An Analysis of the Geothermal Energy Extraction and Utilization Technology R&D Program

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ABSTRACT

The Division of Geothermal Energy (DGE) in the Department of Energy is currently reviewing its RD&D programs to evaluate their relevance to the national goals for the development of geothermal energy during the next 22 years. This report presents the results of an analysis of the RD&D program for geothermal energy extraction and conversion technology. A review of the state-of-the-art was conducted to identify opportunities for improvement. The current RD&D program was checked against the opportunities for improvement to determine if any potential improvements are being ignored. Finally, a benefit/cost analysis was conducted by estimating the benefits expected to result from successful completion of various projects.

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1.0 INTRODUCTION

1.1 Summary

The Division of Geothermal Energy (DGE) in the Department of Energy is currently conducting an extensive evaluation of the effectiveness of its RD&D activities relevant to the development of the geothermal industry in the U.S. The Utilization Branch of DGE is responsible for the RD&D programs in the areas of resource extraction and utilization. Last year, this branch conducted an evaluation of the prospects for improvement in geothermal well technology and their expected benefits.* The results of that study were subsequently utilized for making decisions pertaining to the program justification and redirection. Similar analyses are now being conducted for other segments of the RD&D program of the Utilization Branch.

This report presents the results of an analysis of the DGE program for R&D in the area of Extraction and Conversion Systems and evaluates the effectiveness of this program in terms of the estimated benefit/cost ratios for various activity areas. The first step in this analysis involved a review of the state-of-the-art. This was followed by the identification of the opportunities for improving the technology for geothermal energy extraction and conversion (Section 2). A description of the current DGE RD&D program for extraction and conversion technology was prepared next

* E.J. Friedman and A. El-Sawy, "Prospects for Improvement in Geothermal Well Technology and Their Expected Benefits", MTR-7613, The MITRE Corporation, December 1977.

(Section 3). The ongoing program was matched against the opportunities for improvement to identify the responsiveness of the RD&D program to the state-of-the-art. The projects constituting the current program were analyzed and their benefit/cost ratios were estimated (Section 4). The results of these analyses provide a basis for some recommendations that are aimed at improving the extraction and conversion technology (this section).

1.1.1 Objective

The objective of this task was to provide support for mission-oriented planning of the RD&D program for improving the geothermal energy extraction and conversion technology (including reservoir stimulation and advanced heat exchangers). This effort is a part of the steps being taken by DGE to make its RD&D program as responsive to the industry needs and national goals for the development of geothermal energy as possible. Since the magnitude of the DGE resources for these RD&D activities is limited, it is necessary to undertake realistic benefit cost analyses of individual projects. The results of these benefit cost analyses will be utilized by the Program Managers in DGE as a basis for redirecting their activities with the objective of maximizing the cost effectiveness of their resources.

It is expected that the contents of this report, particularly the conclusions and recommendations, will provide an up to date

rationale for scaling up the effort in some areas, and maintaining the activities in other areas. It is appropriate to point out that the review of the state-of-the-art, and the other activities in this task were aimed primarily at the objective of analyzing and evaluating the current DGE RD&D program for heat exchangers and energy conversion systems. Therefore, the comprehensiveness of presentation of the state-of-the-art and the opportunities for improvement is somewhat limited.

1.1.2 Approach

The approach for this analysis emphasized the importance of (i) exploiting the opportunities for improving the technology; and (ii) formulating a program (the timing and composition of the program) that enhances the probability of achieving the national goals for the development of geothermal industry. Since the Utilization Technology Branch is concentrating on the development of the geothermal resources for electric applications only, the geothermal power-on-line goals were adopted as basis for estimating the benefits resulting from the utilization of the products (outputs) of successful RD&D.

The elements of the program analysis and evaluation process are shown in Figure 1-1. As shown in this diagram, the analysis was initiated by conducting a review of the state-of-the-art in the area of geothermal energy extraction and conversion technology. The major

FIGURE 1-1
ELEMENTS OF THE PROGRAM ANALYSIS AND EVALUATION PROCESS

objective of this review was to determine the cost and performance characteristics of the existing technology. The best possible performance (theoretical) potential for various components of the extraction and energy conversion facilities was estimated. This upper bound on the performance capability was evaluated in conjunction with the RD&D and the technology component costs (capital, and O&M) to set practical targets for optimal performance of the components. These practical targets represent a trade-off between improvements in the efficiency of performance and the associated costs.

The primary goal of the RD&D program is to improve the technology from its current capability to the practically optimal targets. Therefore, a comparison between these targets and the current state-of-the-art identifies the opportunities for improvement. The current DGE program for RD&D in the area of energy extraction and conversion technology was reviewed to determine how well this program is focussed on the opportunities for improvement, and opportunities not being addressed by the current program were identified.

After this, a model for estimating the benefits of the ongoing RD&D projects was developed. This model overlays the benefits expected from the successful completion of ongoing projects on the power-on-line scenario extending to the year 2000 to determine the aggregated benefit in terms of the savings resulting from a reduction in the cost of geothermal power during the next 22 years. This model also accumulates the total cost of each RD&D project, and subsequently determines the estimated benefit/cost ratios.

It is anticipated that the identification of the opportunities for improvement will assist the DGE Program Managers in setting realistic and relevant programmatic goals for the RD&D program. The estimated benefit/cost ratios will provide an indication of the expected effectiveness of the RD&D resources of the Utilization Technology Branch, in terms of the impact on the cost and availability of geothermal electric power.

1.2 Conclusions

A summary of the major conclusions emerging from the analysis of the extraction and conversion technology RD&D program of the DGE is presented in this subsection.

1.2.1 State-of-the-Art

The technological state-of-the-art at this time makes it feasible to undertake commercial scale exploitation of geothermal energy, particularly at resources with good fluid characteristics (high temperature and low salinity). However, the growth of the geothermal industry would require the exploitation of the less attractive resources. These resources constitute the bulk of the geothermal potential of the U.S. and the cost effectiveness and reliability of the technology for their exploitation must be improved significantly before investors can be induced to believe that the geothermal option is technically and economically sound.

The significant conclusions yielded by the review of the state-of-the-art are listed below.

- There are no insurmountable technical problems (go/no-go situations) associated with the conversion of geothermal

energy into mechanical or electrical energy

- Geothermal energy conversion systems utilize technology similar to that being used in conventional thermal and nuclear fueled power plants
- The technology for energy extraction and the disposal of the spent brine is not as well developed as the energy conversion technology and represents an area with potential for significant improvement
- It would be unrealistic to expect substantial improvement in the energy conversion efficiencies associated with components currently in use in dry steam and flashing units because the conversion efficiencies of conventional thermal power plants are already near the practical upper bound
- Due to diverse site-specific factors, there are large variations in the cost and performance characteristics of the components of geothermal power plants. This, coupled with a lack of practical experience in the construction and operation of geothermal power plants*, is the prime reason for the non-existence of a reliable data base for the capital and O&M cost of geothermal power plants
- The future growth of the geothermal electric power generation capacity will depend on the development of a cost effective and reliable binary energy conversion power plant. These plants are now reaching the commercial stage of development, but RD&D will be needed to make these plants economically competitive with conventional power plants.

1.2.2 Opportunities for Improvement

On the basis of a comparison between the current cost and performance characteristics of geothermal energy extraction and conversion equipment and the corresponding practically realistic targets, a

* The oldest geothermal power plant in operation, located at Larderello, Italy, was commissioned about 50 years ago. This is a dry steam plant and therefore has a limited relevance to the problems associated with liquid-dominated hydrothermal plants which are expected to represent the bulk of the U.S. geothermal power generation capacity.

number of opportunities for improvement can be identified. The following is a summary of the important conclusions pertaining to the opportunities for improvement.

- The cost of fuel (geothermal fluid) is one of the largest components of total cost of geothermal power derived from moderate temperature resources; therefore, the need for (1) reducing the cost of production wells (by improving drilling techniques and well completion methods), and (2) increasing the well flow rate (by pumping and reservoir stimulation) cannot be overemphasized;
- The binary energy conversion system will account for a substantial part of the total geothermal power generation capacity in the future, innovations in heat transfer technology, and efficient prime movers are needed for making the binary power plant economically competitive with alternative systems for power generation;
- The temperature differential between the source and the sink in the geothermal power cycle is an important determinant of the efficiency of energy conversion; the concept of floating condensing temperature could be utilized for increasing the energy conversion efficiency; hybrid steam/binary and two-stage binary power cycles could enhance the conversion efficiency associated with energy extracted from moderate temperature resources;
- The disposal of the spent geothermal fluid is a problem not encountered in conventional thermal power plants; injection of these fluids appears to be the most logical solution because it circumvents many environmental problems (i.e., land use, impact on natural bodies of water, seepage, etc.), and also results in the recycling of the resource in an efficient manner.

Table 1-1 presents a listing of the opportunities for improvement in various program subareas. The RD&D needed for exploiting these opportunities and realistic technical objectives for this RD&D are also suggested in this table.

In general, there are two possible approaches to the target of

TABLE 1-1
OPPORTUNITIES FOR IMPROVEMENT

PROGRAM SUBAREA / TECHNOLOGY	OBJECTIVE*	REQUIRED R&D	COMMENTS
EXTRACTION			
1. Well Flow	To increase well flow rate by 20-100% ⁽¹⁾ and reduce O&M cost by 10%	a. Well stimulation b. Two-phase vertical flow and changes of flow area c. Downhole pump d. Gas lift and intermittent gas pump	Advantageous only when choking has not been reached. Scaling problems on well walls and difficulties in determining flash level are anticipated. Testing is needed, high O&M costs are anticipated. Good for corrosive environment but has limits on flow rate.
2. Fluid Transport	To reduce capital cost by up to 20% and O&M costs by up to 10%	a. Two-phase transmission b. Flashers and separator design	This may not yield more energy than double flash ⁽²⁾ but will reduce pipe and equipment costs. Possible vibration problems. Design for higher separation efficiency and reduce erosion problems.
CONVERSION			
1. Conversion cycle	To increase thermal efficiency by up to 30% ⁽³⁾	Cycle and thermodynamic studies	Assessment of many innovative concepts against hardware performance limits is needed.
2. Heat exchanger • Sensible Heat Exchanger • Boiler	To reduce capital by up to 50% ⁽⁴⁾ and O&M costs by up to 20% ⁽⁵⁾ To reduce capital cost by up to 50% ⁽⁶⁾ and O&M costs by up to 10% ⁽⁶⁾	a. Direct contact system b. Fluidized bed system c. Self cleaning shell-tube system (fluted)	Possible problems of foaming working fluid (O&M and environmental) in the rejected primary fluid. Design problems need to be overcome. Testing is needed, possible mechanical problems in the self cleaning mechanisms.
3. Prime Mover	To reduce capital cost by 15% and increase efficiency by 5%	a. Organic turbine b. Other non-conventional steam expanders	For binary plant. Engineering problems (Design, O&M) are anticipated.
4. Condenser	To reduce capital cost by up to 50% ⁽⁷⁾ and O&M costs by up to 10%	a. Tube materials for better film coefficient b. Contact condenser c. Air-cooled condenser	To increase film condensation. Advantageous for binary system. Bulky and high cost, but might solve water shortage problems. Better uses of water. Same as in "condenser".
5. Cooling System • Cooling Water • Heat Rejection System	To reduce O&M costs by up to 10% and minimize the need for cooling water To reduce cooling water consumption	a. Systems study and optimization b. Air-cooled system a. Evaporative air-cooled condenser	Need testing and economic assessment.
DISPOSAL			
Injection Well	To increase injection rate by 20% and well life by 50%	a. Well stimulation b. Maintenance techniques	To increase permeability. Environmental problems might arise.

Notes: *The percentages are based on the component in consideration (not the system) and are estimated from the available information.

(1)- Reference 20 (3)- Total flow system, rotary separator (5)- For self-cleaning system (7)- For contact condenser in the library system
(2)- Reference 26 (4)- For the direct contact preheater (6)- For direct contact boiler

enhancing the cost effectiveness of the technology for geothermal energy extraction and conversion. These are: (1) improvement of existing technology and (2) development of new technology. Table 1-2 gives an indication of the feasible options with regard to the major elements of geothermal power plants.

1.2.3 The Current RD&D Program

The analysis of the current RD&D program showed that the ongoing projects are generally timely and relevant. The technical objectives of various projects are well defined and most of the identified opportunities for improvement are being addressed by one or more projects in progress at this time.

Table 1-3 shows the expected impact of different projects on the cost and technical performance parameters of geothermal energy extraction and conversion systems. It is apparent that the projects relevant to binary power cycles are crucial because of the enormous penalties expected to be associated with the failure of these projects. Lack of success in this area may result in a deficit of 80% in the installed capacity of geothermal power plants by the year 2000*.

In terms of the objectives of the projects, the current RD&D projects can be classified into three categories, namely (1) technical data acquisition projects, (2) hardware development projects, and (3) support activity projects. The projects in the technical data

* This deficit is relative to the national goals for geothermal power-on-line (established by DGE).

TABLE 1-2
OPTIONS FOR IMPROVING GEOTHERMAL ENERGY CONVERSION SYSTEMS

OPTION SYSTEM ELEMENT	IMPROVE EXISTING TECHNOLOGY	DEVELOP NEW TECHNOLOGY
Heat Exchangers	X	X
Condenser		X
Turbine	X	X
Heat Rejection		X
System/Cycle Design	X	X
Well Flow (Extraction)	X	X
Gathering Pipelines	X	
Injection Wells	X	
Geothermal Fluid Pumps	X	X

TABLE 1-3
PRIMARY BENEFITS OF CURRENT RD&D PROJECTS
IN THE EXTRACTION AND CONVERSION TECHNOLOGY PROGRAM

TECHNICAL AREA PROJECT NAME AND CODE	YEAR OF COMM.	IMPACTED PARAMETER ¹	IMPACT (%) ON 50 MW PLANT ²		AFFECTED PLANT TYPE ³
			Pessi- mistic	Opti- mistic	
1. RESERVOIR STIMULATION 2101-2106, 2201	FY85	Well Cost	-5.0	-13.2	F & B
2. WELL FLOW					
• Two-Phase Flow, 2206	FY81	Production Well Number	-10.0	-20.0	F
		Production Well Cost	10.0	10.0	
• Gas Lift, 2205	FY79	Production Well O&M Cost (LS)	-5.0	-10.0	F
		Production Well O&M Cost (HS)	-25.0	-30.0	
		Production Well Life	20.0	30.0	
		Production Well Cost	12.5	5.0	
• Downhole Pump, 2202- 2204	Not Current	Production Well Number	-3.0	-5.0	B
		Downhole Pump O&M Cost	-30.0	-45.0	
3. HEAT EXCHANGER					
• Direct Contact, 2304	FY80	Prod. & Inj. Well Number	-2.0	-4.0	B
		Process Mechanical (Util.) Cost	-20.0	-35.0	
		Condenser & Heat Rejection Cost	-2.0	-5.0	
		General O&M Cost (Util.)	-5.0	-10.0	
• Liquid Fluidized Bed, 2303	FY81	Heat Exchanger Cost	-10.0	-22.0	B
		Heat Exchanger O&M Cost	120.0	96.0	
• Self-Clean (APEX), 2306	FY81	Heat Exchanger Cost	-10.0	-27.0	B
		Heat Exchanger O&M Cost	200.0	160.0	
4. CONDENSER					
• Fluted Tube, 2301	FY79	Condenser & Heat Rejection Cost	-4.4	-5.6	B
		General O&M Cost (Util.)	2.0	2.0	
• Direct Contact, 2302	FY81	Condenser & Heat Rejection Cost	-4.0	-6.0	B
5. CONVERSION SYSTEM					
• Binary Test Program, 2305, 2404, 2414	FY80	Production Well Number	0	-0.2	B
		Heat Exchanger Cost	-4.0	-11.0	
		Proc. Mechanical (Util.) O&M Cost	-9.0	-18.0	
• Well-Head Generator, 2407, 2413, 2415	FY80	Saving other fuels equivalent to 0.194 Quads of electricity	-	-	-
• Gravity Head Binary Plant, 2407, 2409	FY82	Saving other fuels equivalent to 0.315 Quads of electricity	-	-	-
• Helical Screw Expan- der, 2406	FY79	Saving from \$12M to \$16M	-	-	F & B
• Total Flow System, 2405	Discon- tinued	Prod. & Inj. Well Number	-2.0	-15.0	F
		Condenser & Heat Rejection Cost	13.3	10.9	
		General O&M Cost (Util.)	34.1	12.2	
		Turbine-Generator Cost	6.0	3.0	
		Gathering System Cost	-10.0	-20.0	
		Process Mechanical (Producer) Cost	-40.0	-40.0	
• Rotary Separator, 2410	FY80	Prod. & Inj. Well Number	-12.0	-20.0	F
		Turbine-Generator Cost	9.1	5.7	
		Process Mechanical (Util.) Cost	-16.0	-20.6	
		Condenser & Heat Rejection Cost	-7.3	-12.5	
• Hybrid Geothermal/ Fossil Plant, 2403	FY80	Saving from \$50M to \$100M	-	-	-
• Conversion Studies 2401, 2402	FY79	Not analyzed	-	-	F & B
• Direct Bottoming Cycle, 2416	FY79	Not analyzed	-	-	B
6. HEAT REJECTION					
• Waste Heat Rejection, 2412		Not analyzed	-	-	B

1. LS: Low Salinity; HS: High Salinity; Prod. & Inj.: Production & Injection; Util.: Utility

2. Negative sign indicates a reduction

3. F: Flash Steam Plant; B: Binary Plant

acquisition develop the baseline data-base against which progress is to be measured, and the technical objectives of the program are set. The hardware development projects are aimed at the development of new and/or improved components of the geothermal energy extraction and conversion cycle. The output of these projects is more visible than that of the projects in the other two categories, and most of the impact of RD&D on the cost and availability of geothermal electric power can be attributed to the success of hardware development efforts. The support projects are necessary for making logical decisions pertaining to the development of hardware (studies relating to the properties of materials, simulation of the thermal cycle, etc. are examples of such projects).

An analysis of the funding allocation among the three categories mentioned above, shows that DGE's program for RD&D in this area is on the right track. Figure 1-2 shows the division of the total funds for this program, among the three project categories, for FY76, FY77 and FY78. It is observed that in FY 76, the emphasis was on technical data acquisition activities, but hardware development projects account for about two thirds of the total budget for FY1978. This is a good trend and indicates that the program is well planned and is maturing rapidly.

1.2.4 Benefits Versus RD&D Costs

An effort was made to estimate the benefit/cost ratios for each of the 16 projects (or groups of projects) for which the associated

FIGURE 1-2
ALLOCATION OF FUNDS FOR THE RD&D ACTIVITIES IN THE
EXTRACTION AND CONVERSION TECHNOLOGY PROGRAM

costs could be isolated. It turned out that twelve of these projects could be expected to have an impact on the cost of geothermal electric power. Two of the remaining four projects are not expected to reduce the cost of geothermal power, but will probably make more power available by developing and commercializing technology which is needed for exploiting inferior resources (low temperature resources, high salinity resources, etc.). The impact (or benefits) of these projects can be evaluated by comparing the projected geothermal power on-line capacity with these projects, with the projected capacity if these projects were not executed.

Table 1-4 shows the costs and the expected benefits for sixteen projects having quantifiable potential impact on the cost of geothermal power. The pessimistic estimate of benefits is a conservative estimate based on the assumption that the project will not be totally successful and the output of the project will not attain the maximum market penetration. The optimistic estimate assumptions include complete success of the project and the maximum commercialization of the output of the project. The lowest benefit/cost ratio of 0 is associated with the gas lift, self-clean and fluidized bed heat exchanger projects (pessimistic estimates). The highest optimistic benefit/cost ratio is 448 for the rotary separator project. In making these estimates, potential interactions between the benefits of different projects were ignored. Therefore, the benefit/cost ratios resulting from the simultaneous execution of a number of projects may be smaller than

TABLE 1-4
CUMULATIVE BENEFITS AND COSTS OF PROJECTS

PROJECT	R&D COST (\$1000)					DISCOUNTED BENEFITS (\$10 ⁶)(2)		BENEFIT/COST RATIO	
	FY78	FY79	FY80	Post FY80 (1)	Total Discounted (2)	Pessi-mistic	Opti-mistic	Pessi-mistic	Opti-mistic
1. RESERVOIR & STIMULATION	1,095	3,130	2,000	2,000/Year (81-84) 790 (85)	10,674	188.0	496.0	17.6	46.5
2. WELL FLOW									
Two-Phase Flow	200	170	300	300 (81)	828	1.7	38.2	2.1	46.1
Gas Lift	200	350	-	-	518	0	15.8	0.0	30.5
Downhole Pump	-	-	-	-	-	56.4	138.4	-	-
3. HEAT EXCHANGER									
Direct Contact	2,150	1,800	-	-	3,786	130.3	242.9	34.4	64.2
Self Clean	300	100	400	400 (81)	1,022	0	7.4	0	7.2
Fluidized	100	450	500	500 (81)	1,298	0	7.2	0	5.5
4. CONDENSER									
Fluted Tube	400	500	-	-	855	8.5	13.9	9.9	16.3
Direct Contact	100	400	500	-	877	14.8	22.3	16.9	25.4
5. CONVERSION SYSTEMS									
Binary System	765	570	100	-	1,366	1.5	2.0	1.1	1.5
Well Head Generator	1,000	3,000	2,000	-	5,380	See Appendix D		-	-
Gravity Head Plant	1,230	3,400	3,400	3400(81) 1270(82)	10,552	See Appendix D		-	-
Helical Screw Expander	400	-	-	-	400	10.8	14.4	27.0	36.0
Total Flow System	1,700	-	-	-	1,700	0.14	6.2	0.1	3.7
Rotary Separator	15	400	-	-	379	89.3	169.6	235.6	447.5
Hybrid Plant	689	3,000	3,000	-	5,895	25.0	50.0	4.2	8.5
OVERALL (3)	8,114	10,870	6,300	11,260	29,598	470.04	1085.9	15.9	36.7

1. Figure in brackets indicates the Fiscal Year

2. In 1978 dollars. A 10% discount rate is used

3. Excluding Well Head Generator, Gravity Head Plant, and Downhole Pump.

those computed for individual projects. Nevertheless, it is apparent that most of the projects represented in Table 1-4 are cost effective.

Since there are redundancies (duplications) among the ten projects directly related to extraction and conversion systems, it is appropriate to evaluate the benefit costs of subsets of these projects. Table 1-5 shows the estimated costs and benefits of seven combinations with no redundancies. The benefit cost ratios for these combinations range from a low of 14.0 to a high of 58.0. These figures also confirm the cost effectiveness of the groups of projects in this table.

The impacts (benefits) of the remaining six projects were estimated in terms of the availability of geothermal power (installed capacity in MW_e) with and without these projects. Since the binary power cycle is needed for exploiting resources with low temperature, high salinity, and large content of non-condensable gases, the termination of the binary cycle system studies could be expected to delay the commercialization of the binary power plants by 5 to 10 years. On the other hand, the success of the Well Head Generator Project, the Geothermal Power Handbook Project, the Hybrid Systems Study Project, the Helical Screw Expander Project, and the Heat Rejection Project could increase the installed capacity of geothermal power plants to a level above the projected on the current DGE scenarios.

1.3 Recommendations

The review of the state-of-the-art and the current DGE program for RD&D in the area of geothermal energy extraction and utilization

TABLE 1-5

ESTIMATED BENEFIT/COST RATIOS FOR GROUPS OF RD&D PROJECTS

APPLICATION	RD&D PROJECT* IN THIS GROUP										TOTAL RD&D COST (\$1000)**	TOTAL BENEFIT (\$10 ⁶)**		COMBINED TOTAL BENEFIT/COST	
	A	B	C	D	E	F	G	H	I	J		PESSIMISTIC	OPTIMISTIC	PESSIMISTIC	OPTIMISTIC
Flash	X	X	X							X	12,399	279.0	719.6	22.5	58.0
Binary 1	X			X			X				15,315	326.8	752.8	21.3	49.2
Binary 2	X			X				X			15,337	333.1	761.2	21.7	49.6
Binary 3	X				X		X		X		13,917	198.0	519.3	14.2	37.3
Binary 4	X				X			X	X		13,939	204.3	527.7	14.7	37.9
Binary 5	X					X	X		X		14,193	198.0	519.1	14.0	36.6
Binary 6	X					X		X	X		14,215	204.3	527.5	14.4	37.1

*Project Codes:

CODE	PROJECT	CODE	PROJECT
A	RESERVOIR STIMULATION	F	FLUIDIZED BED HEAT EXCHANGER
B	TWO-PHASE FLOW	G	FLUTED TUBE CONDENSER
C	GAS LIFT	H	DIRECT CONTACT CONDENSER
D	DIRECT CONTACT HEAT EXCHANGER	I	BINARY SYSTEM
E	SELF CLEANING HEAT EXCHANGE	J	ROTARY SEPARATOR

** Discounted to 1978 dollars.

technology reveals that the current program is responsive to the needs of the industry and represents an effective utilization of the resources for RD&D. Nevertheless, it is appropriate to point out that the reliability of some of the conclusions may be somewhat speculative because the baseline data based on practical experience pertaining to the capital and O&M costs of many components of the geothermal power plant are not available. Therefore, it is very desirable to develop such a data base as soon as possible. In addition, there appear to be some areas of technology where new initiatives could lead to a significant reduction in the cost of geothermal power.

The following are the major recommendations concerning possible actions aimed at developing a data base of operating experience and reducing the cost of geothermal power by lowering the capital and O&M costs of geothermal power plants:

- A set of realistic cost estimates (capital and O&M) should be developed for each of the three categories of geothermal power plants, namely dry steam, flash steam and binary. These estimates should be relevant to the economy and practical experience in the U.S. The effectiveness of future R&D in the area of geothermal energy extraction and conversion technology should be judged with reference to these estimates.

- A comprehensive system study of the geothermal power cycles should be undertaken to define the theoretical upper bounds, and practically attractive targets for the performance of important components of the geothermal power plant.
- The concept of floating condenser temperature could lead to enhanced utilization efficiencies, particularly in areas with large variations in the ambient temperature. A detailed study of the concept is recommended.
- The concept of hybrid steam/binary and combined binary (binary-binary) cycles appear to have potential for enhancing the efficiency of utilization of low and moderate temperature resources. A detailed study of the optimal design of these power cycles is recommended.
- The cost of extraction of the geothermal fluid is a major component of the total cost of geothermal power. Since the drilling and completion costs of geothermal wells are increasing rapidly, the only possible way for reducing the extraction and disposal costs is to increase the well flow rates and the lifetime of the production as well as injection wells. Reservoir stimulation is the first step in this direction, and it is recommended that the well and reservoir stimulation RD&D effort be stepped up.
- Although a number of downwell pumps have been developed and tested with varying degrees of success, a detailed comparative evaluation of the two major options (electric pump vs. thermal pump) has not been carried out. Such an evaluation should be conducted in order to decide whether it is more cost effective to develop high temperature materials and pump designs for the electric pump, which is a simple system, than to develop the more complex thermal pump. It is recommended that such an evaluation be carried out before concentrating the RD&D efforts on one of these two options.
- A study of the two-phase flow in horizontal and near horizontal pipelines is recommended. The results of this study will indicate whether it is technically and economically justifiable on a site-by-site basis to transport the fluid from the well head to the flashing steam power plant in a single pipeline.

- The problem of separating two immiscible fluids in direct contact heat exchanger does not seem to be receiving the attention it deserves. Although chemical and pharmaceutical industries have successfully separated small amounts of fluids, the large volumes associated with binary power plants might require more cost effective methods. A study of this separation process is recommended.
- If environmental problems and the scarcity of water become acute, geothermal power plants may be forced to resort to indirect cooling in the condenser, and dry or partially dry cooling towers. A systems study of the dry and semi-dry cooling methods for geothermal power plants should be undertaken.
- It is recommended that regular reviews of the state-of-the-art is undertaken to identify the opportunities for the improvement of the energy extraction and conversion technology. If necessary, the DGE RD&D program should be redirected to exploit these opportunities.

2.0 State of the Art and Opportunities for Improvement

In order to evaluate the potential effectiveness of the RD&D program for geothermal energy extraction and conversion technology, it is necessary to review the current state-of-the-art in this area. This review would make it possible to identify the specific areas in which technological improvements could be made. At the same time, duplication of effort can be avoided by recognizing that some elements of the technology for geothermal energy extraction and conversion technology have reached the peak of their performance and any R&D concentrated on these elements will not yield significant dividends.

This review of the state-of-the-art is also expected to provide a baseline against which progress in this area can be judged. Since an effective R&D program should be designed to alleviate the deficiencies in the technology, each RD&D project can be viewed as a series of steps aimed at closing the gap between the current state-of-the-art and the upper bound (optimum) on the performance of the technological element involved. Consequently, the identification of the areas of possible improvement initiates the development of the strategy for total or partial realization of the potential improvement. A well conceived plan for the R&D program will result in the funding and scheduling of projects in a manner that will accelerate the rate of geothermal development by reducing the costs.

The state-of-the-art review presented in this section is confined to the technology for the extraction and conversion of geothermal

energy from liquid-dominated hydrothermal resources. The energy conversion technology segment of this review is focused on the conversion of thermal energy of the fluid into electrical power. Although direct applications of this resource (for process heat, space heating, etc.) could eventually represent a significant part of the total utilization, these applications are excluded because they fall into a different program area within DGE. The well drilling and completion projects are omitted from this review because they have been addressed in another analysis of this type.⁽¹⁾

The state-of-the-art review in this section involves a brief description of technology for fluid extraction, energy conversion and fluid disposal. Following this is a presentation of the cost and performance characteristics of the existing technology. The theoretical and practical limits for efficiency and capital costs are estimated. This is followed by the identification of the opportunities for improving the geothermal energy extraction and conversion technology. Finally, an overview of the relationship between the opportunities for improvement and an RD&D program is presented, and recommendations concerning the make-up of an appropriate RD&D program are listed.

2.1 The Current State of the Art

There are three main types of geothermal power plants in operation at this time. These will continue to be built as long as hydrothermal reservoirs, vapor-dominated or liquid-dominated are being discovered. Figure 2-1 shows a sketch of these three types which are often

STEAM PLANT

Dry steam from well expands through turbine T to drive generator G. Exhaust enters condenser C or vented to atmosphere. Condensate is disposed via evaporating pond or injection well.

FLASH PLANT

Similar to steam plant except that wet steam from well must pass through separators.

BINARY PLANT

Water is used as heat source at heat exchanger HE for a power cycle of a secondary fluid.

**FIGURE 2-1
TYPES OF GEOTHERMAL POWER PLANTS
WHICH ARE CURRENTLY IN OPERATION**

referred to as steam, flash steam, and binary plants, respectively.

Extraction technology covers the processes associated with the extraction of the fluid from the reservoir following the drilling and completion of the production well. The collection of fluid and its transportation to the turbine inlet for steam and flash plants, and to the first heat exchanger in a binary plant, is also treated as a part of the extraction technology. Conversion technology encompasses all the processes in the power house and its vicinity. The disposal of hot water and/or condensate is the third area (disposal technology).

2.2 Extraction Technology

The three topics to be covered here are: well flow; surface pipe flow; and steam-water separation.

2.2.1 Well Flow

The geothermal fluid flowing up a well can be (i) steam, or (ii) water, or (iii) a mixture of both depending on its pressures and temperature. Single phase (steam or water alone) flow in pipes or wells represents problems similar to those normally encountered in many industrial applications. Steam-water flow, which can be formulated as two-phase, gas-liquid, one-component, and near-adiabatic flow, is however, very complex. Since steam-water flow exists in about half of the number of wells which are currently producing in the world (see Table 2-1), it will be discussed in some detail here.

Well flow is generally vertical flow and the well can be regarded as a restriction between two media of different pressures: the

TABLE 2-1

SEGREGATION OF TYPES OF WELL FLOWS IN THE WORLD
 GEOTHERMAL POWER STATIONS
 (by February 1978)

	FLASH STEAM PLANT (Two-Phase Flow)	DRY STEAM PLANT (Steam Flow) (1)	BINARY PLANT (Water Flow)
Number of (4) installed units	27	31	2
Installed (4) capacity (MW)	450.3	999.6	1.7
Number of wells (2)	90	200	2 (3)
Total length (2) of flow (miles)	76.7	227.3	1.7

- Note: (1) There is a possibility that two-phase flow exists in the proximity of the bottom of the well.
 (2) Assuming well capacity of 5MWe/well (3) and well depth of 4,500 ft and 6,000 ft for liquid dominated reservoir and vapor dominated reservoir, respectively.
 (3) Two locations: Japan and USSR.
 (4) Data Ta-en from reference 2.

reservoir and whatever is installed after the well head. Since the two-phase mixture is compressible, it is possible that when the differential pressures over the restriction is increased beyond a certain critical value the mass flow rate ceases to increase. It has reached its maximum possible value called the "critical flow rate". The situation is sometimes called "choking" and has been an important phenomenon in the design of emergency cooling systems of nuclear power plants. In the long pipe (well casing), the liquid phase flashes as the pressure decreases along the flow path. This increases the mixture dryness and consequently affects the pattern of flow. The result is that many flow patterns can co-exist in one well as illustrated in Figure 2-2.

It must be understood here that the extraction rate of the geothermal fluid is naturally limited by the well and surface equipment. The extraction rate will, therefore, be equal to or less than the critical flow rate for that set up. If a restriction is installed after the well head to increase the well head pressure, and, therefore, decrease the differential pressure between the reservoir and the well head, the mass flow would decrease unless choking was occurring prior to the decrease in differential pressure. This is illustrated by the experience gained in Otake Field, Japan (as shown in Figure 2-3).⁽⁴⁾ Figure 2-3 shows a plot of mass flow rate of the steam-water mixture versus well head pressure and indicates that the curve of well number 10(w) shows evidence of choking.

FIGURE 2-2
POSSIBLE CHANGES OF FLOW PATTERN IN GEOTHERMAL WELL FLOW

FIGURE 2-3
CHARACTERISTICS OF THE FLOW RATE AT OTAKE
(AFTER FUKUDA ET AL.⁴)

If the specific enthalpy is measured at the well head and plotted against the well head pressure, it is found that specific enthalpy of the mixture is approximately independent of well head pressure.^(4,5) This suggests that the total enthalpy rate of a well is directly proportional to the mass flow rate of that well.

