycle, flashed-steam and total flow.

(c) Note that we assume an 85% capacity factor in our results, Table I-1.

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