Usually more than one well is required for the operation of a power generating unit. Since the cost of well drilling and completion is high (\$1 Million or more), it would be desirable to reduce the number of wells required for a certain plant capacity by increasing the productivity of producing wells. If the extraction rate of one well can be improved by 20%, five improved wells would have a production equivalent to six wells, thus the cost of geothermal energy could be reduced by $(1/6) \times 100 = 16.67\%$.^{*} The extraction rate of a well can be improved by a number of methods: (1) increasing permeability of the reservoir and, hence, increasing the differential pressure over the well depth if the choking stage has not been reached, (2) redesigning of well geometry to reduce restriction to flow, or (3) increasing the fluid density by increasing well pressure with a down hole pump.

2.2.2 Surface Piping System

For a steam or a binary plant where either dry steam or compressed water is flowing from the well to the power house, the surface

^{*} Assuming that the well-life and O&M costs are unchanged.

piping system is simple. Its design involves well established procedures and, therefore, R&D work on the system is unlikely to yield any improvement. For a flashing plant, however, the surface piping system is somewhat more complex. There, steam is usually separated from the hot water at the well heads and then gathered through small branch pipes into one or more large diameter main pipelines bringing the steam to the power house. Hot water is gathered for disposal in the same manner. In many cases secondary flashing of the hot water also proves beneficial. The secondary flashing usually takes place at the power house to avoid additional large steam pipelines. Hence, in a flashing plant, there are generally two pipeline systems; one for the steam and the other for the hot water. It might be an advantage if both steam and water could be transmitted in a two-phase pipeline directly from the well to the power house where separation and flashing are carried out. In this arrangement only one piping system, and one or two sets of separators and flashers will suffice for many wells. However, it is believed that only Japan is using this system.⁽⁶⁾ Plant designers are generally reluctant to adopt it because of uncertainties encountered in the design of two-phase flashing system and in solving such problems as pipe vibrations due to "slugging" or scale desposition in a flashing system.

In flashing and binary systems, substantial O&M costs are incurred due to the need for cleaning the pipelines regularly. Pipeline networks designed for easy cleaning could reduce the O&M costs significantly.

2.2.3 Steam-Water Separation Systems

It is important to distinguish between two types of steam water separations systems. One is the steam separator which separates steam from the steam-water mixture. The other is the flasher which separates steam from hot water.

Separation of steam from a steam-water mixture is effected by centrifugal action in a vertical cylindrical vessel into which the mixture enters tangentially. The water leaves the vessel through a tangential outlet near the bottom while the steam flows upward and exits through a central pipe emerging from the bottom. In an alternative design, steam is taken off from the top of the vessel. Figure 2-4(a) shows a sketch of the system. The separation efficiency depends on the mechanical design of the separator and is usually high. Efficiency of more than 99.9% (dryness of steam output) has been reported.^(7,8) In a flasher, the hot water is fed directly into a depth of water which is drained off through a bottom outlet and the steam is drawn off at the top of the container, as shown in Figure 2-4(b). A separation efficiency of 99.93% has been reported for a flasher.⁽⁶⁾

Since the separation efficiencies encountered in this area are already high, incentives for improving the performance of the systems might not exist. It is noted that physical and chemical attacks of the geothermal water on the vessel materials are most likely. This means that development of better construction materials or

FIGURE 2-4
SKETCH OF THE STEAM-WATER SEPARATION SYSTEMS
(a) SEPARATOR (b) FLASHER

combinations of materials would be cost-effective. However, since material selection does not fall within the scope of this report, it will not be included as an improvement opportunity.

2.2.4 Downhole Pump

A downhole pump is used to increase the flow of geothermal fluid through the well. Usually, the pump increases the fluid pressure beyond boiling conditions to suppress the formation of steam and, consequently, maintains the fluid (water) flow at high level. In addition, since the water does not lose its mass to the vapor, a large reduction of scale deposition is expected along the flow path. Such reduction would not be possible and scaling could be a serious problem if the water is allowed to evaporate. Water has a better heat transfer coefficient in its liquid form than that of the steam. Hence, the use of the downhole pump also improves the performance of the heat exchanger system through which the water delivers the heat carried from the reservoir.

Downhole pumps maintain a single phase homogenous flow through the well and deliver thermal energy to the point of use in the form of liquid. Without the pump, flashing of the liquid might occur in the well, resulting in the escape of non-condensable gases and the loss of the latent heat of steam, a reduced flow rate, and possible scaling of the well and pipes.*

* A recent study for the geothermal pumping equipment indicated that the use of downhole pumps for a 50MW plant located in the Imperial Valley can result in initial cost savings of \$5 to \$10 million.

Downhole pumps are available in the market. However, a pumping system for geothermal applications requires some critical selection of materials because of the high temperature and corrosivity of the fluid, and scaling possibilities. A recent study⁽⁹⁾ to develop specifications for a pumping system to pump hot geothermal water states that the pump can be installed at depths of 1,000 feet or more and be driven by an electric motor located at the well head, and that the pump can be used for water up to 450°F (232°C).*

2.3 Conversion Technology

2.3.1 Conversion Cycles

The steam conversion cycle used in geothermal-electric production is, by nature, open cycle. The steam extracted from the well, after being expanded through the turbine, is vented to the atmosphere or condensed and disposed into an evaporating pond or injection well.

In contrast to the steam cycles of steam or flash plants, the conversion cycle of a binary plant is a closed cycle (Rankine type). The binary cycle usually, but not necessarily, employs an organic fluid of low boiling point as the secondary or working fluid. Since heat has to be extracted from the geothermal water, heat exchangers are required in this type of cycle. The use of heat exchangers represents additional costs and operating and maintenance problems.

* This pump has not operated successfully on account of the failure of mechanical seals.

However, in many cases the chemical and thermodynamic properties of the geothermal water (e.g. low temperature, high salinity, presence of non-condensable gases) suggest that the binary cycle is more cost-effective than other types of conversion cycles. In some severe conditions, where the water has high salinity and is corrosive, it may be advantageous to combine flashing into the binary cycle. The flashing/binary cycle has not been used anywhere and, therefore, is not state-of-the-art, and is mentioned here for information only. In a flashing/binary cycle, the geothermal water is pumped to the surface where it flashes to steam. The steam will be used to supply heat to the closed Rankine cycle instead of the water.

Generally, geothermal water is at a moderate or low temperature, and it is critical to convert the maximum proportion of the thermal energy in the fluid into mechanical energy by having a sink temperature as low as possible. Due to the relatively small differential between the source and the sink temperatures, the theoretical efficiency of the conversion cycle is small and is sensitive to any change of the two end temperatures. The source temperature cannot be changed while the sink condition is dependent on the ambient temperature which varies hourly, daily and monthly between 100°F and -50°F. Therefore, the sink temperature could range from the water freezing point (32°F), to, say, 80°F for a cycle using condenser and water for heat sink. If t_1 and t_2 are the source and the sink temperatures in °F, respectively,

the theoretical efficiency by definition is

$$\eta = (t_1 - t_2)/(460 + t_1) \quad (1)$$

Thus, it can be shown that

$$\frac{d\eta}{\eta} = - \left(\frac{1}{t_1 - t_2} \right) dt_2 \quad (2)$$

which indicates that for a 300°F difference between source and sink temperature, a 30°F drop in the sink temperature could produce a 10% increase in theoretical efficiency. The improvement in the actual efficiency will be less than the increase in the theoretical efficiency of the cycle. Nevertheless, it might be desirable to allow the sink temperature to float even if the cycle has to be operated in an off-design manner.

2.3.2 Heat Exchangers

Heat exchangers, excluding condenser, are required only in binary systems where heat is to be transferred from the geothermal water to the working fluid. They include preheaters and boilers and are currently of the shell and tube types. The heat transfer surface is generally a major factor in the design considerations of a shell and tube heat exchanger. It represents the size and cost of the unit and is determined from the knowledge of the heat transfer coefficients of the water and working fluid, the fouling characteristics of the system, and the type of the heat exchanger. Because the chemicals in the geothermal water at some reservoirs have a tendency to cause

scale deposition, it is usually placed in the tube side where access is allowed for cleaning at a later date. The tube side heat transfer coefficient of water is usually many times higher than the organic fluid, or shell-side, heat transfer coefficient. Therefore, the controlling coefficient is that of the working fluid. Sometimes, because the fouling resistance of the geothermal water is high, it is also a controlling factor in the sizing of heat exchangers.

In general, the design of shell and tube heat exchangers is fairly standard even if thermal stresses are to be accounted for. However, in geothermal application there are areas of uncertainty which could cause over-design or system failure. They are the specification of water side fouling resistance and the selection of construction materials. These areas are strongly affected by the water chemistry and its interaction with materials. They do not fall within the scope of this report, however. Technologically, if improvement of the heat exchanger system is desired, one must consider other types of heat exchanging systems, e.g. direct-contact heat exchanger, along with the shell and tube type.

2.3.3 Turbines

Steam turbines in steam and flashing plants are similar to the steam turbines used in fossil-fuel or nuclear power plants except for the fact that, because of lower steam density, turbines in a geothermal plant are usually larger than those of equivalent

capacities in plants run by other types of fuel. The simplest type is the non-condensing turbine where steam is exhausted to atmosphere. This is not efficient because the heat available below atmospheric pressure is not utilized. A non-condensing turbine is used if the non-condensable gas content of the steam is too high to permit economical operation under vacuum. It may also be used in the initial development stage of a steam field for the purpose of proving of the field, and, at the same time, supplying the local facilities with electricity. At a later stage, larger plants may well justify greater expenses for condensing turbines and circulating water works, which are offset by the reduction in steam field costs per kilowatt.

In a binary plant, the turbine has to be designed to adapt to the expansion of the organic fluid in use. Organic fluid turbines are currently in production and use in oil and gas industries. However, these turbines are small (the largest is about 8 MW shaft power), and are mostly used to drive compressors. Some organic fluid turbines are used to drive generators. The largest organic turbine-driven generator has a capacity of 3 MWe.⁽¹⁰⁾ Although large organic fluid turbines have not been manufactured, it is expected that with the experience gained from small organic fluid turbines and larger gas turbines, fabrication of large organic fluid turbines would not present any serious problems. Because of the necessary installation of automatic controls between the turbine and generator, they are usually specified and purchased as a set.

2.3.4 Condenser

If condensing steam turbines are used, condensers are usually of the jet or spray type in which direct contact is made between turbine exhaust steam and cooling water. This type of cooling is quite efficient and is possible in a geothermal plant because there is no boiler feed requirement and, therefore, there is no need to keep the condensate free from contamination. The natural place for the condenser is immediately below the turbine and the simplest way to provide for the discharge of the water from the vacuum space is a barometric leg which may be about 30 feet high. Such an arrangement is not always possible and is subject to changes to suit local conditions.

The condensers in a binary plant have been of the shell and tube type, which consists of three sections: desuperheater, condenser and subcooler. The working fluid is usually on the shell side, leaving the tube side for cooling water. The heat transfer coefficient of the steam is controlled by the heat transfer coefficient of the condensing vapor and is in the order of about $200 \text{ Btu/hr. ft}^2 \text{ } ^\circ\text{F}$). In some advanced applications, working fluid can be a mixture of two miscible organic substances with different boiling curves. In such cases, the heat transfer coefficient in the shell side of the condenser might be difficult to estimate and, therefore, might require some study.

2.3.5 Cooling System

The cooling system includes cooling water and cooling tower. It is advantageous for geothermal stations to have natural cooling water available nearby. However, it is noted that a geothermal plant is unique in being capable of providing its own make-up for the cooling towers. Hence, the availability of a cold cooling water source does not greatly affect the design of the cooling system. The make-up for a cooling tower is the water rate required to replace the water lost due to evaporation, entrainment, and blowdown in the cooling tower and is usually only a small fraction of the total rate of circulation of the cooling water. This fraction depends mainly on how many cycles of concentration the cooling water can have without causing scaling and corrosion in its flow path. Cooling systems using steam condensate for make-up usually require minimal chemical treatment and can be concentrated to a high degree because the make-up water has been distilled through the evaporation and condensation process and, therefore, is relatively free from dissolved solids. A similar system in a binary plant would require more chemical treatment because the make-up is a part of the geothermal water which has chemical compositions almost unchanged from the reservoir conditions.

Cooling towers for geothermal stations are costly (per KW capacity) and are usually the largest structure at the site. Cooling towers are either natural draft or mechanical draft type. A mechanical draft cooling tower can either have cross-flow or counter-flow between air

and water droplets. It requires a small portion of the generated power to run the air fans and is smaller in size than the natural draft cooling tower of similar thermal load capacity.

2.3.6 Other Components

There are usually small amounts of dissolved gases which accumulate after passing through the turbine in the region between turbine exit and the water level in the barometric condenser. Air can also leak into the condenser since it is under vacuum. The gases must be removed to avoid their building up to the point at which interference with turbine performance occurs. The removal of non-condensable gases is carried out by many types of ejectors: steam ejectors at Wairakei (New Zealand), the Geysers (USA), Matsukawa (Japan), Mexicali and Cerro Prieto (Mexico); water-jet ejectors at Paulzhетка (USSR); rotary exhausters at Wairakei (New Zealand) and Larderello (Italy); and reciprocating pumps at Otake (Japan).⁽¹¹⁾ The principle of operation of these ejectors is to extract, continuously, a fraction of the condensing steam at the condenser, compress and cool it to liquify the steam, and then discharge the non-condensables before returning the water to the flow path.

2.4 Disposal Techniques

The simplest way to dispose of the hot water and the steam condensate is to discharge them into a river or lake close by. This method is no longer acceptable (even if it is allowed by geographical conditions) due to the increasing consciousness of the people about

their environment. There are two possible alternatives: evaporating pond and sub-surface injection.

2.4.1 Evaporating Pond

Water is lost in an evaporating pond through evaporation at the water-air interface and seepage through the ground. The seepage rate per unit pond area can be calculated if the permeabilities of the soil layers forming the pond are known. Water seeping through the soil can travel into the earth far enough to contaminate water aquifers which directly provide water for human consumption. If this happens, the seeping process might have to be stopped or restricted by artificial lining or conditioning of the pond base.

Evaporating ponds are usually very large in surface area but require a relatively small investment. An earth dike of 6 to 10 feet height can be easily built in an area of suitable permeability to make up the pond sides. Factors considered to affect the evaporation performance of the pond are air temperature, relative humidity, wind speed, water temperature, and solar radiation. Items appearing to have only minor effect include heat transfer between the earth and the pond, changing temperature and humidity of the air as it traverses the water, and rain and snow. A method for calculating pond size can be found in Reference 12.

2.4.2 Subsurface Injection

Subsurface injection in the utilization of geothermal energy is a relatively new practice but is an effective method for the disposal

of the spent fluids. Due to concern similar to water seeping from an evaporating pond, the injection of water must be below the aquifer of usable water. In fact, water should be injected into the high temperature zone to recycle the water with the residual heat, after conversion, to the reservoir. This would minimize the possibility of insufficient water for heat extraction even in areas of limited natural recharge, and, possibly at the same time, effect significant conservation of energy.

The subsurface injection rate depends primarily on the local geological conditions, and is very site-specific. The chance of successful injection is similar to that of drilling a producing geothermal well. If subsurface injection is chosen as the disposal method, injection wells have to be drilled and tried out for each facility. Generally, an injection well must be located at a distance (e.g., 1500 m)⁽¹³⁾ from producing wells to avoid short circuiting.

2.5 Summary of Existing Technology

The review presented indicates that the current technology of geothermal-electric production includes three types of conversion plants, namely steam, flash steam, and binary, and is divided into three main areas: extraction, conversion, and disposal. Table 2-2 shows a summary of the state-of-the-art. It can be noticed that steam plant differs from flash steam plant in the area of extraction technology only.

TABLE 2-2

SUMMARY OF THE EXISTING TECHNOLOGY FOR
ELECTRICITY GENERATION FROM GEOTHERMAL RESOURCE

TECHNOLOGICAL COMPONENT	TYPE OF PLANT		
	STEAM	FLASH	BINARY
<u>Extraction Technology</u>			
Well Flow	Steam, Vertical	Two-phase, Vertical	Water, Vertical
Fluid Transport	Steam pipes	Steam pipes Water pipes Separators Flasher	Water pipes, Working fluid pipes
Downhole Pump	----	----	Shaft extended ≈1000 feet into well, electric motor driven*
<u>Conversion Technology</u>			
Cycle	Steam, open	Steam open	Closed, Rankine CCl ₂ F ₂ , Iso-butane /Isopentane
Heat Exchanger	----	----	Shell tube type water/organic
Turbine	Steam, condensing	Steam, condensing	Organic
Largest turbine unit ² rating (site)	106 MW (U.S.A)	55 MW (Philippines)	1.0 MW (Japan)
Condenser	Spray, barometric	Spray, barometric	Forced draft air cooled spray surface
Cooling water	Geothermal or river water	Geothermal or river water	River water
Cooling Tower	Natural or mechanical draft	Natural or mechanical draft	Mechanical draft
Gas Removal	Steam-or water- jet ejector, compressor,	Steam-or water- jet ejector, compressor,	Water seal rotary pump
<u>Disposal Technique</u>			
	Evaporating pond, injection well, river	Twin-drum silencer, evaporating pond, injection well, river	River

* Not in commercial production at this time.

2.6 Costs and Performance Characteristics of Existing Technology

2.6.1 Purpose

The purpose of this section is to examine the present performance characteristics of the components of geothermal power plants and compare them with the theoretical bounds. The basis of the comparison is the capital investment per unit of electricity produced. The theoretical performance characteristics could be regarded as the ultimate objectives for technological improvements. Those ultimate objectives will rarely be achieved. In addition to the present performance characteristics and the theoretically optimal operational characteristics of the geothermal-electric technology, a set of practically possible performance conditions, which represents the state-of-the-art after all the possible improvements have been carried out, is given. The practically possible conditions of the technology will be used in the next section to identify the opportunities and priorities of improvement. It will be noted that some components are currently operating almost at their practical and/or theoretical limits and, therefore, it is unlikely that they can be improved.

The study is basically a comparative assessment of the present and possible future of the geothermal technology. Therefore, it is necessary to perform the analysis on a common ground. To do so, factors which represent site-sensitivity within a particular type of plant must be removed and the plant size must be the same for the three types of plants. The removal of site-sensitive factors will be

stated wherever necessary. The plant size is assumed to be 50 MW_e (net). The analysis consists of the following steps:

- (i) Determination of the baseline plant cost. This is the capital investment and O&M costs with present technology
- (ii) Calculation of the cost reduction resulting from improvements.

2.6.2 Baseline Costs

The estimates of the capital investment in a 50 MW_e (net) plant are listed for the steam, flash steam, and binary plants in Tables 2-3 and 2-4. The method of estimation is similar to those presented in references 10, 14, and 15 for a 50 MW_e (net) plant capacity. It should be noted that although it is based on the existing technology, the cost estimate presented in some areas is still speculative at best. This is because plants of the capacity under consideration (50 MW_e net) do not exist anywhere (e.g., 50 MW_e binary) or, if they do, only partial cost information is available. The well costs are based on the assumptions derived from Table 2-5 (7 wells are required for the steam plant, 11 wells for the flash plant, and about 10 wells for the binary plant). The number of wells required for the binary plant is slightly smaller than that required for a flash plant because some improvement of well flow is expected from the use of a downhole pump. The estimate of this improvement is conservative here. The well cost is \$0.5 million per well*. A similar breakdown is used

* Please see the footnote under Table 2-3.

TABLE 2-3

COMPONENT INSTALLED COSTS FOR 50 MWe (NET) PLANT (1975 \$)

COST ITEM	TYPE OF PLANT					
	STEAM		FLASH		BINARY	
	\$10 ⁶	%	\$10 ⁶	%	\$10 ⁶	%
<u>Conversion</u>						
Heat Exchangers	-----	-----	-----	-----	4.80	12.76
Condenser	1.05	4.16	1.10	3.14	3.22	8.56
Turbine-Generator	4.90	19.41	8.90	25.42	3.94	10.47
Main Feed Pump	-----	-----	-----	-----	2.89	7.68
Cooling Tower	1.30	5.15	1.69	4.83	1.14	3.03
Pumps and Drives	2.2	8.71	2.42	6.91	2.14	5.69
Auxiliary System	0.43	1.70	0.43	1.23	0.93	2.47
Electrical Equip.	1.24	4.91	1.24	3.54	1.24	3.30
Bulk Materials						
Concrete & Earthwork	1.60	6.34	1.70	4.86	1.12	2.98
Electrical	1.60	6.34	1.60	4.57	1.60	4.25
Site Improvement	0.33	1.31	0.33	0.94	0.48	1.28
Building						
Control	0.40	1.58	0.40	1.14	0.58	1.54
Generating set	0.80	3.17	1.30	3.71	0.82	2.18
<u>Extraction</u>						
Well*	3.50	13.86	5.50	15.71	5.00	13.29
Pipe, Insulation & Valves	3.80	15.04	4.18	11.94	4.03	10.71
Separator & Flasher	-----	-----	0.32	0.91	-----	-----
Instrumentation	0.30	1.19	0.40	1.14	0.30	0.80
Downhole Pump	-----	-----	-----	-----	0.50	1.33
<u>Disposal</u>						
Injection Pump	0.30	1.19	0.50	1.43	0.40	1.06
Injection Well*	1.50	5.94	3.00	8.57	2.50	6.65
TOTAL	25.25	100.00	35.01	100.00	37.63	100.00

* Because of competition from the oil and gas industry, well costs have increased twofold or, possibly, threefold in the last couple of years. However since the present cost information is not available, the cost of \$500,000 per well, which was a reasonable estimate in 1975, is assumed. Any deviation arising when cost indices are applied will be absorbed in the contingency.

TABLE 2-4

CAPITAL INVESTMENT FOR 50 MW_e (NET) PLANT (1975 \$)

COST ITEM	STEAM PLANT	FLASH PLANT	BINARY PLANT
Installed (construction) (\$10 ⁶)	25.25	35.01	37.63
Engineering (\$10 ⁶)	1.50	1.99	3.10
	<hr/>	<hr/>	<hr/>
TOTAL (\$10 ⁶)	26.75	37.00	40.73
CONTINGENCY (16%) (\$10 ⁶)	4.35	5.92	6.52
	<hr/>	<hr/>	<hr/>
TOTAL INVESTMENT (\$10 ⁶)	31.10	42.92	47.25
COST IN \$/KW	622	858	945

TABLE 2-5
WELL FLOW RATE AND WELL REQUIREMENT

SITE	REF.	PLANT TYPE	CAPACITY (MW)	NO.* WELLS	FLOWRATE LB/HR
Hatchobaru (Japan)	1	Flash	50	10p,	---
Kakkonda (Japan)	1	Flash	50	14p, 5i.	---
Heber, CA, USA**	25	Flash	50	----	12,000,000
Niland, CA, USA**	25	Flash/ Binary	50	8p,	3,600,000
Geysers #5, USA	26	Steam	53	7p,	---
Geysers #11, USA	26	Steam	106	13p,	---
Geysers, Ave., USA	26	Steam	100	12-14p,	2,000,000

Notes: * p = producing, i = injection

** planned

for the estimation of the injection well costs. Generally one injection well is required for every two producing wells. It is noted that in the disposal section only fluid injection is considered. This is because the use of other methods, such as discharging into a river or an evaporating pond, only delays facing the problem rather than solving it. In examining the data of Table 2-4, the following points are noted:

- (i) Steam plants are cheaper to build than flash and binary plants; and the binary plant is not much more expensive than the flashing plant. This is because steam plants are the simplest in terms of equipment.
- (ii) Wells (including production and injection wells), and turbine-generator are the two most expensive items in the list. Next in line are the heat exchanger and the fluid transport system. Thus any improvement in these areas would show significant effects on the total plant cost.

2.7 The Theoretical and Practical Limits for Capital Cost

The theoretical and practical limits are found by analyzing equations which govern the performance and cost of currently used components. The analysis consider improvements on existing technologies only. It does not take into account the effects of using new technologies. For example, the type of heat exchanger considered is shell-and-tube type; direct-contact heat exchanger, say, is regarded as new technology.

The analysis is performed for dry steam, flash steam, and binary systems and is presented in Appendix A. The results of the analysis are shown in Table 2-6 from which the following conclusions

TABLE 2-6
COST ESTIMATES FOR GEOTHERMAL PLANTS AFTER
THEORETICAL AND PRACTICALLY FEASIBLE IMPROVEMENTS
ON CURRENTLY USED COMPONENTS

(ALL COSTS ARE IN MILLIONS OF 1975 DOLLARS)

COST ITEM	STEAM		FLASH STEAM		BINARY	
	PRAC.	THEO.	PRAC.	THEO.	PRAC.	THEO.
CONVERSION						
Heat Exchanger	-	-	-	-	3.46	2.85
Condenser	1.05	0.90	1.10	0.94	3.06	2.66
Turbine Generator	4.90	3.71	8.90	6.74	3.76	3.31
Main Feed Pump	-	-	-	-	2.74	2.36
Cooling Tower	1.30	0.91	1.69	1.19	1.07	0.89
Pumps and Drives	2.20	2.12	2.42	2.33	2.13	2.11
Auxiliary Equip.	0.43	0.43	0.43	0.43	0.93	0.93
Electrical Equip.	1.24	1.24	1.24	1.24	1.24	1.24
Bulk Materials	3.53	3.53	3.63	3.63	3.10	3.10
Buildings	1.20	1.20	1.70	1.70	1.40	1.40
EXTRACTION						
Well	2.45	1.33	3.85	2.09	3.31	2.02
Pipe, Insulation, Valves,	3.42	2.66	3.76	2.93	4.03	4.03
Separator & Flasher	-	-	0.22	0.16	-	-
Instrumentation	0.30	0.30	0.40	0.40	0.30	0.30
Downhole Pump	-	-	-	-	0.50	0.50
DISPOSAL						
Injection Pump	0.30	0.25	0.50	0.42	0.39	0.35
Injection Well	<u>1.05</u>	<u>0.57</u>	<u>2.10</u>	<u>1.14</u>	<u>1.65</u>	<u>1.01</u>
CONSTRUCTION	23.37	19.15	31.94	25.34	33.07	29.06
ENGINEERING	<u>1.50</u>	<u>1.50</u>	<u>1.99</u>	<u>1.99</u>	<u>3.10</u>	<u>3.10</u>
	24.87	20.65	33.93	27.33	36.17	32.16
CONTINGENCY (16%)	3.98	3.30	5.43	4.37	5.79	5.15
TOTAL	28.85	23.95	39.36	31.70	41.96	37.31
\$/KW	577	479	787	634	839	746
REDUCTION (%)	7.2	23.0	8.3	26.1	11.2	21.0
From Baseline Cost						

NOTE: Detailed calculations are presented in Appendix A.

are drawn:

- Theoretically, improvements on current technology can reduce initial investment by 21 - 26%.
- Practically, the cost reduction is only about 7 - 11%, however,
- The practical limits of cost reduction increases with increasing plant complexity. It is 7.2% for dry steam plant, 8.3% for flash steam plant, and 11.2% for binary plant.

If the cost reductions due to improvements are broken down for each of three systems: Conversion plant, Extraction system, and disposal system, as shown in Table 2-7,

- The practical limits of cost reduction is highest in the disposal system, and lowest in the conversion plant.

2.8 Operating and Maintenance Costs

The operating and maintenance (O&M) costs can be divided into two distinct areas: field, and plant. The field O&M and plant O&M costs will be discussed separately in the following sections and will be summarized in tables which follow.

2.8.1 Field O&M Costs

The field operating and maintenance costs for the geothermal fields have been difficult to document. The reason for this, according to reference 16, is that contracts are currently under negotiation in which the operating companies feel they may forfeit their competitive advantage if their estimated operating costs were made public. However, an attempt will be made to estimate the field O&M costs on the basis of suggestions made by Chevron for the Heber field

TABLE 2-7

**COST REDUCTION OF THE SYSTEMS AS THE RESULTS OF
IMPROVEMENT ON TECHNOLOGY CURRENTLY IN USE (\$ 1975)**

COST ITEM	STEAM	FLASH	BINARY
Conversion Plant			
Present (\$M)	15.85	21.11	24.90
*P.I.L. (\$M)	15.85	21.11	22.89
Cost Reduction (%)	0	0	8.1
Extraction System			
Present (\$M)	7.60	10.40	9.83
P.I.L. (\$M)	6.17	8.23	8.14
Cost Reduction (%)	18.8	20.9	17.2
Disposal System			
Present (\$M)	1.80	3.50	2.90
P.I.L. (\$M)	1.35	2.60	2.04
Cost Reduction (%)	25.0	25.7	29.7
Total Reduction in Construction Cost (%)	7.8	8.8	12.1

Note: *P.I.L. - Practically improved limit, new technologies are not included.

(liquid-dominated reservoir) producing well as follows:

- (i) Each producing well is acidized once per year at the cost of \$10,000.
- (ii) Major remedial well work is done once every four years for each well at a cost of \$80,000.
- (iii) Well life is ten years⁽¹⁷⁾ and a new well is drilled at the cost of \$500,000* (1975 \$, constant) per well.

Injection well maintenance costs are estimated, on a similar basis, as follows:

- (i) Each injection well is stimulated once per year at a cost of \$25,000. (16)
- (ii) Major remedial well work is done once every two years at a cost of \$80,000.(16)
- (iii) Well life is ten years and a new well costs \$500,000 (1975 \$, constant).*

Every abandoned well costs about \$50,000 to plug up. For dry steam producing wells, acidizing is not important and is included in major remedial programs. Annual surface installation maintenance is calculated as a percentage of the initial capital cost. Other field O&M costs are listed in Table 2-8. It can be observed that the total field O&M cost of a steam plant is about 60% of that of the flash and binary plants. This is understandable because a dry steam well is more controllable, and is less prone to scaling than a flashing well or a well with pumped liquid.

* Please see footnote under Table 2-4.

TABLE 2-8

**FIELD OPERATING AND MAINTENANCE COSTS
(\$1975) PER YEAR FOR A 50 MWe (NET) PLANT**

COST ITEM	STEAM PLANT	FLASH PLANT	BINARY PLANT
Producing Well			
Number	7	11	10.5
Acidizing (\$1000)	0	110.0	100.0
Major Remedial (\$1000)	140.0	220.0	200.0
New Well (\$1000)	350.0	550.0	500.0
Abandoned Well (\$1000)	35.0	55.0	50
Injection Well			
Number	3	6	5
Stimulation (\$1000)	75.0	150.0	125.0
Major Remedial (\$1000)	120.0	120.0	100.0
New Well (\$1000)	150.0	300.0	250.0
Abandoned Well (\$1000)	15.0	30.0	25.0
Well Head Maintenance			
Percentage of Capital Costs (\$1000)	2% 88.0	2% 108.0	4% 209.0
Down-hole Survey (\$1000)	1.0	1.0	1.0
TOTAL (\$1000)	974.0	1,644.0	1,560.0

Note: The O&M Cost for wells increases with time because the number of wells is increased to compensate for the well flow reduction. However it is assumed to be constant at an average value here.

2.8.2 Plant O&M Costs

The plant O&M costs are easier to estimate because the items involved are readily identifiable. The estimates of plant O&M costs for a 50 MW_e (net) plant are shown in Table 2-9.

2.8.3 Total O&M and Electricity Costs

The total O&M cost is the sum of field O&M and the plant O&M costs. The interest charge is assumed to be 13%,⁽¹⁸⁾ which is slightly higher than the normal rate and reflects the relatively higher investment risks associated with the geothermal industry. The capacity factor varies from plant to plant and is currently between 70-90%.⁽²⁾ A value of 80% is assumed in this analysis. The O&M and initial investment charges are listed in Table 2-10.

2.9 O&M Cost Improvement

The O&M costs, as discussed in the previous section, include the field O&M costs and the plant O&M costs. Generally, O&M costs of a power plant depend on four main factors:

- (i) The larger the plant, the more costly it is to operate and maintain. However, for a larger plant, where the labor force and other services are distributed more efficiently, the O&M costs per unit electricity produced are lower.
- (ii) Plant capacity factor. A high capacity factor means reliable operation and high plant productivity. Thus O&M costs per unit of electricity output generally decrease with increasing capacity factor.
- (iii) Operating procedure and operations management. This factor involves interactions between technical and management skills. Well organized operating procedures invariably reduce O&M costs, and good operations management generally increases plant capacity factor which also reduces the O&M costs.

TABLE 2-9

PLANT O&M COSTS OF A 50 MW_e (NET) PLANT (1975 \$) PER YEAR

COST ITEM	STEAM PLANT	FLASH PLANT	BINARY PLANT
Direct Labor			
Resident Management	\$ 27,500	\$ 27,500	\$ 27,500
Engineers	75,000	75,000	100,000
Main Office Support	9,000	9,000	9,000
Reports	30,000	45,000	60,000
Labor	120,000	320,000	420,000
	<u>\$261,500</u>	<u>\$ 476,500</u>	<u>\$ 616,500</u>
Indirect @ 80% (ave.)	\$209,200	\$ 381,200	\$ 493,200
Material & supplies	80,000	155,000	200,000
Travel Expense	50,000	75,000	75,000
Cooling Water and Treatment	50,000	50,000	160,000
	<u></u>	<u></u>	<u></u>
Subtotal	\$650,700	\$1,137,700	\$1,534,700
A & G @ 2%	\$ 13,000	\$ 22,800	\$ 30,700
TOTAL	\$663,700	\$1,160,500	\$1,565,400

TABLE 2-10

O&M AND ELECTRICITY COSTS (1975 \$) OF A 50 MW_e
 (NET) PLANT, CAPACITY FACTOR 0.80 (I.E., 3.504×10^8 KWH/YEAR)

ITEM	STEAM PLANT	FLASH PLANT	BINARY PLANT
Field O&M (\$1000)	974.0	1,644.0	1,560.0
Plant O&M (\$1000)	<u>650.7</u>	<u>1,137.7</u>	<u>1,534.7</u>
TOTAL	1,624.7	2,781.7	3,094.7
O&M Cost (mills/Kwh)	4.64	7.94	8.83
Capital Charge @ 13%* (mills/kwh)	11.54	15.92	17.53
Total Electricity Cost (mills/kwh)	16.18	23.86	26.36

* Capital investments are listed in Table 2-4.

- (iv) In geothermal applications, in addition to the above factors, the brine chemical and physical properties also play an important role in the O&M costs of a power plant. This factor is so important in geothermal applications that it should deserve separate treatment.

Thus, to reduce the O&M costs of a geothermal plant of a certain size, all four factors mentioned above must be considered.

In the preceding sections, the need and the potential for reducing the capital costs of geothermal power plants were discussed. Although considerable emphasis has been placed on the need to reduce the installed costs of a component or the entire system as much as possible, the impact of such reductions on the operating and maintenance (O&M) costs must also be considered explicitly. In some cases, the capital expenditure may be increased deliberately (more expensive materials, over design, etc.) to reduce the O&M costs by an amount exceeding the increase in the capital costs*. Since the O&M costs in a geothermal power production site can be a significant part of the total cost of power**, it is essential to make estimates of the O&M costs associated with individual components, and then consider the possibility of reducing these costs through improved technology and/or operating procedures. Operating procedures can be modified without affecting the capital costs of the plant or the components.

* In some cases, the O&M costs increase when the capital cost decreases (e.g., APEX heat exchanger, a proposal submitted to DOE/DGE by Aerojet Liquid Rocket Company).

** O&M costs make up about 25 to 35% of total production costs, (Table 2-10).

The O&M costs are related more closely to the amount of power generated, than to the installed capacity of the plant. Consequently, it is extremely important to make realistic estimates of the O&M costs and emphasize the sensitivity of the cost of geothermal power to variations in these costs.

It is expected that the estimates of O&M costs will get refined as more operating experience is gained. Nevertheless, the O&M costs should be estimated, as accurately as possible, and should be considered explicitly in formulating the R&D program for heat exchangers and energy conversion systems.

Geothermal fluid behavior depends on the fluid chemical properties and is, therefore, very site-sensitive. Since it is one of the major factors in the O&M costs, the effects of component improvement on the O&M cost are, among other factors, also site-sensitive. Thus, the analysis of O&M costs reduction resulting from technological improvements is very complex and is beyond the scope of this report.

2.10 Opportunities for Improvement

2.10.1 Strategic Considerations

The preceding sub-sections of this report provide (i) an overview of the current state-of-the-art in Geothermal Utilization Technology and (ii) an indication of the cost and technical performance characteristics of the available technology. This subsection presents a list of opportunities for improvement of the Utilization Technology, which, including new technologies, appear to be realistic in terms of

the associated technical objectives.

The total cost of geothermal power (electricity) is composed of the plant cost (energy transfer and conversion system cost) and the fuel costs (the cost of geothermal fluid - costs of reservoir lease, exploration, drilling, well completion, etc.). The ideal objective would be to have a high utilization efficiency (actual work extracted from the fluid divided by the total available heat energy in the fluid). The practical objective is to minimize the cost per unit of electricity, and, as shown in Figure 2-5, the minimum cost per unit of electricity is not always associated with the highest utilization efficiency. (19)

Therefore, the opportunities for the improvement of the utilization technology should be based on a good compromise between the plant costs and the fuel costs. As shown in Figure 2-5, the utilization efficiency for the minimum cost per unit of electricity (point M) is generally below the maximum utilization efficiency.

2.10.2 Opportunities for Improvement

The discussion which follows, concentrates on the fluid extraction, heat conversion and hot water disposal technologies.

(a) Extraction Technology

The extraction technology includes well flow and fluid transport. The costs of these elements represent the fuel cost of the geothermal-electric system. This cost is reduced by increasing the flow per well and reducing the cost of the fluid gathering pipelines. The well flow can be increased by (i) well stimulation which makes the

$$\text{UTILIZATION EFFICIENCY, } \eta_u = \frac{\text{WORK OUTPUT}}{\text{WORK AVAILABILITY}}$$

Assumptions: Fixed Plant Capacity .
 Fuel Cost = Constant x Brine Flow Rate.
 Constant Resource and Sink Temperatures.
 Constant Component Life Spans.

Source: C.B. McFarland, "Approved Minutes of The Third Meeting of The Centers for The Analysis of Thermal-Mechanical Energy Conversion Concepts", Brown University, November 4, 1976.

FIGURE 2-5
COST OF USEFUL ENERGY CONVERTED FROM A GEOTHERMAL RESOURCE

fluid more readily available at the well bottom; (ii) increasing the diameter of the upper portion(s) of the well to accommodate the expansion of the flashing fluid from liquid-dominated resources; or (iii) pumping the fluid with either downhole pump or inert gases. It has been shown that a two-fold increase in well flow rate is possible in a stepped diameter well whose diameter is doubled above the flash level. (20)

The costs of the fluid gathering pipeline systems might be reduced by the use of two-phase transport system in which a single pipeline replaces the hot water system and the steam system in a flash steam plant.

(b) Conversion Technology

The areas of possible improvement are conversion cycle, heat exchanger, prime mover, condenser and cooling system.

The currently used conversion cycles have low efficiency and, there is a potential for improving these cycles. Cycle improvement generally involves the use of more advanced components such as direct contact heat exchangers in binary plant, total flow turbine in the total flow cycle, air cooled condenser, etc. Since there are more components in the conversion system than in the extraction system, the opportunities for improvement are more numerous in the conversion system, although not all of them are realistic.

(c) Disposal Techniques

As mentioned earlier, the only feasible disposal technique with long-term acceptability is subsurface injection. Other methods of

disposal such as evaporating pond, and river discharge only delay facing the problems. Current state-of-the-art assumes that for every two producing wells, one injection well is needed. This is obviously expensive for waste disposal and, therefore, improvement in the injection rate is definitely needed. An injection well can be improved by increasing its subsurface permeability.

The opportunities for improvement are summarized in Table 2-11. This table also includes the anticipated targets of improvement and the R&D needed for achieving these improvements.

2.10.3 Opportunities for Improvement and RD&D Program

On the basis of a review of the current state-of-the-art and the available information concerning the cost and performance characteristics of the components of geothermal energy utilization systems, realistic practical targets for RD&D have been identified. As shown in Figure 2-6, a well-planned RD&D program is designed to close the gap between the current state-of-the-art and the practical targets for improved technology*. This will be accomplished through a set of RD&D activities defined by the sequence, schedule and costs associated with them.

It may be noted that an RD&D program is a dynamic entity that must be responsive to the changing goals of the DGE which could

* If the resources for RD&D (manpower, funds, time) were unlimited, the technical targets for RD&D would be easier to achieve. One of the most difficult tasks in planning an RD&D program is the matching of scarce resources for RD&D with realistic targets for improvements.

TABLE 2-11
OPPORTUNITIES FOR IMPROVEMENT

PROGRAM SUBAREA / TECHNOLOGY	OBJECTIVES*	REQUIRED R&D	COMMENTS
EXTRACTION			
1. Well Flow	To increase well flow rate by 10-100% ⁽¹⁾ and reduce O&M cost by 10%	a. Well stimulation b. Two-phase vertical flow and changes of flow area c. Downhole pump d. Gas lift and intermittent gas pump	Advantageous only when choking has not been reached. Scaling problems on well walls and difficulties in determining flash level are anticipated. Testing is needed, high O&M costs are anticipated. Good for corrosive environment but has limits on flow rate.
2. Fluid Transport	To reduce capital cost by up to 20% and O&M costs by up to 10%	a. Two-phase transmission b. Flashers and separator design	This may not yield more energy than double flash ⁽²⁾ but will reduce pipe and equipment costs. Possible vibration problems. Design for higher separation efficiency and reduce erosion problems.
CONVERSION			
1. Conversion cycle	To increase thermal efficiency by up to 30% ⁽³⁾	Cycle and thermodynamic studies	Assessment of many innovative concepts against hardware performance limits is needed.
2. Heat exchanger • Sensible • Heat Exchanger • Boiler	To reduce capital by up to 50% ⁽⁴⁾ and O&M costs by up to 20% ⁽⁵⁾ To reduce capital cost by up to 50% ⁽⁶⁾ and O&M costs by up to 10% ⁽⁷⁾	a. Direct contact system b. Fluidized bed system c. Self cleaning shell-tube system (fluted)	Possible problems of foaming working fluid (O&M and environmental) in the rejected primary fluid. Design problems need to be overcome. Testing is needed, possible mechanical problems in the self cleaning mechanisms.
3. Prime Mover	To reduce capital cost by 15% and increase efficiency by 5%	a. Organic turbine b. Other non-conventional steam expanders	For binary plant. Engineering problems (Design, O&M) are anticipated.
4. Condenser	To reduce capital cost by up to 50% ⁽⁷⁾ and O&M costs by up to 10%	a. Tube materials for better film coefficient b. Contact condenser c. Air-cooled condenser	To increase film condensation. Advantageous for binary system. Bulky and high cost, but might solve water shortage problems. Better uses of water. Same as in "condenser".
5. Cooling System • Cooling Water • Heat Rejection System	To reduce O&M costs by up to 10% and minimize the need for cooling water To reduce cooling water consumption	a. Systems study and optimization b. Air-cooled system a. Evaporative air-cooled condenser	Need testing and economic assessment.
DISPOSAL			
Injection Well	To increase injection rate by 20% and well life by 50%	a. Well stimulation b. Maintenance techniques	To increase permeability. Environmental problems might arise.

Notes: *The percentages are based on the component in consideration (not the system) and are estimated from the available information.

(1)- Reference 20 (3)- Total flow system, rotary separator (5)- For self-cleaning system (7)- For contact condenser in the library system
(2)- Reference 26 (4)- For the direct contact preheater (6)- For direct contact boiler

FIGURE 2-6
CONCEPTUAL STRUCTURE OF RD&D PROGRAM PLANNING

alter the practical targets for improvement. It is also evident that the applicability of the products of RD&D to the resources scheduled to be developed over the next 20 years should be a major determinant of the relative emphasis on various RD&D activities. The rationale for the existing RD&D program, and any future programs, should recognize the interaction between the opportunities for improvement, and the relevance of these improvements to the national goals for the development of geothermal power.

2.11 Conclusions

The review of the state-of-the-art in the extraction and energy conversion area reveals that there are significant variations in the cost and performance characteristics of the components of geothermal power plants, mainly due to diverse site specific factors. This, coupled with a lack of adequate practical experience in the construction and operation of geothermal power plants, is the prime reason for the non-existence of a reliable data base for the capital and O&M costs of geothermal power plants.

It appears that there are no insurmountable technical problems (go/no-go situations) associated with the conversion of geothermal energy into mechanical or electrical energy. Nevertheless, it is apparent that significant improvements in the cost and performance

characteristics of geothermal power plants are essential for sustaining the rate of growth of geothermal industry at a pace consistent with the national goals for geothermal power-on-line.

The following is a list of the significant conclusions which emerged from the review of the state-of-the-art.

- Geothermal energy conversion systems utilize technology which has been applied for power generation in conventional thermal and nuclear fueled power plants.
- It would be unrealistic to expect substantial improvements in the energy conversion efficiencies associated with the dry steam and flashing units (this is due to the fact that the conversion efficiencies in conventional thermal plants are already near the practical upper bound).
- The binary system may account for a sizable part of the total power generation capacity in the future; such units will be needed for exploiting the moderate temperature and/or high salinity resources; innovations in heat exchange technology, and in the design of prime movers and power cycles could render binary systems competitive with alternative systems for power generation.
- Since the cost of fuel is generally a major element of the total cost of power in the case of moderate temperature resources, the need for (1) reducing the cost of production wells (by improved drilling techniques and well completion methods) and (2) increasing the well flow rate (by reservoir stimulation and well pumping) must be emphasized; improvements in extraction technology can result in significant reductions in cost of geothermal power.
- The temperature differential between the source and the sink in the geothermal power cycle is an important factor in the efficiency of energy conversion; the concept of floating condensing temperature could be utilized effectively to increase the energy conversion efficiency.
- Disposal technologies represent program segments with potential for significant improvements; the disposal

of the spent geothermal fluid represents problems which are not encountered in conventional thermal power plants; injection of these fluids appears to be the most logical solution, because it circumvents many environmental problems (i.e., land use, impact on natural bodies of water, seepage, non-condensable gases, etc.), and also results in the recycling of the resource in an efficient manner.

In general, there are two possible approaches to the target of improving the extraction and energy conversion technology in geothermal power systems, these are (1) improvement of existing technology; and (2) development of new technology. Table 2-12 gives an indication of the feasible options with regard to the major elements of the geothermal power plants. As stated earlier, potential improvements in existing technology are likely to be minimal in some cases (e.g., turbine-generator in steam or flash cycle). In such cases, development of new concepts for the design of power cycles (hybrid steam-binary cycle, or combined binary (binary-binary)) may yield better results than efforts aimed at improving the conventional steam cycle.

TABLE 2-12

OPTIONS FOR IMPROVING GEOTHERMAL ENERGY CONVERSION SYSTEMS

OPTION SYSTEM ELEMENT	IMPROVE EXISTING TECHNOLOGY	DEVELOP NEW TECHNOLOGY
Heat exchangers	X	X
Condensers		X
Turbine	X	X
Heat Rejection		X
System/Cycle Design	X	X
Well Flow (Extraction)	X	X
Gathering Lines	X	
Injection Wells	X	
Pumps	X	X

3.0 DESCRIPTION OF THE CURRENT DGE PROGRAM FOR EXTRACTION AND CONVERSION TECHNOLOGY

The Utilization Branch, which is responsible for the RD&D Program for the utilization of geothermal resources for generating electricity, has split the total program into three technological areas. These are: Well Drilling and Completion, Extraction and Conversion Technology; and Geochemical and Materials Engineering. This section provides a brief description of the Extraction and Conversion Technology Program.

3.1 RD&D Projects in Extraction and Conversion Technology Program

Four subareas can be identified in the program of Extraction and Conversion Technology. They are: (i) Reservoir Stimulation; (ii) Extraction Technology Improvement; (iii) Advanced Heat Exchangers; and (iv) Advanced Conversion Systems. The number of active R&D projects in these subareas ranges from a low of 4 in the Extraction Technology Improvement subarea to a high of 12 in the Advanced Conversion Systems subarea. In terms of the obligated funds for FY78, the obligations range from \$505,000 for the Extraction Technology Improvement subarea to \$7,204,000 for the Advanced Energy Conversion Systems. A breakdown of the Extraction and Conversion Technology Program into subareas is shown in Table 3-1. The current activities in each of these subareas are described in the following sections.

3.1.1 Reservoir Stimulation

This part of the program concentrates on the potential and techniques for the enhancement of the producibility of hydrothermal

TABLE 3-1

COMPOSITION OF THE EXTRACTION AND CONVERSION
TECHNOLOGY PROGRAM - FY 1978

SUB PROGRAM	NUMBER OF PROJECTS	FUNDS	
		(\$1000)	%
Reservoir Stimulation	6	1,065	9.0
Extraction Technology Improvement	4	505	4.3
Advanced Heat Exchangers	6	3,120	26.2
Advanced Conversion Systems	12	7,204	60.5
TOTAL	28	11,894	100.0

reservoirs. Since the cost of geothermal heat is a major element of the total cost of geothermal power, significant reductions in geothermal power cost could be achieved by increasing the flow rates of geothermal wells.

The National Laboratories and private industry will be actively involved in this program. Activities such as the development of formation fracturing techniques and the measurement of the physical, mechanical and thermophysical behavior of the geothermal formations are in progress. These activities are closely coordinated with the hot dry rock stimulation program. A PRDA* pertaining to the technological transfer of the existing well stimulation hardware and experience in oil and gas industry to geothermal industry, with emphasis on the stimulation of hot-water dominated hydrothermal resources, has been announced. The contractor for this project will initiate technical work by mid 1978, and complete the first experiment within one year. This project is expected to lead to the development of reservoir stimulation methods of proven effectiveness by early 1980's. LASL is playing the lead role in this program subarea.

Descriptions of the objectives, activities and rationale for individual projects are presented in Appendix B. Table 3-2 presents a summary of the data pertaining to each of the six projects in the reservoir stimulation R&D program.

* Program Research and Development Announcement.

TABLE 3.2
R&D PROJECTS IN THE AREA OF RESERVOIR STIMULATION

NITRE CODE (1)	TITLE (CONTRACTOR/SUBCONTRACTOR) (LINE ITEM #)	PROJECT OBJECTIVE AND DESCRIPTION	CONTRACTOR'S ESTIMATED BENEFITS	MILESTONE	OPERATING FUNDS (\$ 1000) (2)				TOTAL FUND (\$1000) FROM FY78 (3)	COMPLETION DATE (3)
					PRIOR FY77	FY77	FY78	FY79		
2101	Stimulation Review (LASL) (19002, 10011)	To provide a scientific advisor to the DOE/DCE funded geothermal stimulation program and to coordi- nate hydrothermal/hot dry rock stimulation activities	Expertise in hot dry rock and oil and gas stimulation	Plan to implement a contin- uing stim- ulation program	34	15	150	0	150	Included in 2105
2102	Geothermal Rock Mechanics (Terra Tek) (31103) (311004, 311006, 311007)	To study thermophysical behav- iors of geothermal reservoir rocks and to provide supporting data for the improvement of drilling technology, log inter- pretation, reservoir stimulation	Supporting information	FY78: site characte- rization FY79: Measurement FY80: Frac- turing fluid and documen- tation	0	315	440	500	2000	FY81
2103	Liquid Explosive (Roc- ket Engineering) (31901, 319001)	To develop a high temperature stable pumpable explosive suitable for geothermal well stimulation. Detonability and sensitivity tests of candidate explosives are evaluated to- gether with necessary field support equipment and explo- sive emplacement techniques.	Increase well production	Mid FY79: Completion A suitable explosive has been identified		207	200	300	1500	FY80
2104	Seismic Sensor Response Analysis (N-Tech Labora- tory) (39801) (398001)	To analyze transducer-rock interaction in Fenton-Hill shear wave shadowing experiments so that accurate and reliable predictions of hot dry rock fracture geometry are possible	Better Pre- diction of fluid filled fracture sys- tem geometry	1st half of FY78: completed	0	0	10	0	10	FY78
2105	Reservoir Stimulation-PRDA, (?) (950005) (95005)	To utilize existing hardware and experience in oil and gas well stimulation treatments in geo- thermal industry with emphasis directed toward stimulation of hot-water dominated hydrothermal systems. Phase one includes the development of required specia- lized geothermal hardware, sti- mulation treatment designs, and data analysis interpretation from existing well stimulation treatment. Phase two includes site-specific and field-specific field demonstration experiments.	Availability of reservoir stimulation methods of proven effec- tiveness by early 1980's.	Mid'78: technical work initi- ated. First experiment completed within one year after initiation	0	0	250	2300	10,000	FY85
2106	Technical Consultant at Idaho (?) (950096)	Not available.	Not available	Not available	0	0	15	0	15	FY78
TOTAL					34	537	1065	3100	13,775	

1 First character indicates program (2 indicates Extraction and Conversion Technology), the second character indicates subprogram (1: Reservoir Stimulation
2: Extraction technology,...), the last two characters are project number.

2 The fundings are taken from (1) "Geothermal Energy, Current Year Financial Procurement Plan - Operating Funds", Computer printout R-1508315-007, April
13, 1978, where FY77 plus prior years costs and FY78 planned costs are given; and (11) "Geothermal Energy, Budget and Planning Detail - Operating Funds",
Computer Printout R-1508300-001, December 7, 1977, where FY77 costs and FY79 planned costs are listed.

3 Estimated.

3.1.2 Extraction Technology Improvement

This segment of the program is focused on technology for increasing the productivity of geothermal wells through the utilization of deepwell pumps and other innovative methods. To prevent the deposition of solids in the well bore and the subsequent plugging of the well bore, projects involving gas lift technology are underway. Studies concerning two phase flow in geothermal energy systems are also in progress. These projects are aimed at developing analytical techniques for making accurate predictions of the geofluid flow rate and well-bore pressure drop in self-flowing wells under specific reservoir conditions. A better understanding of two phase flow will enable the field and plant designers to optimize the field development strategy and prepare optimum designs for well casing and the fluid gathering systems.

Table 3.3 presents a summary of the particulars of the projects related to the improvement of extraction technology. The objectives, activity description and the rationale associated with each of these projects are presented in greater detail in Appendix B.

3.1.3 Advanced Heat Exchangers

In order to use geothermal fluid, which is not suitable for a flashing cycle (due to a relatively low temperature and/or high content of solids and non-condensable gases), an organic binary working fluid is utilized for driving the turbine. The exchange of heat between the geothermal fluid and the binary working fluid before

TABLE 3.3
R&D PROJECTS IN THE AREA OF EXTRACTION TECHNOLOGY IMPROVEMENT

MITRE CODE (1)	TITLE (CONTRACTOR/SUBCONTRACTOR) (LINE ITEM #)	PROJECT OBJECTIVE AND DESCRIPTION	CONTRACTOR'S ESTIMATED BENEFITS	MILESTONE	OPERATING FUNDS (\$ 1000) (2)				TOTAL FUND (\$1000) FROM FY78 (3)	COMPLETION DATE (5)
					PRIOR FY77	FY77	FY78	FY79		
2201	National Committee on Rock Mechanics (NAS/NRC) (207001, 378001)	This is a subsidy to the National Academy of Science to maintain a strong national capability in rock mechanics and to insure DOE/DGE is included in policy formulation	Strong national program	Continuing activity	0	15	30	30	240	FY85
2202	Thermal Downhole Pump (Sperry Res. Center) (309002)	Not available.	Not available	Not available	922	336	0	0	0	FY77
2203	Electric Downhole Pump (Lear Jet Motors) (316001)	Not available	Not available	Not available	12	89	0	0	0	FY77
2204	Pump Test Fixture (4) (Barber-Nichols) (335001)	Not available	Not available	Ended 6/78, operation costs cont.	207	55	75	100	175	FY79
2205	Gas Lift Technology (Rogers Engineering) (409001)	To demonstrate the feasibility of CO ₂ gas lift technology to enhance geothermal fluid production and control the well bore chemistry to prevent calcite deposition and borehole plugging. Field test will be conducted.	Eliminate well plugging while increasing production rate	8/78: field testing, 12/78: data and report completed	0	0	200	350	550	FY79
2206	Two Phase Flow in Geothermal Energy System (Denver Research Institute) (704001)	To predict accurately the geofluid flow rate and well bore pressure drop of self flowing wells under specified reservoir conditions. To optimize field development strategy and well casing size selection.	(Optimum) well design manual revised annually	Handbook has been drafted. 3-5 well flow tests per fiscal year are planned	0	409	200	170	970	FY81
TOTAL					1141	904	505	650	1935	

1 First character indicates program (2 indicates Extraction and Conversion Technology), the second character indicates subprogram (1: Reservoir Stimulation 2: Extraction Technology,...), the last two characters are project number.

2 The fundings are taken from (i) "Geothermal Energy, Current Year Financial Procurement Plan - Operating Funds", Computer printout R-1508315-007, April 13, 1978, where FY77 plus prior years costs and FY78 planned costs are given; and (ii) "Geothermal Energy, Budget and Planning Detail - Operating Funds", Computer Printout R-1508300-001, December 7, 1977, where FY77 costs and FY79 planned costs are listed.

3 Estimated.

4 Under different program.

turbine inlet, and between the working fluid leaving the turbine and the condenser cooling water is one of the essential elements of the geothermal power cycle. Considerable RD&D activity is needed for making the heat exchangers cost-effective and reliable. On the condenser side, the emphasis is on reducing the capital cost of the heat exchanger and minimizing the need for cooling water.

The Advanced Heat Exchanger Subprogram consists of six projects dealing with various aspects of heat exchanger design and operation. These projects address problems associated with direct contact heat exchange, fouling of the heat exchanger tubes, and the design and selection of materials. The Oak Ridge National Laboratory is trying to develop an advanced heat exchanger for use in binary power cycles. The Aerojet Energy Conversion Company is going to field test its design of a self-cleaning heat exchanger suitable for use in high salinity binary plant (APEX-Advanced Geothermal Primary Heat Exchanger). The National Bureau of Standards is studying the properties of binary working fluids with the objective of improving the design of direct contact heat exchangers. Direct contact heat exchange research involving development of heat transfer coefficients and design criteria for direct contact boiler, preheater and condenser is now in progress at INEL and University of Utah.

The Direct Contact Binary Demonstration Program is a joint effort of Lawrence Berkeley Laboratory, Ben Holt, DSS Engineers and Occidental

Research. This effort will culminate in a demonstration of the ability of reliable field operation of direct contact heat exchangers at East Mesa and Raft River test facilities.

Table 3.4 shows the significant particulars of the RD&D projects relevant to advanced heat exchangers. More detailed project descriptions are presented in Appendix B.

3.1.4 Advanced Conversion Systems

The fourth and the largest segment of the Extraction and Conversion Technology program deals with advanced conversion systems. There are 16 projects in this subarea (12 of these projects are active in FY 1978). The objectives of these projects are to analyze, test and demonstrate the ability of those cycles which can increase the efficiency of conversion of the geothermal heat into mechanical energy, with minimum increase in the cost of the power plant.

To assist engineers and designers in becoming familiar with the state-of-the art in the area of energy conversion systems, a "Geothermal Power Handbook" is being prepared jointly by Brown University, University of Oklahoma, University of Utah, INEL, NASA, and JPL. A test and demonstration of a shell-and-tube binary heat exchanger is being conducted in the Imperial Valley. An industry coupled field test for demonstrating the thermodynamic and economic benefits of a binary system utilizing downhole heat exchange and a gravity head fluid pump has been initiated.

TABLE 3.4
R&D PROJECTS IN THE AREA OF ADVANCED HEAT EXCHANGER

MITRE CODE (1)	TITLE (CONTRACTOR/SUBCONTRACTOR) (LINE ITEM #)	PROJECT OBJECTIVE AND DESCRIPTION	CONTRACTOR'S ESTIMATED BENEFITS	MILESTONE	OPERATING FUNDS (\$ 1000) ⁽²⁾				TOTAL FUND (\$1000) FROM FY78 (3)	COMPLETION DATE (3)
					PRIOR FY77	FY77	FY78	FY79		
2301	Transport and Conversion of heat at moderate temperature (ORNL), (104003)	To develop advanced heat exchangers for use in geothermal binary power cycles with current emphasis on working fluid condenser (Fluted tubes and/or drain-off skirts)	Organic HT, Coefficient increases 3-7 times	7/78: Condenser tests start at East Mesa	527	245	400	500	900	FY 79
2302	Direct Contact Research (INEL/Univ. Utah), (106001, 715006, 715001)	To develop the heat transfer correlations and design criteria for direct contact boiler, preheater and condenser with current emphasis on experimental study of direct contact condenser	Reduce pinch pt. and cost, eliminate scaling problem	5/78: Complete expt. 9/78: Test of 0.5MW condenser	808	300	100	400	900	FY 81
2303	Liquid Fluidized Dense Bed Heat Exchanger (INEL) (106026)	To demonstrate via the measurement of heat transfer coefficient and cost analysis the feasibility of the fluidized bed heat exchanger (preheater, boiler, and condenser)	30% in heat exchanger capital	7/78: Erosion, corrosion, flow, HT, cost	0	0	100	450	1550	FY 81
2304	Direct Contact Binary Demonstration Program (LBL/Ben Holt, DSS, Occidental), (107005, 107027, 107028, 107031, 107034, 302001, 303001, 305000)	(1) Binary fluid experiment: To provide accurate HT data of organic working fluid. (2) To develop, document and make available a computer model (GEOTHM) for energy conversion processes and power plant design. (3) To demonstrate at East Mesa and Raft River fields the reliability of direct contact heat exchangers (DSS Engineers) and 0.5 MWe organic turbine (Barber Nichols) systems.	Demonstrate the feasibility of direct contact technology	FY78: Experiment and design FY79: Testing FY80: Complete	847	1105	2150	1800	3950	FY 80
2305	Properties of Working Fluids (NBS), (204002)	To measure the equation-of-state properties of isobutane and Freon 114 over the geothermal typical ranges of operating conditions. To support the Direct Contact Heat Exchange and Sperry Thermal Pump Programs.	Supporting Information	9/78: isobutane data	0	0	70	70	240	FY 80
2306	Advanced Geothermal Primary Heat Exchanger, APEX (Aerojet Energy Conversion Co) (300001) (300004)	To develop and design for field testing a self-cleaning heat exchanger for use in high salinity binary plant. Sand is used to reduce scaling.	Tube side fouling factor of 0.0005	FY78: Exp. FY79: Prototype FY80: Testing compl.	24	253	300	100	1200	FY 81
TOTAL					2206	1903	3120	3320	8740	

1 First character indicates program (2 indicates Extraction and Conversion Technology). the second character indicates subprogram (1: Reservoir Stimulation 2: Extraction Technology,...), the last two characters are project number.

2 The fundings are taken from (1) "Geothermal Energy, Current Year Financial Procurement Plan - Operating Funds", Computer printout R-1508315-007, April 13, 1978, where FY77 plus prior years costs and FY78 planned costs are given; and (11) "Geothermal Energy, Budget and Planning Detail - Operating Funds", Computer Printout R-1508300-001, December 7, 1977, where FY77 costs and FY79 planned costs are listed.

3 Estimated.

A well head geothermal rotary separator is being tested. This design could save some of the power loss normally encountered in a conventional flasher. A field test of a helical screw expander (1.0 MW_e capacity) is being conducted. To prove the economic feasibility of base load power production with a small flash steam generator, the University of Hawaii is developing a 5-10 MW_e steam generator for well head operation. This unit could also be used for long-term reservoir testing. The City of Burbank, California is conducting an analysis of the hybrid geothermal/fossil power plant. This effort is aimed at a determination of the economic and energy conservation benefits of a hybrid geothermal/fossil power plant. INEL is undertaking a program for demonstrating the economic potential of low temperature geothermal resource at the Raft River facility.

Table 3.5 presents a summary of the data relevant to the RD&D projects in this subarea. Detailed project descriptions are provided in Appendix B.

3.2 Overview of the RD&D Program

Projects in an ongoing RD&D program can generally be classified, at a point in time, into three types depending on the nature of the projects or how far along the course of development they are. Projects which are exploratory and involve conceptual studies and collection of technical data through literature research or laboratory testing belong to the "Technical Data Acquisition" category. The other categories are "Hardware Development" and "Supporting Activities".

Projects which belong to the hardware development category are usually small in number and involve high costs per project. They involve hardware and concepts which have been proven technically and economically feasible and are selected for possible commercialization. Activities in the hardware development type of projects involve pilot scale studies and/or commercial scale testing and demonstration. "Supporting Activities" type projects do not contribute directly to the development of the hardware, but assist the researchers in selecting alternatives and monitoring the progress and relevance of their efforts. A design handbook for geothermal engineers, and a computer model for simulating the thermodynamic cycle for a reservoir are examples of the outputs of supporting activities.

In terms of the expected benefits and the probability of success, the exploratory projects are quite different from those belonging to the hardware development and supporting activities categories. It may not be possible to identify impacts of exploratory projects on the geothermal industry. Therefore, the common definition of the benefits of an R&D project (i.e., savings for the industry) is not applicable to exploratory projects. Nevertheless, each exploratory project should be clearly associated with a plan which leads to the commercialization of the concept (if the concept gets through the exploratory stage and its subsequent hardware development is successful).

Any R&D program in an early stage of maturity is likely to have a large number of ongoing exploratory projects, and, as mentioned

TABLE 3.5
R&D PROJECTS IN THE AREA OF ADVANCED CONVERSION SYSTEMS

MITRE CODE (1)	TITLE (CONTRACTOR/SUBCONTRACTOR) (LINE ITEM #)	PROJECT OBJECTIVE AND DESCRIPTION	CONTRACTOR'S ESTIMATED BENEFITS	MILESTONE	OPERATING FUNDS (\$ 1000) (2)				TOTAL FUND (\$1000) FROM FY78 (3)	COMPLETION DATE (3)
					PRIOR FY77	FY77	FY78	FY79		
2401	Advanced Conversion Studies (Weidinger Associates) (327001, 327002, 327004)	To develop theoretical basis for evaluating concepts related to the utilization of geother- mal resources. This is to assist the DOE in its decision to support R&D work.	Management benefits	12 months initially	0	10	30	30	60	FY79
2402	Geothermal Power Handbook (Brown Univ./Ok. Univ., Utah Univ., INEL, NASA (JPL) (712001, 712002, 712004, 719001, 201006, 201008, 106024)	To provide, in sourcebook form, an authoritative, complete and current compilation of geo- thermal power plant and energy conversion information includ- ing details of existing facilities	Information Exchange	FY78: draft FY79: completed Update yearly.	307	343	465	200	665	FY79
2403	Hybrid Geothermal/Fossil Power Plant (City of Burbank) (354001, 354002, 354003)	To determine the economic and energy conservation benefits of hybrid geothermal/fossil power plants. The results will be utilized on the basis for obtaining investor's funds for the development of geother- mal energy by the City of Burbank.	Promoting commercial- ization of geothermal energy	FY78: Thermody- namic analysis	0	330	689	3000	6689	FY80
2404	Heat Exchanger Test (EPRI) (323001)	To test and demonstrate the binary, shell-and-tube heat exchanger system at Imperial Valley	Binary system feas- ibility	Not available	0	350	200	0	200	FY79
2405	Total Flow Concept (LLL) (103003)	To study the feasibility of expanding wet steam through a total flow turbine system.	30% increase in utilization	10/78: terminated	3719	1332	1700	0	1700	FY78
2406	Helical Screw Expander (NASA/JPL) (201001)	To evaluate the performance of 1.0 MM helical screw expander power system (invented by Hy- drothermal Power Company, Ltd.) at one or more geothermal sites	For use with wellhead generator	4/78: com- plete first field test 7/78: final report completed.	596	182	400	0	400	FY79
2407	Market Survey for Well Head Generator (NASA) (201007)	Not available	Not available	FY77: Completed	0	30	0	0	0	FY77
2408	Practical Cycles for Geothermal Power Plants (GE) (306001)	Not available	Not available	FY77: Completed	116	70	0	0	0	FY77
2409	Gravity Head Binary Plant (Sperry Res. Center) (309004)	To demonstrate, in an industry coupled field test, the thermo- dynamic and economic benefits of a binary system utilizing downhole heat exchange and a gravity head working fluid pump	For downhole pump application	Will be com- pleted in 4 years start- ing '78.	0	0	1230	3400	12700	FY82

TABLE 3.5 (Cont'd)
R&D PROJECTS IN THE AREA OF ADVANCED CONVERSION SYSTEMS

MITRE CODE (1)	TITLE (CONTRACTOR/SUBCONTRACTOR) (LINE ITEM #)	PROJECT OBJECTIVE AND DESCRIPTION	CONTRACTOR'S ESTIMATED BENEFITS	MILESTONE	OPERATING FUNDS (\$1000) (2)				TOTAL FUND (\$1000) FROM FY78 (3)	COMPLETION DATE (3)
					PRIOR FY77	FY77	FY78	FY79		
2410	Geothermal Rotary Separator (Biphase Engines) (315001)	To design a wellhead geothermal rotary separator	Save part of 20-30% power lost in conventional flasher	6/78: design completed	77	163	15	400	415	FY80
2411	Heat Rejection Systems Analysis (United Eng. and Const) (386001)	Not available	Not available	3 months	0	22	0	0	0	FY77
2412	Waste Heat Rejection (ORNL) (950067)	To prepare an in-depth assessment of waste heat rejection problems and to perform (in-house or subcontracting) the required development work in critical areas which can have significant impact on early commercialization of geothermal power plants. The primary analytical activity is the preparation of a Chapter on Waste Heat Rejection for the Geothermal Energy Source Book.	Supporting information	FY78: Chapter on heat rejection FY79: experimental program	0	0	400	700	2500	FY80
2413	Hawaii 5-10 MW _e Steam Generator (Res. Corp. of Univ. of Hawaii) (950094)	To prove the economic feasibility of base load power production with a small flash steam generator system, and to provide long term reservoir testing	Prove feasibility	10/78: Final design, 5/79: possible power production	0	0	1000	3000	6000	FY80
2414	Moderate Temperature Electric (INEL) (106022) (4)	To provide site support service for the Raft River Demonstration Project	Demonstrate low temp. resource	Not available	0	0	495	500	NOT	CONSIDERED
2415	Small Electric (4) Generator (Sand. Labs) (101004)	Not available	Not available	Not available	217	0	0	0	0	FY76
2416	Direct Bottoming Cycle (Dadealean Assoc.) (326004)	Not available	Not available	Not available	0	0	580	300	880	FY79
TOTAL					5042	2772	7204	11530	32209	

1 First character indicates program (2 indicates Extraction and Conversion Technology), the second character indicates subprogram (1: Reservoir Stimulation
2: Extraction Technology,...), the last two characters are project number.

2 The fundings are taken from (i) "Geothermal Energy, Current Year Financial Procurement Plan - Operating Funds", Computer printout R-1508315-007, April 13, 1978, where FY77 and prior years costs and FY78 planned costs are given; and (ii) "Geothermal Energy, Budget and Planning Detail - Operating Funds", Computer Printout R-1508300-001, December 7, 1977, where FY77 costs and FY79 planned costs are listed.

3 Estimated.

4 Under different program.

earlier, a relatively small number of expensive multi-year hardware development projects. As the program becomes more mature, the emphasis shifts to hardware development activities, and the number of exploratory projects decreases.

The supporting activities are an essential element of the hardware development process. Therefore, their evaluation must be made in conjunction with those projects which are supported by them.

The benefits of hardware development projects can be estimated explicitly by comparing the cost of power if the R&D project is successful, with the cost of power if no R&D were carried out. The cumulative benefit would be the aggregated (discounted, if necessary) benefit over the time period during which the newly developed hardware or technology would be used. The estimation of the cumulative benefit requires a knowledge of the expected power output during each of the years falling in the time period under consideration. Since the supporting activities contribute to the procurement of these benefits, the total R&D costs associated with these benefits should be the sum of the costs incurred in the hardware development phase and the cost of related supporting activities.

It is appropriate to point out that a project may not achieve complete success during the hardware development phase. Therefore, it would be meaningful to make regular estimates of the expected value of the degree of success relative to the original estimate of the project benefit. For example, every project will have an expected

degree of success equivalent to one at the start of the hardware development phase. As the project progresses, the expected degree of success will drop below 1 if it appears that the benefits of the project will not be as large as the original estimate. If the eventual benefits appear to be likely to exceed the original estimate, the expected degree of success could become greater than 1. The estimated benefit will thus be the product of the original estimate of the benefit and the expected degree of success.

Table 3-6 shows a classification of the ongoing RD&D projects into the three categories discussed above. During FY 1978, six technical data acquisition projects are being funded along with sixteen hardware development projects, and seven projects involving supporting activities. The total R&D budget of \$11,894k is divided among the three project categories in the following proportion: Technical Data Acquisition - \$2,720k(23%), Hardware Development - \$7,595k(64%); and Supporting Activities - \$1,579k(13%).

A review of the pattern of funding for the utilization technology R&D program indicates that the overall composition of the program is changing from one in which the major emphasis was on technical data acquisition (prior to the FY 1977) to one which emphasizes hardware development (FY 78). This trend is apparent in Figure 3-1. During FY 1978, 63.9% of the total R&D funds are allocated to hardware development projects as compared with 13.3% during the prior FY 77 period. The detailed breakdowns of the funding allocation for FY 77,

TABLE 3-6

CLASSIFICATION OF R&D PROJECTS* OF THE EXTRACTION AND CONVERSION
TECHNOLOGY PROGRAM AND THEIR FUNDING IN FY78

STANDARD TECHNICAL AREA	TECHNICAL DATA ACQUISITION		HARDWARE DEVELOPMENT		SUPPORTING ACTIVITIES		FY78 TOTAL FUND (\$1000)
	PROJECT NUMBER*	FY78 (\$1000)	PROJECT NUMBER*	FY78 (\$1000)	PROJECT NUMBER*	FY78 (\$1000)	
Reservoir Stimulation	2101, 2104	450	2103, 2105	450	2201, 2101, 2106	195	1,095
Well Flow			2204, 2205	275	2206	200	475
Cycle, System Program	2405, 2305	1,770	2414, 2302, 2304, 2416, 2410	3,340	2401, 2402, 2403	1,184	6,294
Heat Exchanger	2303	100	2404, 2306	500			600
Prime Mover			2406	400			400
Condenser	2301	400					400
Heat Rejection			2412	400			400
Well Head Generator			2409, 2413, 2415	2,230			2,230
TOTAL		2,720		7,595		1,579	11,894
% of Total		22.87		63.86		13.28	100.00

* Project description and designated number are listed in Tables 3.2, 3.3, 3.4, and 3.5.

and the time period prior to FY 77 are shown in Tables 3-7 and 3-8, respectively.

A continuation of this trend will be a proof of the maturity of this program. It can be anticipated that in the future, hardware development activities will dominate the program, and that supporting activities and technical data acquisition projects will become less significant parts of the total program.

TABLE 3-8

CLASSIFICATION OF R&D PROJECTS* OF THE EXTRACTION AND CONVERSION
TECHNOLOGY PROGRAM AND THEIR FUNDING (FY77)

STANDARD TECHNICAL AREA	TECHNICAL DATA ACQUISITION		HARDWARE DEVELOPMENT		SUPPORTING ACTIVITIES		FY77 TOTAL FUND (\$1000)
	PROJECT NUMBER*	FY77 (\$1000)	PROJECT NUMBER*	FY77 (\$1000)	PROJECT NUMBER*	FY77 (\$1000)	
Reservoir Stimulation	2103	207			2201, 2101, 2102	345	552
Well Flow			2202, 2203, 2204	480	2206	409	889
Cycle, System Program	2410	163			2401, 2402, 2403, 2408	753	916
Heat Exchanger	2302, 2304, 2306	1,658	2404	350			2,008
Prime Mover	2405	1,332	2406	182			1,514
Condenser	2301	245					245
Heat Rejection					2411	22	22
Well Head Generator					2407	30	30
TOTAL		3,605		1,012		1,559	6,176
% of Total		58.37		16.39		25.24	100.00

* Project description and designated number are listed on Tables 3.2, 3.3, 3.4, and 3.5.

TABLE 3-3

CLASSIFICATION OF R&D PROJECTS* OF THE EXTRACTION AND
CONVERSION TECHNOLOGY PROGRAM AND THEIR FUNDING (PRIOR FY77)

STANDARD TECHNICAL AREA	TECHNICAL DATA ACQUISITION		HARDWARE DEVELOPMENT		SUPPORTING ACTIVITIES		TOTAL FUND PRIOR FY 77 (\$1000)
	PROJECT NUMBER*	PRIOR FY 77 (\$1000)	PROJECT NUMBER*	PRIOR FY 77 (\$1000)	PROJECT NUMBER*	PRIOR FY 77 (\$1000)	
Reservoir Stimulation					2101	34	34
Well Flow			2202, 2204	1,129	2203	12	1,141
Cycle, System Program	2410	77			2402, 2408	423	500
Heat Exchanger	2302, 2304, 2306	1,679					1,679
Prime Mover	2405, 2406	4,315					4,315
Condenser	2301	527					527
Heat Rejection							
Well Head Generator					2415	217	217
TOTAL		6,598		1,129		686	8,413
% of Total		78.43		13.42		8.15	100.00

* Project description and designated number are listed on Tables 3.2, 3.3, 3.4, and 3.5.

FIGURE 3-1
ALLOCATION OF FUNDS FOR THE RD&D ACTIVITIES IN THE
EXTRACTION AND CONVERSION TECHNOLOGY PROGRAM

4.0 BENEFIT/COST ANALYSIS OF THE PROGRAM

4.1 Estimation of Benefits

4.1.1 Development Scenario and Assumptions

The estimation of the benefits of an RD&D project requires a determination of the extent to which the successful output of the project would be utilized by the geothermal industry. Since the geothermal industry is not well developed at this time, the projections for its growth are not available. However, the Division of Geothermal Energy has prepared a "Power-on-Line" Scenario for programmatic purposes. This scenario consists of realistic estimates of the installed electricity generation capacity which can be expected to come on line at various prospects at different points in time. Table 4-1 shows the DGE's power-on-line goals for each year during the time period 1983 to 2000. The subsequent benefit/cost analyses are based on the assumption that these goals for the development of various sites will be accomplished.

The second major assumption concerns the extent of utilization of the results of successful RD&D projects. Although a sophisticated market penetration analysis could be conducted to estimate the extent of utilization of newly developed or improved technology, the results of such an analysis may not be reliable due to the uncertainty associated with the input data; e.g., date of commercialization, economic impact of complete success, degree of success, cost of alternatives, etc. Therefore, it was decided that all power generation units coming

TABLE 4-1
PROJECTED INSTALLED CAPACITY AT LIQUID-DOMINATED
HYDROTHERMAL PROSPECTS (MWe)*

YEAR		PROSPECT																		
1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	TOTAL		
SALTON SEA	50	0	100	75	100	100	100	100	100	100	100	100	100	100	100	100	100	1600		
VALLIS CALDERA	50	0	0	0	0	0	100	0	0	0	100	100	100	100	100	100	100	1350		
BRADY	50	0	0	50	0	100	0	0	0	0	100	100	100	100	100	0	0	1050		
BRAMLEY	50	0	50	0	100	100	100	100	100	100	100	100	100	100	100	0	0	1000		
ROOSEVELT	50	0	50	0	50	0	50	0	0	0	100	100	100	100	100	50	0	1000		
BROWAWAY	50	0	0	0	50	0	0	0	0	0	100	100	100	100	100	0	0	1000		
COSO	0	0	50	50	150	150	150	0	0	0	0	0	0	0	0	0	0	600		
MONO-LONG VALLEY	0	0	50	0	0	100	0	0	0	0	0	0	0	0	0	0	0	250		
COVE FORT SULF.	0	0	50	0	50	50	100	100	100	100	100	100	100	100	100	100	100	1200		
HREER	0	0	50	0	50	0	100	100	100	100	100	100	100	100	100	0	0	1000		
GEYSERS (LIQUID)	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	1000		
EAST MESA	0	50	50	0	50	0	0	0	0	0	0	0	0	0	0	0	0	1000		
STEAM-BOAT SPRINGS	0	0	50	0	50	0	100	0	0	0	0	0	0	0	0	0	0	200		
SURPRISE VALLEY	0	0	50	0	50	100	100	100	100	100	100	100	100	100	100	100	100	1300		
CHANDLER	0	0	50	0	0	100	50	0	0	0	100	100	100	100	100	0	0	200		
LEACH	0	0	0	0	50	0	0	100	100	100	100	100	100	100	100	100	100	1100		
BRUNEAU-GRANDVIEW	0	0	0	0	50	0	0	100	100	100	100	100	100	100	100	100	100	1150		
LASSEN	0	0	0	0	50	0	50	50	50	50	0	0	0	0	0	0	0	100		
ALTORED	0	0	0	0	50	0	50	50	50	50	0	0	0	0	0	0	0	300		
SAFFORD	0	0	0	50	0	0	0	0	0	0	50	50	0	0	0	0	0	100		
WISNER/CRAVE CREEK	0	0	0	0	50	0	0	0	100	100	100	100	100	100	100	100	0	1000		
VALE	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	600		
THERMO	0	0	0	0	0	0	50	0	0	0	100	100	50	50	50	0	0	500		
RAFT RIVER	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	100		
GLASS MOUNTAIN	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	50		
PUNA	0	0	0	0	0	0	100	200	200	200	100	0	0	0	0	0	0	1000		
MT. HOOD	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	50		
BAKER HOT SPRINGS	0	0	0	0	0	0	50	0	0	0	0	0	0	0	0	0	0	50		
W. YELLOWSTONE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50		
TOTAL	18950	650	700	850	1150	1200	1500	1700	1700	1700	1650	2150	700	1100	775	575	550	0	300	TOTAL

on line three years (or longer) after the commercialization of the products of a project will utilize these products.* Any deviation from this assumption are flagged in the presentation of the results.

The degree of success for each project is assumed to be 1, unless indicated otherwise. This means that the anticipated improvements in the technology due to the successful completion of an R&D project are assumed to occur. However, in certain cases, where a project is not expected to be completely successful, benefits can be estimated by assuming a value of degree of success less than 1.

4.1.2 Computation of Benefits

The computation of the benefits of a successful RD&D project was carried out by utilizing the MITRE geothermal levelized busbar cost model - - GELCOM.** This model determines the revenue required by the utility company to obtain a predetermined rate of return on its equity after meeting all the expenses. These expenses include the cost of fuel (the producer determines these expenses on the basis of his own costs), the capital cost of equipment, the O&M costs, the cost of borrowed capital, taxes, and any other costs.

* The results of RD&D will be utilized in appropriate plant designs only; e.g., binary heat exchangers will be utilized in binary plants only.

** "GELCOM - - A Geothermal Levelized Busbar Cost Model Description and User's Guide" - - M78-17. J.N. Gupta and J.G. Leigh, The MITRE Corporation, Metrek Division, January 1978.

For a resource with a given set of characteristics (temperature, salinity, well flow rate, depth, etc.), and the estimated capital and O&M costs for the production field and the generating plant, the GELCOM model estimates the revenue requirements when the most suitable plant (flash or binary) is selected. If the capital and/or O&M costs are changed, the revenue requirements also change. Therefore, the reduction in the revenue requirements can be viewed as the economic benefit resulting from a reduction in the capital and/or O&M costs of one or more components of the producing or generating plant. A more detailed description of the capabilities and input data requirements of the GELCOM model is presented in Appendix C.

In order to estimate the benefits of a successful RD&D effort, the GELCOM model is run first without superimposing the effects of RD&D on the capital and O&M costs, and afterwards with the cost estimates reflecting the impact of successful RD&D. The revenue requirements without RD&D are higher than the requirements with RD&D, and the difference between the two estimates is the expected saving resulting from the utilization of the results of RD&D. As mentioned in the preceding section, the estimated savings due to RD&D will depend on the degree of success of the projects and the extent of utilization of the products of RD&D (market penetration). The GELCOM model was appropriately modified and augmented account for

variations in the expected degree of success and the expected market penetration of the results of RD&D. Figure 4-1 presents an overview of the procedure for computing the benefit cost ratios of different projects.

It is appropriate to point out that the expected benefit with 100% market penetration and a degree of success equal to 1, represents the upper bound on the benefit. If the benefit/cost ratio for a project is fairly small even with the highest estimated value of the benefit, the project may not represent a good investment because the actual benefit/cost ratio will probably be smaller. The cost associated with an RD&D project is the present value of all estimated expenditure that is expected to be incurred up to and including the commercialization phase.

In the case of technical data acquisition projects and some support projects, it is not possible to identify the benefits explicitly. Whenever possible, a support project is combined with one or more hardware development projects for the purpose of estimating the benefit/cost ratio. In spite of this manipulation, there are some projects for which a quantitative benefit/cost analysis could not be conducted. These projects were evaluated qualitatively, in the context of the ultimate objectives associated with them.

The next subsection is devoted to an evaluation of the results of the benefit/cost analysis.

FIGURE 4-1
COMPUTATION OF BENEFIT/COST RATIOS
FOR A PROJECT/INITIATIVE

4.2 Results of the Benefit/Cost Analysis

Using the methodology described in subsection 4.1, the primary benefits (impacts) of different projects are estimated and translated into inputs for the GELCOM model. The outputs of the model are the benefits which when divided by the project costs give the benefit/cost ratios.

The estimates of the primary benefits are presented in Appendix D and are summarized in Table 4-2. Table 4-3 shows the estimated cost of power in mills/kWhr resulted from the completion of some projects for each prospect at which geothermal electricity is projected to be generated. The second and third columns of this table show the estimated cost per kWhr assuming that no improvements occur in the current state-of-the-art in the geothermal energy extraction and utilization technology. These estimates are also based on the assumption that the other parameters affecting the cost of geothermal power remain unchanged (e.g., environmental technology costs, taxes, interest charge, etc.). The specific values of the input variables for different prospects are the same as those given in the documentation for the GELCOM (cost of electric power) model*.

*GELCOM - "A Geothermal Levelized Busbar Cost Model - Description and User's Guide" - M78-17, J.N. Gupta and J.G. Leigh, The MITRE Corporation, Metrek Division, January 1978.

TABLE 4-2
PRIMARY BENEFITS OF CURRENT RD&D PROJECTS
IN THE EXTRACTION AND CONVERSION TECHNOLOGY PROGRAM

TECHNICAL AREA PROJECT NAME AND CODE	YEAR OF COMPL.	IMPACTED PARAMETER 1	IMPACT (%) ON 50 MW PLANT ²		AFFECTED PLANT TYPE ³
			Pessi- mistic	Opti- mistic	
1. RESERVOIR STIMULATION 2101-2106, 2201	FY85	Well Cost	-5.0	-13.2	F & B
2. WELL FLOW					
• Two-Phase Flow, 2206	FY81	Production Well Number Production Well Cost	-10.0 10.0	-20.0 10.0	F
• Gas Lift, 2205	FY79	Production Well O&M Cost (LS) Production Well O&M Cost (HS) Production Well Life Production Well Cost	-5.0 -25.0 20.0 12.5	-10.0 -30.0 30.0 5.0	F
• Downhole Pump, 2202- 2204	Not Current	Production Well Number Downhole Pump O&M Cost	-3.0 -30.0	-5.0 -45.0	B
3. HEAT EXCHANGER					
• Direct Contact, 2304	FY80	Prod. & Inj. Well Number Process Mechanical (Util.) Cost Condenser & Heat Rejection Cost General O&M Cost (Util.)	-2.0 -20.0 -2.0 -5.0	-4.0 -35.0 -5.0 -10.0	B
• Liquid Fluidized Bed, 2303	FY81	Heat Exchanger Cost Heat Exchanger O&M Cost	-10.0 120.0	-22.0 96.0	B
• Self-Clean (APEX), 2306	FY81	Heat Exchanger Cost Heat Exchanger O&M Cost	-10.0 200.0	-27.0 160.0	B
4. CONDENSER					
• Fluted Tube, 2301	FY79	Condenser & Heat Rejection Cost General O&M Cost (Util.)	-4.4 2.0	-5.6 2.0	B
• Direct Contact, 2302	FY81	Condenser & Heat Rejection Cost	-4.0	-6.0	B
5. CONVERSION SYSTEM					
• Binary Test Program, 2305, 2404, 2414	FY80	Production Well Number Heat Exchanger Cost Proc. Mechanical (Util.) O&M Cost	0 -4.0 -9.0	-0.2 -11.0 -18.0	B
• Well-Head Generator, 2407, 2413, 2415	FY80	Saving other fuels equivalent to 0.194 Quads of electricity	-	-	-
• Gravity Head Binary Plant, 2407, 2409	FY82	Saving other fuels equivalent to 0.315 Quads of electricity	-	-	-
• Helical Screw Expan- der, 2406	FY79	Saving from \$12M to \$16M	-	-	F & B
• Total Flow System, 2405	Discon- tinued	Prod. & Inj. Well Number Condenser & Heat Rejection Cost General O&M Cost (Util.) Turbine-Generator Cost Gathering System Cost Process Mechanical (Producer) Cost	-2.0 13.3 34.1 6.0 -10.0 -40.0	-15.0 10.9 12.2 3.0 -20.0 -40.0	F
• Rotary Separator, 2410	FY80	Prod. & Inj. Well Number Turbine-Generator Cost Process Mechanical (Util.) Cost Condenser & Heat Rejection Cost	-12.0 9.1 -16.0 -7.3	-20.0 5.7 -20.6 -12.5	F
• Hybrid Geothermal/ Fossil Plant, 2403	FY80	Saving from \$50M to \$100M	-	-	-
• Conversion Studies 2401, 2402	FY79	Not analyzed	-	-	F & B
• Direct Bottoming Cycle, 2416	FY79	Not analyzed	-	-	B
6. HEAT REJECTION					
• Waste Heat Rejection, 2412		Not analyzed	-	-	B

1. LS: Low Salinity; HS: High Salinity; Prod. & Inj.: Production & Injection; Util.: Utility

2. Negative sign indicates a reduction

3. F: Flash Steam Plant; B: Binary Plant

TABLE 4-3
ESTIMATED REDUCTION IN THE COST OF POWER DUE TO THE SUCCESSFUL COMPLETION OF VARIOUS PROJECTS

	COST OF ELECTRICITY IN MILLS/KWH (1977 \$)																	
	WITHOUT RAD IMPACT		RESERVOIR STIMULATION		TWO- PHASE FLOW		ROTARY SEPARATOR		DIRECT CONTACT H. EXCH.		SELF- CLEAN H. EXCH.		FLUDED TUBE CONDENSER		DIRECT CONTACT CONDENSER			
	FLASH	BINARY	FES.	OPT.	FES.	OPT.	FES.	OPT.	FES.	OPT.	FES.	OPT.	FES.	OPT.	FES.	OPT.		
CALIFORNIA																		
1 Brawley		37.43	37.43	37.43	37.43	37.43	37.43	37.12	36.43	37.11	36.12	37.37	37.34	37.31	37.20			
2 Coso	29.21		29.21	28.38	29.21	28.33	27.32	26.39	29.21	29.21	29.21	29.21	29.21	29.21	29.21			
3 East Mass		43.62	43.09	42.38	43.62	43.62	43.62	43.62	42.62	43.57	43.25	43.55	43.51	43.49	43.39			
4 The Geysers		69.28	69.28	65.27	69.28	69.28	69.28	69.28	69.11	69.23	68.92	69.22	69.18	69.16	69.06			
5 Glass Mountain	58.77		58.77	55.66	58.77	55.43	53.76	50.83	58.77	58.77	58.77	58.77	58.77	58.77	58.77			
6 Haber		39.12	38.54	36.97	39.12	39.12	39.12	38.38	37.30	39.07	38.75	39.05	39.01	38.99	38.90			
7 Lassen	23.93		23.93	23.93	23.93	23.00	23.02	21.32	23.93	23.93	23.93	23.93	23.93	23.93	23.93			
8 Mono-Long Valley	29.21		29.21	28.38	29.21	28.33	27.32	26.39	29.21	29.21	29.21	29.21	29.21	29.21	29.21			
9 Salton Sea		25.03	25.03	25.03	25.03	25.03	25.03	25.03	24.68	23.97	24.67	23.64	24.98	24.94	24.91	24.81		
10 Surprise Valley		56.35	54.87	54.87	56.35	56.35	56.35	56.35	55.59	54.06	56.30	55.98	56.27	56.23	56.22	56.11		
HAWAII																		
11 Puna	18.86		18.86	18.86	18.86	18.86	18.86	18.81	18.86	18.86	18.86	18.86	18.86	18.86	18.86			
OREGON																		
12 Alvord		76.29	76.29	71.72	76.29	76.29	76.29	76.29	76.28	76.12	76.24	75.93	76.23	76.19	76.17	76.07		
13 Vale Hot Springs		55.66	55.32	54.06	55.66	55.66	55.66	55.66	54.68	55.61	55.30	55.58	55.54	55.52	55.41			
WASHINGTON																		
14 Baker Hot Springs		124.98	121.99	118.98	124.98	124.98	124.98	124.98	120.16	119.90	124.94	124.62	124.91	124.86	124.85	124.74		
IDAHO																		
15 Bruneau-Grandview		60.61	60.61	58.25	60.61	60.61	60.61	60.61	60.61	60.45	60.37	60.25	60.55	60.52	60.50	60.40		
16 Raft River		94.51	93.73	91.51	94.51	94.51	94.51	94.51	93.78	91.84	94.46	94.15	94.42	94.37	94.35	94.24		
17 Weiser-Crane Creek		73.08	72.55	70.39	73.08	73.08	73.08	73.08	73.00	71.65	73.04	72.72	73.00	72.96	72.94	72.83		
NEVADA																		
18 Beowave	32.08		32.08	32.08	32.08	30.62	30.15	27.94	32.08	32.08	32.08	32.08	32.08	32.08	32.08	32.08		
19 Brady Hot Springs	32.89		32.10	31.44	32.89	31.26	31.05	28.29	32.89	32.89	32.89	32.89	32.89	32.89	32.89	32.89		
20 Leach		113.26	110.05	107.04	113.26	113.26	113.26	113.26	108.44	108.18	113.21	112.90	113.19	113.14	113.13	113.02		
21 Roosevelt	20.76		19.45	19.45	20.47	19.66	20.11	18.48	20.76	20.76	20.76	20.76	20.76	20.76	20.76	20.76		
22 Steamboat Springs	23.93		23.93	23.22	23.93	23.16	23.47	22.05	23.93	23.93	23.93	23.93	23.93	23.93	23.93	23.93		
ARIZONA																		
23 Chandler		81.34	79.88	77.47	81.34	81.34	81.34	81.34	79.08	78.82	81.29	80.98	81.27	81.23	81.21	81.11		
24 Safford		60.61	60.61	58.25	60.61	60.61	60.61	60.61	60.60	60.45	60.37	60.25	60.55	60.52	60.50	60.40		
UTAH																		
25 Cove Fort-Sul.		54.85	54.85	51.99	54.85	54.85	54.85	54.85	54.84	54.68	54.80	54.48	54.78	54.75	54.73	54.63		
16 Thermo		47.70	47.70	45.41	47.70	47.70	47.70	47.70	47.70	47.53	47.65	47.33	47.64	47.60	47.58	47.48		
NEW MEXICO																		
27 Valles Caldera	32.08		32.08	32.08	32.08	30.59	30.15	27.94	32.08	32.08	32.08	32.08	32.08	32.08	32.08	32.08		

Note: The "Fluidized bed heat exchanger" project has reduction of cost similar to that of the self clean heat exchanger.

It can be observed that the impact of the success of any project is dependent on the characteristics of the resource. The schedule for the development of a resource is also a factor in the estimation of the cumulative benefits resulting from the success of an R&D project. It is appropriate to mention that the project impact estimates in Tables 4-2 and 4-3 are based on the assumption that these impacts are discrete, and that the success of other projects has no effect on the cost of power impact for a specific project. In reality the impacts of various projects are interrelated, and the total impact of the success of all projects will be considerably less than the sum of the impacts of individual projects*.

Table 4-4 shows the values of the estimated benefit/cost ratios for the projects which are likely to have direct impact on the cost of power. The total benefits represent the discounted savings (at 10%) resulting from the imposition of the reduced cost per kWhr at each prospect (as a result of the successful completion of the project) on the projected scenario for power on line. Since the GELCOM data base covers this scenario up to the year 2000, the benefits are accumulated to this point only.

* For example, the simultaneous success of a reservoir stimulation project and a downwell pump project will create a situation in which the total increase in well flow rate will be less than the sum of the flow rate increases expected from reservoir stimulation and pumping individually.

TABLE 4-4
CUMULATIVE BENEFITS AND COSTS OF PROJECTS

PROJECT	R&D COST (\$1000)					DISCOUNTED BENEFITS (\$10 ⁶)(2)		BENEFIT/COST RATIO	
	FY78	FY79	FY80	Post FY80 ⁽¹⁾	Total Discounted ⁽²⁾	Pessi-mistic	Opti-mistic	Pessi-mistic	Opti-mistic
1. RESERVOIR & STIMULATION	1,095	3,130	2,000	2,000/Year (81-84) 790 (85)	10,674	188.0	496.0	17.6	46.5
2. WELL FLOW									
Two-Phase Flow	200	170	300	300 (81)	828	1.7	38.2	2.1	46.1
Gas Lift	200	350	-	-	518	0	15.8	0.0	30.5
Downhole Pump	-	-	-	-	-	56.4	138.4	-	-
3. HEAT EXCHANGER									
Direct Contact	2,150	1,800	-	-	3,786	130.3	242.9	34.4	64.2
Self Clean	300	100	400	400 (81)	1,022	0	7.4	0	7.2
Fluidized	100	450	500	500 (81)	1,298	0	7.2	0	5.5
4. CONDENSER									
Fluted Tube	400	500	-	-	855	8.5	13.9	9.9	16.3
Direct Contact	100	400	500	-	677	14.8	22.3	16.9	25.4
5. CONVERSION SYSTEMS									
Binary System	765	570	100	-	1,366	1.5	2.0	1.1	1.5
Well Head Generator	1,000	3,000	2,000	-	5,380	See Appendix D		-	-
Gravity Head Plant	1,230	3,400	3,400	3400(81) 1270(82)	10,552	See Appendix D		-	-
Helical Screw Expander	400	-	-	-	400	10.8	14.4	27.0	36.0
Total Flow System	1,700	-	-	-	1,700	0.14	6.2	0.1	3.7
Rotary Separator	15	400	-	-	379	89.3	169.6	235.6	447.5
Hybrid Plant	689	3,000	3,000	-	5,895	25.0	50.0	4.2	8.5
OVERALL ⁽³⁾	8,114	10,870	6,300	11,260	29,598	470.04	1085.9	15.9	36.7

1. Figure in brackets indicates the Fiscal Year

2. In 1978 dollars. A 10% discount rate is used

3. Excluding Well Head Generator, Gravity Head Plant, and Downhole Pump.

The costs of the different projects are also discounted to their present worth, and the benefit/cost ratio is obtained by dividing the discounted savings by the discounted costs.

There are some projects for which it is not possible to estimate the impact of the success of the project on the cost of power. Advanced Conversion Study Project, The Geothermal Power Plant Design Handbook Project are examples of projects belonging to this category.

As shown in Table 4-2, the impact of the projects dealing with well-head generator, gravity head binary plant, and helical screw expander is estimated in terms of the augmentation of power-on-line scenario expected to result from the success of these projects. The cumulative impacts of these projects are discussed in Appendix D, sections 12.0, 13.0, and 14.0 respectively.

The interactions between the impacts of various projects, together with the difficulty in quantifying the cost impact of some projects tend to justify the need for developing a model which can simulate these interactions along with the dynamics of the growth of the geothermal power industry. Until such a model is developed, it may not be possible to make a realistic benefit/cost evaluation of the total RD&D program for geothermal energy extraction and conversion technology.*

* Such a simulation model is also required for evaluating other DGE programs.

4.3 Analysis of the Results

The cumulative costs and benefits of the projects for which impacts on the cost of geothermal electricity could be estimated are listed in Table 4-4. It is observed that the largest cost and benefits are associated with the reservoir stimulation project. However, the rotary separator project has the largest benefit/cost ratios (448 for the optimistic case and 236 for the pessimistic case). The benefit/cost ratios for other projects are given in the last column of Table 4-4.

It is also observed that not all of the projects for which benefit/cost ratios could be estimated are cost-effective. The lowest benefit/cost ratio is 0.0, which occurs in the pessimistic cases of the gas-lift, self-clean heat exchanger, and fluidized bed head exchanger projects. Although twelve of the thirteen groups of projects have benefit/cost ratio values less than 40 (in the pessimistic cases), the whole program can be said to be cost-effective. Since there are interactions between the benefits of some of these projects, the simultaneous execution of various projects could lower the benefit/cost values of some of them.

The grouping of the projects in Table 4-2 points out the duplications of efforts occurring in some technical areas.* For example,

* As stated earlier, some redundancy is necessary for dealing with possible failure of some projects.

TABLE 4-5

ESTIMATED BENEFIT/COST RATIOS FOR GROUPS OF RD&D PROJECTS

APPLICATION	RD&D PROJECT* IN THIS GROUP										TOTAL RD&D COST (\$1000)**	TOTAL BENEFIT (\$10 ⁶)**		COMBINED TOTAL BENEFIT/COST	
	A	B	C	D	E	F	G	H	I	J		PESSIMISTIC	OPTIMISTIC	PESSIMISTIC	OPTIMISTIC
Flash	X	X	X							X	12,399	279.0	719.6	22.5	58.0
Binary 1	X			X			X				15,315	326.8	752.8	21.3	49.2
Binary 2	X			X				X			15,337	333.1	761.2	21.7	49.6
Binary 3	X				X		X		X		13,917	198.0	519.3	14.2	37.3
Binary 4	X				X			X	X		13,939	204.3	527.7	14.7	37.9
Binary 5	X					X	X		X		14,193	198.0	519.1	14.0	36.6
Binary 6	X					X		X	X		14,215	204.3	527.5	14.4	37.1

*Project Codes:

CODE	PROJECT
A	RESERVOIR STIMULATION
B	TWO-PHASE FLOW
C	GAS LIFT
D	DIRECT CONTACT HEAT EXCHANGER
E	SELF CLEANING HEAT EXCHANGE

CODE	PROJECT
F	FLUIDIZED BED HEAT EXCHANGER
G	FLUTED TUBE CONDENSER
H	DIRECT CONTACT CONDENSER
I	BINARY SYSTEM
J	ROTARY SEPARATOR

** Discounted to 1978 dollars.

there are three types of heat exchangers and two types of condensers being developed at this time. If subsets of projects are selected with the objective of eliminating redundancies, a rough estimate of the benefit/cost ratios for these subsets can be made. The benefit/cost ratio estimates for possible combinations are presented in Table 4-5. The benefit/cost ratios for these combinations range from a low of 14.0 to a high value equivalent to 58.0.

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APPENDIX A

CALCULATIONS OF POWER PLANT CAPITAL
COST REDUCTIONS DUE TO THEORETICAL
AND PRACTICAL IMPROVEMENTS ON
CURRENT TECHNOLOGY

1.0 INTRODUCTION

This Appendix presents the calculations for the new costs of Geothermal systems resulted from technological improvements of components which are currently in use. It considers two types of improvements: theoretical and practical, which have been defined in the main body of this report. Cost items which have no room for improvement by the Extraction and Conversion Technology Program, such as instrumentation costs, bulk materials cost, etc., are not included. Improvements by introducing new equipment, e.g. direct contact heat exchangers, rotary separator, and by R&D activities in other programs are not considered in this report and therefore excluded.

The calculations rely, in some cases, on assumptions which will be stated whenever necessary, and are performed for the three systems; dry steam, flash steam, and binary. Baseline costs for each system have been reported in the text.

2.0 DRY STEAM PLANT

2.1 Turbine-Generator

Turbine and generator efficiencies currently used are about 80% and 95% respectively. Hence the efficiency of the system is $0.80 \times 0.95 = 0.760$ or 76%.

Theoretical Improvement: The theoretical improvement will of course bring the system efficiency to 100%. Thus for the same gross output, the steam requirement is now reduced to 0.76 of the baseline requirement. The cost of the system is a function of gross output and steam rate as follows (1):

$$C(\$1000) = 0.0088(MW)^{-0.171} (\text{Steam rate})^{1.015} \quad (1)$$

Where MW is the gross output which is unchanged here. From the above equation the new cost is reduced by a factor of:

$$(0.760)^{1.015} = 0.757$$

and becomes $\$4.90M \times 0.757 = \$3.71M$.

Practical Improvement: Turbine-generator has been used many years. Improvements which are practical have been incorporated into the current technology. Thence the costs change is expected to be zero here.

2.2 Cooling Tower

Cooling tower cost is directly proportional to the amount of rejected heat (1). The increase in turbine-generator system efficiency affects the rejected heat by:

- (i) Reducing the steam rate
- (ii) Increasing the expansion efficiency toward the theoretical isentropic expansion

Theoretical Improvement: Let us assume the steam is available at 400°F saturated, $H = 1200$ Btu/lb. Isentropic expansion of this steam to 2 psia pressure reduces its enthalpy to about 880 Btu/lb, and the condensing further reduces its enthalpy to 80 Btu/lb. Thus heat rejected is $880 - 80 = 800$ Btu/lb, heat converted is $1200 - 880 = 320$ Btu/lb. If the turbine expansion is 80% efficient, the heat rejected is:

$$800 + (1 - 0.80) 320 = 864 \text{ Btu/lb}$$

This when coupled with the new steam requirement calculated in 2.1 gives a reduction factor for rejected heat of:

$$\frac{800}{864} \times 0.760 = 0.704$$

The new cost becomes $\$1.30 \text{ M} \times 0.704 = \0.91M

Practical Improvement Since the amount of rejected heat is a function of turbine expansion which does not change in this case, the amount of rejected heat and consequently the cooling tower cost do not change.

2.3 Condenser

The condenser cost is a function of steam rate as follows⁽¹⁾:

$$C(\$1000) = 470 + 0.000775 (\text{Steam Rate})^{1.0} \quad (2)$$

For a 50 MW (net) plant, the parasitic requirement is about 25% of the gross output. Hence the gross output is:

$$\frac{50\text{MW}}{1-0.25} = 66.7 \text{ MW} = 227.7 \text{ MM Btu/hr} \quad (3)$$

Theoretical Improvement: From 2.2 isentropic expansion gives 320 Btu/lb. If the baseline conversion efficiency is 0.76, the baseline steam rate is:

$$\frac{227.7 \times 10^6}{0.76 \times 320} = 936270 \text{ lb/hr} \quad (4)$$

and the new steam rate is $936270 \times 0.76 = 711560 \text{ lb/hr}$. Hence the new cost according to equation 2 becomes:

$$\$1.05\text{M} \times \frac{470 + 0.000775(711560)}{470 + 0.000775(936270)} = 1.05 \times 0.854 = \$0.90\text{M}$$

Practical Improvement: Since steam rate does not change here, the cost change is zero.

2.4 Pumps and Drives

These are pumps and drives for the cooling water. Their cost is a function of the water flow rate and pump head as follows:⁽¹⁾

$$C(\$1000) = 174.3 + 0.0055(\text{flowrate} \times \text{head})^{0.846} \quad (5)$$

where the flow rate is in 10^3 lb/hr, and head in psi, the above equation applies to motor driven/stainless steel system.

Theoretical Improvement:

Let us assume that the heat capacity of water is 1.0 Btu/(lb. °F) and the temperature change of 30°F across the condenser for the cooling water. The baseline water flow rate can be calculated from the previous results from 2.2 and equation 4 as follows:

$$\frac{864 \times 936270}{1.0 \times 30} = 26965000 \text{ lb/hr}$$

and the new water flow rate as follows:

$$\frac{800 \times 711560}{1.0 \times 30} = 18975000 \text{ lb/hr}$$

Thus the new cost is reduced by a factor, assuming the pump head is unchanged, of:

$$\frac{174.3 + 0.0055 (18,975)}{174.3 + 0.0055 (26965)} \frac{0.846}{0.846} = 0.961$$

and becomes $\$2.20\text{M} \times 0.961 = \2.11M . Note improvement on pump efficiency makes negligible changes in overall system cost.

Practical Improvement: The cooling water rate is unchanged due to unchanged heat rejection rate. Hence the cost change is zero.

2.5 Well

Theoretically, it can be assumed that the number of wells required can be reduced by half through successful reservoir stimulation. This, when coupled with the reduction in steam rate requirement, makes the new well cost reduced to:

$$\$3.50\text{M} \times 0.76/2 = \$1.33\text{M} \text{ (Production Wells)}$$

Practically, the well number is assumed to be reduced by reservoir stimulation by 30%, the new well cost becomes:

$$\$3.50\text{M} \times (1-0.30) = \$2.45\text{M} \text{ (Production Wells)}$$

The above rationale applies to production wells as injection wells.

2.6 Pipe, Insulation, Valves

The cost of pipe, insulation, and valves is reduced due to the reduction in steam rate and well number requirement. For the case of theoretical improvement, the reduction of this cost assumed to be about 30%. For the case of practical improvement, it is assumed to be about 10%. Thus the new costs are:

$$\text{Theoretical: } \$3.80\text{M} \times (1-0.30) = \$2.66\text{M}$$

$$\text{Practical: } \$3.80\text{M} \times (1-0.10) = \$3.42\text{M}$$

2.7 Injection Pump:

Injection pump cost is a function of injection water rate and pump head. It is proportioned to the product of water rate and pump head raised to the power 0.608 (reference 1). This figure is the cost exponent.

Theoretical Improvement: Injection water rate is reduced by the factor 0.760. If the pump head is assumed unchanged, the new cost becomes:

$$\$0.30\text{M} \times (0.760)^{0.608} = 0.30 \times 0.846 = \$0.25\text{M}$$

Cost reduction due to pump efficiency improvement is assumed to be negligible.

Practical Improvement: Water rate is unchanged, hence the cost change is zero.

3.0 FLASH STEAM PLANT

Conversion systems in a flash steam plant are similar to those in a dry steam plant. Therefore it can be assumed that the cost changes due to improvements are in the same proportion as those previously calculated for dry steam plant. Thus the new costs are calculated as follows:

3.1 Turbine-Generator

Theoretical Improvement: $\$8.90\text{M} \times 0.757 = \6.74M
Practical Improvement: No change

3.2 Cooling Tower

Theoretical Improvement: $\$1.69\text{M} \times 0.704 = \1.19M
Practical Improvement: No change

3.3 Condenser

Theoretical Improvement: $\$1.10\text{M} \times 0.854 = \0.94M
Practical Improvement: No change

3.4 Pumps and Drives

Theoretical Improvement: $\$2.42\text{M} \times 0.961 = \2.33M
Practical Improvement: No change

3.5 Well

If the weight fraction of steam relative to the steam-water mixtures is unchanged after stimulation of the reservoir. The effects of reservoir stimulations here can be assumed to be similar to those in the dry steam wells. Hence:

- Production wells:

Theoretical Improvement: $\$5.50\text{M} \times 0.76/2 = \2.09M
Practical Improvement: $\$5.50\text{M} \times (1-0.3) = \3.85M

- Injection well:

Theoretical Improvement: $\$3.00\text{M} \times 0.76/2 = \1.14M
Practical Improvement: $\$3.00\text{M} \times 0.70 = \2.10M

3.6 Pipes, Insulation, Valves

The changes here can also be assumed to be similar to those in dry steam system, Hence:

Theoretical Improvement: $\$4.18 \times 0.70 = \2.93M

Practical Improvement: $\$4.18 \times 0.90 = \3.76M

3.7 Separator and Flasher

With more studies on the total flow transmission pipelines and steam-water separation systems, it is possible to reduce the cost of separators and flashers by reducing the number of these components.

Theoretical Improvement: The cost is assumed to be reduced by half here. Thus the new cost is:

$$\$0.32\text{M} \times 0.50 = \$0.16\text{M}$$

Practical Improvement: The cost is assumed to be reduced by 30% here. Thus the new cost is:

$$\$0.32\text{M} \times (1-0.30) = \$0.22\text{M}$$

3.8 Injection Pump

Similarly to the case of dry steam plant, the new costs are:

Theoretical Improvement: $\$0.50\text{M} \times 0.846 = \0.42M

Practical Improvement: No Change

4.0 BINARY PLANT

4.1 Turbine-Generator

The turbine-generator cost can be calculated by⁽¹⁾:

$$C(\$1000) = 665 + 0.40 (x)$$

where x is the working fluid flow rate in 10^3 lb/hr. If the above equation is used together with the cost of \$3.94M estimated for the turbine-generator, the working fluid flow rate is:

$$x = \frac{3940 - 665}{0.40} = 8187 \times 10^3 \text{ lb/hr}$$

Hydrocarbon turbine efficiency is usually 85%, and generator efficiency is about 95%. The system efficiency is therefore $0.85 \times 0.95 = 0.808$ or 80.8%

Theoretical Improvement:

If theoretical efficiency is 100%, the working fluid flow rate is reduced by a factor of 0.808. Thus the new theoretical cost becomes:

$$\begin{aligned} C(\$1000) &= 665 + 0.40 (0.808 \times 8187) \\ &= 3311 \end{aligned}$$

Practical Improvement:

Hence, it is assumed that the turbine efficiency can be increased to 90%. This when combined with generator efficiency given an efficiency of $0.9 \times 0.95 = 0.855$ or 85.5% for the system. The new cost for this case becomes:

$$\begin{aligned} C(\$1000) &= 665 + 0.40 \left(\frac{0.808}{0.855} \times 8187 \right) \\ &= 3760 \end{aligned}$$

4.2 Heat Exchanger

For the theoretical improvement case, the heat transfer is 0.808 of the original rate. For the practical improvement case, it is $0.808/0.855 = 0.945$ of the original.

The heat exchanger cost is a function of the heat transfer area A as follows⁽¹⁾:

$$C = a (A)^{0.78} \quad (5)$$

The heat transfer area is calculated by:

$$A = \frac{Q}{U\Delta T_m}$$

where Q is the heat transfer rate, U the overall heat transfer coefficient and ΔT_m is the corrected log-mean temperature difference. Thus the value of A depends on U as well as Q . The value of ΔT_m is usually fixed for certain design, therefore its effects on the cost is not discussed here.

The overall heat transfer coefficient can be calculated from:

$$\frac{1}{U} = \frac{1}{U_c} + R_d \quad (6)$$

where U is the U value when the surface is clean and R_d is the dirt factor or fouling factor. The coefficient U_c is a combination of the heat transfer coefficients of water, metal, and the organic working fluid. The dirt factor is the sum of the fouling factors of the working fluid and water. However, an organic fluid chosen as the working fluid is fairly pure, thus making R_d largely dependent on the fouling factor of water. The value of U_c depends on the properties of water and working fluid and the design of the heat exchanger. The design of a heat exchanger follows fairly well established methods and must always be optimized before it is adopted for fabrication. With current technology, the brine fouling or dirt factor is the only changeable term which affects the value of U in equation 6.

Experience in heat exchanger design indicates that heat transfer coefficient of water is usually about 1,500 Btu/(hr. ft.²°F) when corrected for the outside tube diameter, and that for light organic liquids is about 250 Btu/(hr. ft.²°F) for the temperature ranges normally encountered in geothermal power plants. Thus $1/U_c = 1/1500 + 1/250 = 0.0047$ assuming the tube wall resistance is negligible. The dirt factor due to organic fluid fouling is about 0.005 of same unit, and that due to brine fouling can be assumed to be 0.003 making:

$$\frac{1}{U} = 0.0047 + 0.0005 + 0.003 = 0.0082$$

The improvable factor is the brine dirt factor which makes up $0.003/0.0082 = 0.37$ of $1/U$.

Theoretical Improvement: If the brine dirt factor is zero, the total theoretical improvement reduces the heat transfer area by a factor of:

$$\left(\frac{0.0082 - 0.003}{0.0082} \right) \times 0.808 = 0.512$$

New heat transfer rate factor

and the heat exchanger costs, according to equation 5, to:

$$\$4.80M \times (0.512)^{0.78} = 4.8 \times 0.593 = \$2.85M$$

Practical Improvement: In this case, it is expected that the brine dirt factor is reduced to 0.0005 (equal the organic fluid dirt factor). The total practical improvement thus reduces the heat transfer area by a factor of:

$$\left(\frac{0.0082 - 0.003 + 0.0005}{0.0082} \right)^{0.945} = 0.657$$

New heat transfer rate factor.

and the heat exchanger cost, according to equation 5, to:

$$\$4.80M \times (0.657)^{0.78} = 4.8 \times 0.721 = \$3.46M$$

4.3 Condenser

The cost of condenser is a function of the heat transfer area A as follows (1):

$$C = a (A)^{0.78} \quad (7)$$

Since A is directly proportional to the heat transfer rate Q, the cost is proportional to $Q^{0.78}$.

For a binary cycle, the cycle efficiency is about 15%. This means that for 100 Btu absorbed from the brine, 15 Btu is converted and 85 Btu is rejected at the condenser. These figures are used in the calculations which follow.

Theoretical Improvement: Theoretical improvement, as previously discussed, reduces the working fluid rate by a factor of 0.808 with the turbine efficiency increases from 85% to 100%. For 100 Btu absorbed from the brine in the baseline case, only 80.8 Btu is required now. The energy for conversion becomes $0.808 \times 15 = 12.12$ Btu if the expansion through the turbine has the same efficiency of 85%. The expansion is now 100% efficient, the energy for conver-

sion should be $12.12/0.85 = 14.26$ Btu. The remainder, $80.8 - 14.26 = 66.54$ Btu are rejected at the condenser. Thus the new cost is:

$$\$3.22M \times \left(\frac{66.54}{85}\right)^{0.78} = 3.22 \times 0.826 = \$2.66M$$

Practical Improvement: The above rationale applies here:

Energy for conversion = $0.745 \times 15 / (0.85/0.90) = 15.01$ Btu

Energy rejected = $94.5 - 15.01 = 79.49$ Btu

The new cost is:

$$\$3.22M \times \left(\frac{79.49}{85}\right)^{0.78} = 3.22 \times 0.949 = \$3.06M$$

4.4 Main Feed Pump

The feed pump cost is a function of working fluid flow rate x as follows ⁽¹⁾:

$$C = a (x)^{0.955}$$

Thus, the new costs are calculated as follows:

Theoretical: $\$2.89M (0.808)^{0.955} = \$2.36M$

Practical: $\$2.89M (0.945)^{0.955} = \$2.74M$

4.5 Cooling Tower

The cost exponent for cooling tower was found to be 1.0 (reference 1). Since the cooling tower cost is a function of rejected heat. Thus the new costs can be calculated, according to section 4.3, as follows:

Theoretical: $\$1.14M \times (66.54/85) = 1.14 \times 0.783 = \$0.89M$

Practical: $\$1.14M \times (79.49/85) = 1.14 \times 0.935 = \$1.07M$

4.6 Pumps and Drives

Cooling water pumps system cost is a function of water flow rate and pump head as follows ⁽¹⁾:

$$C(\$1000) = 174.3 + 0.0055 (\text{Water rate} \times \text{head})^{0.846}$$

If the pump head is assumed to be unchanged. The new costs are calculated by assuming that the parasitic power is 30% of the gross

power output, and that the cooling water has 20°F rise through the condenser. The calculations are as follows:

Gross power output = 50 MW x 3.413/(1-0.30) = 243.8MMBtu/hr
Heat absorbed at heat exchangers (Baseline):

$$243.8/0.808 = 301.9 \text{ MMBtu/Hr.}$$

Heat rejected (Baseline) = 301.9 x 0.85 = 256.6 MMBtu/Hr
Cooling Water flow rate = 256.6/(1.0 x 20) = 12,830,000 lb/hr

Theoretical Improvement: The cooling water rate is proportional to the amount of rejected heat, hence from Section 4.5, the water rate here is:

$$12,830,000 \times 66.54/85 = 10,043,630 \text{ lb/hr}$$

and the new cost, assuming pump head is unchanged, becomes:

$$\$2.14\text{M} \times \frac{174.3 + 0.0055 (10,043.6)^{0.846}}{174.3 + 0.0055 (12,830.0)^{0.846}} = 2.14 \times 0.984 = \$2.11\text{M}$$

Practical Improvement: The water rate here is:

$$12830000 \times 79.49/85 = 11,998,300 \text{ lb/hr}$$

and the new cost becomes:

$$\$2.14\text{M} \times \frac{174.3 + 0.0055 (11998.3)^{0.846}}{174.3 + 0.0055 (12830.0)^{0.846}} = 2.14 \times 0.995 = \$2.13\text{M}$$

4.7 Well

The well number is assumed to be reduced by half for theoretical improvement and 30% for practical improvement due to reservoir stimulation and by the factors equivalent to working fluid reduction. The new costs are calculated as follows:

Theoretical Improvement: The new cost is:

Production Wells: \$5.00M x 0.5 x 0.808 = \$2.02M
Injection Wells: \$2.50M x 0.5 x 0.808 = \$1.01M

Practical Improvement: The new cost is:

Production Wells: \$5.00M x 0.70 x 0.945 = \$3.31M
Injection Wells: \$2.50M x 0.70 x 0.945 = \$1.65M

4.8 Injection Pump

(1) Injection pump cost is a function of water flow rate as follows

$$C = a (x)^{0.608}$$

assuming that the pump head is unchanged. Since the reduction in injection water rate is proportional to that of working fluid, the new costs can be calculated as follows:

Theoretical: $\$0.40M \times (0.808)^{0.608} = 0.4 \times 0.878 = \$0.35M$

Practical: $\$0.40M \times (0.945)^{0.608} = 0.4 \times 0.966 = \$0.39M$

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APPENDIX B

**DESCRIPTIONS OF R&D PROJECTS IN
THE EXTRACTION AND CONVERSION TECHNOLOGY PROGRAM**

Project descriptions, including the objectives and goals, schedule, rationale and accomplishments, of the projects analyzed in this report are presented in this appendix.

PROJECT TITLE: LASL STIMULATION REVIEW
SOURCE (CONTRACTOR): LASL
MIS LINE ITEM ID#: 100011

Objectives and Goals

To provide a scientific advisor to the DOE/DGE funded geothermal stimulation program and to coordinate hydrothermal/hot dry rock stimulation activities.

Description

Dr. Bob Hanold will function as the expert staff scientist for DGE in the industrial support contractor planned and implemented Reservoir Stimulation Program.

Schedule

Continuous participation throughout the first two program years.

Rationale

LASL has considerable background in high temperature hydraulic fracturing by virtue of field activities in the hot dry rock program. Dr. Hanold, who has been involved in HDR, has spent approximately one half a man year reviewing hydrothermal and oil and gas stimulation technology. His active participation in this program provides HDR coordination as well as much needed staff support for DGE in hydrothermal stimulation.

Accomplishments

LASL has drafted the RFP for selection of an industrial support contractor to plan and implement a continuing stimulation program.

PROJECT TITLE: GEOTHERMAL ROCK MECHANICS
SOURCE (CONTRACTOR): TERRA-TEK
MIS LINE ITEM ID#: 311003, 311004, 311006, 311007

Objectives and Goals

The objective of this initiative is to develop equipment and measurement techniques for in-situ testing of geothermal core samples. The major goal of this program is to establish a focal point for identifying rock properties requirements, testing of core samples, collecting and analyzing data, and disseminating results in both industry and the ERDA Geothermal R&D community.

Description

This program is aimed at the development of techniques for in-situ measurements of the physical, mechanical and thermo-physical behavior of geothermal reservoir formations. Techniques for making such measurements do not exist at this time. Development of the necessary techniques will be accomplished and the methods and results will be documented for publication. This documentation will include design drawings, background information on equipment, and data retrieved from the laboratories testing the equipment. Interaction will be maintained with rock properties user groups.

Schedules

FY78: Material characterization, Model development, Development of tests facilities, and Tests and in-situ response analysis.

FY79: Testing of materials, documentation of results.

Rationale

The data obtained through these tests is used in geothermal resource evaluation, drilling, well completion, reservoir engineering and resource utilization. A large part of this program will involve interaction with other research groups to develop good communications and ensure widespread utilization of the results. Continued testing of rock thermo-physical properties is anticipated to support R&D activities in subsidence, reservoir stimulation, well completion, geophysical prospecting and reservoir engineering. The program will provide a significant laboratory support for the commercialization of new processes, and the growth of the geothermal industry.

PROJECT TITLE: LIQUID EXPLOSIVES
SOURCE (CONTRACTOR): ROCKET RESEARCH
MIS LINE ITEM ID#: 319001

Objectives and Goals

The objective of this program is to develop a high temperature stable pumpable explosive suitable for geothermal well stimulation.

Description

Laboratory formulation and sensitivity and detonability tests of candidate explosives are being performed. An evaluation of necessary field support equipment and explosive emplacement techniques is to be made.

Schedule

To be completed by Mid FY79.

Rationale

High temperature stable explosives suitable for geothermal well stimulation do not exist. This contract will provide industry with a capability to dynamically stimulate geothermal wells.

Accomplishments to Date

Approximately 150 compounds have been formulated, tested and evaluated. One particularly suitable candidate explosive has been identified.

PROJECT TITLE: SEISMIC SENSOR RESPONSE ANALYSIS
SOURCE (CONTRACTOR): H-TECH LABORATORY
MIS LINE ITEM ID#: 398001

Objectives and Goals

The objective of this program is to analyze transducer - rock interaction in Fenton-Hill shear wave shadowing experiments so that accurate and reliable predictions of hot dry rock fracture geometry are possible.

Description

Gage orientation, frequency response, package resonant frequencies and reduced data will all be analyzed to determine the relationship between transducer output and motion input in dynamic wave propagation experiments through fluid filled fracture systems.

Schedule

Work will be completed during the first half of FY78.

Rationale

Locating pre-existing and man-made fractures in hot dry rock systems is essential to successful energy recovery from such resources. Since no direct techniques are available for fracture mapping, indirect methods using acoustic signals will be attempted. Evaluation of gage-media interaction is essential to a meaningful analysis of data where slight differences in sound wave patterns can be indicative of wave propagation across a fracture system.

Accomplishments to Date

New program.

PROJECT TITLE: PRDA - RESERVOIR STIMULATION
SOURCE (CONTRACTOR): NOT YET IDENTIFIED
MIS LINE ITEM ID#: 950005

Objectives and Goals

The objective of the geothermal reservoir well stimulation program is to utilize the existing hardware and experience developed for oil and gas well stimulation treatments and then extend the state of the art to geothermal-specific conditions. Program direction stresses the practical aspects of geothermal fluid production with emphasis directed toward stimulation of hot-water-dominated hydrothermal systems by hydraulic fracturing techniques. The goal of this program is to assure the availability of geothermal reservoir well stimulation methods of proven effectiveness in the commercial marketplace very early in the 1980's, on a schedule commensurate with the anticipated commercial exploitation of hydrothermal geothermal resources.

Description

The geothermal reservoir well stimulation program will consist of two parallel phases: the first phase will be devoted to the development of the required specialized geothermal hardware, stimulation treatment designs, and data analysis interpretation from existing well stimulation treatments, while the second phase will directly address and provide for site-specific and technique-specific field demonstration experiments. Initial emphasis for phase two will be directed toward stimulation treatment designs which can be applied to lower temperature geothermal wells using existing hardware and technology. As new hardware and technology become available as a result of the phase-one work, field stimulation experiments will advance to higher temperature wells requiring advanced stimulation treatment designs and equipment.

Schedule and Major Milestones

A program management organization will be used to formulate, manage, and implement the proposed well stimulation program. This organization will provide the technical focal point for all activities within the program and will be selected through responses to an RFP scheduled to be issued early in calendar year 1978. The management organization will be selected, a contract negotiated, and technical work initiated by mid 1978. The first field stimulation experiment will be completed within one year of the program initiation date.

Rationale

Stimulation methods have been used successfully to improve the flow in petroleum and natural gas wells in tight formations. Well

Rationale, Continued

stimulation has the potential economic advantage of providing a very rapid return on the required investment. By selectively identifying and eliminating the impediments to commercial well stimulation, this program is designed to enhance private development of geothermal energy production through the effective stimulation of previously noneconomic wells.

Accomplishments

As an FY1978 new-start, a draft program plan and the RFP for the selection of the program management organization have been prepared.

PROJECT TITLE: NATIONAL COMMITTEE ON ROCK MECHANICS
SOURCE (CONTRACTOR): NATIONAL ACADEMY OF SCIENCE
MIS LINE ITEM ID#: 378001

Objectives and Goals

To support the U.S. National Committee on rock mechanics.

Description

This is a subsidy to the National Academy of Science to maintain a strong national capability in rock mechanics and to insure DOE/DGE is included in policy formulation.

Rationale

DGE will benefit from a strong national program in rock mechanics which includes a geothermal emphasis.

Schedule

Continuing activity.

Accomplishments to date

A meeting of the committee was held in FY77 in which energy related rock mechanics programs and requirements were reviewed. A specific assessment of geothermal requirements for rock mechanics research was made.

PROJECT TITLE: GAS LIFT TECHNOLOGY
SOURCE (CONTRACTOR): ROGERS ENGINEERING
MIS LINE ITEM ID#: 409001

Objectives and Goals

The objective of this program is to demonstrate the feasibility of CO₂ gas lift technology to enhance geothermal fluid production and control the wellbore geochemistry to prevent calcite deposition and borehole plugging.

Description

Relatively small quantities of CO₂ are to be pumped downhole to lift the geothermal brine and control the wellbore brine chemistry. One field test on a privately-owned well is to be conducted and analyzed.

Schedule

Field testing by August 1978 is expected. Data analysis and report completion is to be accomplished by December 1978.

Rationale

Calcite plug formation is a frequent and serious problem in many flowing geothermal wells. By controlling the wellbore chemistry, it is theoretically possible to eliminate this problem while simultaneously increasing production flow rates.

Accomplishments

New program.

PROJECT TITLE: TWO PHASE FLOW IN GEOTHERMAL ENERGY SYSTEM
SOURCE (CONTRACTOR): DENVER RESEARCH INSTITUTE
MIS LINE ITEM ID#: 704001

Objectives and Goals

The objective of this research is to develop an accurate predictive capability of geofluid flow rates and well bore pressure drop for self flowing geothermal wells under specified reservoir conditions. The predictive capability will be parametrically exercised to determine optimum field development strategy and well casing size selection.

Description

Semi-empirical pressure drop correlations are being compared with available data and modified to be more generally applicable. Laboratory tests at the University of Houston and parametric calculations by Coury and Associates are being conducted to improve and validate correlations. Field tests are conducted with downhole measurements in flowing wells to improve the quality of data used in the correlations. A users handbook to predict pressure drop is being prepared.

Schedule

Continued field testing and data correlation will continue through 1983. The number of tests and site locations will be dependent upon negotiations of site use agreements.

Rationale

Strategy on how to produce geothermal wells is generally lacking due to an inability to predict production rates under phase flow conditions. As a result, it is presently impossible to determine optimum casing diameters or to evaluate the merits of mechanical pumps over self flow. In low temperature systems (300°F) flow rates have been doubled with mechanical pumps although analysis would indicate only a marginal benefit. This program will enable us to determine a priori the need for pumps and their benefits.

Accomplishments to Date

Two field tests have been conducted and downhole pressure and temperature measurements obtained under flowing conditions. Numerous pressure drop correlations have been evaluated and a handbook has been drafted to estimate pressure drop using the best existing correlation.

PROJECT TITLE: TRANSPORT AND CONVERSION OF
HEAT AT MODERATE TEMPERATURES
SOURCE (CONTRACTOR): ORNL
MIS LINE ITEM ID#: 104003

Objectives and Goals

The overall objective of this program is to obtain and disseminate commercially useful technical and cost information on components and systems for converting heat from geothermal sources to useful work. This activity is directed toward the goal of achieving near-term competitive power generation plants using geothermal heat sources.

Program Description

This program has been mainly involved in the development of advanced heat exchangers for use in geothermal binary power cycles with current emphasis on working-fluid condensers. This work consists of performing precise single-tube heat transfer experiments, data correlation, and development of design methodology for applying the results to full-size geothermal plant condensers. It also includes design and fabrication of prototype heat exchangers for evaluation of performance under actual operating conditions to confirm size scale-up algorithms. Work is planned for developing improved evaporators for geothermal power cycles.

Schedule and Major Milestones

Phase I (two-tube) condenser test in East Mesa direct-contact isobutane loop - 2/1/78; Phase II (40-tube) condenser test - 3/1/78; Process design of 500 kW(e) condenser for East Mesa Demo Plant - 3/7/78; Award contract for condenser fabrication - to be developed; Condenser shipped to test site - to be developed; Test loop revised for evaporator tests - 7/1/78.

Rationale

In the design and operation of power generation systems using low-to-moderate temperature heat sources, heat transfer considerations often become of controlling economic significance. Typical near-term geothermal conversion cycles reject three to six times more heat than modern large coal-fired stations and, thus, in some cases the heat rejection system can be the most costly part of such a plant. Improving the efficiency and reducing the cost of these systems represents an important area for development work to assure the early commercialization of power stations using thermal heat sources.

Accomplishments

With the candidate working fluids (fluorocarbons), condensation heat transfer coefficients have been improved (over smooth vertical tubes) by a factor of from 3 to 7 by the use of fluted tubes and/or drain-off skirts. Seven fluids and ten tube geometries have been evaluated.

A heat exchanger design has been completed incorporating these developments and is being fabricated for testing at the East Mesa site.

A book entitled, "Geothermal Energy as a Source of Electric Power" was written and published.

PROJECT TITLE: DIRECT CONTACT RESEARCH
SOURCE (CONTRACTOR): INEL (UNIVERSITY OF
UTAH SUBCONTRACT)
MIS LINE ITEM ID#: 715001

Objectives and Goals

Develop the heat transfer correlations and design criteria for direct contact boilers, preheaters and condensers, provide direct contact cycle analysis codes and evaluate working fluid recovery methods necessary to design a direct contact binary energy conversion system. FY 1978 efforts are primarily directed toward experimental and analytical investigation of direct contact condenser systems.

Program Description

Direct contact boiling heat transfer data has been obtained from experiments and heat transfer correlations have been derived. A computer code was developed and direct contact cycle analysis was performed. During FY 1977 theoretical models for two types of direct contact condensers were studied.

The FY 1978 program primarily consists of theoretical and experimental evaluation of three types of condensers: collapsing bubble, drop, and film. Economic evaluations will be performed to aid in selecting the best type condenser. Near the end of the fiscal year a scaled unit will be built and tested. A small amount of systems analysis will be performed to evaluate the best type of heat rejection systems for use with direct contact binary systems and to investigate the potential of direct contact bottoming cycles.

Schedule and Major Milestones

Complete single bubble and packed bed experiments - 2/1/78;
complete analysis of data and development of correlations for condenser heat transfer - 5/30/78; complete evaluation of direct contact bottoming cycles - 2/15/78; design and construct a "Scale Size" condenser and conduct preliminary test (for 500 kW unit) - 9/30/78.

Rationale

Conventional heat exchangers represent a substantial portion of the capital cost of a binary power plant. The use of direct contact units offers the potential to reduce heat exchanger pinch points, eliminate scaling problems and reduce capital cost of the conversion system. Heat exchange data and correlations are non-existent for the proposed application and therefore R&D work is required.

Accomplishments

Analytical models to predict direct contact boiler performance based upon experiments were developed in FY 1977. A cycle analysis code was also developed. In FY 1978 analytical models of condensing, based upon experimental data will be completed as will a comparative evaluation of the best type of heat rejection system.

PROJECT TITLE: LIQUID FLUIDIZED BED
HEAT EXCHANGER
SOURCE (CONTRACTOR): INEL
MIS LINE ITEM ID#: 106001

Objectives and Goals

Phase one development objectives includes demonstration of the principle measurement of heat transfer coefficients, and cost analysis, leading to the goal of reducing conversion system heat exchanger capital cost by a minimum of 30 percent.

Program Description

Project authorization for FY 1978 is \$65k. At this funding level, the following items and a phase one final report are planned.

Corrosion-erosion Test - Candidate materials for tube bundles are being evaluated. Significant cost savings can be achieved if a material can be identified which is less expensive than stainless steels, but has similar hardness. Fluidized beds inhibit pitting corrosion, so the corrosion property of stainless is not required.

Flow Distribution and Heat Transfer - Fluidized beds require uniform cross sectional flow. Vertical and horizontal vessels were fabricated to use in design of flow distribution systems. The same vessels are used to compare heat transfer in vertical parallel flow with horizontal cross flow.

Size-Cost Analysis - The size and cost of heat transfer equipment, including high and low pressure preheaters, high and low pressure boilers, and condenser, are being calculated for fluid bed and conventional exchangers in a 50 MW plant. This will provide the basis for a midyear proposal for phase two development.

Phase two will include vendor evaluation of size and cost, retrofitting the 60 kW unit with fluid bed preheaters, boiler and condenser, and evaluation of unique distribution systems.

Schedule and Major Milestones

Install vertical flow test unit - 1/15/78; final draft of cost analysis for liquid fluidized bed plant - 3/15/78; final draft report on liquid fluidized bed project - 7/31/78.

Rationale

When this project began, it was believed that heat exchanger fouling would be the major problem, so emphasis was placed on scale control. Now it is assumed scaling will not be a major barrier to geothermal development and the major emphasis is on cost. Reflecting this change the scale control and basic heat transfer data collection is referred to as phase one development. Cost reduction and scale-up of the liquid fluidized bed exchanger which logically follows will be phase two.

Accomplishments

The original goals of demonstrating scale control and providing basic design data were successfully accomplished.

PROJECT TITLE: PROPERTIES OF WORKING FLUIDS
SOURCE (CONTRACTOR): NBS
MIS LINE ITEM ID#: 204002

Objectives and Goals

To measure the equation of state properties of binary cycle working fluids.

Description

Temperature, pressure, volume relationships for isobutane and freon 114 will be experimentally determined by the NBS.

Schedule

To be concluded during FY78. September 1978.

Rationale

Existing equation of state data for isobutane and freon 114 over the geothermal-typical range of operating conditions are subject to uncertainties which have serious plant design implications. Reliable data are needed to support the Direct Contact Power System Program and the Sperry Thermal Pump Binary Program.

Accomplishments

New program.

PROJECT TITLE: APEX-ADVANCED GEOTHERMAL
PRIMARY HEAT EXCHANGER
SOURCE (CONTRACTOR): ENERGY CONVERSION COMPANY
MIS LINE ITEM ID#: 300001, 300004

Objectives and Goals

The objective of this initiative is to collect sufficient experimental data to permit the designing of a primary heat exchanger which does not foul up when dissolved salts and minerals are precipitated during the heat transfer process in a geothermal power system. The major goals are to demonstrate non-fouling of the heat exchanger surface, and to measure allowable heat exchange rates, optimum velocities, bed make-up requirements, pressure drop and long-term fouling influence parameters.

Description

The APEX design aims at developing a self-cleaning heat exchanger for economic utilization of geothermal brines with high total dissolved solids. Solid material, separated from previously circulated brine, inhibits the fouling of the heat exchanger by mechanically scouring the tube walls and by providing nucleation sites for precipitating solids. The concept and design of APEX has been proved successful in laboratory tests. The future efforts will involve well-site verification of the concept and design.

Schedules

FY78 - field test of experimental model at Heber; FY79 - design and testing of prototype; FY80 - completion of design and testing

Rationale

One of the major objectives of the geothermal energy program is the exploration of hot water and brine for power generation. These heat containing fluids create problems due to the precipitation of dissolved salts and other minerals within the process equipment. The successful implementation of the APEX concept would provide the following benefits for power generation from geothermal resources:

1. Long continuous operation without requiring maintenance due to fouling.
 2. Minimized fouling of re-injection wells.
 3. Removal of salts and minerals for recovery as by-products.
- Results of laboratory tests and economic analysis indicate a potential 40 percent reduction in capital costs relative to the conventional shell and tube heat exchangers.

PROJECT TITLE: ANALYTICAL STUDY OF CONCEPTS
RELATED TO THE UTILIZATION OF
GEOTHERMAL ENERGY

SOURCE (CONTRACTOR): WEIDLINGER ASSOCIATES
MIS LINE ITEM ID#: 327001, 327002, 327004

Objectives and Goals

The objective of this initiative is to develop a theoretical basis for evaluating the concepts related to the utilization of geothermal energy resources. The primary goal is to conduct a theoretical evaluation of each candidate approach in geothermal power systems components/areas such as energy conversion concepts, prime movers, separators, etc.

Description

Theoretical analysis will be performed by applying the principles of Thermodynamics and Applied mechanics to specific techniques and approaches being considered as candidates for the advancement of technology related to the practical development of geothermal resources for producing useful energy. The areas/components to be analyzed may include (i) energy conversion processes, (ii) prime movers, (iii) liquid vapor separator, (iv) geothermal reservoir priming, (v) efficiency of hybrid power plant cycles, (vi) direct contact heat exchangers, (vii) thermochemical conversion systems, and (viii) lift translator turbines.

Schedules

The initial agreement covers a 12 month period involving quick response efforts.

Rationale

As a potentially important domestic energy resource, geothermal energy offers the promise of contributing significantly to the achievement of the goal of developing and commercializing alternative energy resources. Because the extent of utilization is highly dependent on technology, it is important that ERDA should support only the most promising and fundamentally sound approaches to the development of the required technology. This initiative is designed to aid the evaluation of the soundness of the approaches available to DGE and ERDA.

PROJECT TITLE: SITE-SPECIFIC ANALYSIS OF HYBRID
GEOTHERMAL FOSSIL PCWER PLANTS
SOURCE (CONTRACTOR): CITY OF BURBANK
MIS LINE ITEM ID#: 354001, 354002, 354003

Objectives and Goals

The objective of this initiative is to determine the economic and energy conservation benefits of hybrid geothermal/fossil power plants. An important goal is to identify the operating system design criteria for plant design through an analysis of the impact of typical site-specific variables on the cost of power and the efficiency of usage of the resource.

Description

A combined analytical and planning study will be undertaken to develop quantitative prediction of energy conservation efficiencies as well as electric power production and distribution cost/benefits for a range of typical geothermal reservoir conditions. East Mesa, Long Valley, Coso, and Roosevelt Hot Springs will be evaluated as potential plant sites. Proximity to existing and developed coal reserves and transportation systems, as well as electrical distribution systems will be investigated. Thermodynamic analysis of cycle performance will be carried out and the optimum ratio of geothermal heat addition/fossil heat addition will be determined.

Schedules

Complete thermodynamic in FY78.

Rationale

The results and conclusions of this study will be incorporated into the Geothermal Energy Conversion Panel's Geothermal Energy Conversion Handbook. These results will also be utilized as the basis for obtaining investor funds (through a bond referendum) for the development of geothermal energy by the City of Burbank. This initiative thus contributes directly to the achievement of DGE's goal of promoting commercialization of the nation's geothermal energy resources.

PROJECT TITLE: HEAT EXCHANGER TEST
SOURCE (CONTRACTOR): LBL, EPRI
MIS LINE ITEM ID#: 323001

Objectives and Goals

The overall objective of this project are to: (a) verify the performance under field conditions of large-scale shell-and-tube heat exchangers heating and vaporizing hydrocarbon fluids with geothermal brine, (b) establish overall heat transfer and condensing coefficients that can be used for design of commercial-scale geothermal power plants using hydrocarbon working fluids, (c) determine the effects of heat exchanger cleaning on subsequent heat exchanger performance, (d) confirm time rates of accumulation of solid scale and fouling films on tube heat-transfer surfaces.

Rationale

Rankine-cycle processes using a light hydrocarbon working fluid, "binary cycles" are considered the leading contenders for the initial power generating plants exploiting moderate temperature hydrothermal resources. The heat exchangers in these plants are major capital cost items. Initial binary-cycle geothermal power plants will use shell-and-tube heat exchangers to transfer heat from the geothermal fluid to the working fluid. Reliable, empirically verified heat transfer coefficients for this type of service do not exist. Development of this information and effective and economical tube cleaning methods are needed for the successful application of this type of heat exchanger to geothermal service.

Program Description

This project is jointly sponsored by DOE and EPRI. The test will duplicate the working-fluid compositions, velocities, pressures, temperatures, and process circuitry which are expected to occur in a commercial-size binary geothermal power plant. Pure isobutane will be used as the working fluid initially, followed by blends of other hydrocarbons. Data will be taken from which overall heat transfer coefficients will be developed. Time rates of scale formation will also be obtained, and cleaning procedures will be tested. It is presently planned to conduct the test at Chevron Resources Corp's leasehold at Heber, California.

Schedule and Major Milestones

LBL/EPRI management agreement signed - 11/77; contracts for design and construction let - 2/78; begin tests - 7/78; submit final report - 10/78.

Accomplishments

The work accomplished to date is: (a) LBL and EPRI issued parallel, complimentary requests for proposals, (b) the resulting proposals have been evaluated and LBL and EPRI are currently selecting the successful proposers, (c) firm quotations were obtained on all long-delivery equipment.

PROJECT TITLE: GEOTHERMAL TOTAL FLOW
SUBPROGRAM
SOURCE (CONTRACTOR): LAWRENCE LIVERMORE LABS
MIS LINE ITEM ID#: 103003

Objectives and Goals

The objective of this initiative is to develop and to evaluate methods for commercial production of electric power from the energy of hydrothermal deposits, particularly the hot brines (~300°C). The major goal of this program is to develop systems for the recovery and conversion of energy stored in hot water deposits containing more than 3 percent dissolved solids.

Description

The approach is directed toward the development of an entirely new method called the Total Flow Concept. This, in principle, consists of expanding the total well-head brine-steam mixture directly through a mixed-phase expander to drive an electrical generator. Among the candidates are tangential, axial and radial flow impulse turbines, reactive turbines, and positive displacement devices such as the helical screw expander. A detailed analysis shows that substantial increase in total power output can be achieved. The program for the development of this system involves four basic activities - resource assessment, brine chemistry and materials technology, energy conversion systems engineering, and field testing of the system.

Schedules

FY78 - resource analysis, waste disposal and mineral recovery, testing of materials and components, brine tolerant systems design test, design and fabrication of 10 MW experimental system, development of materials for commercial use; FY79 - design and fabrication of 10 MW systems, operation and performance evaluation, fabrication of materials for commercial use; FY80 - operation and evaluation of performance, fabrication of materials for commercial use.

Rationale

High temperature brines (~300°C) with high content of total dissolved solids (TDS) represent a significant segment of the exploitable geothermal resources in the U.S. The current interest in conversion machines and systems designed uniquely for these resources is stimulated by the need for minimizing the cost of exploiting them. The range of chemical conditions in high salinity deposits will require new approaches. Thermodynamically, the Total Flow Process is

the simplest and can be shown to provide an upper bound on cycle efficiency. A detailed analysis indicates that an increase in power output could be achieved by the successful development of the Total Flow Concept. In order to promote the commercialization of this concept for utilization under a variety of well head conditions, it is essential that ERDA undertake this program of testing and evaluation of performance.

PROJECT TITLE: HELICAL SCREW TEST
SOURCE (CONTRACTOR): JPL
MIS LINE ITEM ID#: 201001

Objectives and Goals

The objective of this project is to provide an independent and credible evaluation of the performance capability of a megawatt-size helical screw expander for the extraction of energy from geothermal brines, over a range of expander inlet conditions broad enough to encompass the wellhead conditions expected for most hydrothermal geothermal resources. The goal is to demonstrate to the geothermal industry the availability of a commercial technology for energy extraction which is brine compatible, has broad applicability, and offers performance or operational advantages over "conventional" geothermal energy extraction systems.

Description

A nominal one megawatt helical screw expander power system, including an electric power generator, is being procured from Hydrothermal Power Company, Ltd., the inventor, by the Jet Propulsion Laboratory (JPL), which will conduct the evaluation. The evaluation will be conducted at one or more geothermal sites. The program is divided into two phases: in the first phase, the power system was designed and fabricated, the test plan was developed, the instrumentation and support equipment were assembled, potential test sites were evaluated, and a site was selected for the field test. This phase is now completed. The second phase, currently under way, encompasses the detailed design of the site layout, the erection of the test equipment, and the conduct of the test program.

Schedule

The present schedule calls for the completion of the field evaluation test at the first site by the end of April 1978. Major milestones in the program are: delivery of the helical screw expander power system to the test site - 1/5/78; complete installation of the test equipment - 1/27/78; complete field test - 4/15/78; deliver final report - 7/31/78.

Rationale

Several years ago (1972-73), a 62.5 kVA prototype helical screw expander was built and tested by the inventor at a number of geothermal wells in the Imperial Valley, California, and in Mexico, with very promising results. However, the size of the unit and the quality of

the test data were not sufficient to enable the inventor to sell the technology to potential users, nor to raise the capital necessary to provide a more convincing demonstration. After careful evaluation, the DGE decided that this technology had sufficient promise for stimulating geothermal development and that it warranted the investment of Federal funds to determine convincingly if the apparent promise were real.

Accomplishments

To date, the helical screw expander power system has been fabricated and tested on compressed air flow and is ready for movement to the field. All necessary instrumentation and support equipment has been designed and built, and integration and checkout of the instrumentation with the power system has been accomplished. Arrangements have been completed with Phillips Petroleum Company for use of their well 54-3 at Roosevelt KGRA, Utah. All the necessary process piping for integrating the power system with the Phillips' wellhead equipment and brine disposal system has been designed and procured.

PROJECT TITLE: GRAVITY HEAD BINARY PLANT
SOURCE (CONTRACTOR): SPERRY RESEARCH CENTER
MIS LINE ITEM ID#: 309004

Objectives and Goals

The objective of this program is to demonstrate, in an industry coupled field test, the thermodynamic and economic benefits of a binary system utilizing down-hole heat exchange and a gravity head working fluid pump.

Description

A 5 MW_e binary system will be designed, built and operated on a moderate temperature (~350°F) low salinity resource. The design will include a downhole turbine driven brine pump and counterflow heat exchange between the brine and Freon-114 in the well bore. By varying heat exchange surface area as a function of depth, pinch effects can be minimized and cycle efficiency optimized.

Schedule

The program will be completed in 4 years. The first year will establish design parameters, accomplish site selection and initiate fabrication of brine pump hardware. Subsequent phases will include well drilling and completion and installation and test of system hardware. The schedule for FY 79 and beyond is dependent upon final site selection and is still tentative.

Rationale

The majority of the National Geothermal Resource consists of hydrothermal systems at temperatures below 360°F. These systems are at best marginally economic with today's technology. The thermal pump binary program has a realistic potential of reducing electric generating costs by 10-20% thus bringing a much larger resource base into the realm of commercial feasibility.

Accomplishments to Date

New program.

PROJECT TITLE: GEOTHERMAL ROTARY SEPARATOR
SOURCE (CONTRACTOR): BIPHASE ENGINES
MIS LINE ITEM ID#: 315001

Objectives and Goals

To design a wellhead geothermal rotary separator.

Description

Under the FY77 basic contract, performance data were gathered through laboratory and field testing of a small scale rotary separator. This information is to be used in this contract modification to design a full scale wellhead separator.

Schedule

To be completed by June 1978.

Rationale

From 20 to 30 percent of the available power at the wellhead is lost during throttling in the flash tank and separator of a typical flash steam conversion system. The rotary separator is capable of recovering a sizeable percentage of that lost work in the form of a high pressure liquid phase suitable for driving a hydraulic turbine or direct reinjection.

Accomplishments to Date

A small scale rotary separator has been built and successfully flow tested on a geothermal well.

PROJECT TITLE: WASTE HEAT REJECTION
SOURCE (CONTRACTOR): ORNL
MIS LINE ITEM ID#: 950067

Objective

The main objective of this program is to prepare an in-depth assessment of waste heat rejection problems associated with the utilization of geothermal energy and to perform in-house or via subcontract) the required development work in critical areas which can have a significant impact on the early commercialization of geothermal power plants.

Program Description

This program is composed of two main parts, analytical and experimental studies. The primary analytical activity is the preparation of a Chapter on Waste Heat Rejection for the Geothermal Energy Source Book. This work includes in-depth assessment of the technical, economic, and the environmental factors associated with the components and subsystems used for waste heat rejection and will form the basis for planning an experimental program in this area as well as in the area of waste heat utilization. The experimental activity will likely include efficiency improvements and cost reduction development work for the various options available for heat rejection from geothermal heat utilization cycles.

Schedule and Major Milestones

Preliminary draft of the Waste Heat Rejection Chapter for the Geothermal Energy Source Book - 3/1/78; final draft submitted for editing - 6/15/78; program plan for experimental program - 6/1/78; beginning in-house experimental program - to be developed; preparation of PRDAs and/or RFPs for subcontracted work - to be developed.

Rationale

Waste heat rejection systems for geothermal power cycles take on unusual importance in the overall economics of the plant, and will probably incorporate special features that are not now used in today's conventional power plants. Geothermal plants differ from most fossil and nuclear powered stations in several important aspects: (a) amount of waste heat three to six times greater; (b) greater sensitivity to sink temperature level; (c) often use unusual working fluids in a binary cycle which can incorporate a direct-contact evaporator; (d) plant size usually smaller by a factor of from 5 to 25; (e) plant sites are often in remote areas with poor availability of acceptable cooling water.

Thus, the importance of performing development work in waste heat rejection systems with special attention to the unique requirements of geothermal plants is evident.

Accomplishments

This is a relatively new program which is an outgrowth of the program on Transport and Conversion of Heat at Moderate Temperatures that is more oriented toward specific heat transfer problems. The preparation of the Waste Heat Rejection Chapter for the Geothermal Energy Source Book began in Mid-FY 1977 and is proceeding according to schedule.

PROJECT TITLE: HAWAII 5-10 MWE STEAM GENERATOR
SOURCE (CONTRACTOR): RESEARCH CORPORATION OF THE
UNIVERSITY OF HAWAII
MIS LINE ITEM ID#: 456001

Objectives and Goals

Prove the economic feasibility of base load power production with a small flash steam generator system. Provide performance and economic data for comparison to other geothermal generating systems. Provide long term reservoir testing.

Description

The Research Corporation of the University of Hawaii will be contracted with to design, purchase, install, and operate for 2 years an environmentally acceptable small electric generator at the Puna Geothermal well.

Schedule

Submit cost proposals and work breakdown structure - 12/5/77; contract begin - 3/1/78; conceptual design completed - 4/15/78; preliminary design review - 7/1/78; final design - 10/1/78; possible power production - 5/79.

Rationale

The installation of this pilot plant will stimulate the development of geothermal resources and the production of electric power using small electric generating systems by providing small power companies with data on economics, reliability and operation.

Accomplishments to Date

A program begun by the NSF in 1974, to develop geophysical exploration techniques for locating geothermal resources mapped the Puna Rift Zone. This work delineated several possible resources. ERDA funded the drilling of an exploratory hole to verify the geophysical data. The ERDA hole was completed in 1977, and is capable of producing over three megawatts of electricity for tens of years.

PROJECT TITLE: DIRECT CONTACT BINARY
DEMONSTRATION PROGRAM

SOURCE (CONTRACTOR): LBL

MIS LINE ITEM ID#: 107005, 107027, 107028,
107031, 107034, 302001,
303001, 305001

Objective

To verify the anticipated advantages of direct-contact heat exchange when used in geothermal power plants.

Rationale

Rankine-cycle processes using a light hydrocarbon working fluid, "binary cycles," are considered the leading contenders for the initial power generating plants exploiting moderate temperature hydrothermal resources. The heat exchangers in these plants are major capital cost items. Direct-contact heat exchange promises to reduce the capital cost of second generation power plants by permitting lower-cost heat exchangers. Plant maintenance costs can also be reduced by avoiding the chemical scaling inherent in conventional heat exchangers. Direct-contact heat exchange is a relatively recent technology. Design data and performance parameters must be determined and the economic advantages must be evaluated. A direct-contact heat exchanger cannot simply replace a conventional heat exchanger in an existing process. The process must also be redesigned to take full advantage of this new concept.

Program Description

The evaluation of direct-contact heat exchange for geothermal power plants involves three activities: (1) Conceptual design studies will delineate the parameters of the optimum processes using direct-contact heat exchange, and establish the economics of these optimum processes; (2) Component tests have established the basic performance of small direct-contact heat exchangers in the field. Additional component testing will further establish heat exchanger and auxiliary subsystem performance; (3) A 500kW pilot plant will confirm the thermodynamic performance of the direct-contact binary process and provide design information for prototype commercial-size power plants.

Schedule and Milestones

Complete initial component tests - 3/77; operate direct-contact heat exchanger with hydrocarbon turbine - 7/77; operate 500kW pilot plant at East Mesa - 9/78; operate 500kW pilot plant at Raft River - 1/79.

Accomplishments

Direct-contact heat exchangers have been successfully operated in the field and a 500 hour test of a small hydrocarbon turbine and direct-contact heat exchange loop has been completed. Initial economic studies have shown a capital cost advantage for the direct-contact binary process.

PROJECT TITLE: GEOTHERMAL POWER HANDBOOK
SOURCE (CONTRACTOR): BROWN UNIVERSITY
MIS LINE ITEM ID#: 719001, 712002, 712004,
719001, 201006, 201008,
106024

Objectives and Goals

The Brown University program is intended to provide, in sourcebook form, an authoritative, complete and current compilation of Geothermal Power Plant and Energy Conversion information.

Description

A working group chaired by Brown University and composed of the National Laboratories, A&E's, equipment manufacturers and others has been formulated to draft and assist in editing the Geothermal Energy Conversion Sourcebook. The working group meetings serve not only to maintain sourcebook progress but as a mechanism for information exchange on DGE technical programs. Detailed minutes of seven such meetings have been prepared and distributed. Brown University will compile, author, edit and publish the sourcebook based on contribution from the committee and the Brown technical staff. The manual will cover all aspects of geothermal power plants including details of existing facilities.

Schedule

A completed draft is planned for August 1978. Dissemination of a final first edition will be accomplished during FY78.

Rationale

The existing geothermal literature on geothermal power cycles and energy conversion is incomplete, contradictory and in many cases, erroneous. This project is intended to provide an authoritative assessment of the problem and provide a correct methodology for power plant conceptual design as well as an accurate state-of-the-art presentation.

Accomplishments

Approximately half of the ten sourcebook chapters have been drafted. A close working relationship and flow of information between DGE funded programs has resulted from the working group meetings.

APPENDIX C

DESCRIPTION OF GELCOM

A GEOTHERMAL LEVELIZED BUSBAR COST MODEL

Appendix C contains an explanation of the logic and the algorithm for the GELCOM - Geothermal Levelized Busbar Model which was utilized for estimating the benefits associated with projects for which quantitative impacts on the cost of power could be identified.

METHODOLOGY FOR ECONOMIC ANALYSIS¹

The technique for estimating the levelized busbar costs of electricity involves the utilization of two models constituting GELCOM. The first model generates engineering cost and performance data and the second uses these data to compute levelized busbar costs of electricity.²

Engineering Cost Model

This model, which applies to liquid-dominated hydrothermal resources above 150°C, is based upon interpolations between representative conceptual field and plant designs for binary and flash cycle systems at three resource temperatures and two salinity levels. Basically, the capital costs are estimated separately for eight categories within the production area and nine within the generation area, as functions of system type (flash or binary), resource temperature, and resource salinity. These categories are detailed in Table C-1. Well costs are estimated separately, depending upon reservoir depth and overlying rock hardness.

Generally, operating and maintenance costs are taken to be proportional to the capital costs, and the constants of proportionality are modified by the system type and resource salinity level. Operations and maintenance costs associated with deep well pumps and waste

¹The contents of this appendix were extracted from "GELCOM - A Geothermal Levelized Busbar Cost Model Description and User's Guide - M78-17. J.N. Gupta and J.G. Leigh, The MITRE Corporation, Metrek Division, January 1978 and modified slightly.

²The levelized value of a variable money stream is the (constant) money stream which has the same present worth.

TABLE C-1
CAPITAL COST CATEGORIES

CATEGORY		MAJOR EQUIPMENT OR FUNCTION
PRODUCTION	Wells	Production wells, collars, corrals
	Gathering System	Piping for steam, brine or both to plant
	Process Mechanical	Deep well pumps, process pumps, valves, separators at well head or in plant
	Instrumentation and Control	Instrumentation, motor controllers valve operators
	Waste Purification	Clean up of brine for disposal
	Distribution System	Piping for spent brine from plant to disposal wells
	Disposal wells	Wells, collars, corrals
	Engineering and Administration	Support of design and construction
GENERATION	Turbine Generator	Turbine, generator and aux. systems
	Process Mechanical	Heat Exchangers, pumps, valves, process support equipment
	Piping and Insulation	In-plant process piping and insulation
	Instrumentation and Control	Plant control board, instrumentation, motor controllers, valve operators
	Electrical	In-plant electrical requirements
	Civil and Structural	Turbine pedestal, pads, buildings, fencing, site roads
	Condenser and Heat Rejection	Condenser, cooling towers, pumps for circulating water system
	Switchyard	Switchyard
	Engineering and Administration	Support of design and construction

brine treatment are calculated separately.

In the analyses of the economic viability of the prospects, binary conversion systems have been designated for prospects for which the best estimate of the resource temperature is 200°C or less; binary plants are thought to be more economic than flash plants at lower temperatures. Flash conversion systems have been assumed for the other prospects. Deep-well pumps have been assumed to be necessary for binary systems below 260°C and flash systems below 200°C .¹

Levelized Busbar Cost Model

The model used to compute the levelized busbar costs of electricity is a formulation used as a standard by MITRE (Bennington, 1976). The same approach, with some variations, is in common use (Goudarzi and Trehan, 1977).

It is assumed that the geothermal production field and the electricity generating plant will be owned and operated by two different organizations with differing capital, regulatory and tax structures. These organizations are referred to as the Producer and the Utility, respectively.

The model computes, individually for each plant, the revenues required by the Producer and the Utility to cover all their operating costs and to make a minimum acceptable return. These revenue requirements are translated into levelized busbar electricity costs. The

¹When evaluating the effects of high and low resource temperature estimates on prospect economic viability, these considerations may be relevant.

Producer cost is expressed in mills per kWh (from the generating plant) for convenience. The busbar cost of electricity is the sum of the Producer and Utility costs.

As previously stated, all electricity costs are reported in 1977 dollars, regardless of the plant start-up year.

The computation process is the same for the Producer and the Utility (and also the same for the cost of electricity from competing sources). It equates the present value (in the start-up year) of all cost streams to the present value of an equivalent revenue stream. The discount rate used to obtain these present values is the average net after-tax cost of capital to the organization.

The process starts with the computation of charges accruing to capital. These comprise sinking fund payments or equivalent (for capital recovery), interest on debt, profits to equity, property taxes and insurance, and income tax on profits. All these except profit are sheltered from income tax; interest on debt and property taxes and insurance are tax-deductible, and the sinking fund payments are covered by depreciation allowances. These capital charges are applied to a costbasis consisting of the present value in the start-up year of all investments, allowing for inflation, escalation¹ and the time value of money (cost of capital), and allowing for fiscal adjustments such as reduction of income taxes by accelerated depreciation allowances, investment tax credits and expensing intangible drilling costs.

¹Escalation here denotes real cost changes, which are different from general inflation.

To the present value of these capital charges are added the present values of the cost streams arising from operating and maintenance charges and fuel (the latter applicable only to competing energy sources), again adjusted for inflation, escalation, and the time value of money.

When adjusted for depletion allowance and royalty payments, if applicable, this figure represents the present value of all costs associated with the plant. This is equated to the present value of the revenue stream in order to determine the levelized busbar cost, in the start-up year.

A crucial factor in determining the levelized busbar cost is the way in which future inflation is handled. Two conventions are in common use, and to clarify the difference between them, it is necessary to distinguish between constant (or real) dollars and nominal (or current) dollars. Constant dollars are the dollars of a particular year (1977 in this report) and have constant purchasing power. Nominal dollars are the dollars of whatever year is under consideration and have differing purchasing powers depending upon inflation.

The two conventions in common use are:

- Convention 1: the levelized revenue requirement is taken to be constant over the life of the plant in constant dollars (and hence increases in nominal dollars with the passage of time due to inflation).
- Convention 2: the levelized revenue requirement is taken to be constant over the life of the plant in nominal dollars (and hence decreases in real value with the passage of time due to inflation).

Figures C-1 and C-2 illustrate the differences. Figure C-1 is plotted in constant dollars and shows the revenue requirements according to convention 2 decreasing in real terms. Figure C-2 is plotted in nominal dollars and shows the revenue requirements according to Convention 1 apparently increasing (while remaining constant in terms of real value).

The two conventions represent slightly different ways of expressing the levelized value of the same cost stream and are related by an expression which depends only on the inflation rate, discount rate, and plant life. Under the assumptions made in this report concerning inflation, the value derived under Convention 2 is about 41 percent higher than that derived under Convention 1 (used in this report) for the Producer for a 30-year project life and about 70 percent higher for the Utility. Care must therefore be taken when comparing cost estimates acquired from different sources, in order to ensure that the costs are presented in equivalent terms.

Electricity-generating costs were roughly constant in current dollars (or declining in real terms) through the 1950s, but over the last decade they have been rising with the general inflation rate. It appears that economies of scale associated with larger generation plants are no longer sufficient to offset the effects of increases in capital and fuel costs. It is for this reason that the constant real cost definition (Convention 1) has been adopted in this analysis.

FIGURE C-1
EFFECTS OF INFLATION ON LEVELIZED COSTS AND
REVENUE REQUIREMENTS, CONSTANT DOLLARS

FIGURE C-2
EFFECTS OF INFLATION ON LEVELIZED COSTS AND
REVENUE REQUIREMENTS, NOMINAL DOLLARS

APPENDIX D

RATIONALE FOR THE ESTIMATES OF PRIMARY BENEFITS

1.0 INTRODUCTION

This appendix presents the primary benefit analyses of the projects in the Extraction and Conversion Technology. (See the results in Table 4-1 of the main body of this report). The analyses are based on the assessment of the potential impact of the projects or groups of projects on the cost of geothermal power. In the next sections, the basis and the results of the computation of benefits for various projects or groups of projects are detailed. Each section consists of the following items:

0. Title
After the title a list of related projects is provided. The projects are coded in the same manner as in Tables 3-2 - 3-5 of the main text.
1. Identification of Impacted Parameters
The technical/economic parameters of the geothermal electric power plant (field and generation plant), which are expected to be impacted by the project(s) under consideration, are identified in this section.
2. Estimation of Primary Benefits
The impact of the successful completion of the project(s) on the system parameters, identified in Section 1, is estimated in this part of the evaluation. The estimated impacts are compatible with the input requirements of the GELCOM model. (The structure of this model is explained in Appendix C). Two estimates of impact, optimistic and pessimistic are developed for each impacted parameter.

2.0 STIMULATION STUDY

<u>Project Code</u>	<u>Project Title</u>
2101	Stimulation Review
2102	Geothermal Rock Mechanics
2103	Liquid Explosive
2104	Seismic Sensor Response Analysis
2105	Reservoir Stimulation - PRDA
2106	Technical Consultant at Idaho
2201	National Committee on Rock Mechanics

2.1 Identification of Impacted Parameters

The objective of the above projects is to maximize the fluid production from different geothermal wells. In the extreme case, a dry well may be stimulated to create a connection between the well and a geothermal reservoir. A more common situation involves wells with low output. These wells are stimulated to increase the permeability around the bottom of the well and thereby increase the well flow rate. In all cases, the primary impact of successful stimulation would be to reduce the number of production wells for a given quantity of geothermal fluid. Stimulation can also reduce the number of injection wells needed for disposing of a given quantity of spent brine. In terms of the cost, stimulation will increase the average capital cost of a production/injection well.

Thus the geothermal power system parameters impacted by well stimulation are:

- (i) The number of production and injection wells
- (ii) The capital costs of production and injection wells.

2.2 Estimating of Primary Benefits

Due to a lack of practical experience in geothermal well stimulation, it is not possible to estimate the expected benefits for these projects on the basis of empirical data. Nevertheless, it is possible to estimate the expected benefits on the basis of some reasonable assumptions regarding the number of dry wells and low production wells that are candidates for stimulation and the percentage of attempted stimulation jobs which can be classified as successful.

The estimates of impacts and resulting economic benefits were developed by considering four logically separate scenarios with respect to stimulation of production and injection wells at U.S.

hydrothermal prospects:

- . Scenario I - No stimulation is attempted.
- . Scenario II - The geothermal drilling industry carries out some stimulation efforts without federal assistance, with moderate success.
- . Scenario III- The federal R&D program assists the industry's efforts to a moderate degree (pessimistic estimate of federal program's impact).
- . Scenario IV - The federal R&D program assists the industry's efforts to a high degree (optimistic estimate of federal program's impact).

There are a number of assumptions made here which apply to all of the above scenarios. These common assumptions include:

- . dry hole fraction
- . low producer fraction
- . good producer fraction
- . the nominal flow for each type above.

Other assumptions vary with each of the four scenarios. These scenario-specific assumptions include:

- . percent of wells to be stimulated
- . percent of normal well cost required to stimulate
- . percent of success of stimulation.

With respect to these scenario-specific factors, it is reasonable to assume that the federal program will:

- (1) increase the percentage of dry or poor producer wells at which stimulation is attempted;
- (2) decrease the cost per stimulation attempt;
- (3) increase the probable success of each stimulation attempt.

Estimates of dry hole fraction and low producer fraction are based on the survey by Overton and Hanold¹.

Working from Hanold and Overton's data on the fraction of dry wells encountered at active geothermal sites

¹Harold L. Overton and Robert I. Hanold, "Geothermal Reservoir Categorizations and Stimulation Study", LA-6889-MS, Los Alamos Sci. Lab., July 1977.

world-wide (Their table III, page 14), the dry-hole fraction has been about 20% for all wells, 14% for wells in liquid-dominated fields from which electricity has been produced, and 7% for vapor-dominated fields from which electricity has been produced. Therefore it is assumed that the dry-hole fraction for production and injection wells for U.S. liquid-dominated prospects will be on the order of 15%, that all of these will be near producing wells, and that all are candidates for stimulation.

Some wells that are not dry will produce considerably less water or steam-water mixture than adjacent wells. This can be due to skin damage while drilling, or poor communication with the producing formation. These wells, also, are candidates for stimulation. While it could be argued that almost all geothermal wells are candidates for treatment to attempt to increase the flow, some limiting practical assumption has to be made. It is assumed here that the fraction of low or poor producers is similar in magnitude to the fraction of dry holes, that is, 15%.

Estimating the effect of stimulation on fluid economics, we compare the four scenarios with each other.

Scenario 1 - Base Case:

For 100 holes drilled, 15 will be dry, 15 will be low producers (assumed to be 50% flow of good producer), and 70 will be good producers. Thus for 100 units of drilling cost there will be $0 + 7.5 + 70 + 77.5$ nominal units of flow. There are no added costs of stimulation since none is attempted. Thus the net outcome = $77.5 / 100 = 0.775$ unit of flow per unit cost.

Scenario 2 - Industry Efforts:

Industry efforts alone would have an effect on stimulation. We assume that 33% of the dry holes and low-producing wells would be stimulated with 33% success. Thus $15(.33)(.33) + 15/2 (.33)(.33) = 2.45$ units of additional flow are gained. The cost of this stimulation is calculated by assuming that 50% of the dry wells stimulated will be stimulated using hydrofracture at 30% of the drilling cost, and the remaining 50% of the dry wells plus all the stimulated low producing wells will be stimulated using explosive and chemical techniques at 10% of the drilling cost of a nominal well. Therefore, the added cost of stimulation is $15(.5)(.30) + 15(.5)(.1) + 15(.1) = 4.5$ units of additional cost.

Thus, for Scenario 2, the net outcome is $(77.5+2.45)/(100+4.5) = 0.765$ units of flow per unit cost. This suggests an industry-only effort may be marginally counter-productive.

Scenario 3 - Federal R&D (Pessimistic):

In Scenario 3, we assume 66% of the dry holes and low producers will be stimulated with 50% success. The result is $15(.66)(.5)+15/2(.66)(.5) = 7.43$ units of additional flow. The cost is calculated in the same manner as in Scenario 2 except that the costs of stimulation are slightly cheaper due R&D, and are assumed to change from 30% and 10% of nominal well cost to 28% and 9%, respectively. Thus the cost is $15(.5)(.28)+15(.5)(.09) = 4.13$ units of additional cost.

For Scenario 3, then, the net outcome is $84.93/104.13 = 0.816$ units of flow per unit cost. This is an improvement over Scenario I or Scenario II.

Scenario 4 - Federal R&D (Optimistic):

We assume in Scenario 4 that 100% of the dry hole and low producer wells will be stimulated and will have a success of 66%. The result is $15(1.0)(.66)+15/2(1.0)(.66) = 14.85$ additional units of flow. The cost is calculated in the same manner as Scenario 2 with 30% and 10% cost factors being replaced by 25% and 7% respectively. Therefore the cost is $15(.50)(.25)+15(.50)(.07)+15(.07) = 3.45$ additional units of cost.

The net outcome of Scenario 4 is $92.35/103.45 = 0.893$ units of flow per unit cost.

These four scenarios are compared to estimate the savings that would probably be achieved by industry and federal efforts. Comparing scenario 2 to Scenario 1 is especially interesting because the assumptions used here suggest that the industry-only effort could result in economic losses rather than gains. In the no-stimulation base case Scenario 1, 0.775 units of flow are recovered per unit cost, whereas in Scenario 2, the industry-only case, only 0.765 units of flow are obtained per unit cost. This suggests that the stimulus of an effective federal R&D program is especially necessary in this area.

The effects of this R&D Subelement are estimated by comparing Scenarios 3 and 4 to the base case scenario. (If Scenario 2 had resulted in savings, it would have been the appropriate baseline from which to estimate effects of federal R&D). Scenario 3 (pessimistic case) results in a $(1 - .775/.816) \times 100 = 5.0\%$ overall reduction in

well cost for a given amount of required flow. Scenario 4 (optimistic case) results in a $(1 - .775 / .893) \times 100 = 13.2\%$ overall reduction in well cost.

The total primary benefits are summarized below:

	Optimistic	Pessimistic
1. Change in Well number	0*	0*
2. Change in Well cost	-13.2%	-5.0%

* Impacts on well number has been included in the impacts on well cost.

3.0 TWO-PHASE FLOW

Project Code

2206

Project Title

Two Phase Flow Studies

3.1 Identification of Impacted Parameters

Since the concept of two phase flow is being studied with the objective of increasing the well flow rate, the successful completion of this project could result in a reduction in the number of production wells required for achieving the power-on-line goals. The optimal two phase flow design of production wells will probably increase the production well cost. Thus the two system parameters likely to be affected by this project are:

- (i) the number of production wells; and
- (ii) the average cost per production well.

3.2 Estimation of Primary Benefits

Single phase flow (steam in dry steam fields or water in binary applications) in wells represents the same problems normally encountered in many industrial applications. Steam-water flow, which can be formulated as two-phase, gas-liquid, one-component (except for the case of non-condensable gas), and near adiabatic flow, is however very complex.

Well flow is generally vertical flow and the well can be regarded as a restriction between two media of different pressures: the reservoir, and whatever is installed at the well head. Since the two-phase mixture is compressible, it is possible that when the differential pressure over the restriction is increased beyond a certain critical value, the mass flow rate ceases to increase. It has reached its maximum possible value called the "critical flow rate". The situation is sometimes called "choking" and has been an important phenomenon in the design of emergency cooling systems of nuclear power plants. Let us ignore those phenomena such as flow pattern, holdup, frictional pressure drop, and slippage etc., for the time being, and concentrate on what is affecting the availability of the fluid mixture leaving the well head.

The extraction rate of the geothermal fluid is limited by the reservoir permeability, perforation of the well entrance region and, naturally, the well and surface equipment. If a restriction, say, a valve is installed after the well head to increase the well head pressure, and, therefore, decrease the differential pressure between the reservoir and well head, the mass flow would decrease unless

choking was occurring prior to the application of the restriction. The set up is illustrated by the experience gained in Otake field, Japan¹ (as shown in Figure 3-1). Figure 3-1 shows a plot of mass flow rate of the steam water mixture versus well head pressure and indicates that the curve of well number 10(w) shows evidence of choking. For well number 10(w), choking exists when the valve is fully open. A slight turn in the closing direction of the valve actually increases the flow rate. The choking exists but does it exist in the well or in that part of reservoir bed near the well bottom? To answer this question, well bottom pressure must also be recorded together with well head pressure to see if the pressure difference between well bottom and well head is actually decreasing as the valve of well number 10(w) is closing from the fully open position.

Choking limits the mass flow rate and, consequently, limits the well head availability. However, availability is not a function of mass flow rate only. The specific availability (energy per unit mass) of the fluid mixture at the well head relative to the sink (environment) is defined by²:

$$\psi = (h - T_o s + \frac{V^2}{2g_c} + Z \frac{g}{g_c}) - (h_o - T_o s_o + Z \frac{g}{g_c}) \quad (1)$$

$$= (h - h_o) - T_o (s - s_o) + \frac{V^2}{2g_c} \quad (2)$$

where h and s are specific enthalpy and entropy respectively, $V^2/2g_c$ is the kinetic energy which can be difficult to define for two-phase mixture, and Z is height. The subscript o denotes sink variables. Equation 1 is reduced to equation 2 by assuming $Z = Z_o$. In maximizing the availability, the mass flow rate must be maximized together with the specific availability defined by equation 2. A simplified³ model of two-phase well flow without slippage was examined by Elliott³, who defined the specific availability for the model by:

$$\psi = \Delta h_1 - g \left[\frac{P_{sat} - P_{atm}}{\rho g} \right] Z_w \quad (3)$$

¹Michihiro Fukuda, Kowashi Aosake, and Kotohiko Sekoguchi, "Some Considerations on Well Characteristics at Otake and Hatchobaru Geothermal Areas, Japan", San Francisco Symposium, P.1643, May 1975.

²Van Wyler, and Sowntag, "Fundamental of Classical Thermodynamics", John-Wiley and Sons, 1965.

³David G. Elliott, "Geothermal Energy Conversion, Chapter III: Production Well Flow", draft to DOE/DGE, January 24, 1977.

FIGURE 3-1
CHARACTERISTICS OF GEOTHERMAL WELL FLOWS
AT OTAKE (AFTER FUKUDA ET AL.¹)

where

- Δh_i = Isentropic enthalpy change for expansion of saturated liquid from reservoir temperature to sink temperature T_o
- P_{sat} = Saturated pressure at flashing point in the well (at reservoir temperature)
- P_{atm} = Atmospheric pressure
- ρ = Well water density
- Z_w = Well depth
- ρ_o = Ground water density

Equation 3 shows that the specific availability is a function of reservoir P and T and the well depth. This means that only the mass flow rate needs to be maximized.

The next step is to look at the costs for well drilling and completion because optimum design means maximum availability/\$.

For a particular reservoir, the reservoir P and T, and the well depth are fixed. Other variables which affect the $\Psi/\$$ ratio are well diameter and possibly well configuration (e.g., diameter changes with depth). Let us ignore the well configuration variable and assume that the well has a constant diameter in the two phase region. Let us also assume, that the availability increases with increasing well diameter as shown by curve 1 in Figure 3-2. The well drilling and completion costs of a well vary with well diameter in the manner shown by curve 2 of Figure 3-2 and Table 3-1.⁴ Curve 1 is only an assumption and, therefore, has no base value. The resulted optimum diameter is also shown.

In the treatment of his model, Elliott concluded that the availability could be doubled if the pipe diameter is doubled at and above the flashing point. Of course, this does not consider the possibility of choking in the region near well bottom and the restriction imposed by what comes after the well head. All things considered, it can be seen that the two-phase study will benefit geothermal industry by increasing well availability. How much the increase

⁴ Joseph M. Kennedy, and Roy M. Wolke, "From Here to There by Demonstration Drilling", San Francisco Symposium, p. 1503, May 1975.

TABLE 3-1

SUMMARY HOLE SIZE COST COMPARISON
(10,000 ft. T.D.)*

ITEM	6	7-7/8	8-3/4	9-7/8	12-1/4
Drill pipe*	\$ 32 100	\$ 40 000	\$ 40 000	\$ 40 000	\$ 40 000
Drill collars*	7 740	7 940	8 776	8 776	8 942
Bits	19 320	19 212	20 273	20 680	31 940
Rig move	81 900	88 200	100 800	107 100	126 000
Drilling Fluids	1 263	2 012	3 030	4 377	8 152
Cementing	6 237	7 257	6 577	8 060	7 421
E. Logs	18 000	18 000	18 000	18 000	18 000
Float Equipment	408	511	585	675	913
D.S.T.	1 150	1 150	1 150	1 150	1 150
Surf Casing	7 830	5 900	12 710	12 970	13 590
Support Cost*	45 240	31 200	31 200	31 920	31 920
Location	5 000	5 000	5 000	7 000	10 000
Instrumentation van	18 400	11 500	11 500	10 000	10 925
Rig up & down	20 000	20 000	22 000	25 000	30 000
Water	2 000	2 000	3 000	4 000	7 000
Wellhead	347	347	406	406	590
BOP Rental	1 350	1 675	1 675	1 600	1 600
Supervision	8 800	7 000	7 000	6 650	6 650
Drill String inspection	7 500	7 500	5 000	5 000	5 000
Rig rental (\$3200/day)	92 800	64 000	64 000	60 800	60 800
Total	\$337 545	\$292 464	\$313 906	\$326 313	\$371 651
Relative Cost	1 154	1 000	1 073	1 115	1 271

*Items for one-time purchase, not included in well cost.

FIGURE 3-2
VARIATION OF WELL COST AND AVAILABILITY
AS FUNCTIONS OF WELL DIAMETER

will be, is difficult to estimate at this stage. However, for the purpose of this exercise it is assumed that the number of wells required for particular electricity plant capacity will be reduced by 20% and the cost per well will increase by 10%. In the pessimistic scenario, it is assumed that the number of wells will decrease by 10% only.

In summary, the primary benefits of this project are:

	Optimistic	Pessimistic
1. Change of production wells	-20.0%	-10.0%
2. Change of production well cost	10.0%	10.0%

4.0 GAS - LIFT

Project Code

2205

Project Title

Gas Lift Technology

4.1 Identification of Impacted Parameters

The objective of this project is to suppress the carbonate scaling in production wells. Therefore, the result will be a marginal increase in the average well flow rate and lower cost of operation and maintenance of the wells. Reduced scaling will also make it possible to utilize the production wells longer. The injection of CO₂ for suppressing the scale formation will result in additional well cost. The system parameters likely to be impacted by this subelement are listed below:

1. Production well O & M cost
2. Production well life
3. Production well capital cost

4.2 Estimation of Primary Benefits

In the early stages of development of geothermal resources, the chemical deposition has always created considerable O&M problems. Calcite deposition was reported in Iceland wells at a depth of 49 - 90 meters (130 - 300 ft.). In one of those wells, the output was reduced to about 46% of its original output after 8 days of continuous discharge. In Nevada, wells were reported to get plugged with calcite within a few weeks. Siliceous sinter deposits are also found in other places. Table 4-1 shows examples of deposits found in various geothermal fields. It appears that major deposits are calcite and silica.

Calcite solubility in water decreases with increasing temperature and, therefore, cooling of water does not precipitate out the calcite (e.g., well flow for binary cycle application). Deposition of calcite can occur only in the case of flashing flow. As water evaporates to become steam in the flashing flow, there are two factors which contribute to the deposition of calcite. One is the loss of water and the other is the loss of carbon dioxide which causes the water pH to increase. If the CO₂ content of the geothermal fluid is high, the separation of CO₂ from the fluid, when the pressure on the fluid decreases, causes an increase in the pH value, and this promotes calcite deposition. To increase the fluid pressure above the flashing level, it is proposed to inject carbon dioxide into the well at various points below and above the normal flashing level. This is expected to maintain the CO₂ partial

TABLE 4-1

EXAMPLES OF DEPOSITS FOUND IN VARIOUS GEOTHERMAL UTILIZATION SCHEMES

Scheme	Deposits
New Zealand	
Wairakei	Minor calcite (pipes), silica (drains)
Broadlands	Calcite (pipes), silica (silencers, drains)
Kawerau	Calcite (pipes), silica (drains)
Turkey	
Kizildere	Calcite, aragonite (pipes and plant)
Chile	
El Tatio	Calcite (pipes)
Japan	
Matsukawa	FeO, FeS, FeSO ₄ , silica, sediments
Otake	Calcite, silica (drain pipes)
Taiwan	
Matsao	Silica, PbS, FeS, Pb (pipes)
Iceland	
Reykjavik	Fe oxides, MgO, silica (pipes, plant)
Namafjall	Amorphous silica, chalcedony
Italy	
Larderello steam fields	Silica, FeS, borates, silicates
Soviet Union	
Bolshe-Bannoe	Calcite (pipes)
Phillippines	
Tiwi	Calcite
Tongonan, Leyte	Aragonite
United States	
Steamboat Springs	CaCO ₃ , probably aragonite (pipes)
Casa Diablo	CaCO ₃ , probably aragonite (pipes)
Salton Sea	Silica, hydrated Fe oxides, metal sulfides (pipes and plant)
The Geysers	Siliceous material, rock dust (pipes and plant)
Mexico	
Cerro Prieto	Calcite, silica, Fe oxides (pipes, plant)

pressure in the vapor phase at a level which will minimize the evolution of the CO_2 from the brine. The injected CO_2 will be recovered at the well head. The compression of CO_2 for injection requires energy and equipment.

4.2.1 Energy Required for CO_2 Compression

In the following calculation water temperature at well head is assumed to be 350 F (180 C) with the saturation pressure of 136 psig CO_2 solubility is more sensitive to pressure than to temperature in the range of temperatures of interest. Since the change of pressure is unavoidable if the brine flows upward, the CO_2 solubility decreases and evolution of CO_2 from the brine cannot be avoided. If flashing of brine is eliminated, the flow is possible only if it is a two-phase, CO_2 -water flow (extreme case).

Assuming that the point of CO_2 injection is 1,000 feet deep, the two-phase column has an average void fraction of 0.5, and the compression of CO_2 will be from (136 + 15) psia at well head to (136 + 15) psia + 500 feet of water) or from 151 psia to 151 + 200 = 351 psia at CO_2 injection point. The minimum compression work is:

$$W = RT \ln \frac{351}{151} \text{ (isothermal)} = -1.987 \times (460 + 350) \ln \frac{351}{151} \\ = -1358 \text{ Btu/lb-mole} \quad (1)$$

The minus sign indicates that energy must be supplied to the CO_2 . It can be assumed that the brine flow rate per well is about 100,000 lbs/hr (the injection of CO_2 might reduce the well flow rate as compared to the natural flow case). If 1% by weight, i.e., 1,000 lbs/hr, of CO_2 is circulated, the energy required is $1358 \times 1000/44 = 31,000 \text{ Btu/hr} = 0.009 \text{ MW}_e = 12 \text{ HP}$ (negligible).

4.2.2 Equipment Cost

The compressor cost is based on the inlet gas volume of about 47,300 cu. ft./min. is about \$100,000. This means that the well cost is $100,000/800,000 = 12.5\%$ higher. A more optimistic estimate based on a smaller volume of gas and less expansive equipment for injection, is a 5% increase in well cost.

4.2.3 The O&M Cost

The O&M cost of the well head system will be increased because of additional equipment, but the well maintenance costs will be reduced considerably. The O&M cost for the well + well head system is assumed to decrease by 10%. A pessimistic estimate would be a reduction equivalent to 5% of the current costs. (Increased well life and output)

4.2.4 Other Benefits

Other benefits include the utilization of those wells which would have been abandoned because of the apparent clogging tendency. This, coupled with the prolonged usability of normal production wells can be expected to result in an increase of 20% to 30% in the average well life of production wells.

Although there may be some increase in the production well flow rate, this potential benefit is not likely to be significant in comparison with other benefits. The results are summarized below:

	Optimistic	Pessimistic
1. Change in Production Well O&M Cost (Low salinity)	-10.0%	- 5.0%
2. Change in Production Well O&M Cost (High salinity)	-30.0%	-25.0%
3. Change in Production Well Life	+30.0%	+20.0%
4. Change in Production Well Cost	+ 5.0%	+12.5%

5.0 DOWNHOLE PUMPS

<u>Project Code</u>	<u>Project Title</u>
2202	Thermal Downwell Pump
2203	Electrical Downhole Pump
2204	Pump Test Fixture

5.1 Identification of Impacted Parameters

The major benefit of better downhole pumps is the expected reduction in the required number of wells due to increased average well flow rate. The development of better pumps is also likely to reduce the downwell pump O&M costs. It is reasonable to assume that the new pump designs and construction will not increase the cost of pumps significantly. Therefore, the system parameters likely to be impacted by this subelement are:

- (i) the number of production wells
- (ii) the downhole pump O&M costs

5.2 Estimation of Primary Benefits

Downhole pumps are available and have been used successfully in Iceland. The pump used in Iceland is an extended shaft pump driven by a motor located near the well head, and is used in a shallow well. Some tests of electric pumps at East Mesa have proved that pumps with current technology might be used at some U.S. sites. However, assuming that current pump technology is used in the U.S. prospects, the O&M cost would be high and considerable losses would be incurred due to the down-time associated with frequent maintenance requirements.

The benefits can be identified in (i) the change in number of required wells, and (ii) the change in O&M costs. These impacts are estimated below:

(i) Change in well number: To avoid down-times due to pump failure and maintenance requirements, reserve wells must be drilled. The GELCOM model engineering (plant design) subroutine assumes that current pump technology requires 20% reserve wells. If pumps are more reliable, the number of reserve wells might be reduced to 15% of the number needed to provide the fluid for operating the power plant. This change will bring about a reduction of:

$$\frac{1.15 - 1.20}{1.20} = - 4.17\%$$

in the number of production wells. It would be reasonable to conclude that the reduction in the number of wells will range from 3.0 to 5.0%.

(ii) Change in O&M cost: More reliable pumps means less O&M cost. The major component of O&M cost would be the labor which is assumed to be reduced by 50%. The labor cost in maintaining a downwell pump is relatively high as compared with the labor cost in maintaining other components in the field, and is assumed to be about 60 to 90% of the O&M cost. From these figures, the overall reduction in the O&M cost of downwell pumps is estimated to be between 30 and 45% of the present O&M cost.

	Optimistic	Pessimistic
1. Change in Number of Production Wells	-5.0%	-3.0%
2. Change in Downwell Pump O&M Cost	-45.0%	-30.0%

6.0 DIRECT CONTACT HEAT EXCHANGER

Project Code

Project Title

2304

Direct Contact Binary Demonstration
Program

6.1 Identification of Impacted Parameters

The direct contact heat exchange concept is expected to lead to the design of more efficient and less expensive heat transfer units (i.e., preheater, boiler, and condenser). The reduction in the cost of the preheater and boiler will impact the process technical cost item in the GEOBEN cost data. The condenser cost reduction will impact the "Condenser and Heat Rejection Equipment" cost item. The direct heat exchange is also expected to produce a small increase in the utilization efficiency. As a result, the number of production and injection wells will be impacted. The general plant O&M costs will also be impacted.

The following system parameters are going to be impacted by this program:

1. Process mechanical capital cost
2. Condenser and heat rejection equipment capital cost
3. Number of production wells
4. Number of injection wells
5. Plant O&M costs

6.2 Estimating Primary Benefits

A direct contact heat exchange system involves sensible heat exchanger (preheater) between two immiscible fluids in direct contact with each other. There are two types of direct contact boilers. In the first type, (the volume type) the boiling fluid (organic) is injected into the boiler beneath the surface of the heat carrying fluid (geothermal water). In the surface type heat exchanger, the working fluid is injected onto the geothermal water surface. The latter type is used when the water is highly corrosive and can attack the injection nozzle, or has high TDS content and causes precipitation at the nozzle (where the temperature difference is highest).

EG&G of Idaho Falls has conducted a conceptual study of a direct contact 50 MW plant. The contractor who did the cost estimate for this is^e Ford, Bacon and Davis of Utah. Mr. Gary Stuart of EG&G indicates that the fixed cost for a 50 MW (net) plant is 24.6 mills/kwh compared with 29.5 mills/kwh for shell and

tube heat exchanger plant of the same size. The capital equipment costs for the heat exchangers are: (1976\$)

	DIRECT CONTACT SYSTEM	SHELL AND TUBE SYSTEM
Boiler	\$ 1,595,000	\$ 4,931,000
Preheater	\$ 1,916,000	\$ 3,717,000
Condenser (extended shell and tube)	\$10,994,000	\$12,207,000
Gross Output	70.4 MW _e	73.3 MW _e

Assuming that the difference between the gross output of the direct contact and the shell and tube systems is due to the higher utilization efficiency of the direct contact system, the decrease in the number of production and injection wells can be estimated to be:

$$\left(\frac{70.4 - 73.3}{73.3} \right) \times 100 = -3.96\% \quad (\text{optimistic})$$

The cost figures given above can be utilized for estimating the impact on the process mechanical cost. The boiler and preheater costs drop from \$8,648,000 to \$3,511,000 when the design is changed from the shell and tube to direct contact. This is equivalent to a reduction of 59.4% since the boiler and preheater account for 60% of the capital cost of process mechanical, the estimate reduction in the process mechanical cost is 59.4×0.60 or 35.5%.

The cost data given above also show that the condenser costs decrease from \$12,207,000 to \$10,994,000, (this is a 9.94% reduction). The condenser cost represents 50% of the condenser and heat rejection equipment cost. Therefore, the expected reduction in this cost item is 9.94×0.50 or 4.97%.

The plant O&M costs of a direct contact system are expected to be 20% lower than those for the shell and tube system. However, a penalty amounting to 10% of the plant O&M costs is likely to be incurred due to the loss of the working fluid in the direct contact heat exchanger. Therefore, an estimated reduction of 10% in the

plant O&M costs can be expected. The results are summarized below:

	Optimistic	Pessimistic
1. Number of Production Wells	- 4.0%	- 2.0%
2. Number of Injection Wells	- 4.0%	- 2.0%
3. Process Mechanical Capital Cost	-35.5%	-20.0%
4. Condenser and Heat Rejection Equipment Cost	- 5.0%	- 2.0%
5. General Plant O&M Cost	-10.0%	- 5.0%

Reference:

1. Bechtel Corporation, "Conceptual Design of Commercial 50 MW (net) Geothermal Power Plants at Heber and Niland, California", Report SAN-1124-1, ERDA, DGE, October 1976.

7.0 LIQUID FLUIDIZED BED HEAT EXCHANGER

Project Code

Project Title

2303

Liquid Fluidized Bed Heat Exchanger

7.1 Identification of Impacted Parameters

This project is aimed at the development of less expensive and more reliable shell and tube (indirect) heat exchangers. The successful completion of this project will impact the following system parameters:

- (i) Primary heat exchanger capital cost
- (ii) Primary heat exchanger O&M costs

7.2 Estimating Primary Benefits

The concept underlying the development of the improved shell and tube primary heat exchangers is based on the use of suspended solid for scouring the heat exchange surface. This scouring action is expected to minimize the rate at which scales build up on the heat exchange surfaces. This concept also makes it possible to put the low pressure fluid on the shell side, although the shell has to be enlarged to accomplish this. The corrosion rate in the advanced heat exchanger is much lower than that in the ordinary shell and tube heat exchangers.

The net result of all these changes is a reduction in the heat exchanger capital costs as well as the O&M costs. The impact on the capital cost can be estimated in a similar manner as in section 4.2, Appendix A. The heat transfer area of a conventional heat exchanger where brine is in the tube side and organic fluid in the shell side is proportional to $1/U$ calculated using the same numbers used in section 4.2, Appendix A, by:

$$\frac{1}{U} = \frac{1}{250} + \frac{1}{1500} + 0.0005 + 0.003(1.15) = 0.008617$$

where the outside to inside diameter ratio of the tubings is considered here and is assumed to be 1.15. The liquid fluidized bed heat exchanger has brine in the shell side and organic fluid in the tube side. Thus the new heat exchanger with a brine fouling factor of 0.0005 has the overall heat transfer coefficient determined by:

$$\begin{aligned}\frac{1}{U_{\text{New}}} &= \frac{1.15}{250} + \frac{1}{1500(1.15)} + 0.0005(1.15) + 0.0005 \\ &= 0.006255\end{aligned}$$

which shows a reduction of 27.4% as compared with the previous number 0.008617. If a size versus cost exponent of 0.78 used in section 4.2, Appendix A is used here, the new cost becomes:

$$(1 - 0.274)^{0.78} = 0.779 \text{ of the old cost.}$$

Hence a cost reduction of 22.1% results. The actual cost reduction will be less than 22.1% because the new heat exchanger would require additional equipment. However, the cost of these additional equipment is expected to be small compared with the heat exchanger cost, and therefore is neglected. The above cost reduction is taken as an optimistic estimate. The pessimistic estimate is assumed to be 10%.

Impacts on the heat exchanger O&M cost are rather difficult to estimate because of the lack of information. It is anticipated, however, that the O&M requirements for a fluidized bed heat exchanger would be similar to but slightly less than the O&M requirements for the APEX heat exchanger discussed in the next section, section 8.0. As it will be seen in section 8.0, the APEX heat exchanger increases the heat exchanger O&M cost by 160 to 200%. Let us assume that 60% of this increase is applicable for the liquid fluidized bed heat exchanger. Thus the primary benefits of this project are:

	Optimistic	Pessimistic
1. Change in Capital Cost of Heat Exchanger	-22%	- 10%
2. Change in O&M Cost of Heat Exchanger	+96%	+120%

8.0 SELF-CLEAN HEAT EXCHANGER

Project Code

2306

Project Title

Advanced Geothermal Primary Heat
Exchanger (APEX)

8.1 Identification of Impacted Parameter

This project is aimed at the development of less expensive and more reliable shell and tube heat exchanger. The concept is similar to that of the liquid fluidized bed heat exchanger, except that the brine is fed through the tube side here rather than the shell side. The impacted parameters are:

- (i) Primary heat exchanger capital cost
- (ii) Primary heat exchanger O&M costs.

8.2 Estimation of Primary Benefits

The primary benefits of this project can be estimated as similar to those of the liquid fluidized bed heat exchanger. The new value of $1/U$, with brine in the tube side and organic in the shell side, is:

$$1/U = 1/250 + 1/1500 + 0.0005 + 0.0005 \times 1.15 = 0.005742$$

which show a reduction of 33.4% as compared with the base value of 0.008617 (see section 7.2). The new cost becomes:

$$(1-0.334)^{0.78} = 0.729 \text{ of the old cost.}$$

Hence a capital cost reduction of 27.1% results. This estimate is taken as optimistic. The pessimistic estimate is assumed to be 10%.

The contractor has estimated the maintenance costs for a 30 MW_e (net) APEX heat exchanger as follows⁽¹⁾:

(1) Letter from B. Breindel, Aerojet Energy Conversion Company, to John Walker, DGE, 26 August 1976.

O&M ANNUAL COSTS (1976)

	<u>CONVENTIONAL</u>	<u>APEX</u>
Cleaning costs	\$29,000	\$ 0
Cost due to P increase	0	48,500
Centrifuge	0	19,000
Slurry Pumps	<u>0</u>	<u>7,000</u>
Total	\$29,000	\$74,500

The O&M cost is therefore increased by a factor of 2.6 or by 160% (optimistic estimate). The pessimistic is assumed to be 200%. The results are summarized below:

	Optimistic	Pessimistic
1. Capital Cost of Heat Exchanger	- 27%	- 10%
2. O&M cost of Heat Exchanger	+160%	+200%

9.0 FLUTED TUBE CONDENSER

Project Code

2301

Project Title

Transport and Conversion of Heat
at Moderate Temperature

9.1 Identification of Impacted Parameters

The current objective of this project is to develop a more efficient and less expensive shell and tube condenser. The fluted tube design is expected to reduce the requirement of heat exchange area. The use of fluted tubes can be expected to affect the O&M costs also.

Therefore, the following system parameters are expected to be impacted by this project:

- (i) The capital cost of the condenser and heat rejection equipment
- (ii) Utility general O&M cost factor (binary systems).

9.2 Estimation of Primary Benefits

It was suggested by the Project Manager of this project that the film coefficient of the organic fluid increase 3 - 7 times when the fluted tube is used instead of the finned tube in heat exchangers. On the basis of this, the primary benefits of this project can be estimated as follows.

The heat transfer area of a heat exchanger is defined by

$$A = \frac{Q}{U \Delta T_m} \quad (1)$$

where A is the required heat transfer area, Q: amount of heat transferred, U: overall heat transfer coefficient, and ΔT_m is log mean temperature difference.

Taking log and then differentiating equation (1) w.r.t. U, keeping Q & ΔT_m constant give:

$$\frac{\partial A}{A} = - \frac{\partial U}{U} \quad (2)$$

The overall U is defined by:

$$\frac{1}{U} = \frac{1}{h_i} \frac{A_o}{A_i} + \frac{1}{h_o} + R_o + R_i \frac{A_o}{A_i} \quad (3)$$

where h and R are the film coefficient and fouling factor respectively (the subscripts i and o denote inside and outside heat exchange surface of the tube). Note that the pipe wall resistance is neglected. Condenser usually employs extended surface tubings and the ratio A_o/A_i is generally about 2.5. Other terms have the following values:

$$h_i \text{ (Water, } 2^5 \text{ ft/s, } 85^\circ\text{F)} = 1130 \text{ Btu/(hr.ft}^{2o}\text{F)} \text{ (reference 1)}$$

$$h_o \text{ (organic, assumed)} = 250 \text{ Btu/(hr.ft}^{2o}\text{F)}$$

$$R_o \text{ (organic)} = 0.0005 \text{ (hr. ft}^{2o}\text{F/Btu)}$$

$$R_i \text{ (water, assumed)} = 0.0010 \text{ (hr. ft}^{2o}\text{F/Btu)}$$

Substituting these values into equation 3 gives:

$$\frac{1}{U} = \frac{2.5}{1130} + \frac{1}{250} + 0.0005 + 0.0010 \times 2.5 = 0.00921$$

$$U = 108.60 \text{ Btu/(hr. ft}^{2o}\text{F)}$$

If fluted tubes are used, extended surface has different configuration (See Figure 9-1) and the ratio A_o/A_i is much less than 2.5, but is slightly greater than 1.183 (the ^ooutside/inside diameter ratio of 3/4 (16BWG)). Let us assume a figure of 1.5 for the fluted tube and use equation 3 to calculate the overall U. The results are listed in Table 9-1.

9.2.1 Initial Investment Cost

Equation 4 indicates the cost per unit area of heat transfer of a heat exchanger having a total heat transfer Area A (taken from Reference 2).

$$$/\text{ft}^2 = 900 A^{-0.4186} + 0.50 \quad (4)$$

For a 50 MW output, let us assume that 70 MW gross is to be generated with efficiency of 25%, i.e., 75% of the ^eheat is rejected or $(75/25) \times 70 \text{ MW} = 210.00 \text{ MW} = 716.73 \times 10^6 \text{ Btu/hr}$ transferred through the condenser. If a Δt_m^e is assumed as shown in Figure 9-2, the total areas required and costs for finned tube and fluted tube

FIGURE 9-1
A SECTION OF FLUTED TUBE

$$\Delta t_m = \frac{(105 - 75) - (105 - 95)}{2.3 \log \frac{30}{10}} = 18.20^\circ\text{F}$$

FIGURE 9-2
ASSUMED LOG MEAN TEMPERATURE
DIFFERENCE FOR THE CONDENSER

TABLE 9-1
EFFECTS OF FLUTED TUBES

	REFERENCE 1 FINNED TUBE	FLUTED TUBE	
		$h_o = 3 \times 250^*$	$h_o = 7 \times 250^*$
U* based on outside surface	108.60	214.56	256.49
U* based on inside surface	276.80**	321.84	384.73
$\Delta U/U$ (%)	0	16.27	38.99
$\Delta A/A$ (%) (Inside surface)	0	-16	-39

* Btu/Hr.ft.²°F

** 108.60 X 2.50 X 1.02. Extended area tube has smaller ID than base tube of the same size because of the rolling effects in the manufacturing process. Thus the inside film coefficient is higher by about 5% (Reference 1 - "Process Heat Transfer" by D.Q. Kern, McGraw/Hill, 1950) which will cause an effect of about 2% on the overall U.

TABLE 9-2

BENEFIT OF FLUTED TUBE CONDENSER
(50 MW_e PLANT)

TUBE TYPE	U (Approx.) Btu/(hr.ft. ² °F)	A (ft. ²)	\$/ft. ²	TOTAL COST (\$)	COST REDUCTION
Finned	108.60	363000	4.74	1,720,000	0
Fluted	230.0**	285000*	5.18	1,477,000	~ 14%*

* Converted to equivalent finned area by using $U = 230 \times 1.50/2.50$.

** Average.

Note - The calculation is based on equation 4 which is assumed to be applicable to inside, outside, finned or fluted surfaces. The result is expressed in percentage to eliminate the effects of cost indices and accuracy of assumed values.

would be as shown in Table 9-2. It is noted that although the cost figures in Table 9-2 are low, they are adequate for the purpose of comparison. Assuming that the heat exchanger represents 40% of the capital of condenser and heat rejection equipment, the optimistic estimate of the reduction in this cost item is $14 \times 0.4 = 5.6\%$. The pessimistic estimate is a reduction of 4.4%.

9.2.2 O&M Costs

Since the specific heat transfer rate for fluted tube is high, scaling is expected to be more pronounced. Tube cleaning and, maybe, chemical treatment are, therefore, more costly compared with those of low efficiency condenser. The increase in O&M costs is however, partially compensated for by the smaller size of the condenser (20% smaller, Table 9-2). A possible additional cost might occur in relation to the vertical position of the condenser, which may or may not be significant. Since it is difficult to estimate the effects on O&M costs of the use of fluted tubes and vertical condenser, it is assumed that the fluted tube-vertical condenser increase the condenser O&M costs by 10%. Assuming that 20% of the utility general O&M cost factor is attributable to the cleaning and treatment of the heat exchanger, the estimated impact on this parameter is 2.0%. (increase).

The expected impacts are summarized below:

	Optimistic	Pessimistic
1. Change in Capital Cost of Condenser and Heat Rejection Equipment	-5.6%	-4.4%
2. Change in Utility General O&M Cost Factor (Binary)	+2.0%	+2.0%

Reference

1. Donald Q. Kern, "Process Heat Transfer", McGraw Hill, 1950.
2. W.H. Giedt, "The Geothermal Binary Fluid Cycle: Heat Exchanger Area Requirements and Initial Costs", Report #UCRL-51912, Lawrence Livermore Laboratory, September 23, 1975.

10.0 DIRECT CONTACT CONDENSER

Project Code

2302

Project Title

Direct Contact Research

10.1 Identification of Impacted Parameters

The concept of direct heat exchange in condensers for binary power plants is expected to have impact similar to those projected for the direct contact primary heat exchanger project. Therefore, the following system parameters are likely to be affected by this project:

- (i) Capital cost of condenser and heat rejection equipment
- (ii) Utility general O&M cost factor (binary).

10.2 Estimation of Primary Benefits

Although it is generally believed that the concept of direct heat exchange is going to reduce the capital costs of heat exchange equipment in the heat rejection system, a quantitative analysis of this impact cannot be carried out due to insufficient empirical data. Nevertheless, the impact is expected to be substantial, and an optimistic estimate of a 15% reduction in the cost of the heat exchanges component of the heat rejection system appears to be reasonable. Assuming that 40% of the capital cost of the heat rejection system is attributable to the heat exchanger, the capital cost of the condenser and heat exchange equipment can be expected to go down by 6.0% (0.4×15.0). An estimated cost reduction of 4.0% represents the pessimistic value.

The utility general O&M costs can be expected to be reduced due to the elimination of the frequent cleaning of the heat exchanger. However, some of this saving will be neutralized by the cost of the working fluid which will be lost in the cooling fluid due to incomplete separation of fluids. Therefore, it would be logical to assume that there will be no change in the O&M cost until it is confirmed that the two fluids (working fluid and cooling fluid) can be separated completely.

The following is a summary of the primary benefits of this project:

	Optimistic	Pessimistic
1. Capital Cost of Condenser and Heat Rejection Equipment	-6.0%	-4.0%
2. Utility General (O&M Cost Factor (Binary)	0.0%	0.0%*

*These estimates may be changed later.

11.0 BINARY PROGRAM

Project Code

Project Title

2305

Properties of Working Fluid

2404

Heat Exchanger Test

2414

Moderate Temperature Electric

11.1 Identification of Impacted Parameters

The successful completion of these projects may result in the design of a more efficient binary conversion cycle. The better understanding of working fluid properties may reduce the requirement of geothermal fluid (thermodynamic properties), and heat transfer area requirement (heat transfer properties). The knowledge gained in the large-scale heat exchanger tests would help plant engineers to reduce the O&M costs of heat exchanger systems. Thus the impacted parameters are:

- (i) Well number requirement
- (ii) Heat exchanger capital cost
- (iii) O&M costs of heat exchanger systems

11.2 Estimation of Primary Benefits

11.2.1 Well number requirement:

Enhancement of the knowledge concerning the thermodynamic properties of the binary working fluids can be expected to enable the plant designers to design a more efficient binary cycle. Some improvements could be expected in the design of heat exchangers and turbines. It is appropriate to point out that one of the objectives of this subelement is to confirm the validity of the current data concerning fluid properties. Therefore, the impact of the information generated by this subelement cannot be very significant.

Nevertheless, some improvements may occur in the efficiency of the binary energy conversion cycle. These improvements will result in a reduction in the quantity of geothermal (primary) fluid. So as pointed out earlier, the reduction is likely to be very small. Therefore, the following estimates of the primary benefit appears to be reasonable:

	Optimistic	Pessimistic
1. Change in Number of Production Well	-0.2%	0.0%

11.2.2 Heat Exchanger Capital Cost

The cost of the primary heat exchanger depends heavily on the heat transfer area. This area (A) is determined by using the following relationship:

$$A = \frac{Q}{U \Delta t_m}$$

where Q is the heat transfer load, t_m is the log mean temperature differential, and U is the overall heat transfer coefficient.

For a shell and tube type heat exchanger involving the geothermal fluid and the organic working fluid,

$$\frac{1}{U} = \frac{1}{h_o} + \frac{A_o/A_i}{h_i} + F_o + F_i \frac{A_o}{A_i}$$

where h_o is the heat transfer coefficient for working fluid (with no fouling), h_i is the heat transfer coefficient for the geothermal fluid (with no fouling), F_o is the fouling factor for the working fluid and F_i is the fouling factor the the geothermal fluid. A_o/A_i is the outside over inside area ratio. Tube wall resistance has been neglected.

Assuming an outside diameter to inside diameter, hence outside to inside area, ratio of 1.15 for the heat exchanger tubes, and using typical values for the variables in the above formula as used in Section 7.2, the value of U can be calculated as follows:

$$\begin{aligned} \frac{1}{U} &= \frac{1}{250} + \frac{1}{1500} + 0.0005 + 0.003(1.15) = \frac{1}{250} + 0.004617 \\ &= 0.008617 \end{aligned}$$

If the lack of better data concerning working fluid properties is causing the designers to underestimate the value of h_o by 30% (assumption), the availability of more reliable data will result in the utilization of a higher value of h_o (the value will be $250/(1-0.30)$). The resultant value of U will be given by:

$$\frac{1}{U} = \frac{0.7}{250} + 0.004617 = 0.007417$$

The higher value of the heat exchange coefficient will result in a reduction in the heat exchange area. This reduction is equivalent to:

$$(0.008617 - 0.007417)/0.008617 = 13.9\%$$

As in section 7.2, the new capital cost of the heat exchanger is: calculated as follows:

$$(1 - 0.139)^{0.78} = 0.890 \text{ of the old cost.}$$

Hence a cost reduction of 11% results. This estimate is taken as optimistic. The pessimistic estimate can be calculated if 10% instead of 30% is assumed for the under-estimate of h_o . The resulting heat exchanger area reduction is 4.6%, and the corresponding cost reduction is 4%. In summary:

	Optimistic	Pessimistic
2. Change in Capital Cost of Primary Heat Exchangers	- 11%	- 4%

11.2.3 Heat Exchanger O&M Cost

The last two projects involve demonstrating and testing the reliability and performance of heat exchangers and binary plant. If these projects are not funded the above knowledge would not be available to design engineers, and would only be gained from full scale plant operations. The result would be high O&M costs for a period of time. It is assumed that lack of funding for these projects would cause a two year delay in the attainment of the knowledge in actual geothermal binary power plant operations.

The estimates of the benefits derived from these projects are likely to be conservative because the cooperative program will also provide test facilities for testing other types of heat exchangers developed in other projects. This side benefit will not be realized if the knowledge on heat exchanger operation must be gained in actual plant operation since the plants will have been designed for a specific type of heat exchanger.

The primary benefits here are:

	Optimistic	Pessimistic
3. Utility Process Mechanical O&M Cost (Binary) Utility	-18.0	-9.0

12.0 WELL HEAD GENERATOR

<u>Project Code</u>	<u>Project Title</u>
2407	Market Survey - Well Head Generator
2415	Small Electric Generator
2413	Hawaii 5-10 MWe Steam Generator

12.1 Identification of Impacted Parameters

The impact of these projects will not be observed through any changes in the cost of power estimates for the power-on-line goals. These goals were developed by assuming that increments in the power-on-line will occur in 50 MW_e units. If the well head generator concept turns out to be technically and economically viable, the utilization of the fluid in individual wells need not be delayed until enough wells have been drilled for supporting a 50 MW_e unit (10 to 15 wells could be needed for a plant with this capacity). The lead time for the utilization of a well will be shortened by 3 years from the average lead time of 7 years for a 50 MW_e unit. This acceleration of the utilization of individual production wells will result in the saving of fossil fuel which would be utilized for generating the electricity needed during the 5th, 6th, and 7th years of the lead time for developing a 50 MW_e unit.

Therefore, the logical measure of impact would be the additional energy generated due to the early utilization of the production wells by installing well head generators.

12.2 Estimation of Benefits

The primary objective of these projects is to stimulate the development of geothermal resources and increase the production of electric power using small electric generating systems by providing small power companies with data on economics, reliability and operation. If the project is successful, all the flash steam sites will be candidates for the flash steam well head generator systems. A conventional 50 MW_e or bigger plant would require about 7 years to build and operate (after the drilling of the first successful exploration well). This duration includes field development, plant design and plant installation. A well head generator system would require less time for design and installation, and would shorten the lead time by 3 years for a comparable capacity. Thus the expected benefit of this subelement is that power will be available about 3 years earlier than planned.

If it is assumed that only 10% of the projected power-on-line by 2000 will be replaced by well head generators, approximately

655 MW will be on line 3 years earlier.* Also, assuming that isolated resources, which are not adequate for 30 years of operations of a 50 MW unit can be explored and utilized, an additional 10% of the projected power-on-line can be expected to be generated from these isolated resources (additional power over and above the power-on-line goals).

The benefits resulting from these impacts can be computed as follows:

(i) Early on-line-power: This provides $655 \times 3 \times 0.7 = 1375.5$ MW-yrs or $1375500 \times 8736 \text{ hrs/yr} = 12.016 \times 10^9$ Kwh additional to the scenario. A production factor of 0.7 has been assumed.

(ii) Isolated resources: The estimation of benefits is based on the developing isolated resources. This scenario is similar to the scenario of conventional plants, except that it precedes the national scenario by 3 years.

* 6550MW is the total of the last row in Table 12-1.

TABLE 12-1
PROJECTED POWER-ON-LINE GOAL
FOR FLASH STEAM PLANTS TO THE YEAR 2000

SITE	TOTAL CAPACITY (MWe)
COSO	600
GLASS MOUNTAIN	50
LASSEN	100
MONO-LONG VALLEY	250
PUNA	1000
BEOWAWE	1000
BRADY HOT SPRINGS	1000
ROOSEVELT	1000
STEAMBOAT	200
VALLES CALDERA	1350
TOTAL	6550

SOURCE: Table 4-1 in the main body of this report

TABLE 12-2
ELCTRICITY PRODUCTION FROM
WELL-HEAD PLANTS

YEAR	CAPACITY OF FLASH STEAM PLANTS (MWe)	CAPACITY OF WELL- HEAD PLANTS ⁺ (MWe)	PRODUCTION [*]	
			(YEARS)	(MWe-YRS) ^{**}
1983	200	20	20	400
84	0	0	19	0
85	150	15	18	270
86	300	30	17	510
87	200	20	16	320
88	500	50	15	750
89	150	15	14	210
90	950	95	13	1235
91	600	60	12	720
92	600	60	11	660
93	600	60	10	600
94	600	60	9	540
95	500	50	8	400
96	400	40	7	280
97	400	40	6	240
98	200	20	5	100
99	100	10	4	40
2000	100	10	3	30
2001	0	0	2	0
2002	0	0	1	0
TOTAL	6550	655	-	7305

* Production starts 3 years prior to the power-on-line year of the flash steam plant scenario.

** Production factor has not been included.

+ 10% of the capacity of flash steam plants.

The total production, as shown in Table 12-2, is $7305 \times 0.7 = 5113.5$ MWe-yrs or $5113500 \times 8736 \text{ hrs/yr} = 44.672 \times 10^9$ kWh additional to the scenario.

(iii) Total gain: The total gain is the sum of i and ii:

$$\begin{aligned} 12.016 + 44.672 &= 56.688 \times 10^9 \text{ kWh} \\ &= 0.194 \text{ Quads of Electricity} \end{aligned}$$

If this gain is fed into the nation's grids, an equivalent amount of energy from other fuels can be saved. It is possible that this electricity will be less costly than electricity from other sources, but at this time it is not possible to confirm this. However, if this turns out to be true, the benefit of these projects can be computed in terms of dollars also.

13.0 GRAVITY HEAD BINARY PLANT

<u>Project Code</u>	<u>Project Title</u>
2407	Market Survey
2409	Gravity Head Binary Plant

13.1 Identification of Impacted Parameters

These projects are also those whose benefits cannot be estimated by computing the savings due to reduced cost of geothermal electricity. The primary benefit of these projects will be the early generation of power through the use of gravity head binary plant at individual wells. It is expected that a percentage of the power-on-line scenario for binary plants will come on-line about 3 years prior to the scheduled development as projected in the national geothermal power-on-line scenario. The availability of the gravity head binary plant will also make it possible to augment the amount of geothermal electricity by making it possible to exploit isolated resources with small potential for power output (i.e., much less than 50 MW_e).

13.2 Estimation of Benefits

The primary objective of these projects is to enable geothermal developers to utilize the available resource (suitable for binary energy conversion) more rapidly by generating electricity at individual wells during the initial stages of development. The availability of the gravity head binary plant is assumed to make it possible to generate electricity 3 years earlier than the scheduled dates shown in the power-on-line scenario for binary power plants. It is assumed that 10 percent of the power-on-line goals to the year 2000 will be generated by the gravity head plants when they are available.

Table 13-1 shows the national power-on-line goals for binary geothermal power plants (50MW) by the year 2000. Ten percent of the totals shown in Table 13-1 are assumed to come on line 3 years earlier than scheduled. This would result in 1240 MW coming on-line three years earlier, and the net impact will be $1240 \times 3 \times 0.7 = 2604$ MW-Years of additional electrical power from binary geothermal power plants.

It is also assumed that resources, which are either remote (relative to demand points) or are too small for supporting a 50 MW_e unit, could be exploited by utilizing binary gravity head generators. If the aggregated power resulting from this impact amount to 10% of the power-on-line goals, the additional geothermal electricity generated by the year 2000 will amount to 8846 MW-yrs.

TABLE 13-1
PROJECTED POWER-ON-LINE GOAL
FOR BINARY PLANTS TO THE YEAR 2000

SITE	TOTAL CAPACITY (MWe)
SALTON SEA	1600
BRAWLEY	1000
COVE FORT SULF.	1200
HEBER	1000
GEYSERS (LIQUID)	1000
EAST MESA	100
SURPRISE VALLEY	1300
CHANDLER	200
LEACH	1100
BRUNEAU-GRANDVIEW	1100
ALVORD	300
SAFFORD	100
WEISER/CRAVE CREEK	1000
VALE	600
THERMO	500
RAFT RIVER	100
MOUNT HOOD	50
BAKER HOT SPRINGS	50
W. YELLOWSTONE	50
TOTAL	12400

SOURCE: Table 4-1 in the main body of this report.

TABLE 13-2
ELECTRICITY PRODUCTION FROM
GRAVITY HEAD PLANTS

YEAR	CAPACITY OF BINARY PLANTS (MWe)	CAPACITY OF GRAVITY PLANTS ¹ (MWe)	PRODUCTION ²	
			(YEARS)	(MWe-YRS) *
1983	100	10	20	200
84	0	0	19	0
85	400	40	18	720
86	275	27.5	17	467.5
87	575	57.5	16	920
88	600	60	15	900
89	550	55	14	770
90	1200	120	13	1560
91	1050	105	12	1260
92	1100	110	11	1210
93	1100	110	10	1100
94	1100	110	9	990
95	1000	100	8	800
96	800	80	7	560
97	750	75	6	450
98	650	65	5	325
99	600	60	4	240
2000	550	55	3	165
1	0	0	2	0
2	0	0	1	0
TOTAL	12400	1240	-	12637.5

¹ 10% of the capacity of the binary plants.

² Production starts 3 years prior to the power-on-line year of the binary plant scenario.

* Production factor has not been included.

assuming a production factor of 0.7 and the result of Table 13-2.

The total gain is:

$$\begin{aligned}(2604 + 8846) \times 8736 \text{ hrs/yr} &= 10.003 \times 10^{10} \text{ kWh} \\ &= 0.315 \text{ Quads}\end{aligned}$$

If this gain is fed into the nation's grids, an equivalent amount of energy from other fuels can be saved. It is possible that this electricity will be less expensive than electricity from other sources, but at this time it is not possible to confirm this. However, if this turns out to be true, the benefit of these projects can be computed in terms of dollars also.

14.0 HELICAL SCREW EXPANDER

Project Code

2406

Project Title

Helical Screw Expander

14.1 Identification of Impacted Parameters

The helical screw expander is being developed for special applications. The most likely application is that as a well head generator. For such applications, a comparison of the cost and performance with the 50 MW_e power plant is not very meaningful.

A direct approach will be made to calculate the savings attributable to the use of the helical screw expander during the initial phase of development of each of the 27 sites in the IGCC scenario for hydrothermal electric development.

14.2 Estimation of Benefits

As indicated earlier, the helical screw expander is likely to be used primarily as a well head generator during the initial phase of development at various geothermal sites. In comparison with the conventional well head power plant, the helical expander is simpler to manufacture, operate, and maintain. Therefore, the cost per unit of electricity generated by using this device can be expected to be less than that of electricity which is either generated by using other well head generators purchased from other suppliers.

The subsequent estimation of benefits is based on the following assumptions:

- (i) The well head generator will provide electricity needed for installation of the 50 MW plants as specified in the scenario.
- (ii) Only one generator is needed per site.
- (iii) The generator will operate with free fuel (geothermal fluid would be otherwise wasted during the development phase) and for two years prior to the finishing of the 50 MW plant. After two years the well will be used for providing fluid to the 50 MW plant.
- (iv) A well head helical screw generator has an output of 5 MW (net) and costs \$1,000k (assumed). It has a salvage value of \$600k after two years of operation (which can be discounted to 1978 dollars as $\$600k/(1.1)^2 = \$496k$).

- (v) Electricity cost with free fuel is about 15 mills/kwh (including O&M costs and investment interest).
- (vi) Electricity which would otherwise be needed from other sources costs about 30 mills/kwh (this is also the assumed cost of electricity if a different type of well head generator were used).

The benefits associated with the utilization of helical screw expander head generator for two years (under the assumptions stated above) can be computed as follows:

1. Savings due to the generation of 5,000 kW for 7000 hours per year for 2 years = $5000 \times 7000 (0.030 - 0.015) = \$1,050,000$.
2. Depreciation in the plant = $\$1,000,000 - 496,000 = \$504,000$.
Net savings at one site = $\$546,000$.

Since it is assumed that this helical screw expander will be used at 27 sites, the total savings will amount to:

$$27 \times 546 \times 10^3 = \$14.7 \times 10^6 \quad (78 \text{ dollars})$$

Thus the benefit of this project can be assumed to be from \$12 - 16M.

15.0 TOTAL FLOW SYSTEM

Project Code

2405

Project Title

Total Flow Concept

15.1 Identification of Impacted Parameters

The concept of total flow systems involves the expansion of the total well head brine-steam mixture directly through a mixed-phase expander for converting the thermal energy of the mixture into mechanical energy. Thus, the conversion efficiency will be changed and consequently the number of production and injection wells will be changed. Since the system is a novel one, capital costs of many components will be altered, as will the plant O&M costs.

15.2 Estimation of Primary Benefits

To calculate the benefits of the use of the total flow system, the first step is to estimate the increase in utilization efficiency of this system. If a higher utilization efficiency is realized for the conversion plant, the geothermal fluid requirement can be reduced for the same net power output. The estimate of the utilization efficiency increase must be made in relation to a base case which is here selected to be the double-flash (2-stage flashing). The double flash system is chosen as the base case because:

- o The single-flash system is low in utilization efficiency and, therefore, is generally used for the first installation at a prospect where flash-steam systems are economical to provide experience for subsequent plants.
- o The three-stage flashing system, although it has high utilization efficiency, requires a large third turbine and a third barometric condenser. These additional equipment requirements bring the cost of the additional power to a higher value than the cost of a two-stage flashing system (2).

The utilization efficiency of the total flow system, as shown in reference 1, is 0.6. The utilization efficiency of a double flash system is 0.535 for 150°C fluid and is 0.588 for 300°C fluid. Since the geothermal fluid at the 27 prospects in the U.S. that are suitable for electricity generation is between 150°C and 300°C, the increase in the utilization efficiency of the total flow system is somewhere between:

$$\frac{0.6 - 0.588}{0.588} = 2.04\%,$$

and

$$\frac{0.6 - 0.535}{0.535} = 12.15\%.$$

Note that utilization efficiency is the ratio of output power to available wellhead power.

From the above figures, it is reasonable to assume that the total flow system efficiency is 2 (pessimistic) to 15 (optimistic) percent higher than the double flash system efficiency. This is equivalent to a 2 - 15% reduction in the required number of production and injection wells.

The change in utilization efficiency is usually associated with some change in heat rejection load. This problem is also examined by Elliott (1) who showed that:

Reservoir Temperature :	150°C	300°C
$\frac{\text{Output Power}}{\text{Heat Rejection}}$ of Total Flow	= 0.080	0.182
of Double Flash	= 0.095	0.224

Hence the change for constant power output is about:

$$\frac{\frac{1}{0.08} - \frac{1}{0.095}}{\frac{1}{0.095}} = \frac{0.015}{0.080}$$

$$= 18.75\% \text{ for } 150^{\circ}\text{C fluid}$$

and:

$$\frac{0.224 - 0.182}{0.182} = 23.08\% \text{ for } 300^{\circ}\text{C fluid}$$

These changes are now converted into the changes in the cost of condenser and heat rejection system. Since these changes involve capacities of components, the 0.6 power law can be assumed as follows:

steam plant. High strength and high toughness materials might be costly to develop, but would not cost much more than conventional materials to purchase, because the fabrication process does not have to be modified if they have the same base (e.g., iron-base, steel) as the conventional materials. Thus, the cost increase for a two-phase turbine is rather small. If this increase is due to the increase in the material purchase cost, it can only be about 10% at most, and in the optimistic case it can be assumed to be about 5%.

The remaining erosion problems and the scaling problems must be met through frequent maintenance. Hence it is expected that the O&M costs for a two-phase turbine is substantially higher than the O&M costs of a conventional steam turbine. How much higher it is is difficult estimate because the development of a two-phase turbine is still remote from even the pilot testing stage. It may well be believed that a two-phase turbine would probably be inspected, have some blades changed and/or cleaned, have the housing cleaned and clearance between housing and blades adjusted two to four times more frequently than a conventional steam turbine. Thus, although it might be rather speculative at this stage, it can be assumed that the maintenance cost of a two-phase turbine would be 100 to 300% more than the maintenance cost of a conventional steam turbine. If operating costs are included, it is assumed maintenance is 60% of the total O&M costs of the unit. Hence the O&M increase for the total flow turbine is 60 to 180%.

The O&M cost charges of the turbine and the increase in O&M cost due to size increase of the condenser and heat rejection system must be factored into the GELCOM input parameter called "Utility General O&M Cost Factor" (flash system). To do so, it is reasonable to assume that the O&M cost is proportional to the capital cost. Using the cost figures in GELCOM model, we have:

$$\frac{\text{Turbine Cost}}{\text{Utility Plant Cost}} = 0.18$$

$$\frac{\text{Condenser and Heat Rejection System Cost}}{\text{Utility Plant Cost}} = 0.13$$

Hence, the charge in utility general O&M cost factor is:

$$\frac{\text{Cost}_1}{\text{Cost}_2} = \left(\frac{\text{Load 1}}{\text{Load 2}} \right)^{0.6}$$

Hence the cost for the condenser and heat rejection system of the total flow plan is from:

$$\left(\frac{1.1875}{1} \right)^{0.6} = 1.109,$$

$$\text{to } \left(\frac{1.2308}{1} \right)^{0.6} = 1.133$$

times the cost of the condenser and heat rejection system of a flash-steam plant of the same net power output. That means an increase from 10.9% to 13.3% of the heat rejection system occurs if the total flow system is used.

Other Components

No flashers are required for a total flow system, hence, the cost charge for this component is -100%. This equivalent to -40% of the cost of "process mechanical (producer)" which is an input variable for the GELCOM model.

The gathering piping system for a total flow system involves two-phase transmission pipelines which are more expensive for each unit length but less in length than a flash steam system. Note that the current technology of a flash steam system requires separate steam lines and hot water lines. The effects of this on cost is rather difficult to estimate because the design of two-phase transmission pipelines is nowhere near being an established procedure. For this reason it can only be assumed a cost reduction of, say, 10 to 20% for this component here.

Two-phase turbine requires special design and much testing before it can be commercialized. It is also expected that the first commercial unit, if it can reach commercial stage, would be expensive and that cost would be reduced for subsequent units. The basic operational problems of a two-phase turbine are the erosion due to suspended solids and liquid droplets, and scaling due to silica content of the brine. The erosion problems can be partially overcome by using properly selected or suitably developed materials for nozzles and turbine blades. These materials must have high strength and toughness to withstand the impingement of solid and liquid particles presented in the steam-brine mixtures, and therefore, more costly than those materials used in conventional steam turbines of a flash

Optimistic Case:

Turbine: $0.18 \times 60\% = 10.8\%$

Heat Rejection: $0.13 \times 10.9\% = \underline{1.4\%}$
12.2%

Pessimistic Case:

Turbine: $0.18 \times 180\% = 32.4\%$

Heat Rejection: $0.13 \times 13.3\% = \underline{1.7\%}$
34.1%

Summary

The cost changes for a total flow system when compared with a conventional flash steam system area summarized as follows:

	Pessimistic	Optimistic
1. Number of production wells	- 2.0%	-15.0%
2. Number of injection wells	- 2.0%	-15.0%
3. Capital Cost of Condenser and Heat Rejection System	+13.3%	+10.9%
4. Utility General O&M Cost Factor	+34.1%	+12.2%
5. Capital Cost of Turbine Generator*	+ 6.0%	+ 3.0%
6. Capital Cost of Gathering System	-10.0%	-20.0%
7. Capital Cost of Producer Process Mechanical Items	-40.0%	-40.0%

* Turbine cost is assumed to be 60% of Turbine-generator cost.

REFERENCE:

1. David G. Elliott, "Comparison of Brine Productions Methods and Conversion Processes for Geothermal Electric Power Generation," Reports of Environmental Quality Laboratory, California Institute of Technology, July 1975.
2. Russel James, "Second-Generation Geothermal Power," New Zealand Engineering, 23 (6), 298, 1968.

16.0 ROTARY SEPARATOR

Project Code

2410

Project Title

Geothermal Rotary Separator

16.1 Identification of Impacted Parameters

The rotary separator will make more thermal and hydraulic energy available for conversion to mechanical energy by reducing the energy lost in the water-steam separation process (flashing). This will result in a reduced requirement of production wells as well as injection wells. The replacement of flash tanks and gravity separators by the rotary separator will lower the plant capital costs. The plant O&M costs are expected to go up due to the installation of rotary separators in place of static equipment.

The following system parameters are expected to be impacted by this subelement:

1. Number of production wells
2. Number of injection wells
3. Capital cost of the plant
4. O&M cost of the plant.

16.2 Estimation of Primary Benefits

Based on the estimates in reference 1, the two stage dual steam system with a rotary separator/expander will utilize 68 percent of the energy available in the fluid, compared to 53 percent for a conventional two-stage flash steam system with flash tanks.

16.2.1 Production and Injection Wells

Because more energy is drawn from each unit of fluid, for a fixed plant size (50 MWe), less fluid is required. Consequently fewer production and injection wells are needed. Ideally, the number of wells is reduced in proportion to the increase in utilization, or by a factor of $(68 - 53)/68$, equivalent to 22.1 percent. There will be additional losses due to the rotational motion of the expander. If we assume these losses reduce the incremental useful energy by a factor of 0.9, the change in mass flow and well number becomes $-22.1 \times 0.9 = 19.9$ percent, which we round to 20 percent (optimistic estimate) for convenience in later computations.

In the pessimistic case, the utilization efficiency assumed to be only 90 percent of the ideal case, and therefore is $68 \times 0.9 = 61.2\%$

and the change in well number including the above mentioned losses, becomes:

$$0.9 \times \frac{61.2 - 53}{61.2} = 12\%$$

16.2.2 Plant Costs

The effects on the plant of adding the rotary separator to the conventional steam plant will be to replace the flash tanks and gravity separators, reduce the size of the main turbogenerator, and reduce the number of reinjection pumps. The added cost of the rotary separator, including the attached electric generator, will be about \$300/kWe initially and about \$200/kWe (mid-1978 dollars) in commercial production.*

Table 16-1 shows a capital cost summary for a conceptual design for a 50_eMWe (net), 59.1 MWe (gross) dual flash geothermal electric plant. (2) To simplify calculations, the estimates cost of the rotary separator is converted to late-1975 dollars, assuming inflation of 8 percent for 2.5 years; the separator cost per kWe is then \$248 initially and \$165 in production, including the attached operator.

The gross capacity of the turbogenerator set is 59.1 MW_e, with 9.1 MW_e used internal to the plant and to drive injection pumps. Of this gross power requirement, the rotary separator will provide 59.1 x 0.20 = 11.8 MW_e, so the main turbogenerator, and its associated equipment will have to provide only 59.1 - 11.8 = 47.3 MW_e. Working from Table 13-1, eliminating the flash tanks, and assuming a size/cost scaling factor of 0.6, the resulting mechanical equipment cost is

$$(16,590 - 290) \cdot \left(\frac{47.3}{59.1} \right)^{0.6} = \$14,262k.$$

To this must be added the cost of the separator, equal to 11.8 x 165k = \$1,947k, for a total mechanical equipment cost of \$16,210k. This represents a reduction in the overall cost of these types of equipment of 2.3% (optimistic estimate).

The GELCOM model disaggregates these items into accounts labeled: Turbine Generator, Process Mechanical, and Condenser and Heat Rejection Equipment. Without showing the calculations, the percentage change in each of these accounts is estimated to be:

* These costs were given by the contractor, Mr. Lance Hays of BiPhase Energy Systems, Research Cottrell, Santa Monica, CA.

Table 16-1

CONCEPTUAL CAPITAL COST ESTIMATE SUMMARY
 50MWe (NET) GEOTHERMAL POWER PLANT
 HEBER, CALIFORNIA⁽²⁾

	INSTALLED COST ⁽²⁾ (\$1000)	PERCENT OF TOTAL
Mechanical Equipment	16,590	58%
Turbine-Generator (59.1MWe	10,690	37
Flash Tanks Gross)	290	1
Condensers	1,070	4
Cooling Tower	1,690	6
Pumps and Drives	2,420	8
Auxiliary Systems	430	2
Piping and Instrumentation	5,230	18
Piping, Valves and		
Insulation	4,180	15
Instrumentation and		
Controls	1,050	3
Electrical	2,840	10
Distribution Equipment	1,240	4
Cable and Raceways	1,070	4
Lighting and Miscellaneous	530	2
Civil/Structural	3,940	14
Turbine Building	1,910	7
Site Improvements	330	1
Concrete and Earthwork	1,700	6
Field Construction Cost	28,600	100%
Engineering Services	3,400	
Allowance for Uncertainty	5,200	
Total Installed Cost	37,200	

(1) From reference 2.

(2) Fourth quarter 1975 \$

Turbine Generator (including Separator): + 5.7%
 Process Mechanical (less Flash Tank) : - 20.6%
 Condenser and Heat Rejection Equipment : - 12.5%,

for the optimistic case.

In the pessimistic case, the mass flow in the system is estimated to be reduced by 12.0%. The rotary separator then provides $59.1 \times .12 = 7.1$ MWe, and the turbogenerator is reduced in size to $59.1 - 7.1 = 52.0$ MWe. Calculating as for the optimistic case, but using \$248/KW for the separator cost, the derived changes for the GELCOM accounts are:

Turbine Generator (Including Rotary Separator): + 9.1%
 Process Mechanical (less Flash Tanks) : -16.0%
 Condenser & Heat Rejection Equipment : - 7.3%.

In this case, for reference purposes, the total mechanical equipment cost is estimated to be \$16,856K, an increase of 16% relative to the same portions of the conventional plant.

Effects on reducing the number of reinjection pumps are included in the "Process Mechanical" accounts above. O&M costs are assumed to remain the same.

16.2.3 Summary of Impacts (Flash Steam Plants)

	Optimistic	Pessimistic
1. Number of Production and Injection Wells	-20.0%	-12.0%
2. Turbine Generator Capital Cost	+ 5.7%	+ 9.1%
3. Process Mechanical Capital Cost	-20.6%	-16.0%
4. Condenser & Heat Rejection Capital Cost	-12.5%	- 7.3%

References

1. David G. Elliott, "Comparison of Brine Productions Methods and Conversion Processes for Geothermal Electric Power Generation," Reports of Environmental Quality Laboratory, California Institute of Technology, July 1975.

2. "Conceptual Design of Commercial 50 MWe (Net) Geothermal Power Plants at Heber and Niland, California," prepared by Bechtel Corporation, San Francisco, California for The Energy Research And Development Administration, July 1976.

17.0 HYBRID GEOTHERMAL/FOSSIL PLANT

Project Code

2403

Project Title

Hybrid Geothermal/Fossil Power Plants

17.1 Identification of Impacted Parameters

The impact of the successful completion of this project will be observed through the generation of additional power (over and above the power-on-line goals). This approach will require the assumption of a scenario for the development of hybrid geothermal fossil power plants. The benefits can then be estimated in terms of the additional electrical energy made available by the hybrid plants. The savings associated with the successful completion of the subelement will also occur in the form of reduced demand for fossil fuels, higher efficiency of utilization of geothermal energy and reduced environmental control costs for a given output of electricity.

17.2 Estimation of Benefits

This project is aimed at:

- (i) Making use of geothermal energy as a supplemental energy source for fossil fuel power plant, and
- (ii) Using some geothermal water as a substitute for the surface water used for industrial cooling.

The project, if successful, will confirm the usefulness of low temperature geothermal resources which have been found unsuitable for electricity generation.

Since the geothermal energy used in hybrid plants is additional to the output specified in the national geothermal energy scenario, the benefit of this project has to be estimated on the basis of an assumed scenario for the development of hybrid plants.

17.2.1 Scenario for Hybrid Plants

The first plant (City of Burbank) will be on-line in 1985. The subsequent increment is assumed to occur in 1992 (with an addition of 900 MW). The additional electrical energy generation is estimated below:

YEAR ON LINE	MW INSTALLED	GENERATION TO YEAR 2000 (Capacity factor = 0.8)
1985	100	$10^5 \text{ kW} \times 8760 \text{ Hrs/Yr} \times 0.8 \times 15 = 105 \times 10^8 \text{ kWh}$
1992	1000	$10^6 \text{ kW} \times 8760 \text{ Hrs/Yr} \times 0.8 \times 8 = 560 \times 10^8 \text{ kWh}$

The saving per unit of energy according to the City of Burbank, is 10% of the cost of electricity from the least expensive best fossil fuel fired power plants. The best cost is about 15 mills per kWh. The saving is, therefore:

$$\$0.015 \times 0.10 \times 665 \times 10^8 = \$99.75 \times 10^6$$

A low value of \$50 million can be assumed as pessimistic estimate. (The fact that the benefits are not discounted does not cause a serious error, because the impact of this counting is likely to be offset by the increase in the savings, in constant dollars, with the passage of time).

17.3 Degree of Success

The degree of success is expected to be 0.50 for this project because it involves a new concept which has yet to be proven. As such it has many institutional and technological problems which must be identified and solved.